GREENHOUSE GAS REDUCTION IN MARYLAND:

NEW STATE-LEVEL STRATEGIES FOR CHANGING TIMES
Preface

This report was prepared as part of the environmental policy workshop at the School of Public Policy of the University of Maryland. The environmental policy workshop is a course in the masters degree program of the School. Each masters student devotes a full semester of course work to the study of an important public policy issue. In the spring of 2013 there were eleven students studying policy issues relating to the efforts of the State of Maryland to curb its emissions of greenhouse gases, including in part through its participation in the Regional Greenhouse Gas Initiative (RGGI). The combined efforts of these students amounted to more than 1,000 hours, including review of the literature, meetings with experts, and other methods of study. The environmental policy workshop is supervised by Professor Robert H. Nelson of the environmental policy program of the School of Public Policy.

The Executive Summary presents the principal findings, conclusions and recommendations. The report is available on the web at http://faculty.publicpolicy.umd.edu/nelson/pages/static-publications.

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EXECUTIVE SUMMARY

Since the United Nations Conference on Environment and Development in 1992 – the Rio Summit -- the efforts of the world to address the problem of accumulating greenhouse gases (GHGs) in the atmosphere of the earth have largely taken a “top-down” approach. The Kyoto Protocol in 1997 exemplified this approach, setting specific future GHG emission targets for the United States, Japan, the European Union and other developed nations. Although no targets were set for China, India, Brazil and other developing nations, the expectation was – and the long run success of the Kyoto approach required – that such nations would eventually also agree to limit their GHG emissions to specific acceptable total levels.

By 2013, more than twenty years after the Rio Summit, it has become apparent that such a top-down strategy has significant limitations. Not the least is that there seems to be no prospect of a world agreement that would allocate specific acceptable levels of total GHG emissions among all – or even the key emitting -- nations of the world. Developing nations are in particular unwilling to make binding commitments in international negotiating forums concerning their future total greenhouse gas emissions. They fear that such commitments might become too costly in terms of limiting their ability to catch up with the economically more advanced nations of the world in their future levels of economic development.

In the United States, despite considerable optimism in 2009, and the approval of the Waxman-Markey bill in the House of Representatives, it was never voted on in the Senate. There is little prospect at present of national legislation to address greenhouse gas emissions. In the absence of Congressional efforts, the Obama administration is taking various actions under its executive authority, most importantly announcing proposed regulations in September 2013 to control greenhouse gas emissions from new power plants and confirming plans to develop regulations for existing power plants, acting under the authority of the Clean Air Act. The necessity to move forward under executive authority alone, however, limits the range of actions available to EPA and raises the possibility of significant legal challenges to the proposed EPA regulations for new power plants.

The failures thus far to take more decisive GHG reduction actions at the international and national levels have caused some people to despair that no practical solution might be available to the world to slow the rapid growth of levels of GHGs in the earth’s atmosphere. There is another possibility, however, one that is showing increasing promise, even as it has attracted less worldwide attention. It is possible that GHGs emissions can be controlled by a “bottom-up” strategy. Rather than requiring a full set of national binding commitments made in international negotiations, individual governing jurisdictions – in some cases below the national level -- might make voluntary commitments to reduce their future GHG emissions. If enough jurisdictions take such actions, the cumulative impact on world GHG emissions could be substantial. Maryland is one such jurisdiction that might be a participant in such a collective worldwide voluntary effort.
These voluntary commitments, moreover, might take the form of a number of separate jurisdictional GHG “cap and trade” systems – as Maryland has already done in joining the Regional Greenhouse Gas Initiative (RGGI) in 2007. Building on such separate steps, individual cap and trade programs in different jurisdictions might then voluntarily agree to “link” their programs, effectively creating in this fashion a larger area of an integrated GHG cap and trade system. If such processes continued over a period of time, the integrated areas might eventually expand to include multiple subnational regions, multiple full nation states and conceivably even extend to include participating jurisdictions from different continents.

Such a voluntary decentralized approach moved a large step forward with the commencement of operations in January 2013 of a GHG cap and trade system in California. This system is one part of California’s overall strategy for implementing its Global Warming Solutions Act of 2006 (AB32) which requires California to reduce its GHG emissions to 1990 levels by 2020 -- this amounting to a 25 percent reduction in California GHG emissions (a 15 percent reduction from 2009). California will pursue this objective through various means including reducing its dependence on fossil fuels and investing in energy efficiency and clean energy technologies.1 The California GHG cap and trade program will be the second largest in the world after the Emissions Trading System (ETS) of the European Union (EU) which commenced operations in 2005. In 2013 California and Quebec agreed to combine their cap and trade systems to create one integrated system, illustrating the potential for such integration across national boundaries and between subnational jurisdictions separated by large physical distances.

Internationally, seven GHG pilot cap and trade systems are under design in China and expected to begin operations soon at the provincial and municipal levels. The first of these, the Shenzhen Carbon Exchange, opened in 2013 covering 635 companies that produced 38 percent of the city’s total GHG emissions in 2010. Plans for the Shanghai and Beijing exchanges have also been moving forward rapidly. The Beijing exchange has a target for a 40 percent cut in GHG emissions from 2005 levels by 2020. A writer for Slate observed in May 2013 that “in almost every way you cut it, China is already taking a much more aggressive approach toward climate change than the United States is.”2

Maryland’s Greenhouse Gas Strategy

Maryland is the source of 1.5 percent of total U.S. GHG emissions. 3 In 2007, Maryland joined with nine other mid-Atlantic and Northeast states to form the Regional Greenhouse Gas Initiative (RGGI) that established a regional cap and trade system for these states, the first such cap and trade system in the United States. RGGI was reduced to nine states with the withdrawal of New Jersey as announced by Governor Chris Christie in 2011. RGGI now consists of Maryland plus Delaware, New York State, Connecticut, Massachusetts, Vermont, New Hampshire, Rhode Island and Maine. Unlike California, whose new cap and trade system covers most sources of GHG emissions, the RGGI cap and trade system is limited to carbon dioxide (CO₂) emissions from the electric power sector. Total RGGI emissions of CO₂ in 2010 were 7 percent of total U.S. CO₂ emissions (a much smaller share than the 16 percent of the total U.S. population living in the RGGI member states, reflecting various distinctive economic, political and geographic features of these RGGI states).
The RGGI cap and trade system commenced operation in 2008 with the first auctions of CO₂ emission permits – RGGI having decided that such permits would be made available almost exclusively by auction, unlike the grandfathering of significant numbers of free permits in California, the EU ETS, and most other cap and trade systems. New York State CO₂ emissions in 2010 were the largest share, 41 percent of the total RGGI emissions from all CO₂ sources. Maryland CO₂ emissions were the second largest, 17 percent of the RGGI total.

In 2009, Maryland enacted the Greenhouse Gas Reduction Act (GGRA) that set a target of a 25 percent reduction in total Maryland GHG emissions by 2020, as compared with 2006 levels. GGRA required that Maryland issue a draft plan in 2011 and a final plan by December 2012 (not actually released until July 2013) for achieving the targeted 2020 GHG reductions. The Act did not create new state authorities or provide new funding for implementing the final Climate Action Plan (CAP).

Another legislative action with important implications for GHG outcomes in Maryland, most recently modified in 2008, sets a renewable energy portfolio standard for the state’s electric power sector. According to this law, 20 percent of Maryland’s power is to be derived from renewable sources by 2022, including at least 2 percent from solar sources.

**Maryland GHG Emissions**

Maryland emissions of CO₂ peaked in 2005 at 83.9 million metric tons of CO₂, falling to 70.5 million in 2010, a large decline of 16 percent. In this respect Maryland substantially exceeded the national average decline in CO₂ emissions over this period, equal to 6 percent for the United States from 2005 to 2010. As of 2012, total U.S. greenhouse gas emissions from all sources had fallen by 7 percent from 2005, even as most other developing nations around the world such as China and India were experiencing large GHG increases.

Maryland emissions of CO₂ per capita in 2010 were only 12.3 metric tons, well below neighboring Pennsylvania (20.3 metric tons per capita) and the U.S. national average (18.2 metric tons per capita). Maryland in 2010 also had a low level of CO₂ emissions per unit of state gross domestic project (GDP), equal to 266 metric tons of CO₂ per million dollars of GDP, compared with 507 metric tons in Pennsylvania and a U.S. national average of 430 metric tons. Maryland’s low level of CO₂ emissions for the size of its population and economy partly reflects the fact that Maryland imports about 30 percent of its electric power – among the highest such percentages in the nation -- from surrounding states such as Pennsylvania and West Virginia where the resulting CO₂ emissions instead count as part of their CO₂ emission totals. As discussed below in Chapter 6, this constitutes an important form of “leakage” that needs to be addressed by Maryland in its GHG policies.

Maryland also obtains a high percentage of its electric power – 32 percent compared with a U.S. national average of 20 percent – from nuclear power, specifically the Calvert Cliffs nuclear facility within the state. This heavy reliance on nuclear power partially counteracts the fact that about 55 percent of Maryland’s in-state power production is at present coal-fired, well above the national average, and only 7 percent of its power comes from natural gas, well below the national
average. Generation of electric power from coal yields about twice the amount of CO₂ per unit of energy, as compared with natural gas. There is a concern that the production and use of natural gas may nevertheless result in significant releases of methane, thus partially cancelling the combustion advantages for CO₂. As of September 2013, research results released by the Environmental Defense Fund suggest that this concern may not be as large as feared.

Interestingly, California, the only other place besides RGGI in the United States with a GHG cap and trade system at present, also shares some of these GHG emission characteristics that differ significantly from much of the rest of the nation. CO₂ emissions in 2010 in California were 9.9 metric tons per capita, only 54 percent of the U.S. national average, while California emissions per million dollars of GDP were 213 metric tons, only 50 percent of the U.S. national average. California is also similar to Maryland in importing a large percentage of its electric power (both around 30 percent) which is not counted in “California” (or “Maryland”) as part of in-state GHG emissions. California differs significantly from Maryland, however, in that it relies heavily on natural gas for in-state power generation (45 percent) and has almost no in-state power generation from coal. It is perhaps surprising that two areas of the United States that contribute among the lowest GHG emissions per capita and per unit of GDP have been among the most aggressive in pursuing further GHG reductions.

Maryland has a lower level of CO₂ emissions from its industrial sector as a proportion of total state CO₂ emissions -- equal to 6 percent for Maryland in 2010, as compared with 15 percent from industrial sources in Pennsylvania, for example, and a U.S. national average from such sources of 17 percent. Maryland in-state emissions from its electric power sector are also relatively lower as a proportion of total Maryland CO₂ emissions, equal to 35 percent in 2010, as compared with 47 percent in Pennsylvania, and a national average of 40 percent (partially reflecting, as noted above, Maryland’s large reliance on nuclear power and its large imports of power from other states).

Balancing things out, Maryland CO₂ emissions from the transportation sector are proportionately higher, equal to 42 percent in 2010, as compared with 26 percent in Pennsylvania, and a national average of 33 percent. Unlike California, however, the transportation sector is not included in the RGGI cap and trade system. Maryland has not enacted any legislative cap or other officially binding target of its own for the transportation sector.

Ineffective Maryland Policies

Like the United States in total, Maryland has been seeing significant reductions in GHGs since 2005 but this GHG outcome has had little to do with Maryland GHG policies. The leading influences on Maryland GHG trends have been exogenous economic developments, including especially the national economic downturn of 2008 and 2009 and the subsequent persistence of high unemployment and other adverse economic outcomes. A second key economic factor has been the rapid increase in the supplies of natural gas as a result of the spread of fracking methods of gas extraction, and the sharp declines in the price of gas, resulting in significant shifts in electric power production from coal to less GHG intensive gas. Warmer weather has also been a contributing factor in reducing heating energy requirements.
Although Maryland joined RGGI in 2007, as mandated by the Healthy Air Act in 2006, RGGI has had little impact on GHG levels in Maryland and the other RGGI member states. As noted above, Maryland (along with RGGI in total) experienced a sharp decline in CO\textsubscript{2} emissions from 2005 to 2010, a trend that had not been anticipated in setting the original RGGI cap. By 2010, the RGGI cap substantially exceeded the total CO\textsubscript{2} emissions from the electric power sector within the RGGI states.

As a result, as discussed further in Chapter 5 below, from 2010 to 2012 large numbers of CO\textsubscript{2} emission allowances offered in RGGI auctions went unpurchased. Lacking any competition for allowances, those that were sold went for the minimum acceptable price of less than $2.00 per ton of CO\textsubscript{2} emissions, established as part of the RGGI auction procedures. Even many of the sold allowances were not actually used immediately, resulting in the accumulation of a large bank of unused allowances that could be carried over to future years.

RGGI took three years to respond to this problem but in February 2013, Maryland and the other RGGI states agreed to a reduction of the RGGI cap by about 45 percent, from 165 million tons of CO\textsubscript{2} to 91 million tons per year. At the first RGGI auction under the new cap in March 2013, there was now a scarcity of allowances, competitive bidding occurred for the first time since 2009, the allowance price rose above the minimum acceptable bid, and all allowances offered were sold. While this was an important step forward, RGGI still confronts a large inventory of past “banked” allowances and other issues that may limit its future impacts on total Maryland and RGGI CO\textsubscript{2} emissions from the utility sector.

While the Healthy Air Act required Maryland to join RGGI, it had other consequences that in retrospect have proved counterproductive with respect to GHG emissions in Maryland. The principal purpose of the Healthy Air Act was to significantly reduce the emissions of NO\textsubscript{x}, SO\textsubscript{2}, and other conventional pollutants from existing power plants (in Maryland mostly nuclear or coal-fired). The 2006 Act proved to be very successful in this regard, inducing Maryland power producers by 2010 to spend about $5 billion to retrofit expensive new pollution controls on their coal fired plants. As shown in Chapter 1, emissions of NO\textsubscript{x} and SO\textsubscript{2} have fallen sharply, benefiting the health of Maryland citizens.

Unfortunately, controlling GHG emissions from coal power plants would require use of methods of carbon capture and sequestration. At present, such methods are still in a developmental phase and would in any case be difficult or impossible to employ for an existing – as opposed to a new – coal fired power plant. Hence, the GHG emissions from Maryland coal fired power plants were not affected by their large capital spending on conventional pollution controls in response to the 2006 Act (and RGGI, as noted, has not itself had much impact).

In other states, the national EPA has been increasingly requiring similar actions to reduce conventional air pollutants from existing coal-fired power plants. Many electric power producers have been shutting down coal-fired power plants, rather than making large expenditures to retrofit these plants with pollution controls, and instead making greater use of natural gas for power production (either by using existing natural gas power plants more intensively or by building new gas fired plants). This has a significant environmental advantage
as compared with retrofitting pollution controls on existing coal-fired plants in that it achieves all
the environment gains with respect to conventional air pollutants and, in addition, results in
significantly lower emissions of GHGs (about half the level of coal per unit of power produced).
The shift to natural gas power generation has been an important factor in the significant overall
reductions in GHG emissions in the United States since 2005.

Because Maryland was an early actor in terms of retrofitting coal-fired power plants, there was
less awareness at the time of the potentially very large supplies of shale gas and the possibility of
resulting sharp reductions in natural gas prices. Maryland in this respect may have simply made
an understandable mistake, as matters have turned out in retrospect. If it had acted later, there
might have been greater encouragement for gas-fired power. Yet, despite the large
environmental advantages of natural gas, Maryland has continued to be surprisingly reluctant to
consider GHG reduction strategies that involve shifts to gas-fired power generation. It excluded
consideration of such strategies, for example, in its recent July 2013 Final Plan for GHG
reductions to meet the 2020 requirements of the 2009 GGRA. Maryland has also moved slowly
in terms of setting in place the necessary environmental controls for the responsible production
of natural gas from shale within Maryland itself.

Electric power is not the only area in which emissions of GHGs in Maryland have been a
secondary consideration. In the development of Maryland transportation policies, as explored in
Chapter 3, impacts on GHGs have not been the central goal. The main objectives have been to
improve the ease of travel of Marylanders throughout the state, to curtail vehicle congestion, and
to achieve land use goals such as higher densities of residential and commercial development.
Unlike California, transportation is not included in the RGGI cap and trade system for
controlling GHGs. Maryland has not thus far taken other significant actions in its transportation
policies to reduce GHGs. The most important recent actions affecting future GHG emissions in
the Maryland transportation sector have been taken by the federal government, notably the
increase in corporate fuel economy standards to 35 miles per gallon for light duty vehicles by
2016 and to 54 miles per gallon by 2025 (and similar increases for heavy duty vehicles).

One of the most cost-effective ways to limit GHG emissions is to achieve greater energy
efficiencies in the use of fossil fuels, thus reducing their total consumption and the associated
emissions of GHGs. Maryland in 2008 enacted the EmPOWER Maryland Energy Efficiency
Act, establishing a goal of a 15% reduction in per capita energy consumption and per capita peak
energy demand by 2015, compared with a 2007 baseline. Utilities are responsible for 10% of
the 15% reduction in per capita electricity use by 2015 under the Public Service Commission’s
direction, while the Maryland Energy Administration (MEA), the Department of Housing and
Development, the Department of General Services, and other private and public interests have
responsibility for the remaining 5% of reductions.

As discussed in Chapter 4, however, Maryland partially undercut this effort by diverting the
Maryland share of revenues from RGGI auctions from the achievement of greater state energy
efficiency (the stated purpose of the revenues) to providing support for low-income Maryland
residents in paying their electric power bills. While Maryland has been making good progress in
achieving greater energy efficiencies, the impact of public legislative and other actions has been
limited.
Another legislative action with a significant potential to impact future Maryland GHG emissions was the enactment of a Renewable Portfolio Standard (RPS), most recently revised by the state legislature in 2008. At present, as noted above, the Maryland RPS requires that 20 percent of Maryland electric power must come from renewable sources by 2022, including a minimum of 2 percent from solar sources. The 2011 report of the environmental policy workshop at the Maryland School of Public Policy identified a number of weaknesses that made it unlikely that this RPS goal would be achieved. Rather than actual GHG reductions, emitters of GHGs in Maryland may find that it is more economical to purchase “alternative compliance payments” that substitute money penalty payments in lieu of the GHG reductions that would otherwise be required. In March 2013, Maryland sought to increase the likelihood of success by enacting legislation to support the building of a 200 megawatt offshore wind farm for which Maryland would assume GHG credit responsibility. Significant doubts, however, remain as to whether this wind farm will be built under the terms of the new legislation. Other steps to improve the workings of the RPS program (a number of them explored in the 2011 workshop report) have since been proposed by the State, but remain to be implemented.

As of this writing in September 2013, the 25 percent GHG reduction target by 2020, as contained in the Greenhouse Gas Reduction Act of 2009, has had little impact on GHG emissions in Maryland. The GGRA sets no penalties for a failure to meet its goals. It does not establish new legal or budgetary mechanisms in Maryland designed to ensure compliance with the 2020 GHG target.

As discussed in Chapter 2 below, the draft GGRA plan as issued in 2011 consists largely of a compilation of policies and actions that various state agencies and other governmental bodies in Maryland had already established or proposed. The 2011 draft Climate Action Plan then estimated how much these actions – if implemented – would contribute to Maryland GHG reductions by 2020, optimistically concluding that they would be sufficient to meet the 2020 GGRA target. However, in a number of cases full implementation of assumed CAP programs is unlikely.

Despite the statutory deadline of December 2012, the final GGRA plan was not issued until July 2013. It suggests various steps for enhanced GHG reductions in Maryland, again projecting that, if these steps are taken, Maryland will meet its target of a 25 percent GHG reduction in 2020 from 2006 GHG emission levels. Most of the future GHG reductions estimated from 2013 to 2020 are due to measures expected to be adopted outside the context of the GGRA plan. Since this still leaves a shortfall below the 2020 GHG target, various additional “enhanced” actions are suggested in the latest July 2013 plan. No funding estimates or expected sources of funds are provided, however, nor are specific timelines for implementation proposed. Some key suggestions for enhancements would require state legislative action, although that is an uncertain possibility. As compared with California, for example, Maryland has failed to provide the levels of planning resources, funding, implementation deadlines, legal authorities and other actions required to set Maryland on a firm course towards a 25 percent GHG reduction by 2020.

By comparison, the 2010 plan released by EPA for cleaning up the waters of the Chesapeake Bay by 2025 – the Chesapeake Bay “TMDL” – included interim pollution reduction targets,
requirements for followup development of implementation plans at state and local levels, two year milestones for more detailed plan implementation measures, and a system of monitoring of the compliance with these two-year milestones. The Bay water quality planners were responding in part to past failures to meet nutrient pollution reduction targets that had been set for the Bay for 2000 and then for 2010. Learning from these experiences, they revised their planning procedures to require the above more detailed planning and implementation procedures. Maryland should apply these same lessons to the development of its GHG reduction plan for 2020 (and other future dates).

**Getting Serious About GHGs in Maryland**

Maryland’s actions to date might be seen as calling into question the actual seriousness of the State’s intentions to pursue GHG emission reductions. It will be assumed below, however, that the passage of the Greenhouse Gas Reduction Act in 2009 offers a genuine indication of the collective commitment of Maryland leadership and the citizenry – that the State of Maryland is in fact willing to make serious efforts to reduce Maryland GHG emissions, even when some additional costs inevitably will be incurred and other potentially politically difficult steps may have to be taken.

Maryland can take actions to reduce GHG emissions in three general ways. First, Maryland can implement its own in-state policies that result in GHG reductions occurring within the state itself (or by addressing leakages of GHGs occurring elsewhere that result from activities occurring within Maryland). Second, as a member of RGGI, Maryland can work with other RGGI member states to reduce their collective total GHG emissions, and thereby directly and indirectly Maryland’s GHG emissions. Third, Maryland can work with EPA and other federal agencies to reduce total GHG emissions nationwide, thus again directly and indirectly reducing Maryland’s own GHG emissions. Part I, Part II, and Part III of this report explore alternative actions and roles for Maryland in each of these three areas, respectively, and offer recommendations for future actions.

This report is informed by a vision that, as described above, there is not likely to be a world agreement soon to replace the Kyoto Protocol with a similar set of national GHG quotas that would now have to be extended to include China, India, and much of the rest of the developing world. Actions to control GHG will instead have to be taken at the national and the subnational levels, based on voluntary agreements at these levels. Maryland is among the many jurisdictions currently having to decide on the form of its participation in such a new decentralized strategy for greater worldwide GHG reductions.

It is acknowledged that such voluntary agreements may not serve the immediate narrow economic interests of each of the participating parties. According to a traditional interpretation of economic analysis, the “free rider” problem will make it difficult or impossible for large groups of separate parties to achieve collectively desired and beneficial results. In practice, however, the world is filled with collective actions that have surmounted the free rider problem based on a concern for future human welfare and other ethical considerations. As discussed above, several Chinese municipalities and provinces, the State of California and a number of other jurisdictions in just the past year have taken voluntary actions on their own to address the
problem of world GHG emissions. Maryland has the opportunity of joining with this group in
its own state efforts to reduce GHG emissions.

Key Recommendations

The key recommendations of the report are described below. Additional narrower
recommendations are developed in each chapter, as also listed below as part of this Executive
Summary. It is recognized that these recommendations vary considerably in their immediate
political viability. With strong Maryland leadership, the prospects for near term implementation
of some of the recommendations would be good. In other cases, more novel actions are
recommended whose benefits would have to be better understood and appreciated in Maryland
and elsewhere before their implementation would be likely. In still other cases, the costs of
implementation might be high enough that a more complete assessment of budgetary and other
economic priorities within Maryland would be required before full implementation might
become possible.

Part I -- GHG Reduction Actions Internal to Maryland

A Maryland “Greenhouse Czar” – Reducing greenhouse gases is such a challenging problem
for any state or other governing jurisdiction because it requires basic changes in the energy
sector, land use, and other matters fundamental to the workings of the economy. Orchestrating
such a set of changes is, to say the least, a challenging task. It requires, among other things,
careful economic analysis and planning; systematic evaluation of alternative policy and program
areas; coordination of the actions of various state administrative bodies; establishment of
appropriate legal authorities; and the commitment of the necessary funding. Maryland does not
at present have the institutional capacity to effectively accomplish such a strategy. It needs a
central GHG policy making and coordination point within state government with greater
authority to develop and implement the ambitious GHG reduction targets set by the state in 2009.
The head of this body might be described as a new Maryland “greenhouse czar.”

Act of 2009 has a limited ability to impact GHG emissions in Maryland because it lacks
penalties for failure to meet its targets; does not create new authorities; does not provide new
funding; includes only vague requirements for the development of GHG reduction plans; lacks
detailed implementation steps and timelines; and does not establish any other implementation
and enforcement mechanisms. A new GGRA is needed to address these problems, learning in
part from the planning and implementation strategies incorporated into the 2010 TMDL for the
cleanup of the waters of the Chesapeake Bay. A key provision would be the establishment of a
strong Maryland government greenhouse coordination and implementing body, as recommended
above.

Require GHG Impact Statements for Significant New State Actions -- A first step in
analyzing and implementing Maryland GHG reductions is to have a better understanding of the
GHG implications of current state policies and of alternative state plans and actions. State
agencies whose actions would have significant impacts on GHG emissions within Maryland
should be required to analyze and publish official estimates of those impacts and of alternative
ways of pursuing the same state objectives with fewer GHG emissions. Overseeing this process would be an important function of a new Maryland “greenhouse czar.”

**Take Greater Steps to Improve Maryland Energy Efficiency Including a New Law (Chapter 4)** – The lowest hanging fruit for achieving GHG reductions in Maryland is to improve energy efficiency. Maryland should redirect the funds received as Maryland’s share of RGGI auction revenues to their originally intended purpose – promoting improvements in energy efficiency in Maryland. First enacted in 2008, the final targets for the EmPOWER Maryland Energy Efficiency Act are for the year 2015, a date that will arrive soon. A new energy efficiency law is thus needed which sets new targets; commits greater funds for on-time monitoring and control of individual properties; provides for greater overall coordination of Maryland electric power use; encourages further actions to implement peak load pricing, and in general promotes stronger measures to improve energy efficiency in Maryland.

**Consider establishing a legal requirement that large GHG emitters in Maryland outside the electric power sector must achieve certain GHG emission standards. (Chapter 9)** Electric power producers in Maryland are required to hold allowances within the overall GHG cap set by RGGI. Unlike California, however, other large emitters of GHGs in Maryland – in particular in the transportation and industrial sectors – face no regulatory limitations on their emissions of GHGs. RGGI as a whole might follow the California example and extend its GHG allowance requirements to such additional sectors. Absence RGGI action, Maryland might act on its own to establish regulatory limitations on GHG emissions from such large facilities outside the power sector. As analyzed in Chapter 9, this could be done in two main ways. One alternative would set an emissions limitation for individual large GHG emitters in Maryland (including distributors of petroleum products) and allow the trading of emission credits among such emitters. A second alternative would be to establish a full fledged cap and trade system limited to large GHG emitters in Maryland (again, outside the power sector). If other RGGI states followed this approach, a wider cap and trade system encompassing these states as well might be formed to extend beyond the power sector. Under these alternatives, it might be possible to purchase offsetting credits from sources outside Maryland (as RECs can now be purchased outside Maryland to comply with the Renewable Portfolio Standard).

**Part II – Encouraging Improvements to RGGI**

As one of the RGGI member states, Maryland participates in RGGI decision making and can seek to encourage improvements in RGGI as part of its wider Maryland GHG policy role.

**RGGI Should Enter into Discussions with California and Quebec to Explore the Possibilities for a Common Harmonized Cap and Trade System (Chapter 7)** – Increasing the geographic area of a cap and trade system increases the number of possibilities for making GHG reductions and hence the ability to find the least expensive actions, thus reducing costs and improving the overall efficiency of the system. California and Quebec have formally agreed to form one harmonized cap and trade system, as of January 2014. RGGI should enter into discussions with California and Quebec to explore the possibilities for forming a still larger cap and trade area with the objective to establish a combined harmonized system of RGGI,
California and Quebec. This will require reconsidering a number of existing RGGI methods of operation.

Set a Minimum Acceptable Bid in RGGI Auctions of $10 per ton of CO₂ (Chapter 5) – A necessary key step in harmonizing the RGGI cap and trade system with the California/Quebec system will be to establish a common minimum acceptable bid. The minimum bid in the California/Quebec system is now equal to about $10. If RGGI were to maintain its current minimum acceptable bid of about $2 per ton, this might undermine the California/Quebec efforts – depending on the size of the RGGI cap and the actual resulting auction prices (if the RGGI cap is tight enough, RGGI auction prices might exceed $10 per ton, whatever the minimum bid, and there would not be a problem). Ideally, the minimum bid should bear some relationship to the external costs to society of GHG emissions, estimated in some recent studies at about $20 per ton or more. The California minimum is thus closer at present to the social ideal than the RGGI minimum.

Raise the Maximum Allowance Price in RGGI Auctions to California Levels (Chapter 5) – Cap and trade systems may also set maximum sale prices for allowances as a form of insurance against what might be regarded as unacceptably large economic impacts. If the allowance price reaches such maximum levels, a supply of additional allowances will be made available sufficient to prevent further price increases. RGGI at present has a complicated system that will in effect annually raise the maximum sale price in its auctions from $4 per ton of CO₂ in 2014 to a level of $10 per ton in 2017. California’s equivalent maximum sale price is $40 or above, again posing a large barrier to harmonization of the two cap and trade systems. Moreover, if the new RGGI cap is tight enough to significantly impact GHG emissions, it will work to drive the price of RGGI allowances well above the planned RGGI maximums. Given RGGI’s low maximums, offering additional allowances for sale when the maximum price is reached will act to undermine the effectiveness of the RGGI cap (in effect, superceding it at that point). Even without the consideration of cap and trade harmonization with California/Quebec, therefore, the current very low RGGI price maximums are unworkable if RGGI is serious about setting caps at levels that bring about actual meaningful reductions in GHG emissions.

Consider Allocating Some Free Allowances within RGGI – If a much reduced RGGI cap, and a consequent much reduced level of GHG emissions in the RGGI member states, leads to large increases in RGGI auction prices, an alternative way of mitigating any potentially unacceptable economic impacts is to allocate at least some free allowances to electric utilities. As compared with a low maximum allowance price (such as the current RGGI policy), a suitable allocation of some free allowances has the advantage of offering a degree of economic relief while maintaining a high marginal cost of GHG emissions with its desirable economic incentive effects.

Adopt a RGGI System to Control Leakage of GHG Emissions from RGGI Member States to Adjoining non-RGGI States (Chapter 6) – Given the substantial imports of electricity of Maryland and some other RGGI states, and other ways in which economic activity might be diverted outside of the RGGI member states, there is a significant possibility for the “leakage” of GHG emissions from RGGI. California has established a system whereby power imports from out of state require the purchase of GHG allowances within its new cap and trade system.
RGGI’s circumstance is more complicated because of the multiple states and regional power grids involved but methods have been proposed – see Chapter 6 -- by which RGGI might also estimate leakages and require the purchase of RGGI allowances for these leaked emissions.

**Liberalize the RGGI Offset Policy (Chapter 8)** – In addition to purchases of allowances in RGGI auctions, another way of complying with RGGI emissions requirements is to allow the purchase of “offsets” in areas outside the boundaries of the RGGI member states. If these offsets are less expensive than allowances obtainable in RGGI auctions, overall compliance costs for the RGGI member states can be reduced. RGGI at present makes limited provision for offsets and, given the low price of RGGI allowances, offsets have never been used within RGGI. As RGGI allowance prices presumably rise in future auctions, however, this will make use of offsets more economically attractive. RGGI should review its offset policies and liberalize them to allow wider use of offsets in the future, coordinating with the offset policies adopted by California and Quebec.

**Study the Feasibility of Enlarging the Scope of RGGI to Include the Transportation Sector** -- Beginning in 2015, California will also include the transportation sector in its cap and trade system. In Maryland, transportation is a greater source of CO₂ emissions than the electric power (or any other) sector. Enlarging RGGI to include transportation would extend the full efficiency and administrative advantages of a cap and trade system to a much larger part of the RGGI member state economies. It would also facilitate harmonization of RGGI with the California/Quebec cap and trade system.

**Consider Implementing changes to RGGI’s Governance Structure** -- RGGI cannot adapt to changing circumstances or modify its programs without consent from 9 states, a major barrier to program effectiveness in response to changing circumstances. California, in comparison, is able to adapt more quickly, since only one state is involved in decision-making (although the future linkage with Quebec may slow down that process). RGGI should seek an alternative mechanism for decision making that shifts decision-making power towards supermajority decision making but less than unanimous consent. RGGI administrators might also be given wider discretionary authority in at least some areas in implementation, thus speeding up the implementation process and putting technical issues in the hands of those with appropriate expertise.

**Consider Seeking Congressional ratification of RGGI as an interstate compact** -- RGGI has felt constrained in considering governance reforms and other administrative changes by the legal concern that this might be seen as an actual treaty compact among the RGGI states, and thus might not be constitutionally valid, unless blessed by Congress. This concern could be addressed by seeking formal Congressional approval for RGGI. There are many precedents in interstate water compacts and other formal agreements among states that could be drawn upon.
Part III – Encouraging EPA to Facilitate a State-Based GHG Reduction Approach in Implementing the GHG provisions of the Clean Air Act.

An additional important element of Maryland GHG policy making arises from Maryland’s participation in national discussions with EPA and other parts of the federal government relating to national policies and steps to reduce GHGs. Maryland should act in this role as well to promote better national GHG policies that will then have beneficial consequences for GHG reductions in Maryland and the nation.

Implement the Clean Air Act (CAA) to Allow States to Adopt Cap and Trade Systems as a Means of Compliance with CAA Requirements for Existing GHG Sources in the Electric Power Sector (Chapter 9). EPA in September 2013 announced final GHG regulatory requirements for new power plant sources of GHGs. The announced regulations would effectively limit new fossil fuel generation of electric power to natural gas, foreclosing new coal-fired plants as a possibility (unless carbon sequestration becomes much less expensive and more available in the short term that appears likely). EPA is now in the process of developing regulations for the much larger category of existing electric power sources of GHGs, including many existing coal-fired power plants. For the purpose of regulating such sources, the level of GHG emissions from any one source is not environmentally significant. It is the total of GHG emissions from all existing power (and other) GHG sources within a state (or region) that is the environmentally meaningful outcome. For the purposes of reducing this grand total of existing sources, a cap and trade system encompassing all GHG sources is an ideal method of implementation (the cap in effect setting the allowable grand total of all the existing sources within the geographic scope of the cap and trade system). If EPA allows participation of an existing power source in a GHG cap and trade system as a means of complying with the Clean Air Act, this would provide important encouragement for the wider voluntary creation of state and regional GHG cap and trade systems in the United States, in addition to the current California/Quebec and RGGI systems.

Encourage EPA to Develop a Method of Defining the Necessary “Stringency” of a State or Regional GHG Cap for the Purposes of Compliance with the GHG Requirements of the Clean Air Act (Chapter 10) -- The above proposed use of a cap and trade system as a means of CAA compliance for existing sources within the electric power sector would shift the regulatory issue from the acceptable emissions of any one existing GHG source to the acceptable size of the total GHG cap within which all the existing GHG sources in a state or region must fall. In order for EPA to adopt this regulatory approach, it must therefore have a means of determining an acceptable cap – a sufficiently “stringent” cap -- for purposes of CAA compliance at the state or regional level. This is a complex matter, as discussed in Chapter 10, involving various ways of assessing efficiency and equity. While no solution will be perfect, the problem is, however, potentially resolvable, likely involving a compromise among the various competing considerations.
INIDIVIDUAL CHAPTER SUMMARIES AND ADDITIONAL RECOMMENDATIONS

Chapter 1 – Introduction: Maryland Greenhouse Gas Emissions and Policies

Chapter 1 reviews Maryland’s energy landscape, greenhouse gas emission (GHG) trends, and other climate and energy related policies. Maryland ranks 39th nationwide in terms of energy intensity with less energy use per capita than most states, and had an energy use distribution of 30.2 percent residential, 29.9 percent transportation, and 29.5 percent commercial in 2010. For the electric power sector, Maryland imports about 30 percent of its electricity from surrounding states on the PJM network. Coal, supplying 60 percent of Maryland electric power as recently as 2007, has been the dominant source, although declining to 55 percent in 2010 and still further since then.


Under the Greenhouse Gas Reduction Act (GGRA), Maryland has established out an aggressive plan to decrease its GHG emissions. Enacted in 2009, the GGRA covers a broad range of sectors, and sets ambitious goals for achieving GHG reductions. However, the GGRA plan has several major problems that will work to limit its impacts. One problem is its optimistic assumptions about achieving reduction goals in each Maryland sector of the economy, without providing for much description of how these goals will be implemented, nor for flexibility and adaptation if progress towards the goals lags. The Climate Action Plan (CAP) is less of a strategic document containing Maryland programs that are specifically designed to reduce GHG emissions than an amalgamation of largely preexisting sectoral programs that often reduce emissions only incidentally. Little independent analysis has been conducted by Maryland in developing the Plan. Outside studies cast doubt on the ability of Maryland to achieve the GHG reduction goals for 2020 of the GGRA. Moreover, given the fact that the final CAP plan was not released until July 2013, this leaves a rapidly narrowing time window for implementing any reduction programs before the 2020 GHG deadline.

While the failure of Maryland to release a final CAP until July 2013 made it difficult for this report to assess in detail the adequacy of the final CAP, based on a review of the final CAP, the executive summary of the final CAP and other publicly available information, and on informal communications, the following recommendations are offered.

Chapter 2 Recommendations

1. The Climate Action Plan (CAP) should be based on more realistic assumptions. The CAP needs to make sure that its assumptions relating to target goals, rates of success expected, swiftness and effectiveness of implementation, and other key matters are all realistic. Alternative scenarios might be constructed to reflect the large degree of uncertainty that exists in some cases.

2. A CAP should fully assess what Maryland can, should, and is able to achieve in an economic manner. This might lead the state to reduce its reduction goals in some areas (like transportation) while increasing them in other areas (like conservation of electricity). Economic
factors will inevitably have a significant impact on implementation feasibility. Such factors should be explicitly explored in GGRA planning.

3. **A more scientific -- analytical -- approach to setting future GHG reduction goals should be adopted.** The current goal of a 25 percent reduction by 2020 apparently was somewhat arbitrarily set. Ideally, Maryland would consider the various opportunities it has for making GHG reductions and their benefits and costs. Based on such calculations (if necessarily of a rough nature), Maryland could establish future GHG targets that would be more analytically defensible.

4. **The cost-effectiveness of CAP programs should be a key concern in a revised Plan.** Some of the programs listed in the Climate Action Plan are of doubtful cost-effectiveness. This is likely the case for some transportation infrastructure projects such as significantly expanding mass transit service. Such programs can be enormously expensive, but deliver relatively small GHG reductions. Greater attention should be paid to lower cost, higher GHG emissions benefit programs such as fees or taxes which reduce driving.

5. **The CAP should take a broader, more strategic and long-term approach to GHG emissions reduction.** Rather than listing programs that have incidental emissions effects, the Plan should design sector emissions initiatives that can be integrated with and embedded in existing programs. For example, an emissions cap and trade program could be designed to be integrated with the Renewables Portfolio Standard.

6. **The CAP should make greater provision for adaptive management.** Inevitably, major surprises will occur in the process of implementing a plan involving so many parts of the economy as the Maryland strategy for GHG reduction. The planning and implementation process for GHG reduction must incorporate steps and procedures to allow for learning by doing as the implementation process moves forward.

**Chapter 3 – Transportation Policy and Maryland GHG Emissions**

The transportation sector in Maryland contributes the largest CO₂ emissions. Maryland is heavily dependent on highway modes for its transportation needs, both passenger and freight. Given the relative inefficiency of road transport in terms of energy and emissions for distance travelled, the automotive sector presents a large opportunity for GHG reductions. Chapter 3 presents a review of the various measures being proposed and undertaken within Maryland on a state, regional, and national level to reduce transportation GHG emissions. These include initiatives such as the revised national fuel economy standards, a regional low carbon fuel standard, various mass transit initiatives, new transportation technologies, and programs to reduce travel demand and shift travel to less carbon intensive modes.

**Chapter 3 Recommendations:**

1. **Study the possibilities for integrating emissions reduction programs more closely so that a more cohesive and robust GHG transportation strategy can be developed.** Many of the research reports examined in this chapter find that almost all of the policies employed to curb
transportation GHG emissions depend on other factors, and very often are most effective when employed as part of a package of options.

2. **Explore more fully options which were not included in the earlier Maryland Department of Transportation (MDOT) GHG report.** One of the biggest classes of programs not currently implemented or studied as part of the MDOT plan is taxes or fees which impose costs on driving. Given that many studies have concluded that these initiatives could potentially be quite effective at GHG emissions reductions, it would be worthwhile for Maryland to study them more seriously. The Final GGRA Plan in July 2013 recommends the adoption of pricing strategies (and includes the projected resulting GHG reductions in its estimates for 2020) but it is notably vague about the details of transportation pricing being proposed.

3. **Consider emphasizing longer term transportation strategies for reducing dependence on automobiles and related GHG emissions.** While many of the options for doing this, such as increasing rail service, have been shown to have relatively small short term effects on GHG emissions, there are still good reasons to begin a long term transition away from automotive transportation to less carbon-intensive modes, as well as potentially reducing transportation demand altogether. This will require large shifts of investments away from roads towards mass transit, rail, bicycling, and other more GHG efficient modes. It would also require a serious redesign of land use laws and procedures which would actually encourage compact development and mixed use so as to reduce travel demand overall.

4. **Consider integrating Maryland transportation programs into other climate programs, such as cap-and-trade.** Many transportation programs are implemented in isolation to one another, as well as in isolation from other GHG programs. Many of the fuel programs have credit trading regimes. These could potentially be integrated into the currently operating RGGI cap and trade regime. This might have the benefit of adding flexibility to both types of programs and allowing market forces to assist firms in using the most cost-effective means for reducing emissions in all pertinent sectors. This would also address the inherent interconnectedness of GHG emissions across sectors.

**Chapter 4 – Energy Efficiency and Maryland GHG Emissions**

The EmPOWER Maryland Energy Efficiency Act of 2008 utilizes a variety of programs to encourage energy conservation. The Public Service Commission has worked with five Maryland utilities, BGE, Delmarva Power, Pepco, Potomac Edison, and Southern Maryland Electric Cooperative (SMECO), to implement demand reduction programs to lower homeowners’ utility bills and energy use. The State is also making other efforts such as the EmPOWER Maryland Low Income Energy Efficiency Programs (LIEEP), which provide no-charge installation of energy-saving materials to low income homes, and the State Agency Loan Program (SALP), which provides zero interest revolving loans to support energy efficiency improvements in state facilities. Since 2008 Maryland has achieved significant reductions in per capita energy use, but much of this can be attributed to the economic downturn and mild weather.

The Maryland Energy Administration concludes that, if the economy improves over the next few years, the EmPOWER Act goals for energy consumption per capita goals for 2015 will not be
met. In terms of per capita peak demand, Maryland has exceeded the EmPOWER goals in place and will probably meet the 2015 targets, although more rapid economic growth than expected may alter this projection. To account for these short term successes and failures, Maryland has created “EmPOWER 3.0” to develop a plan for improvements to EMPOWER and to establish a framework for new potential legislation addressing goals beyond 2015. EmPOWER 3.0 calls for greater emphasis on cost-effectiveness and movement in the direction of commercial and industrial demand reduction.

**Chapter 4 Recommendations:**

1. **Increase Maryland funding for energy efficiency measures.** Spending on energy efficiency improvements offers many of the most cost-effective methods by which Maryland can take actions to reduce future GHG emissions. Improving energy efficiency should therefore be central to Maryland’s overall GHG reduction strategy. Attractive possibilities would include local energy efficiency initiatives such as through the Maryland Smart Energy Communities program; real-time pricing mechanisms for utilities; advertising of energy efficiency programs and products; greater use of smart grid technologies; increased implementation and enforcement of PSC utility demand reduction plans; and expanded subsidized loan or guaranteed loan programs for energy efficiency improvements.

2. **Commit more of the Strategic Energy Investment Fund (SEIF) revenues (obtained by Maryland from RGGI auctions) to energy efficiency programs, their original purpose.** Maryland has diverted much of the SEIF funds into subsidies for portions of low-income households’ utility bills. This budgetary choice has limited Maryland’s success with energy consumption reductions and in the long run will hinder the potential to achieve future GHG reduction targets. A study by the University of Maryland’s Center for Integrative Environmental Research found that if Maryland uses 100% of the SEIF revenues for energy efficiency programs, energy consumption will decrease by 11.2% by 2020 as opposed to a 7.4% reduction if only 25% of the revenues are used.

3. **Maryland’s Public Service Commission (PSC) should strictly enforce EmPOWER guidelines on utilities and streamline the approval process of utility energy efficiency improvements.** PSC has been slow to approve utility plans for energy reductions and has been reluctant to impose penalties against utilities that do not adhere to its guidelines. PSC should evaluate the cost effectiveness of these programs and move forward to ensure that economically feasible plans are implemented.

**Chapter 5 – RGGI Auctions**

RGGI initially adopted a cap of 165Mt of CO\(_2\) for all RGGI member states combined. Yet, this cap turned out to be too high and left the market with a large number of extra allowances. RGGI addressed the problem in its 2012 program review and updated the Model Rule in February 2013 with a new cap set at 45% below the preceding one, i.e. 91Mt. Additional changes include a new higher minimum price of $2 in 2014 (+2.5%/y), interim control adjustments for previously banked allowances, and a cost containment reserve to prevent RGGI auction prices from rising above certain maximums. In some ways, RGGI has been a successful model for carbon dioxide
emissions trading. The program instituted some rather ground breaking and important policies, including its policy of auctioning, not giving away allowances; implementing and acting upon the 2009 program review and its recommendations; and the RGGI emphasis on reinvesting in energy efficiency. However, there are have also been large RGGI weaknesses that must be addressed.

Chapter 5 Recommendations:

1. **Increase the RGGI auction price floor significantly.** The current RGGI floor is well below the California floor of about $10 per ton of CO$_2$. It is even further below most estimates of the social cost of each additional ton of CO$_2$ such as a recent study finding that this cost is about $20 per ton.

2. **Increase the maximum RGGI auction price – the price at which the cost containment reserve allowances are then made available for sale.** The current RGGI maximum prices for allowances in its auctions over the next few years will gradually rise from $4 to $10 per ton of CO$_2$, far below the California maximum of $40 and above. If additional reserve allowances are so readily supplied to the market at such low prices, the additional allowances made available will work to undermine the positive step achieved by RGGI’s recent sharp reduction in its cap.

3. **Implement a way for RGGI to react more quickly to market results by adjusting its cap, instead of using rigid price floors and maximum price levels.** One of the greatest weaknesses of the RGGI program has revolved around RGGI’s inability to react more quickly to changing market indicators and realities. Until very recently, the RGGI cap was not really acting as a cap because the cap was set at levels well above existing CO$_2$ emissions. It took three years to alter the RGGI cap to reflect this reality.

4. **Consider the adoption of a “floating cap.”** Perhaps RGGI administrators could be given discretion to alter the cap within certain boundaries in a much shorter time frame. Similar to a floating exchange rate, the cap for greenhouse gas emissions might be set within a floating range. This would give the regulatory entity more flexibility to adjust for uncertainty in emission forecasts. Where the floating range should be set would largely depend on how carbon emissions under business as usual through a model rule period are estimated. Despite the fact that accurate estimation is difficult, an allowable range for the floating cap can be established by examination of various emission scenarios from the bearish to the bullish.

5. **Authorize RGGI to make allowance repurchases.** Establishing a program for allowance repurchases would help the market achieve balance and therefore reduce the risk of price collapse when extra allowance supply becomes material. Specifically, the regulatory entity should monitor the market balance closely to identify any supply or demand shocks, such as the oversupplied allowances under the European Trading Scheme. Especially in the presence of oversupply, the risk of price collapse might rise and it might then be desirable for the regulatory entity to be able to conduct repurchases of the extra allowances from the market, including those banked privately. The U.S. Federal Reserve System employs such methods in seeking to maintain interest rate stability at the desired levels.

6. **Consider the use of a tiered RGGI auction pricing scheme.** Current cap-and-trade programs under operation employ a uniform pricing mechanism, a single price system for all
regulated industries. It might be more efficient in terms of emission reduction if the regulatory entity could introduce a tiered pricing scheme that reflects the varying demands and economic sensitivities to the price of carbon of different consumer groups. Like a perfect monopolist in a conventional market, RGGI administrators might be able in this way to minimize the social adjustment costs of making GHG reductions across different economic sectors. For instance, some heavy-polluting industries facing inelastic demands, such as coal-fired power plants, might be required to hold more allowances per ton of CO₂ they emit, as compared say with auto manufacturers. This would at least partly reflect the differing elasticities of demand in different sectors for RGGI allowances, as economic theory recommends for maximizing social efficiency of regulation.

Chapter 6 – RGGI Leakage Problems

As RGGI allowance prices increase in the future, the possibility of leakage – shifting GHG emissions to other states outside RGGI to avoid the cost burdens of purchasing allowances within RGGI – will increasingly become a threat to the integrity of the RGGI cap. For example, power generators might shift their operations from RGGI states to unregulated states within the same regional grid. Another form of leakage is contract shuffling, where facilities substitute power from lower GHG emissions sources into a regulated area, while shifting their higher GHG emissions power to unregulated areas. In either case, overall GHG emissions can remain unchanged or increase, defeating the purpose of a regulatory regime such as a cap and trade system. Thus far, given the low RGGI allowance prices, leakage may not have been a large problem, and RGGI has not adopted any actions to address leakage.

But with rising RGGI allowance prices this could change. California on the other hand has developed a stringent leakage control policy and it aims to to track 96% of power imported into the state and assigned corresponding emissions rates and required allowances. California is also in the process of adopting measures to prohibit resource shuffling.

Chapter 6 Recommendations:

1. **Follow California’s example by adopting RGGI policies and measures to address the problem of leakage.** Given an estimate of the GHG leakage associated with the importation of electric power into the region, RGGI should require that the purchasers of this imported power in the RGGI states hold allowances to cover these leaked GHG emissions. RGGI would then need to expand the cap to reflect the additional allowance demands that would result.

2. **Request PJM and its other regional power grids to develop a modeling system to assign levels of GHG emissions associated with the generation of imported electric power that is crossing state lines into RGGI member states.** Given the workings of regional electric power grids, it is usually impossible to specify any one source of the power imported into Maryland and other RGGI member states. It should be possible, however, for PJM to develop a model for distributing Maryland (and other RGGI) imported power among originating states within PJM. The models would have to be internally consistent in that the assigned disaggregated figures for GHG emissions in particular areas would add up to the actual grand sum of all PJM emissions at any given time. PJM could then estimate the GHG emissions associated with Maryland (and RGGI) power imports, providing a basis for the allowance requirements to be associated with
these leaked power imports. California (a single regional power grid by itself which simplifies its task) has successfully implemented such a system for calculating GHG leakage associated with power imports into California.

3. **Encourage Pennsylvania, West Virginia, Ohio and other nearby states to join RGGI.** To the extent that the geographic scope of RGGI can be expanded, the problem of leakage can be diminished. If electric power generators in nearby states presently outside of RGGI were newly incorporated into RGGI, these generators would then have to purchase RGGI allowances within the RGGI cap (expanded appropriately). There would be no GHG incentive for leakage to these states. To the extent that RGGI is able to devise an effective leakage policy, this would in itself increase the incentive for Pennsylvania, West Virginia, Ohio and other nearby states to join RGGI.

Chapter 7 – The California/Quebec Cap and Trade System and the Potential for Linkage with RGGI

California’s published amendments to its cap and trade regulation discuss how linkage between California and Quebec is beneficial by providing “a framework for additional partners to join and demonstrating a workable template for urgently needed action at the national and international levels to address climate change.” From this statement, it appears that California might be amenable to working with RGGI to develop a linked common system. In addition, California’s regulation grants the Air Resources Board the authority of linkage, provided there is a public comment period, thus providing the regulatory framework for external linkage beyond Quebec, such as potentially RGGI. Adding partners such as RGGI to California’s cap and trade program beyond Quebec, could help to initiate a process towards a wider use of GHG cap and trade programs in the United States.

An April 2013 Resources for the Future (RFF) study examines the potential for linkage between RGGI and the California/Quebec cap and trade systems. The RFF study identifies ten key program elements and evaluates them in the context of RGGI and California linkage according to three criteria: difficulty of administrative alignment, importance for the market to be able to function, and importance for the political economy. The ten program elements identified by RFF mirror the key carbon market components discussed in this and other chapters of this report for California and RGGI: 1) measurement, reporting and verification; 2) allowance tracking; 3) emissions cap; 4) scope and timing of coverage; 5) allocation; 6) auction coordination; 7) banking; 8) offsets; 9) price collars (floor and ceiling); and 10) legal contingencies. Resolving all these linkage issues would not be easy but appears to be potentially feasible with good faith efforts on both sides.

Chapter 7 Recommendations:

1. **RGGI should move forward in discussions with California and Quebec to explore the possibility of linking their two cap and trade systems, thereby forming a newly international and transcontinental integrated GHG cap and trade system.** Combining the California/Quebec and RGGI cap and trade systems into one integrated cap and trade system would significantly expand the geographic scope of trading, thus increasing the efficiency of
GHG reductions in the combined area, and lowering the total GHG reduction costs. In addition, RGGI could benefit from the experience and expertise that California and Quebec have developed in implementing their cap and trade systems – as they might benefit in some areas from RGGI experience and expertise. The additional recommendations below would facilitate the linking process.

2. Develop a RGGI plan for phasing in transportation and other economic sectors besides electric power generation. California’s cap and trade system is schedule to include the transportation sector as of 2015. At present, RGGI is limited to the electric power sector. Expanding the scope of RGGI to also encompass transportation, industrial activity and other sectors, while perhaps not a requirement for linkage, would facilitate the process, and would also have GHG benefits internal to RGGI.

3. Develop a RGGI mechanism to phase in minimum allowance price increases more rapidly: California has a minimum allowance sales price of about $10, much higher than the RGGI minimum sales price of about $2.00. If California GHG emitters could buy RGGI allowances for much lower RGGI prices, it would reduce their incentive to make GHG reductions in California – an undesirable form of leakage. In order to facilitate any plan for linkage with California, RGGI should raise its minimum price to correspond to the California minimum. Alternatively, it might be sufficient for RGGI to reduce the cap enough to drive up the price of RGGI allowances. RGGI’s cap is set to be reduced by 2.5% per year. A decrease of 5% per year or more might bring allowance prices much closer to CARBs allowance price and facilitate linkage.

4. Link RGGI’s and California’s offset programs: RGGI should take steps to link its offset program with California’s as a means of promoting less costly GHG reductions by RGGI GHG emitters, and invigorating the RGGI offset program. In California, industry is already enthusiastic about an expanded offsets market, and some power utilities have expressed concern that CARBs offset market is not sufficiently large and will be further strained by linkage with Quebec.

Chapter 8 -- Offsets and other “One Way” Linkages in RGGI

Realistic current projections of future Maryland GHG reductions raise many questions with respect to Maryland’s ability to reach its 2020 greenhouse gas emission goal of a 25 percent reduction from 2006 levels. One possible way for Maryland to move closer to achieving this goal would be to permit GHG emitters within Maryland to purchase offsets from outside the state as an acceptable element of a broader Maryland strategy for reaching the 25 percent target. Since the GHG emissions of electric power producers in Maryland are regionally controlled by RGGI, any offsets obtained by Maryland GHG emitters within the power sector would have to be obtained within the RGGI system of offsets. One potential new means for electric power generators in Maryland and other RGGI states to obtain their offsets would be to purchase allowances in the California/Quebec cap-and-trade system. This would only become attractive if the prices of RGGI allowances were to rise rapidly to California levels.

Another way that RGGI GHG emitters could in concept acquire offsets would be to purchase them from other such cap and trade systems around the world such as the ETS of the EU or the
new Chinese pilot cap-and-trade programs. If any such linkages between two cap and trade systems were not reciprocal, they would be what are called “one-way” linkages (RGGI could accept the purchase of other cap and trade system allowances as legitimate offsets for its purposes but the reverse would not necessarily be the case).

Another offset acquisition strategy, rather than from other cap-and-trade systems, would be to purchase offsets generated by individual carbon reduction projects, either projects internal to the United States or international. These by definition would be “one way” transactions as Maryland and RGGI GHG emitters could buy an offset from a specific project somewhere else. Internationally, the best known such offset system is the Clean Development Mechanism (CDM), established by the Kyoto Protocol. Thus far, over one billion CDM offset credits have been created in 80 countries. Another offset system is the program for “reducing emissions from deforestation and forest degradation” (REDD). RGGI members could pay developing countries that reduce deforestation over a given period and claim these credits as offsets. Aside from CDM and REDD, a third source of offsets are credits for projects that make GHG reductions that are certified by private third parties and then can be bought and sold voluntarily.

Chapter 8 Recommendations:

1. **Consider establishing a policy by which GHG emitters in Maryland (but outside the electric power sector) can purchase GHG offsets as a means of contributing to compliance with the Maryland GGRA emissions reduction goals set by the GGRA of 2009.** The GGRA sets a goal of a 25 percent reduction in GHGs emissions in Maryland, relative to 2006 levels. It has been assumed that this goal should be met by GHG reductions within Maryland itself. It would be possible in concept, however, to allow Maryland GHG emitters to purchase offsets outside of Maryland, and then have these offsets count towards the Maryland 25 percent reduction target set by the GGRA. A similar approach is used for compliance with Maryland’s renewable energy standards in which Maryland electric power distributors can purchase Renewable Energy Credits (RECs) either inside of Maryland or in certain states outside of Maryland, in reaching compliance with Maryland’s renewable portfolio standards. Maryland GHG emitters (outside the power sector) might make such offset purchases voluntarily, or – as suggested below – according to a legal mandate.

2. **Study the possibility, as part of the GGRA strategy, of requiring specific GHG percentage reductions by 2020 for appropriate categories of (non-power) GHG emitters.** For those Maryland GHG emitters included in these mandatory reduction categories, the required GHG emission reductions could be made either by making the GHG reductions directly or by purchasing GHG offset credits from some other source (within or outside of Maryland).

3. **Within RGGI and the electric power sector, expand the range of offsets acceptable to RGGI and the numbers of offsets that can be purchased in lieu of purchasing an allowance in a RGGI auction.** If the RGGI cap is tightened sufficiently to increase significantly the sale price of allowances in RGGI auctions, the wider purchase of offsets would be encouraged. Total costs of complying with the RGGI cap for GHG reduction would then be reduced to the extent that the price of an offset was below that of a RGGI allowance.
4. Allow Maryland (non-power) offsets and RGGI electric power GHG offsets to be obtained by purchasing allowances in cap and trade systems outside of RGGI. The purchase of an allowance in another cap and trade system amounts in practice to the reduction of the cap in that other system. This will generate a reduction in world GHG emissions in the same way that the purchase of an offset consisting of an individual project making a GHG reduction would have this consequence. RGGI thus might allow offsets consisting of allowances purchased in the EU, China and other future locations of GHG cap and trade systems.

5. Create a RGGI system for recognizing and certifying acceptable GHG offsets. RGGI already includes limited provision for offsets but the minimal price of RGGI allowances has in practice meant that there has been no demand for RGGI offsets. If offsets are to become an important part of the workings of the RGGI system, new procedures will needed for defining the characteristics of an acceptable RGGI offset and then establishing certification procedures that such characteristics have in fact been satisfied.

6. Consider adopting the California/Quebec system for recognizing and certifying offsets as also satisfying RGGI requirements for an acceptable offset. California has already invested considerable resources in developing its own offset system. RGGI might be able to profit by simply accepting California approved offsets for acceptance also in RGGI.

7. Consider adopting the EU system for recognizing and certifying acceptable CDM credits as also meeting RGGI requirements for acceptable international offsets. The EU cap and trade system has been exercising a leadership role in addressing the many problems that have developed in practice with the CDM system. Under recent policy changes, for example, CDM projects in many countries such as China and India will no longer be accepted by the EU ETS. Here again, RGGI might be able to profit by simply accepting EU determinations with respect to internationally acceptable CDM projects.

Chapter 9 -- GHG Regulation of Existing Power Plants under the Clean Air Act: Encouraging EPA to Facilitate Bottom-Up Cap-and-Trade Programs and Linkages

Under §111 of the Clean Air Act (CAA), EPA has a variety of options for regulating GHG emissions from existing sources in the electric power sector. EPA can take a traditional performance standard approach that regulates on an individual plant basis or it can take an approach that recognizes market-oriented programs such as cap and trade as options for CAA compliance. A traditional performance standard may be less vulnerable to political and legal attack than the incorporation of a market-oriented approach, at least on the national stage, given the intensity of past cap and trade debates. States, however, may well favor a market-oriented approach that allows them more flexible compliance options with lower costs.

States such as California and RGGI members are thus interested in having their existing cap and trade programs qualify as meeting the GHG requirements for existing power sources of the CAA. Other states may be interested in linking with these existing cap and trade programs as a method of state compliance as well. Or these other states, or new regional groupings of states, might create brand new cap and trade systems for this purpose. One approach would be for EPA in its existing source GHG program to offer several alternative means of compliance for states,
including emission rate averaging, energy efficiency standards, increased use of renewable energy, and trading among covered sources. EPA need not require a cap-and-trade program but could make this available as an option that states might voluntarily select.

Chapter 9 Recommendations

1. EPA should establish a set of alternative model compliance methods for CAA GHG regulation of existing power sources among which states could voluntarily choose. One such model would be a standard cap and trade system such as found in RGGI and California. Another model might be a market-oriented approach through a tradable performance standard for existing power sources. As proposed by NRDC and discussed in Chapter 9, this would incorporate demand-side efficiency, state generation fleet averaging, trading, and credit banking as well as establishing state authority to combine fleets into multistate regions. By outlining a detailed set of alternative CAA model rules, EPA would reduce overall uncertainty and provide guidance for state planning as well as a signal to industry of possible methods of compliance.

2. To ensure that trading across covered sources is encouraged and as cost-effective as possible, EPA should keep its definition of source categories broad. A single category of “electric power plant” – as opposed to “coal plant,” “gas plant,” etc. -- lays the groundwork for including greater trading and other compliance flexibility in its performance standard and leads to lower-cost emission reductions. It also leads to greater efficiency in regulating sources.

3. EPA, in its upcoming proposed CAA rule for existing GHG sources, should address criteria for establishing equivalency in state programs, including scope (i.e. trading across sectors), offsets, and international linkages. While additional means other than direct emission reductions such as energy efficiency programs might count as compliance through credit certification, existing state and regional cap-and-trade programs would still likely not be able to take advantage of such additional means as well as others like offsets. EPA should assess the legal ability of offsets and international linkages to count as CAA GHG compliance under tradable performance standards and specifically address this in its proposed rule.

4. EPA should clearly state that existing state and regional cap-and-trade programs in California and in RGGI may serve as methods of CAA GHG compliance under its existing source performance standard. If sufficient allowances were held within a cap and trade system, this would constitute compliance with the EPA existing source standard. Maryland and the rest of RGGI would thereby benefit in terms of the ease of CAA GHG compliance. The RGGI states can avoid the superimposition of federal CAA GHG regulation on top of existing RGGI regulations. This might encourage other nearby states such as Pennsylvania or West Virginia to join RGGI in order to comply with EPA GHG standards which would offer advantages in dealing with leakage and other matters.

Chapter 10 -- Assessing the Stringency of State and Regional GHG Caps

In order for EPA to follow the proposed alternative strategy in Chapter 9 of allowing for CAA GHG compliance for existing power sources by means of participating in a cap and trade program, there would need to be some method of verifying that the cap in any such state or
regional cap and trade system was sufficiently stringent to qualify for such CAA purposes. This might be conceived as involving two questions: (1) what is the appropriate target of total GHG reductions for the United States for a given future date, and (2) how should the responsibility for the necessary total U.S. GHG reductions be equitably and efficiently distributed among the 50 states and regions. This chapter explores three alternative criteria for addressing the second question – (a) the GHG reductions should be made within the United States in proportion to state or regional gross domestic product; or (b) the GHG reductions should be made in proportion to state or regional population levels; or (c) the GHG reductions should be made in proportion to the historic GHG emissions of each state or region in some given prior base year.

For example, assume the United States were hypothetically to commit to a 25 percent total reduction in GHG emissions in 2020, relative to 2006 levels. The above three criteria, as explored in this Chapter, would then suggest three alternative distributions of GHG reduction responsibilities. For any given state or regional cap, the magnitude of the cap could be compared with the assignment of GHG reduction responsibilities under each of the three above criteria. If the actual cap were equal to or below all the assigned GHG reduction responsibilities, it would be deemed “sufficiently stringent.” Given the existence of three plausible criteria, however, the cap might be stringent enough by one criterion, but not by another. Hence, some compromise among them -- and other possible criteria -- might be necessary in practice.

Chapter 10 Recommendations:

1. EPA should define “sufficient stringency” for the purposes of a cap and trade system that will qualify as one acceptable alternative for meeting the existing source regulatory requirements for electric power plants of the CAA. As suggested in Chapter 9, EPA should allow states the option to comply with the CAA if its existing power plants are included in an acceptable state (or regional) cap and trade system. In order to make this an operational approach, some definition of “acceptable” system will be required. The concept of the “sufficient stringency” of the cap would usefully serve this purpose.

2. For the purposes of calculating “sufficient stringency,” EPA (or the President by executive authority, or both the President and Congress by legislation) should set a desired GHG reduction target for the United States for some future date. This GHG reduction target is needed as a critical element of assessing whether any actual state or regional caps are tight enough to come within the CAA GHG policies of the United States. One possible such target might be a 25 percent reduction in total U.S. GHG emissions by 2020, as compared with 2006 levels. This would likely fall below the business as usual level of GHG emissions for 2020, but would hopefully not impose undue economic burdens. If the target date were instead set at 2030, a larger national GHG reduction would be sought, perhaps a target of 40 percent below 2006 levels.

3. In deciding how the total GHG reduction target should be allocated within the United States, EPA should determine the appropriate criteria to be applied. Among many possibilities, such criteria might include state and regional GHG targets for 2020 (and corresponding caps in 2020) that reflected proportional GHG reduction responsibilities based on relative state and regional GDP, relative state and regional population, or relative historic past
levels of GHG emissions (say in 2006). These and potentially other such criteria might be applied and then a final assessment of “sufficient stringency” made by weighting the criteria to produce an acceptably tight cap.

4. EPA should encourage forming greater linkages among state and regional cap and trade systems in the United States in order to increase the geographic area of the resulting cap and trade systems for the purposes of CAA GHG compliance. The need to distribute overall GHG reduction responsibilities in the United States among states and regions would be avoided to the extent that the geographic scope of the ultimate cap and trade systems is enlarged. If, for example (and hypothetically), there were a single cap and trade system for the United States, no distribution of GHG reduction responsibilities within the United States would be necessary. More realistically, one might imagine a system in which most states belong to one of (say) five regional cap and trade systems and the rest of the states go it on their own.
Chapter 1 – Introduction: Maryland Greenhouse Gas Emissions and Policies

Over the last decade, Maryland has implemented a number of initiatives to reduce its carbon footprint. In 2007, Maryland joined with nine other mid-Atlantic and Northeastern states in the Regional Greenhouse Gas Reduction Initiative (RGGI), which sets a maximum limit on the states’ collective greenhouse emissions from the electric power sector. The state has also implemented other programs to reduce greenhouse emissions from the transportation, residential, industrial, commercial, and other sectors. These programs are discussed in this report. Reducing greenhouse gases is a particularly challenging environmental problem because it involves significant changes in such core parts of the Maryland economy.

Maryland’s Energy Landscape

Maryland’s energy landscape is key to understanding challenges and opportunities for GHG reductions and to clarify Maryland’s role in RGGI.

Energy Intensity

Energy intensity is a useful quantity for analysis and cross comparison of energy use and efficiency among actors. It can be defined as for example energy use per capita or per GDP, or as shown later GDP per energy use. Figure 1.1 shows Maryland’s energy intensity, calculated by dividing the state’s total energy consumption by population. According to the most recent data from the U.S. Department of Energy (DOE), Maryland’s energy intensity in 2010 was 256 million Btu per capita, compared with a U.S. average level of 363 million Btu per capita. Maryland, ranked 39th in the United States in energy intensity. As shown in Figure 1.1, the state reached its lowest energy intensity in 2010, a 10% reduction relative to its historic maximum in 2005.

Figure 1.1 Maryland Total Energy Consumption per Capita 1980-2010 (million Btu)

Source: U.S. Energy Information Administration (EIA) State Energy Data System (SEDS) database
As shown in Figure 1.2, energy intensity in Maryland has historically been less than half that of Texas, and even lower than other mid-Atlantic states such as Pennsylvania and Virginia. Also shown is the energy intensity of California, Massachusetts, and Florida, all lower than that of Maryland. The fact that Maryland already economizes on energy use relative to most of the rest of the United States complicates its task of convincing policy makers for the need of more aggressive GHG reduction or changes in existing policy initiatives.

**Figure 1.2 Maryland Total Energy Consumption Per Capita Compared to Other States (million Btu/person)**

![Figure 1.2](image)

*Source: U.S. Energy Information Administration (EIA) State Energy Data System (SEDS) database*

**Energy Consumption Distribution**

The figures below show how energy use was distributed in 2010 in Maryland across all end-use sectors. The residential sector, representing 30.2% of total energy consumption in Maryland in 2010, requires energy for heating, cooking, cleaning and to supply electric power, followed by transportation and the commercial sector, using 29.9% and 29.5%, respectively. The leading source of Maryland energy used in 2010 was petroleum (34%), followed by net interstate flow of electricity (20%), coal (18%) and natural gas (14%). Relative to the U.S. national average, Maryland relies significantly more heavily on coal and significantly less heavily on natural gas. Additionally, a significant amount of Maryland’s electricity is imported from other states, an issue which will be discussed further in Chapter 6.
Figure 1.5 shows Maryland’s energy consumption by sector and fuel. The electricity losses incurred during the generation, transmission and distribution are 31% of overall energy consumption, which indicates that improvements in efficiency could make a significant difference to reduce energy consumption.10

Source: EIA, Maryland State Profile, 2011 data
For the electric power sector, as shown in Figure 1.6, Maryland’s energy usage profile has not changed greatly since 1990. Coal has been the dominant source of electric power, supplying 60% as recently as 2007. Although it declined to 55% in 2010, coal usage was still well above the national average in that year of 48%. Nuclear power in 2010 supplied 33% of Maryland’s power, which is also well above the national average of 20%. Maryland is also distinctive in that natural gas plays such a small role in the power sector, equal to 7% in 2010, much below the national average of 19%.

Energy Supply

In terms of energy development within the state, Maryland relies on imported coal and natural gas for a significant fraction of its energy needs. Most of the state’s nuclear power is provided by Calvert Cliffs nuclear plant in southern Maryland. About 30% of electric power used in Maryland is imported from surrounding states, a higher percentage than any other states in the United States except Virginia and Delaware. As shown in Figure 1.7, imported power is expected to increase by about 60% from 2006 to 2020, compared with an increase in in-state generated power of about 30%, reflecting Maryland’s inability to keep up with its rising energy demands from its own in-state power sources.
Figure 1.7 2006 Baseline vs. Projected 2020 “Business-As-Usual” for Electricity Consumption by both In-State and Import (million metric tons CO₂-equivalent)

Source: Maryland Greenhouse Gas Reduction Act Draft Plan, p.69

Maryland is part of the regional Pennsylvania-New Jersey-Maryland (PJM) Interconnection grid. PJM encompasses 13 states and the District of Columbia, and its installed capacity of 163,000 MW serves more than 50 million people. Over the past few years, the transmission congestion in the PJM region has led to an increase in Maryland electricity prices and reduced reliability of electricity delivery. However, recent energy efficiency programs such as EmPOWER Maryland are aimed at effectively reducing peak demand and delaying the threat of significant capacity deficits. In the long run, Maryland also needs to increase in-state generation capacity and build new transmission facilities to gain better access to out of state generation.

Maryland’s Greenhouse Gas Emissions

Reflecting the impact of climate change, Maryland is experiencing warmer winters and summers, and wetter autumns and springs over recent decades. Such trends will lead to increasing water stress for agriculture and loss of coastal wetlands. The restoration of the Chesapeake Bay will become more of a challenge due to increased environmental stress from increasing water temperature and shifts in rainfall patterns. In part because of the potential risk to Maryland’s residents and ecosystems, the State has stated its commitment to reducing greenhouse gas emissions and preparing communities for the impacts of climate change. Maryland’s 2008 Climate Action Plan (CAP), written by the Maryland Commission on Climate Change, aims to address the drivers of greenhouse emissions in Maryland, to prepare for the likely impacts of a warming climate, and to establish goals and timetables for implementation. As of 2012, there are 38 states that have either completed or are in the process of completing Climate Action Plans (CAP) to reduce their carbon emissions.

In 2009, the Maryland General Assembly passed the Greenhouse Gas Emission Reduction Act (GGRA). This law sets a state target to reduce Maryland GHG emissions 25% by 2020 relative to a 2006 baseline. The legislation requires that its implementation must not cause any loss of
existing jobs in the State’s manufacturing sector and must provide a net economic benefit to the State’s economy. In addition, the law requires that implementation should create the side benefits of improving air quality and helping restore the Chesapeake Bay.

**Historical Trends in Emissions**

As shown in Figure 1.8, carbon dioxide emissions per capita vary greatly by state, partly reflecting the wide state variations in energy use per capita, as shown above in Figure 1.2. The highest carbon dioxide emitting states such as Alaska and Wyoming can be six times higher than the lowest states such Vermont and New York State on a per capita basis.\(^\text{17}\) If overall U.S. per capita \(\text{CO}_2\) emissions were equal to the emission level of its most populous state, California, global \(\text{CO}_2\) emissions would fall by \(8\%\).\(^\text{18}\)

Besides Vermont and New York, the other RGGI states of Rhode Island, New Hampshire, Connecticut, and Massachusetts also rank among the ten lowest carbon dioxide emitting states on a per capita basis. Interestingly, the states that have the lowest greenhouse emissions per capita such as California and the RGGI states are among the most ambitious in seeking to achieve further greenhouse gas reductions.

This suggests that the “low hanging fruit” in terms of achieving significant reductions in carbon dioxide and other greenhouse gases in the United States probably lies outside of California and RGGI. There are therefore potential advantages, as discussed in Parts II and III, of creating programs to establish linkages between high emitting and low emitting states, including potentially between state and regional cap and trade programs in different areas of the United States.

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**Figure 1.8 U.S. emissions per capita by state (MtCO\(_2\))**

![Graph showing U.S. emissions per capita by state](image)

In 2006, Maryland emitted a total of 106.9 million metric tons of CO₂ (MMTCO₂) equivalent emissions, about 1.5% of total U.S. GHG emissions (7,054.2 MMTCO₂-equivalent). There were three leading sources of GHG emissions in Maryland in 2006: electricity consumption accounted for 42% of gross GHG emissions, transportation for 30% and residential, commercial and industrial buildings (RCI) fossil fuel use accounted for 16%.19

Figure 1.9 Baseline 2006 CO₂-equivalent Emissions by Activity (MMTCO₂-equivalent, percentage)

Roughly 85% of Maryland’s total greenhouse gas emissions stem from the burning of fossil fuels.20 From 2005 to 2010, Maryland CO₂ emissions from fossil fuels declined sharply by 17%. There were three main reasons for this drop. First, with the increasing supply of natural gas in the US, prices have declined dramatically since 2008 leading to increased demand for natural gas. More investment in natural gas power plants and non-fossil generation (eg. hydroelectric, wind and solar), and retirement of existing coal-fired capacity all contributed to fewer CO₂ emissions. Second, the 2008 economic recession led to significant reductions in electricity demand in the industrial and commercial sectors. Third, more moderate northeast temperatures have lowered the use of heating and cooling and have helped to keep down CO₂ emissions.21 However, in order to achieve the 25% reduction goal as set by the GGRA, Maryland must reduce emissions by 55 MMtCO₂-equivalent annually, which requires further action beyond even the current decline.22 This is illustrated in Figure 1.10. As will be examined in Chapter 4, it is unlikely that Maryland will be able to meet its 2020 greenhouse gas reduction goals without taking steps beyond those already planned and in progress.
Compared to other states, a relatively large share of Maryland CO₂ emissions comes from the transportation sector (see Figure 1.11). On-road gasoline powered vehicles are major sources for CO₂ emission from the transportation sector. Other contributors include on-road diesel-powered vehicles, airplanes, trains, and commercial marine vessels. As examined further in Chapter 2, the GGRA aims to reduce GHG emissions by 14.78 MMTCO₂-equivalent annually, involving full implementation of 110 transportation sector programs. The Maryland Department of Transportation (MDOT) is responsible for the development and implementation of policies to control and manage travel demand and adopt new technologies. Transportation sector initiatives include Maryland Clean Cars programs, transit service expansion and a Low Carbon Fuel Standard. On the other hand, a significantly smaller share of emissions comes from the industrial sector, while Maryland is fairly typical in the share of CO₂ coming from the electric power, residential and commercial sectors.

Notably, California also has an unusually large share of CO₂ emissions coming from the transportation sector (58%), and its relatively small share coming from the electric power sector (12%). The latter is attributable at least in part to the absence of coal burning power plants in California and the greater reliance on natural gas sources of power (53% of in-state power generation in 2010), in-state nuclear (16%), in-state hydro (15%), and in-state renewables (15%). California, like Maryland, also imports an exceptionally large percentage of its power. It produces only 70% of the electricity it uses internally; the rest is imported from hydroelectric sources in the Pacific Northwest (8% in 2010) and a variety of power sources in the U.S. Southwest (21%).
Maryland within the Regional Greenhouse Gas Initiative (RGGI)

The Healthy Air Act of 2006 required Maryland to join RGGI. Under RGGI, electric generators with over 25 megawatts (MW) of fossil fuel-based capacity must purchase emissions allowances for every ton of greenhouse gas emitted. RGGI’s original goal was to reduce carbon dioxide emissions from the power sector of all the RGGI states by 10% by 2019, but with a new lower cap, the program will cut emissions by more than half.

As shown in Figure 1.12, compared with other states in RGGI, Maryland has a higher proportion of CO₂ emissions generated from the power sector and it is among the states with the smallest proportion of emissions from the residential, industrial and commercial sectors. The most distinctive CO₂ profiles within RGGI are found in Vermont and Maine. Vermont in-state power generation is entirely from nuclear, hydro and renewables, thus emitting no greenhouse gases (and its imported power is mainly New York State and Canadian hydro). Maine has the smallest share of CO₂ emissions from the electric power sector.

In absolute terms, New York State dominates the CO₂ emissions from RGGI (Figure 1.13). Other larger emitting states are Maryland and Massachusetts. The remaining RGGI states of Delaware, Connecticut, Rhode Island, Vermont, New Hampshire and Maine cumulatively emit only 22% of the total CO₂ emissions from RGGI.
Figure 1.12 Maryland CO₂ Sources Compared to RGGI States in 2010, by Percentage

Source: EIA, Maryland State Profile, 2010 data

Figure 1.13 Maryland CO₂ Sources Compared to RGGI States in 2010, by Amount (MMTCO₂)

Source: EIA, Maryland State Profile, 2010 data
Maryland’s Current Path for Greenhouse Gas Emissions Reduction

Over the past decade, Maryland has taken a variety of steps to reduce its GHG emissions. These include the establishment of a renewable portfolio standard, joining RGGI, adopting measures to improve state energy efficiency, and setting a target reduction of 25% in greenhouse gas emissions in 2020, as compared with 2006 emissions.

2004 Renewable Portfolio Standard

Maryland initiated a series of new climate and energy policies with its Renewable Portfolio Standard (RPS), hoping to address its lack of in-state energy generation along with its heavy dependence on fossil fuels. Setting its first renewable portfolio standard in 2004, Maryland required electricity suppliers to provide 7.5% of their energy sales from renewable sources by 2019. If suppliers were unable to meet that standard on their own, they could purchase renewable energy credits (RECs) to meet their renewables requirement.

Maryland quickly surpassed the goals in its original RPS. In 2008, the state legislature responded by raising the standard to 20% by 2022, of which 2% must be solar energy generated within Maryland, doubling both the state’s Renewable Portfolio Standard and compliance payments to match similar policies in the region. This is depicted in Figure 1.14. The Maryland Energy Administration (MEA) has also set its own internal goal for making 20% of the electricity produced in the state renewable.

This year, Maryland took another important step towards achieving its renewable energy goals. The Offshore Wind Act of 2013 incentivizes 500MW of new offshore wind projects each producing about 200MW of electricity. Those 500MW would be able to meet about 4% of the state’s 2012 electricity demand. Maryland currently has no offshore wind generation. In the summer of 2013 the U.S. Department of Interior plans to lease enough areas off the state’s coast to produce 1,000MW of wind energy, and eight prospective developers have already expressed interest.

With all of these initiatives, Maryland estimates that it is on track to meet its goals. At present, 7.8% of Maryland’s energy comes from in-state renewable sources. As analyzed by the University of Maryland environmental policy workshop report for 2011, a number of uncertainties remain, however, in meeting the goals.
2006 Healthy Air Act

Maryland took another step towards improved air quality and reduced GHG emissions with the 2006 Healthy Air Act. The state advertises the policy as stronger than the Clean Air Act, requiring 70% reductions in NOx (the sum of NO and NO\textsubscript{2} emissions), 85% in SO\textsubscript{2}, and 90% in mercury emissions from 2002 levels by 2013.\textsuperscript{28} The law also mandated that the Governor of Maryland join RGGI.

Power plants have invested billions to comply with these standards. To meet the required emissions reductions, generators have added scrubbers and other technology to capture emissions at the source, costing power plants $2.6 billion.\textsuperscript{29} With both high emissions and high compliance costs, coal-fired power plants have struggled to keep up. Some have cited the regulations as the cause of plant shutdowns.\textsuperscript{30,31}

Still, the law has proven a success in reducing air pollution. Both SO\textsubscript{2} and NO\textsubscript{x} emissions saw sharp declines after the Healthy Air Act took effect and have stayed consistently low. Mercury too has far surpassed its mercury reduction goals. Figures 1.15 and 1.16 show the trend in NO\textsubscript{x}
and SO₂ emissions in Maryland and the steep decrease that occurred with implementation of the Healthy Air Act.

**Figure 1.15 Maryland NOₓ Emissions**

![NOₓ Emissions chart]

*Source: Maryland Department of the Environment, Air & Radiation Management Administration, “Clean Air Progress in Maryland Accomplishments 2012, April 2013.*

**Figure 1.16 Maryland SO₂ Emissions**

![SO₂ Emissions chart]

*Source: Maryland Department of the Environment, Air & Radiation Management Administration, “Clean Air Progress in Maryland Accomplishments 2012, April 2013.*
The law also sought to reduce GHG emissions by requiring the state to join RGGI. While Maryland was legally required to join RGGI, the law does give the Governor the executive option to leave the program after 2009.

Maryland Joins RGGI

When Maryland joined RGGI in 2007, the program became a cornerstone of the state’s climate and energy policies. In joining RGGI, Maryland agreed to work with nine other northeastern states to use a market-based strategy to reduce their GHG emissions from the power sector. At the time, Maryland, Connecticut, Delaware, Massachusetts, Maine, New Hampshire, New Jersey, New York, Rhode Island, and Vermont were all part of the program. New Jersey has since withdrawn.

As the nation’s first GHG cap and trade program, RGGI establishes a mandatory market-based strategy for cutting GHG emissions from the electricity sector. Every power producer in the RGGI states must have enough RGGI allowances to cover its greenhouse emissions over a pre-designated compliance period. To meet these requirements, emitters can buy allowances at quarterly auctions or purchase allowances from other holders to cover any excess emissions. Within RGGI, Maryland’s role is defined in part by its carbon-intensive electricity sector. In 2008, the year before RGGI began auctions, Maryland emitted 20,601,805 Mt of CO₂, 21% of emissions from RGGI states. Maryland’s initial base cap was established at 37,503,983 short tons of carbon, the second highest of the RGGI states, equal to 20% of the total RGGI greenhouse gas cap.

As a result, Maryland has received 20% of the revenues received in RGGI auctions of allowances (which can be used in any RGGI state). As of a report released in September 2012, Maryland has received a total of $197,434,490 in revenues. The other states that receive major shares of RGGI auction revenues are New York (37%) and Massachusetts (16%).

Maryland, however, generates only 12% of the electricity out of all the RGGI states. Maryland’s shares of revenue and electricity generation, in comparison to other RGGI states, are shown in Figures 1.17 through 1.20. Maryland’s significantly higher share of the RGGI cap and revenues reflects the fact that, as shown in Figure 1.21, its power sector is more dependent on burning coal than any other RGGI state, and thus is more greenhouse intensive per unit of electricity generated, especially as compared with states such as Vermont (which emits essentially no greenhouse gases from its in-state power generation) and New York State. Rhode Island generates almost all its power from fossil fuels but this is almost entirely from natural gas, which emits only about half the greenhouse gases per unit of energy, as compared with coal. The initial RGGI caps were set to recognize in part the existing levels of greenhouse gas emissions in each RGGI state, and their varying potentials for making reductions from higher or lower initial bases, reflecting their in-state sources of power generation.
Figure 1.17 Cap Distribution

Figure 1.18 Cumulative Auction Revenue Distribution

Figure 1.19 2008 Electricity Sector Emissions

Figure 1.20 2008 Net Generation
RGGI effectiveness, however, has been limited by its excessive supply of initial allowances, resulting in less demand than supply and low prices for allowances. After Maryland joined RGGI in 2007, and as the economy declined, so did RGGI electricity use and demand for allowances. With declining natural gas fuel costs, power production shifted in RGGI states towards greater use of natural gas, requiring fewer allowances to cover the lower levels of greenhouse emissions from gas. Hence, the GHG emissions of the power generators in the RGGI states have been consistently below RGGI’s cap. As a result, as shown in Figure 1.22, auction-clearing prices have consistently bottomed out at the price floor since 2010, without selling all available allowances.
Recognizing these challenges, RGGI states agreed to change the program in February 2013. In revisions to the Model Rule, RGGI lowered the total emissions cap to 91 million tons for 2014, a significant reduction from the original 165 million tons cap. Other changes include the expiration of banked and unsold allowances, offset reform and the creation of a cost containment reserve, which will release new allowances if RGGI’s price exceeds a set limit starting a $4 in 2014 and rising annually. RGGI predicts that these changes will reduce 2020 emissions from electricity generation in RGGI states by 45% below 2005 levels, and generate $2.2 billion in RGGI auction revenues. Electricity prices are projected to increase by less than 1%. These changes could cut Maryland’s carbon emissions by up to 3.6 MMT below business as usual, or 10% percent, by 2022.

Maryland’s Clean Cars Program

As is examined further in Chapter 3, there are 14 states (including the District of Columbia) in the United States that have adopted the Clean Cars Program in order to reduce global warming pollution from light-duty vehicles. The Maryland Clean Cars Act was adopted in 2007. It required Maryland to implement California’s more stringent emission standards for light-duty cars and trucks. Cars sold in Maryland must meet the most stringent standards in law, starting with 2011 model year vehicles.

In addition to control emissions from passenger vehicles, Maryland’s Clean Cars Program also requires auto manufactures to meet the Zero Emissions Vehicle (ZEV) mandate. ZEV program promotes hybrids, fuel-cell vehicles and electric vehicles to ensure zero or near zero tailpipe emissions.

The Maryland Clean Cars Program is a key part in the GGRA plan to reduce transportation emissions. It will also speed up Maryland’s progress to meet federal health-based standards for ozone and fine particles. It aims to reduce four key pollutants: GHGs, nitrogen oxides, volatile organic carbon, and air toxics. If successfully implemented, this program is estimated to reduce GHG emissions by 7.8 million tons per year and air toxics by 80.2 tons per year. The CO₂ reduction is equivalent to removing one 1,200 megawatt coal burning power plant from Maryland.

2008 Maryland Energy Efficiency Act (EmPOWER Maryland)

While Maryland made extensive commitments to reduce GHG intensity, the sheer demand for electricity in the state has posed additional challenges. With rising energy demand in the state and limited transmission capacity, PJM in 2008 warned that the state would risk rolling blackouts as early as 2011. With this impetus, as examined further in Chapter 4, the state legislature passed the Maryland Energy Efficiency Act in 2008 (EmPOWER Maryland), setting a goal of reducing per capita electricity consumption and peak electricity demand by 15% of 2007 levels by the year 2015. Both MEA and the Public Service Commission must review goals for after 2015, and are currently conducting the evaluation.
Through EmPOWER Maryland, utilities and the public sector work to improve energy efficiency. While utilities offer programs like rebates on efficient appliances and home energy audits, the public sector has set goals and monitoring procedures for its own buildings and has provided revolving funds for state and local governments to implement efficiency projects. RGGI is integral to these programs because RGGI revenues contribute one-third of the funding for EmPOWER. The remainder of the program is funded through a surcharge on ratepayers from participating utilities and MEA funds.

EmPOWER plays a key role in meeting Maryland’s GHG goals by reducing the energy intensity of the state’s economy. In 2007, just before passing EmPOWER Maryland, the state’s per capita peak demand was over 2.5 MW and per capita electricity consumption was 12.30 MWh/year. Since then, peak demand has dropped 9% and per capita electricity consumption has dropped 5%.

However, EmPOWER Maryland is not on track to meet its energy efficiency goals. MEA predicts that both peak demand and per capita consumption will fail to meet their 2015 goals, especially as low natural gas prices and economic recovery boost electricity demand. As a result, some stakeholders have highlighted the need to increase funding, either through RGGI or an increased surcharge, in order to increase available funding for EmPOWER projects.

Out of all of Maryland’s GHG reduction programs, EmPOWER Maryland has brought the greatest emissions reductions so far (See Table 1.1). The program has resulted in 8.22 MMT CO₂ already, and seeks to reach 10.52 MMT in its 2013 GHG plan. Yet, Maryland’s plan is based on a 15% demand reduction goal that is unlikely to be met—again bringing into question Maryland’s ability to meet its GHG goals without reforming its energy efficiency programs.

2009 Greenhouse Gas Reduction Act

After a string of climate programs, Maryland finally established overarching GHG goals in 2009. As is explored in greater detail in Chapter 2, the GGRA set a goal of a 25% reduction in GHG emissions from 2006 levels by 2020. It also requires the state to conduct a greenhouse gas emissions inventory. As part of the review, state agencies will produce a project report that includes an analysis of the economic impacts on the manufacturing sector, and the legislature can maintain, adjust, or eliminate the GHG reduction goals.

Also as part of the GGRA, Maryland must develop a legislative review of the GHG goals for 2016. MEA was scheduled to complete a revision of the GGRA Plan by December 2012. The final plan was not released until July 2013. Table 1.1 shows planned reductions in four key areas of GHG emissions.
Table 1.1: Top four programs in GGRA (MMTCO$_2$ -equivalent)

<table>
<thead>
<tr>
<th>Sector</th>
<th>Program</th>
<th>Description</th>
<th>Initial Reduction</th>
<th>Enhanced Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>RPS</td>
<td>Maryland power providers supply 18% of electricity from renewable sources by 2020, increasing to 20% renewables by 2022.</td>
<td>6.86</td>
<td>10.96</td>
</tr>
<tr>
<td>Energy</td>
<td>EmPOWER Maryland</td>
<td>Reduce both Maryland’s per capita total electricity consumption and peak load demand by 15% by 2015.</td>
<td>8.42</td>
<td>10.52</td>
</tr>
<tr>
<td>Transportation</td>
<td>Maryland</td>
<td>Clean Cars</td>
<td>Reduce transportation emissions including volatile organic compounds (VOCs) and nitrogen oxides (NOx).</td>
<td>4.33</td>
</tr>
<tr>
<td>Energy</td>
<td>RGGI</td>
<td>Reduce carbon dioxide emissions from the power sector by 10% by 2019.</td>
<td>0</td>
<td>3.6</td>
</tr>
</tbody>
</table>

Source: adapted from Executive Summary of the 2013 Maryland Greenhouse Gas Reduction Plan, Pg.7

Moving Forward

While Maryland has made progress in passing energy and climate polices, it has made limited progress in overall GHG reductions.

In fact, Maryland StateStat reports “insufficient progress” towards greenhouse gas reductions. After a sharp dip in emissions at the height of the recession, greenhouse emissions have been slowly increasing, leaving concerns that emissions will increase as the economy picks up. RGGI’s cap has failed to produce both the direct and indirect GHG reductions. With a cap that far exceeded actual emissions until the recent RGGI modifications, Maryland would have achieved its current GHG reductions without participation in the RGGI program. This low demand has resulted in low auction prices, limiting the revenue the state receives for its energy efficiency programs.
At the same time, RGGI only covers a portion of the state’s emissions. With transportation accounting for nearly 30% of the state’s emissions and industry composing another 10%, Maryland has significant opportunities in these sectors to advance its GHG goals. Yet, RGGI only covers the electricity sector. Other cap and trade programs, particularly California and Quebec, incorporate these other sectors in their program design.

If Maryland hopes to make real reductions to its GHG emissions, RGGI will have to change. The most recent updates to the Model Rule take a step in the right direction, but a variety of other alternatives remain to create progress towards GHG goals. This report explores those options in Chapter 5, providing a comprehensive review of the programs challenges and avenues for improvement based on expert analyses and lessons learned from other cap-and-trade systems.
PART I – GREENHOUSE GAS (GHG) REDUCTION WITHIN MARYLAND
Chapter 2: The Maryland Greenhouse Gas Reduction Act and its Prospects

In 2009, Maryland passed the Greenhouse Gas Reduction Act (GGRA), which calls for the state to reduce GHG emissions 25% below 2006 levels by 2020 in an effort to “address the drivers and causes of climate change, to prepare for the likely consequences and impacts of climate change to Maryland.” The law was intended to build upon Maryland’s existing climate change actions, including RGGI, the state’s renewable portfolio standard (RPS), and EmPOWER Maryland. These programs play a significant role in meeting the state’s 25% emission reduction goal. The GGRA was also intended to serve as the impetus for interagency coordination in the development of a long-term strategy to address climate change. MDE’s Draft Plan, released in 2012, included 65 measures among a variety of state agencies that would reduce the state’s overall emissions.

A Final Plan was not released until July 2013, too late for a full analysis of its provisions in this report. Chapter 2 therefore focuses on the 2011 draft Plan. While the Final Plan includes additional measures to reduce GHGs in Maryland, its basic strategies follow those previously identified in the Draft Plan. The concerns expressed below with respect to the Draft Plan continue to apply to the Final Plan as well (perhaps even more so).

At the time Maryland passed the GGRA, at the federal level, Congress was considering national climate change legislation and it seemed momentum was swinging towards the establishment of comprehensive climate policy framework. With its climate plan in the works, Maryland was set to become a national leader. Yet, as discussed in Chapter 9, federal legislation failed, and Maryland’s implementation of the GGRA has also been somewhat hindered since the initial groundswell. Under the law, MDE was required to issue a Draft Plan by the end of 2011 and a final plan by the end of 2012, but failed to meet these deadlines. This chapter discusses the Draft Plan and several key issues that need to be addressed regarding its efficacy. As was shown in Chapter 1, Maryland has so far made little progress in reducing its GHG emissions. If the state intends to meet its ambitious future goals and become a national leader, the provisions within the GGRA and coordination among the various programs of the plan should be significantly strengthened.

An Introduction to the Greenhouse Gas Reduction Act of 2009

In 2007, Governor O’Malley issued an Executive Order that established the Maryland Climate Change Commission and directed the state to join RGGI. The commission was to be comprised of three working groups whose members included sixteen state agency heads and six members of the Maryland General Assembly. Its key task was to develop a Plan of Action addressing climate change and to create firm benchmarks and timetables for implementation of the plan.
Accordingly, the Commission developed the 2008 Climate Action Plan (CAP) that would serve as the basis for the GGRA in 2009. The report proposed that the state create a goal of reducing GHG emissions by 25 to 50% by 2020 and recommended the implementation of 42 GHG reduction strategies previously submitted by state agencies. The Commission estimated the potential reductions that Maryland could make by adopting its proposal and projected emission reductions due to RGGI, Maryland’s Clean Cars, and EmPOWER Maryland. This estimate is shown in Figure 2.1.

**Figure 2.1 GHG Reduction Potential from Maryland’s Enacted and Proposed Actions**

As indicated in Figure 2.1, the Commission estimated that existing programs already satisfied about 60% of a goal of 25% reduction in GHGs from 2006 levels by 2020 and thus concluded that the state could easily meet such a goal.

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This optimistic proposal is reflected in the 2009 GGRA, which uses this projection as the basis for its 25% requirement. In order to meet this goal, the law required MDE to develop an inventory of 2006 statewide emissions to establish a base, develop a projected “business as usual” emissions inventory for 2020, and develop and publish an implementation plan for public comment by 2011. This Draft Plan was to incorporate expected GHG reductions from existing
programs as well as the Commission’s 42 proposed measures. The final plan was to have been adopted by 2012.

The law also requires that the final plan ensure the following:

1. no loss of existing jobs in the manufacturing sector;
2. a net increase in state jobs and a net economic benefit to the state’s economy;
3. opportunities for new green jobs in the energy and low carbon technology fields; and
4. no adverse impact on the reliability and affordability of electricity service and fuel supplies.

These requirements indicate a strong concern for the economic impacts of the GGRA on the state. Indeed, the final legislation passed was heavily shaped by these concerns and the manufacturing sector was completely exempted from regulation in an effort to appease the bill’s opponents, which had blocked its passage in 2008. While a Towson University analysis of the 2011 Draft Plan shows a positive economic impact, it is clear that the Final Plan will need to relieve public concerns about economic issues in order for implementation to be entirely successful.

Finally, the law requires MDE to submit a review to the Governor and the General Assembly by 2015, including the state’s progress towards achieving the 25% goal, a cost-benefit analysis of the plan, needs for adjustments, and the status of any federal GHG emission reduction program and the potential transition of the Maryland plan to a federal program. However, as the final plan was not issued until mid-2013, the state is already behind on its timeline, which may not allow adequate time for review and adjustment.

**Evaluation of the 2011 Draft Plan**

The Draft Plan released by MDE in 2011 seeks to achieve the targeted reductions by 2020 via 65 programs controlled by 11 different state agencies. Many of those programs are already required by other Maryland legislation such as the RPS and RGGI. Therefore, rather than introducing novel programs, the Draft Plan provides an assessment of how current programs would enable Maryland’s to meet its GHG reduction goals.

The projected reductions are shown in Figure 2.2. Almost half the projected GHG reductions would occur in the “energy sector” (mainly the generation of electric power). Another 22% would come from the transportation sector. Six percent would come from unspecified “innovative initiatives.”

Figure 2.2 details the projected emissions reductions by sector. In total, the programs under the Draft Plan would achieve 81.64 MMt of GHG reductions.

The adjusted estimate, when taking into account overlapping measures among the programs is 64 MMt, or 7 MMt more than the 57 MMt called for by the GGRA. The 2011 Draft Plan thus projects that Maryland would more than achieve its GHG reduction targets as set by the GGRA in 2009.
As can be seen above, if MDE’s estimates are correct, Maryland will significantly exceed its mandated target of emissions reductions. This would be a considerable achievement if it were fulfilled.

Figure 2.3, shows a bar graph of the major emissions sectors’ contribution to GHG reductions and the emissions reductions mandated by the GGRA. The energy sector is expected provide the largest reductions, closely followed by the transportation/land use sector and the commercial sectors. The industrial/residential building sector and agriculture/forestry/waste is expected to play a minor role.
The Draft Plan, however, includes a number of optimistic assumptions. The plan assumes a great deal of cooperation between state agencies but does not offer new organizational strategies to facilitate such widespread cooperation and coordination. Additionally, the plan assumes that existing Maryland GHG reduction programs will continue to be fully implemented between 2012 and 2020. Successful implementation, however, depends on many factors including continued economic recovery, continued private sector innovation and investment into the clean energy economy and continued funding and authority to support GHG reduction programs.57

The Maryland plan does not specify how funding will be obtained in order to implement its provisions, or address any other budgetary details. The implementation portions of all of the programs differ in that some are plans required by existing law, some depend on future legislation, and some are entirely voluntary.

The Power Sector

One area in which the 2011 Draft Plan seems particularly flawed is the power sector. Many advocacy groups have rightly noted that the assumptions used for projecting emissions reductions in this sector are problematic, including emission reductions as a result of RGGI and projected renewable energy generation.

Electricity consumption accounted for 41% of GHG emissions in Maryland in 2006. In order to achieve the 2020 goals, 49% of the needed reductions will have to come from this sector.58 It should also be noted that Maryland gets about 30% of its power from out of state so the figures used in the plan are based on energy consumption, not in-state generation. The plan calls for 16
separate programs in the energy sector, largely administered by MDE and MEA. Combined energy sector programs hope to reduce emissions by roughly 40 MMt by 2020.

The Draft Plan calls for achieving 17.71 MMt of reductions via the state’s participation in RGGI, which sets a declining cap for the electric power sector. RGGI does not, however, set a cap for Maryland itself. However, Maryland power producers can avoid making reductions in their own in-state GHG emissions by purchasing RGGI allowances from other states.

Contributing to this problem is the fact that CO₂ sequestration remains a distant possibility, which means that there is little that coal-fired power plants can do to reduce their CO₂ emissions, other than curtailing their power-generating operations. This would require that the power be replaced from other sources, likely its purchase from out-of-state sources; obtaining it from natural gas burning power plants within Maryland; or obtaining it from new renewable energy sources in Maryland.

Another barrier to the GHG reductions from Maryland’s electricity sector is that historically, Maryland has relied less than other states on natural gas for its in-state power generation. Moreover, Maryland’s coal-fired power plants have recently invested several billion dollars in pollution control equipment, as required by Maryland’s Healthy Air Act in 2006. There is thus not much prospect that in the near term Maryland would seek to invest in natural gas generation as an alternative to coal.

Recognizing these realities, the Draft Plan looks to the efficacy of Maryland’s RPS program to play a large part in achieving the GGRA GHG reduction goals. The state’s RPS requires Maryland to obtain 20% of its electricity from renewable sources by the year 2022. The RPS was further strengthened in 2008 and 2010 to total emissions reductions of 6.78 MMt by 2020 Maryland’s RPS is administered by MEA and it requires utilities to purchase energy from renewable sources in two tiers. The first Tier is comprised of wind, solar, geothermal, ocean, methane from landfills or wastewater treatment plants, and qualifying biomass. Tier 2 includes hydroelectric power other than pump storage generation, and waste-to-energy. However, because the renewable energy credits (RECs) can be purchased outside Maryland the program does not guarantee investments in renewable energy within the state.

As other advocacy groups have noted, The Draft Plan assumes that coal or gas energy would be displaced by a corresponding amount of clean energy. However, the definition of “clean” in the Plan includes energy from black liquor and wood waste which can also be a significant source of GHGs.

Additionally, the Draft Plan makes specific assumptions about the use of wind power to meet RPS requirements. For example, it states that offshore wind in Maryland will generate “at least 450 MW” of power. However the Maryland Offshore Wind Energy Act of 2013, which passed in March of 2013, only provides for a 200MW offshore wind energy project.

Given the limited ability of Maryland power generators to reduce their own in-state emissions of GHGs, a large part of the Maryland GHG emissions from the power sector, as called for in the Draft Plan, will need to be achieved through improved energy efficiency in the electricity sector.
The Draft Plan expects much of the improved energy efficiency to result from a successful full implementation of the EmPOWER Maryland Act enacted in 2008. As stated in Chapter 1, this law sets a goal to reduce Maryland’s power consumption by 15% by 2015. MEA estimates, however, that the state is on track to achieve only 56% of that goal, and that it will need to triple its current savings rate to meet the deadline. According to CCAN, the Draft Plan assumes savings that are even beyond the 15% goal that the state is currently failing to meet. Chapter 4 of this report addresses in greater detail the prospects for achieving significant increases in efficiency in the use of electric power in Maryland.

A University of Maryland’s Center for Integrative Environmental Research (CIER) 2011 study analyzed EmPOWER Maryland, RGGI, and the RPS. It found that these programs would have a positive impact on electric power capacity, and would not adversely impact electricity cost. The report also assumed all three programs would be implemented in full, but did not analyze the effects of other GHG emission reduction programs on electricity generation and distribution. Finally, the CIER report points out that the trends used to construct Maryland’s projected business-as-usual scenario can change. In contrast, in the Draft Plan, MDE did not take into account possible variations in its underlying assumptions, or in the extent of program implementation, even though such variability is to be expected in any real world scenario.

Prospects for Greenhouse Gas Emissions Reduction through GGRA

As the subject of his 2013 Ph.D. dissertation, a University of Maryland graduate student in urban studies, Tim Welch, examined the implementation of the 2008 CAP and the 2009 GGRA and the likelihood that Maryland would meet the 25% reduction goal by 2020.

Figure 2.4 shows his estimates of future Maryland greenhouse emissions of CO₂ under various scenarios. The upper line shows the business as usual scenario from 2006 to 2020, resulting in an increase in CO₂ of about 18% by 2020. Reflecting the lack of effectiveness of RGGI in the past, Welch then estimates the impact of the Maryland CAP in the absence of any contribution from RGGI. This would result in a decline in Maryland CO₂ emissions of only about 4 percent from 2006 to 2020. Adding in a full implementation of RGGI, this significantly increases the projected Maryland CO₂ reductions to 17% by 2020, which is still short of the GGRA target of 25% for all greenhouse gases. Welch is thus pessimistic that the GGRA can achieve its goals, unless Maryland adopts significant new measures to promote greater reductions in CO₂ emissions.
Interestingly, Welch develops an even more pessimistic analysis based on a calculation of the worldwide percentage reductions in greenhouse gases from 2006 that would be required to hold future global temperature increases to 2 degrees Centigrade, as has been widely advocated. The GGRA target GHG reduction of 25% by 2020, if adopted throughout the world, would not be enough to achieve this desired degree of world climate stabilization. If the Maryland reduction target were therefore further increased, sufficient for Maryland to play its part in holding a future increase in global temperature to 2 degrees, the necessary Maryland reduction in CO₂ levels by 2020 would need to be about 69% below the actual 2006 level.

Compared with business as usual, the Maryland reduction by 2020, as shown in Figure 2.2, would have to be even larger, about 73%. This would mean that Maryland in absolute terms would be curtailing its CO₂ emissions, compared with business as usual, by about 62 million tons, even as its total CO₂ emissions in 2006 were only about 72 million tons. This analysis illustrates the great difficulty of holding GHG emissions to levels that would result in a 2 degree temperature increase, and the importance of adopting future adaptation measures in Maryland.

**2013 Final Plan**

Prior to releasing the completed Final Greenhouse Gas Emissions Reduction Plan in July 2013, MDE in the spring of 2013 released an Executive Summary of the Final Plan. Generally, the Executive Summary follows the optimistic scenarios assumed in the previous draft documents. A substantial part of the report emphasizes the positive economic, health, and environmental impacts of the GHG Reduction Plan, portraying it as an overall positive development with no easily identified costs. Further, the summary asserts, similar to previous documents, that the goal of a 25% reduction in GHG emissions over 2006 levels will be achieved by the target date of 2020. In fact, the summary lists several major programs, such as RGGI and the RPS, which it
predicts will achieve even steeper emissions reductions than in the previous draft plans. Waste reduction and recycling, as well as green buildings, are accorded a higher profile in reducing overall state emissions than in previous draft documents.65

Concerned that projected GHG reductions may not be sufficient to meet 2020 goals, and in order to achieve greater GHG emissions, the Final Plan in July 2013 proposes to eliminate black liquor as a renewable energy source for the purposes of RPS compliance. It also proposes as an enhancement to its GHG reductions from the electric power sector that the Maryland RPS standard should be increased to 25 percent in 2020. The Final Plan estimates that these two measures would contribute an additional 2.7 MMtCO2e in additional GHG reductions in 2020. Implementation of these measures would require legislative action, however, an uncertain possibility. Moreover, there were already significant uncertainties that the existing RPS standard of 22 percent by 2022 was in practice achievable.

The Final Plan issued in July 2013 also included enhanced transportation measures designed to achieve greater GHG reductions. It estimated that enhanced “pricing measures” in the transportation sector would generate 2.3 MMtCO2e in GHG reductions, an increase from the previously estimated 0.41 MMtCO2e from pricing measures in the absence of the enhancements. These newly proposed pricing measures – representing 63 percent of new transportation enhancements in the Final Plan -- are not clearly spelled out and appear to be politically difficult. Although counted as estimated Maryland GHG reductions for 2020, this is an example of the inclusion of estimated reductions in the Final Plan for which there is little legal, political and administrative argument provided that would provide a strong basis to expect them actually to be realized.

Thus, the Final Plan continues the pattern of optimistic assumptions of older documents. While summaries are meant to be broad and general, the MDE Executive Summary again assumes a more favorable strategic outlook for program implementation than is probably realistic. The Executive Summary does not give any indication that MDE will take into account problems of implementation or suggest ways to compensate for problems. In summary, unrealistic assumptions and hopes continue to dominate Maryland’s GHG emission reduction planning under the GGRA.

**Recommendations**

This evaluation of the GGRA and its subsequent plans shows that unless the implementation and enforcement of the law is strengthened, Maryland likely to fall well below its GHG emissions reduction goals. Particular attention should be paid to the programs on which the GGRA relies heavily, such as RGGI, the RPS, EmPOWER Maryland, and the Maryland Clean Cars Program, if these programs are to meet their projects under GGRA. Chapters 3 and 4 discuss several of these programs in further depth, while Part II focuses on improvements to RGGI.

While the failure of Maryland to release a final plan in a timely fashion has made it impossible for this report to assess fully the adequacy of any final plan, based on a review of the draft CAP, the executive summary of the final CAP and other publicly available information, and on informal communications, the following recommendations are offered.
1. **The final Climate Action Plan should be based on realistic assumptions.** The CAP should be revisited and revised as needed to make sure that its assumptions relating to target goals, rates of success expected, swiftness and effectiveness of implementation, and other key matters are all realistic. Alternative scenarios might be constructed to reflect the large degree of uncertainty that exists in some cases.  

2. **The final CAP should fully assess what Maryland can, should, and is able to achieve in an economic manner.** This might lead the state to reduce its aspirations in some areas (like transportation) while increasing them in other areas (like electricity generation).

3. **A more scientific -- analytical -- approach to setting GGRA goals and designing and implementing CAP programs should be adopted.** The current goal of a 25% reduction by 2020 apparently was somewhat arbitrarily set. Ideally, Maryland would consider the various opportunities it has for making GHG reductions and their benefits and costs. Based on such calculations (if necessarily of a rough nature), Maryland could establish future GHG targets that would be more analytically defensible.

4. **The cost-effectiveness of CAP programs should be a key concern in a revised plan.** Some of the programs listed in the draft Climate Action Plan are of doubtful cost-effectiveness. This is likely the case for some transportation infrastructure projects such as significantly expanding mass transit service. Such programs can be enormously expensive, but deliver relatively small GHG reductions. Greater attention should be paid to lower cost, higher emissions benefit programs such as fees or taxes which reduce driving.

5. **The CAP should develop a detailed plan for coordination among agencies while taking a broader, more strategic and long-term approach to emissions reductions.** Rather than listing programs that have incidental emissions effects, the Plan should be a strategic framework for coordinating and implementing current and future agency activities. In addition, the plan should include designs for sector emissions initiatives that can be integrated with and imbedded in existing programs. For example, an emissions cap and trade program could be designed to be integrated into the RPS.
Chapter 3: Transportation and Maryland GHG Emissions

The transportation sector accounts for a significant proportion of Maryland’s GHG emissions. As discussed in Chapter 1, transportation is responsible for about 30% of GHG emissions, although that percentage is even higher for CO₂ emissions alone, at about 44%. Transportation therefore represents a crucial sector in implementing an effective GHG reduction strategy. After the energy sector, the transportation sector makes up the second largest reductions in MDE's plan, as outlined by the April 2013 GGRA Summary. These reductions are made largely through the Maryland Clean Cars Program, federal Corporate Average Fuel Economy (CAFE) standards, and public transportation initiatives. This chapter discusses in further detail the programs aimed at reducing GHG emissions from this sector. While there are several effective programs in place and promising proposals, many of these initiatives are underfunded and politically unpopular, making Maryland’s transportation reduction goals difficult to attain.

Emissions from Transportation in Maryland

The transportation sector is the second-largest GHG emitter and the largest CO₂ emitter in Maryland. Within the transportation sector, 91% of these emissions come from on-road vehicles, the remainder from off-road vehicles. Light-duty vehicles, which include passenger cars, sport-utility vehicles (SUVs), and minivans contribute 82% of the on-road vehicle emissions, while medium/heavy-duty trucks, which include buses, commercial vehicles and semi-trailer trucks, contribute 18%. There were 56 billion vehicle miles traveled (VMT) in Maryland in 2010, ranking 21st among states in the country. This partly reflects the fact that 73% of Marylanders drive alone to work, while only about 8.62% used mass transit.

Also contributing to the problem is the amount of freight traffic as, according to the Maryland Department of Transportation, 82% of all freight was moved by highway in 2006. Highways thus account for the largest share of GHG emissions from the Maryland transportation sector. Since Maryland is expected to grow in population over the next several decades, the transportation system, already largely at capacity and dated, will need to be upgraded and expanded to meet the increased demand. As such, reducing emissions from the transportation sector will be critical to ensuring a sustainable and functional network that meets the future needs of the state. In response to this imperative, Maryland included many transportation emission reductions goals within its climate legislation.

National Vehicle Standards

As part of the implementation of the 2009 GGRA, MDOT was mandated to produce a plan to help reduce emissions from transportation by 2012. Included in this plan are a wide range of programs, some of which have already been implemented or are being actively pursued. Of those currently being implemented, national standards including fuel efficiency and renewable fuel, while not administered by Maryland, do play a role in MDOT’s plan to reduce GHG emissions. For this reason, these standards are described here as they fit in with MDOT’s overall plan.
Fuel Efficiency Standards (CAFE)

The U.S. vehicle fleet is regulated under the Corporate Average Fuel Economy (CAFE) standards, which are administered by the EPA and the National Highway Transportation Safety Administration (NHSTA). EPA has recently established various new standards that significantly increase U.S. vehicle fuel efficiency. In 2012 the Obama Administration issued standards for the 2017-2025 model years for cars and light trucks, setting a 54 mile per gallon (mpg) standard by 2025. These new standards are expected to reduce GHG emissions nationwide by 2 billion metric tons.

This followed in the wake of an earlier regulation finalized in 2010 which mandated an increase of fuel economy of light-duty vehicles from 26 to 34 mpg for model years 2012-2016. Additionally, in 2011, the Obama Administration also revised CAFE standards for medium and heavy-duty trucks for model years 2014-2018, which is projected to reduce emissions by over 200 million tons of GHG over the life of vehicles built during those years.

The CAFE standards have generated considerable controversy over the years. Proponents have argued that they achieve lower emissions in a more effective way than other more traditional top-down measures. Costs incurred to the manufacturers and consumers are estimated to be more than offset by fuel savings over the lifetime of the vehicle. Proponents also argue that the standards are a good combination of command and control and market mechanisms, as there is a strong efficiency and emissions standard but considerable flexibility through the ability of firms to distribute the required improvements throughout their vehicle fleet and to engage in credit trading.

However, there have also been studies which suggest that other measures, especially direct fuel taxes, are more efficient at achieving lower emissions, since these directly penalize people for driving, providing an incentive to drive less. A tax is thus also perceived by its supporters to have wider social benefit like reducing congestion. Nevertheless, given the political unacceptability of significantly higher fuels taxes in the current political environment, the CAFE standards have become the default option for achieving greater fuel and emissions efficiency.

Since this a federal program, Maryland has no authority to implement or change this regulation. One major effect of the program is that for model years 2012-2016, Maryland will allow compliance with the federal standard to serve as compliance with the stricter Maryland Clean Cars Program standard. By MY2017, the national standards will be fully implemented and will harmonize with the Maryland standard.

MDOT has estimated that all of the national fuel economy programs will achieve around 7.48 MMT CO₂ equivalent reduction in emissions in Maryland by 2020. This is predicted to be one of the largest contributors to transportation GHG reductions, which is not surprising given Maryland’s heavy reliance on automotive transportation.
Emissions of GHG from the transportation sector in Maryland will also be impacted by the existence of a national renewable fuel standard (RFS) in the US. The original RFS was passed as part of the Energy Policy Act of 2005. This mandated that 7.5 billion gallons of renewable fuels (mostly biofuels) be used in the US by 2012. A revised RFS was implemented as part of the Energy Independence and Security Act of 2007 (EISA). This legislation increased the amount of renewable fuels to be used by the end of the decade, but it also mandated that 36 billion gallons be in use by 2022. It also directs that 16 billion gallons of this figure come from cellulistic biofuels.

The 2007 RFS also divides the fuel requirements into four separate categories—total renewable fuels, advanced biofuels, biomass-based diesel, and cellulosic biofuels, each of which has their own volume requirements. Biofuels must also usually meet certain lifecycle GHG emissions requirements. The regulation also describes how renewable fuels must be made from feedstock that meets biomass definitions.

To qualify as a renewable fuel under EISA, the fuel must reduce GHG emissions by at least 20% relative to conventional fuels. To qualify as an advanced biofuel, cellulosic and agricultural waste bio fuel, or biomass-based biodiesel, the fuels must reduce GHG emission by 50%, 60%, and again 50%, respectively. EPA is responsible for monitoring and ensuring that the mandated percentage of renewable fuels is achieved each year. Each gallon of fuel is assigned a Renewable Identification Number (RIN). RINs can be used for current year or next year’s RVO requirements, thus giving each RIN a two year lifespan. Importantly the RIN can be separated from the gallon of fuel, and be sold to other producers to meet their renewables requirements. In essence this has created a market for trading in RINs.

A main purpose of the RFS is to promote the rapid development of a renewable fuels industry in the US. According to its proponents, this will not only decrease carbon emissions, but will also provide several other benefits. A RFS will promote energy production from a renewable domestic source, which will reduce reliance on foreign energy imports and thus increase US energy security. The cultivation of a renewable fuels industry will also have positive economic benefits for agricultural and rural communities, both in terms of increased agricultural demand and in employment.

However, there have been many problems associated with the RFS. One of the most pressing is the diversion of food and land to growing biofuels. These processes are energy intensive, and reduce the food supply, which is especially worrisome for poorer countries that rely on food imports from the United States. Critics also argue that by “picking winners” the government is promoting biofuels at the cost of other potentially useful technologies, and that a more technologically neutral policy would be more appropriate. Moreover, there is difficulty in measuring the total GHG impact of biofuels production, because the resulting changes in land-use patterns are also associated with increases in GHG emissions. Also, there is criticism that an RFS unjustly uses taxpayer money to support an already favored industry, namely big agriculture.
Federal support for biofuels has been significant in recent years, with total federal support reaching $7.8 billion in 2011. However, most of this support has been in the form of tax credits most of which expired in 2012. In that year, federal support dropped to about $1.3 billion. However, the cellulosic biofuels tax credit and the biodiesel tax credit, $1.01 and $1.00 per gallon respectively, were extended through 2013.80

As shown in Table 3.1, taken from a 2011 National Academy of Sciences report detailing the amount of subsidy required for various biofuels, there is considerable doubt as to the competitiveness of many biofuels. The NAS concluded that only under very high oil prices, technology breakthroughs, and a high carbon price would biofuels be competitive with petroleum fuels without a government subsidy.

<table>
<thead>
<tr>
<th>Feedstock</th>
<th>Willingness to Accept</th>
<th>Willingness to Pay</th>
<th>Price Gap (Per Dry Ton)</th>
<th>Price Gap (per Gallon of Ethanol)</th>
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<tbody>
<tr>
<td>Corn Stover (stalks, leaves, and cobs)</td>
<td>$92</td>
<td>$26</td>
<td>$67</td>
<td>$0.96</td>
</tr>
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<td>$26</td>
<td>$66</td>
<td>$0.94</td>
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<td>Alfalfa</td>
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<td>$1.31</td>
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<td>$106</td>
<td>$1.51</td>
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<tr>
<td>Switchgrass in Appalachia</td>
<td>$100</td>
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<td>$74</td>
<td>$1.06</td>
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<tr>
<td>Miscanthus in the Midwest</td>
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<td>$89</td>
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<tr>
<td>Miscanthus in Appalachia</td>
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<td>$0.93</td>
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<td>Forest Residues</td>
<td>$78</td>
<td>$24</td>
<td>$54</td>
<td>$0.77</td>
</tr>
</tbody>
</table>


Again, since the RFS is a federal program, Maryland does not have direct control over implementation. However, MDOT estimates that Maryland’s emission reduction would be minor at about 0.24 MMT CO₂e by 2020.81

Proposed Solutions for Reducing Maryland Transportation GHG Emissions

MDOT’s GHG reduction plan also includes several programs and initiatives that Maryland could adopt as part of its GGRA effort. However, a considerable fraction of the initiatives mentioned in the Draft Plan are unfunded or unplanned, so that MDOT does not expect to meet its targeted emissions reduction goal by 2020.

There are several main categories of programs in the 2011 Draft Plan. The first has mainly to do with the automotive sector. These policies include improving vehicle power technologies and improving vehicle fuel economy standards, as well as renewable fuel standards. These initiatives are intended to reduce the carbon intensity of the transportation sector, and in particular the automotive sector. Also included are several other initiatives including public transportation.
expansion, freight rail improvements, bike and pedestrian initiatives, other transportation technologies, and more compact land use. These initiatives are largely designed to reduce reliance on the highway modes and shift traffic onto less carbon-intensive modes like buses and trains, as well as reducing travel demand by promoting close proximity between different activities, including homes, businesses, and recreation. While there are some other programs mentioned in the Draft Plan, due to their ambiguity and lack of quantification, they have not been included in this analysis.

Low Carbon Fuel Standard

A Low Carbon Fuel Standard (LCFS) is a policy instrument that is used to reduce the carbon content over the entire life cycle of transportation fuels used in vehicles. It sets a cap on the amount of GHG emissions which a fuel can emit during its lifetime from production to final combustion, and all fuel producers must ensure that the fuels they manufacture meet this standard by reducing its GHG content, or by purchasing credits from other regulated parties which will help them meet their own goal.

California is the only state in the nation which has a currently functioning LCFS program. Several states, including Maryland, are investigating the possibility of implementing their own programs which are largely based on California’s. As such, the California program is described below to give a description of the overall LCFS model.

California’s LCFS was designed and implemented in 2011 by the California Air Resources Board (CARB). It aims to reduce the total carbon emissions for the life cycle of petroleum based fuel sources by 10% in 2020. This is to be accomplished by setting a declining cap in total GHG emission over time. Regulated parties include fuel producers, blenders, and refiners, and they are required to submit regular reports every quarter to demonstrate their compliance with the LCFS.

Currently, the success of the California LCFS is unclear, partly owing to the short time it has been in effect. The LCFS has met several legal challenges from fuel producers. Currently, several out of state fuel producers are suing California for discriminating against them and thus violating the interstate commerce clause of the constitution. These producers claim that because takes more energy to deliver out of state fuels to California, the process generates more GHG emissions than in-state sources, thus putting out of state producers at a disadvantage. The case is still being reviewed by the federal Ninth Circuit Court of Appeals -- the decision could lead to a major revision or abandonment of the LCFS.

Studies have suggested that an LCFS can be a potentially effective means of securing GHG emission reductions in transportation. In contrast to a renewable fuel standard, a LCFS is more flexible in its approach, allowing producers to determine the ways they want to reduce emissions from their fuels over the allotted time period. Given the inbuilt market for emissions credit trading, a LCFS can harness market forces that will incentivize fuel producers to produce carbon credits to sell to other producers who do not meet the standards.

An LCFS is also potentially more flexible than other more traditional regulatory approaches like a carbon tax, since it allows producers to pursue the most cost effective approaches to reducing
carbon intensity. It is also more effective than other market-based policies like a renewable fuel standard since it does not mandate a certain type of fuel or process that has to be used; this allows fuel producers to use multiple processes and integrate them so as to achieve the most efficient and cost-effective options menu for achieving their mandated GHG targets.\textsuperscript{84}

However, an LCFS has been criticized as expensive and not cost-effective when compared to other options like carbon taxes and a broader cap-and-trade regime. It is generally not considered as efficient as a carbon tax, since it is punishing producers and does not prevent consumers from using more fossil fuels. It is also suggested by critics than the program will reduce production of high emissions fuels but stimulate the greatly expanded production of low emissions fuels, which may lead to a net increase of emissions overall. There are concerns that it imposes too many costs on certain groups for limited benefits. There are further estimates that it is extremely expensive to reduce emissions this way from a larger societal viewpoint, and some calculate that an LCFS reduces consumer welfare overall.\textsuperscript{85}

While no plans exist to actually implement an LCFS in Maryland on the purely state level; there is a regional compact that has put forward some preliminary work on the matter. The Northeast States for Coordinated Air Use Management (NESCAUM) is the organization that is coordinating a planned Northeast and Mid-Atlantic LCFS. A compact was signed in December, 2009 between the New England states, New York, New Jersey, Delaware, Maryland, and Pennsylvania. Some preliminary studies have been undertaken to analyze what this operation would involve.

The program would be largely based on the California LCFS. However, only preliminary work has been undertaken as to the exact format of the Northeast/Mid-Atlantic LCFS, and as of this writing, the regional collaborative appears to be stalled with no further action being taken to actually implement a realizable LCFS within the region. However, an economic assessment carried out by NESCAUM in 2011 estimated that regional GHG emissions would be reduced at or below a 10% reduction goal depending on oil prices, with positive cost-benefit ratios under high oil prices.\textsuperscript{86} MDOT estimates that Maryland will see emissions reductions by 2020 of 1.21-2.24 MMT CO\textsubscript{2}e, depending on if either a 5% or 10% reduction goal is implemented by the Northeast and Mid-Atlantic states.\textsuperscript{87}

Public Passenger and Freight Rail Transportation

Improvements in public passenger and freight rail transportation have been estimated by the Maryland greenhouse transportation plan to provide a small but significant amount of GHG reductions in the years leading up to 2020. This includes several different programs, including expanded commuter rail facilities and service through the Maryland Area Regional Commuter (MARC), such as increased track capacity at various choke points, purchase of more and newer equipment, more frequent trains, and extension of service in some areas such as northeastern Maryland; construction of new metro and light rail lines such as the Red Line in Baltimore that will serve as a connection between downtown and the eastern and western ends of the city, and the Purple Line in Prince George’s and Montgomery Counties, which will serve as a connection between the existing metro station at Silver Spring and the rail and metro station at New Carrollton; working with federal authorities to expand intercity Amtrak between Baltimore and
Washington, including capital improvement projects like expanded track capacity and rebuilding the BWI Airport station.\textsuperscript{88}

Freight rail will be improved through projects like increased rail tunnel capacity in Baltimore, which has been a major bottleneck, as well as increased rail facilities in the city. A partnership between Maryland and CSX railroad to increase the height clearance of CSX’s lines through Maryland will allow the rail system to move more freight between the Midwest and the port of Baltimore. Other projects include increased bus services and the construction of a new bus terminal in Baltimore.\textsuperscript{89}

There have been many studies written on the efficiency and desirability from an environmental, energy, and social standpoint of increased use for rail and public transport over roads. Trains are usually more fuel efficient than cars and trucks, and emit fewer GHG emission per passenger- or ton-mile than do road vehicles. They also help to reduce congestion and are safer on a per mile basis than cars and trucks. A report from the National Renewable Energy Laboratory (NREL) released in March 2013 concluded that shifting more freight to rail and waterborne transportation would greatly reduce GHG emissions. For example, rail can move a ton-mile of freight on 0.4 BTUs, while a truck requires 4 BTUs. The NREL report also states that a major shift of freight to rail is possible, given that rail has a relatively small current share of total freight, and rail often parallels major highways.\textsuperscript{90} Use of truck “piggyback” on rail cars allows for combinations of rail and truck that could be more fully utilized and also leads to efficiency improvements.

Given the large amount of investment already made in highway transport, achieving a major shift to railroads and other forms of mass transit could be politically difficult. Given the developed infrastructure of roads, a revision of investment priorities would be needed for mass transit to lead to an actual and substantial reduction in driving and its GHG emissions.

MDOT estimates that public transportation initiatives will achieve about 0.277 MMT CO\textsubscript{2}e in reductions in Maryland by 2020. This would come at a cost of $6.963 billion over the 2011-2020 time period. There is no MDOT estimate for rail emissions reductions, but it does estimate the cost for rail projects to be $3.085 billion over 2011-2020.\textsuperscript{91} These estimates reflect the findings of other studies which suggest that public and rail transit expansion comes at high costs but with ambiguous emissions reductions.

The prospects for achieving such projected transportation-related GHG reductions are uncertain or even quite doubtful. Many projects, such as the MARC expansion plan, Red Line construction, and others are either being held up in their planning and development processes, or are not being allocated adequate funds, so again, their success will depend on a shift in investment priorities from additional highway construction to mass transit and freight rail. The decision as to whether Maryland should take a stronger approach to mass transit is an important one, for despite some ambiguity, if there was a major shift to public transportation, this could potentially reduce greatly vehicle emissions, albeit at a relatively high cost.
There are several Maryland strategies for improving bike and pedestrian facilities to decrease driving and other carbon intensive forms of transport. Some of the most common include building bike paths, increasing bike access and availability, increasing the amount of sidewalks, and making sure pedestrians and bicyclists are separated from motor traffic to ensure safety. In short, this strategy promotes the infrastructure and ease of use necessary to encourage more cycling and walking, and thus reduce more carbon intensive forms of transport, especially driving.

However, a problem with these strategies is that their effect is quite limited in actually reducing GHG emissions unless they are done in conjunction with land use policies that promote compact communities, with facilities in relatively close proximity to one another, or are built in communities which are already compact.

One study estimated that between 2010 and 2025, total on-road GHG emissions would only be reduced by 0.15% to 0.4% nationally across the United States due to pedestrian improvements, and a similar amount to cycling improvements. MDOT estimates that for funded bike and pedestrian improvements the total cost to Maryland will be $1.385 billion, but this only achieves 0.001 MMT CO$_2$e in Maryland. There is a Maryland statewide bike plan, but apparently it has not been substantively implemented.

This strategy has various components, many of which were not explored in great detail in the MDOT Draft Plan. These strategies are essentially methods by which governments can reduce travel demand as whole, and thus lead to fewer GHG emissions. One of the most important means by which this can be accomplished is through land use regulations, especially those that concentrate development and promote mixed use between residential, commercial, and recreational activities. This allows people to live in closer proximity to where their main activities are, and they thus do not need to travel as much, and when they do it is more feasible for them to choose less GHG-intensive modes such as mass transit or biking.

Other methods are designed to price travel so as to encourage people to travel less and/or use less emissions-intensive modes. This can include methods like parking fees which people have to pay every time they travel and use their cars. Other fees can include increased gas taxes, as well as vehicle miles travelled (VMT) taxes which charge people a certain amount for the number of miles they drive, usually over a year. Congestion pricing charges people tolls when driving on roads during the most congested periods and most congested places.

There have been studies which suggest that pricing and congestion fees can be quite effective policies, achieving several percentage points lower vehicles miles travelled in a given year if they are all implemented together. However, these pricing policies are heavily dependent on the price elasticity of drivers. Indeed, there is mixed evidence as to how responsive drivers would be to even substantial price increases on automobile use. Land use regulations are also difficult to
implement, especially in the United States, given its dispersed settlement patterns. Pricing is also politically contentious in the heavily anti-tax climate of current American politics.95

MDOT anticipates that 0.199 MMT CO$_2$e in reductions will take place at a cost of $1.397 billion. This is for currently funded programs.96 Beyond that, it is ambiguous as to what specific measures the state is taking to implement these kinds of programs. They are apparently diffused across many different transportation components. And, also again, it is unclear if the state will provide the necessary funds to implement these programs in a serious way.

The Final Plan in July 2013 included enhanced transportation measures designed to achieve greater GHG reductions. It estimated that enhanced “pricing measures” in the transportation sector would generate 2.3 MMT CO$_2$e in GHG reductions, an increase from the previously estimated 0.41 MMT CO$_2$e from pricing measures in the absence of the enhancements. These newly proposed pricing measures – representing 63 percent of new transportation enhancements in the Final Plan -- are not clearly spelled out and might be politically difficult. Although counted as estimated Maryland GHG reductions for 2020, this is an example of the inclusion of estimated reductions in the Final Plan for which there are large uncertainties as to whether they might actually be realized.

**Discussion and Recommendations**

While there are some other programs that are related to transportation, both under MDOT jurisdiction and other state agencies, the components listed above are the most important ones. As can be seen, the MDOT plan contains some ambitious program goals that in theory will have a substantive impact on transportation GHG emissions. It does seem that Maryland is moving in a positive direction in terms of improved transportation policies. Many of the strategies described above have the potential to substantially reduce emissions, and given the broad scope and flexibility of many of them, there is ample room to be positive.

However, there remains considerable room for improvement. The MDOT report itself admits that given the degree of uncertainty for its list of programs, and even the absence of other components, the transportation sector will not be able to meet its GGRA designated emissions reduction target by 2020. As shown in Figure 3.1, a business as usual projection shows GHG emissions from the transportation sector rising by 27%, while the Maryland transportation plan seeks a GHG reduction of 25%. Thus, relative to business as usual, the total reduction in GHG emissions from the transportation sector alone would have to be 52%, a difficult task at best.
MDOT estimated the impacts on transportation-related GHG emissions from fully implementing the above strategies. The Maryland transportation plan includes actions for which funds are not currently available. Excluding these actions, but assuming all the other transportation GHG reductions were fully implemented, the transportation reduction in GHG emissions would be 13%, compared with the GGRA-mandated target of a 25% reduction. If implementation of the unfunded programs is included in the calculations, the transportation reduction in GHG emissions by 2020 would rise to 18%, but this is still well below the GGRA target. The Final Plan in July 2013 includes projections of an additional 3.0 MMTCO2e in GHG reductions from transportation sector enhancements that seek to address this problem but are unlikely in fact to be realized.

Besides the fact that the programs will not be able to fulfill the mandates from the GGRA, the list of programs is just that -- a list rather than a full strategic vision. The initiatives listed in the MDOT Plan are practically all programs that have been implemented not in response to the GGRA, but as part of preexisting transportation programs. Several of the federal fuel efficiency programs mentioned here are not even the responsibility of Maryland. As such, there appears to be less of a strategic vision for GHG emission reductions in transportation, and more of an ad hoc approach adopted in reaction to the legislature’s mandate.
Further, as has already been discussed, many of these programs have serious limitations, such as negative externalities, high expense for low or ambiguous emissions reduction benefits, complex interaction with other initiatives, a necessity to be implemented with other complementary programs, etc. So there is room for doubt as to whether the programs mentioned in the Plan will be able to deliver the results MDOT has estimated. This fact, coupled with those already mentioned, lead to serious misgivings about the true practicality and effectiveness of the transportation emissions reduction plan. The following recommendations include several points of consideration for strengthening the effectiveness of this plan.

1. **Study the possibilities of integrating emissions reduction programs more closely so that a more cohesive and robust GHG transportation strategy can be developed.** Many of the research reports examined in this chapter find that almost all of the policies employed to curb transportation GHG emissions depend on other factors, and may be most effective when employed as part of a package of options.

2. **Study options which were not included in the MDOT GHG report.** One key program category not currently implemented or studied as part of the Maryland transportation emissions Draft Plan is taxes or fees which impose costs and can serve as a deterrent to driving. Given that many studies have concluded that these initiatives could potentially be quite effective at GHG emissions reductions, it might be worthwhile for Maryland to study them seriously. Politically, however, significant GHG reductions in this manner might be difficult to implement.

3. **Develop longer term transportation strategies for reducing dependence on automobiles and related GHG emissions.** While many of the options for doing this, such as increasing rail service, have been shown to have relatively small short-term effects on GHG emissions, there are still good reasons to begin a long term transition away from automotive transportation to less carbon-intensive modes. This will require large shifts in investments away from roads towards mass transit, rail, bicycling, and other more GHG efficient modes. It would also require a serious redesign of land use laws and procedures which would actually encourage compact development and mixed use so as to reduce travel demand overall.

4. **Consider integrating Maryland transportation programs into other climate programs, such as cap-and-trade.** Many transportation programs are often implemented in isolation to one another, and in isolation from other GHG programs. Many current and proposed LCFS and biofuels programs outside of Maryland have credit trading regimes. These could potentially be integrated into the currently operating RGGI cap and trade regime for the electricity sector in Maryland and other mid-Atlantic and Northeast states. This might have the benefit of adding flexibility to both types of programs and allowing market forces to assist firms in using the most cost-effective means for reducing emissions in all pertinent sectors. There is already an inherent interconnectedness of GHG emissions across sectors, and even though it might be more complicated, if it was well-designed it could help to promote a more cohesive and integrated GHG emissions strategy for the future.
Chapter 4: Energy Efficiency and Maryland GHG Emissions

According to the 2013 Executive Summary of the GGRA, the energy sector will account for 25.3 MMTCO\(_2\)e in GHG emissions reductions annually. Over one-third of these reductions will come as a result of EmPOWER Maryland, an energy efficiency initiative established in 2008. This implies that while emissions reductions in electricity production are important, energy efficiency and demand-side management will also play an important role in Maryland’s GHG emissions strategy.

Through the launch of the EmPOWER program, the state demonstrated its commitment to energy efficiency, which is often the fastest and most cost-effective approach to reducing emissions. However, despite some modest success, EmPOWER has not necessarily translated into the anticipated reductions in GHG emissions as Maryland has diverted funds away from further energy efficiency measures and the electricity market has so far encouraged leakage rather than continued efficiency improvements. For these reasons, emissions reductions from the program may in fact be overstated. Given that EmPOWER Maryland plays such a large role in Maryland GHG policy, substantial changes to the current program dynamic may need to be made in order to meet the state’s GGRA goal.

**Background on EmPOWER Maryland**

The EmPOWER Maryland initiative, created in 2008, has a goal of a 15% reduction in per capita energy consumption and per capita peak energy demand by 2015, compared with a 2007 baseline. Peak demand is the maximum amount of power supply needed for Maryland at one time in order to keep electricity running.

A primary component of EmPOWER involves residential energy consumption changes. The EmPOWER Energy Efficiency Act of 2008 requires that Maryland’s five utilities (BGE, Delmarva Power, Pepco, Potomac Edison, and Southern Maryland Electric Cooperative [SMECO]) develop energy-saving programs that help lower demand. BGE’s Smart Energy Saver’s program, for example, offers rebates for HVAC systems, duct sealing, Energy Star products, and the recycling of appliances such as old refrigerators. For a small fee, BGE also offers Energy Star audits to check for air leakage, insulation effectiveness, and dangerous natural gas and carbon monoxide leaks. From there, BGE may install faucet aerators, pipe insulation, and other tools to save energy. Another program, BGE’s PeakRewards program, offers financial incentives for users to turn off their air conditioning systems during times of peak electricity demand. Delmarva Power and Pepco offer similar Energy Wise programs. In addition, the state itself, through the Maryland Public Commission, has approved higher rebates through 2014.

Another component of the program is the EmPOWER Maryland Low Income Energy Efficiency Programs (LIEEP) run by the Maryland Department of Housing and Community Development (DHCD), which provides free installation of energy-saving materials to low income homes. Improvements offered include lighting retrofits, added insulation, and furnace cleaning.

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97 Peak demand is the maximum amount of power supply needed for Maryland at one time in order to keep electricity running.
98
99 BGE’s Smart Energy Saver’s program, for example, offers rebates for HVAC systems, duct sealing, Energy Star products, and the recycling of appliances such as old refrigerators. For a small fee, BGE also offers Energy Star audits to check for air leakage, insulation effectiveness, and dangerous natural gas and carbon monoxide leaks. From there, BGE may install faucet aerators, pipe insulation, and other tools to save energy. Another program, BGE’s PeakRewards program, offers financial incentives for users to turn off their air conditioning systems during times of peak electricity demand. Delmarva Power and Pepco offer similar Energy Wise programs. In addition, the state itself, through the Maryland Public Commission, has approved higher rebates through 2014.
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These consumer programs represent 10% of the total emissions reductions from EmPOWER while the other 5% is to be achieved through efficiency measures implemented in state government operations.

In combination with StateStat, a performance measurement system created by Governor O’Malley, state agencies must create plans for better energy use, including designating energy conservation plan leaders. The state has pushed for improved building operations, including the use of Energy Star products. Some of these efforts include low-cost options such as the utilization of compact fluorescent lights (CFLs) and individual employee plans and behavioral changes. The Energy Performance Contracting (EPC) program has allowed agencies to improve energy efficiency in facilities through the hiring of energy service companies to start improvement projects.

Additionally, the state provides loans through the State Agency Loan Program (SALP)’s zero interest revolving loan program to support projects such as energy efficient lighting, heating, and air conditioning. A final loan program is the Expand Community Energy Loan Program (CELP) that provides low interest revolving loans to local governments and nonprofit organizations to install energy efficient improvements. To further expand and improve this program, the Maryland Energy Administration has suggested providing more funding to hospitals, schools, and local governments.

In its latest program, the Maryland Smart Energy Communities initiative, the state provides grant funding to cities and counties to adopt energy efficiency, renewable energy, and transportation gasoline reduction policies and plans. The local government must adopt two of the three policies as a requirement of the program. Thus, local governments choose between establishing an energy consumption baseline and a five year 15% reduction plan, implementing 20% of energy generation from renewable sources by 2022, or finding the petroleum consumption baseline for governmental vehicles in the district and planning to reduce this baseline by 20% within five years.

**Progress in the Program**

From 2008 through September 2012, EmPOWER Maryland has helped to fund measures that will reduce energy usage of ratepayers by 2.0 million MWh per year, reduce peak demand by over 1,000 MW, and save ratepayers $250 million annually in avoided electricity bills. MEA estimates that these savings will continue to save “ratepayers $3.7 billion over the useful life of currently installed investments.”

StateStat reports annually on Maryland’s progress towards meeting the EmPOWER Maryland energy consumption goals. Figure 4.1 shows the current progress indicators listed on StateStat.
According to StateStat, EmPOWER Maryland is currently on track to meet its peak demand goal, having reduced peak demand by 10.8% in 2012 from the 2007 baseline. However, the program is not on track to meet the per capita consumption goal, having reduced consumption by 9.4% in 2012 from the 2007 baseline. Significant reductions still need to be made to meet the 15% goal by 2015. Figure 4.2 illustrates actual and predicted per capita energy usage in Maryland. The trend for energy use is significantly better than what would have occurred.
without the EmPOWER program, if energy consumption practices had continued on a ‘business as usual’ basis. Nevertheless, Figure 4.1 does not acknowledge that most reductions thus far have been due to national macroeconomic factors and mild weather. Assuming economic improvement in the next few years, the projections indicate that energy consumption will not meet the EmPOWER target per capita reductions of 15 percent by 2015.\textsuperscript{108}

Figure 4.3 shows Maryland’s progress towards the 2015 per capita peak demand goals. In 2015, per capita peak demand will be about .4 kW per capita below the business as usual projections according to MEA’s forecast. The current projections show that Maryland will exceed the goals in place, but these figures are contingent on economic output.\textsuperscript{109}

\textit{Why Energy Efficiency Reductions Are Not On Track}

While the success of EmPOWER has been modest, even much of that success correlates with economic downturn and mild weather.\textsuperscript{110} Further, EmPOWER implementation has lacked enforcement authority by MEA of the reduction goals for utilities.

Maryland is disadvantaged by the relative newness of the program. EmPOWER’s enactment in 2008 was Maryland’s first true push toward utility-oriented efficiency programs, so Maryland has a lot to learn and adjust to.\textsuperscript{111} Maryland utilities ran efficiency and demand response programs during the 1980s but deregulation of the utilities when they were restructured in the
1990s removed these initiatives. Other states such as Massachusetts and California, which perform better in energy efficiency measures, have had programs for decades, allowing administrators, businesses, and residents to gain an understanding of the processes of energy efficiency and of the different programs and requirements that come in conjunction.

*The Strategic Energy Investment Fund*

From the advent of EmPOWER in 2008 through 2011, MEA relied heavily on funding from the federal American Recovery and Reinvestment Act to finance energy efficiency programs in the state. As this source of funding closed off, MEA hoped to rely ever more so on the Strategic Energy Investment Fund (SEIF), which is comprised of revenues from RGGI permit auctions. However, while the SEIF revenues were initially expected to fund energy efficiency measures in Maryland, much of the fund was diverted to low-income utility rate relief.

A temporary amendment for March 1, 2009 to June 30, 2012 under House Bill 101: Budget Reconciliation and Financing Act of 2009 provided for emergency energy cost relief to Maryland consumers. This allocated the funds as 8.75% for low and moderate-income residential energy efficiency, 8.75% for multi-sector energy efficiency and conservation, 6.5% for clean energy and climate change through renewable energy measures, 23% for residential rate relief, 50% for low-income direct energy bill assistance, and 3% for administration. While this decision to support residential rate relief aided certain Maryland residents, it had negative implications for the success of Maryland’s energy efficiency programs.

MDE contracted the University of Maryland’s Center for Integrative Environmental Research to conduct a study to analyze the economic and energy impacts of auctioning off 100% of RGGI allowances in a state and using the proceeds to promote energy efficiency. The study projected energy efficiency improvements under three scenarios:

1. Baseline: If Maryland auctions 100 percent of RGGI allowances and uses 25% of auction revenue to stimulate efficiency improvements in electricity consumption, the state will only cut consumption 7.4% from 2007 levels.

2. 50% Efficiency Scenario: If Maryland auctions all of its allowances and allocates half of its auction revenue to efficiency improvements, then electricity demand will decline 1.3% per year in 2015 and 2.6% in 2020. This will achieve an 8.7% reduction from 2007, with $25 in annual savings per household, $25 million added to the state’s GDP, and 4,300 jobs in 2020.

3. 100% Efficiency Scenario: If Maryland auctions all of its allowances and allocates all of its auction revenue to efficiency improvements, demand will decline 4% annually in 2015 and 6% annual in 2025. This will achieve an 11.2% reduction from 2007, with $72 in annual savings per household, $500 million added to the state’s GDP and 1,700 jobs in 2020.

However, jobs and GDP gains are relatively small compared to Maryland’s overall GDP and employment figures. Also, these percentage reductions all depend on the year and may be altered by unforeseen and uncontrollable changes.
**EmPOWER 3.0**

MEA released a final report in March 2013 regarding the extension of the EmPOWER targets beyond 2015. The report seeks to influence and give evidence-based recommendations to the Senate Finance Committee and the House Economic Matters Committee. To develop the report, called EmPOWER 3.0, MEA worked with stakeholders such as the electric and gas utility companies, environmental advocacy groups and state agencies. While EmPOWER is authorized to continue beyond 2015, the legislature may need to change the statutory goals.

MEA found that electricity and natural gas goals should be set beyond 2015 with a focus on demand-side resources given that such changes in general cost less than other forms of emission reductions. To do so will require additional investment in energy efficiency and conservation programs from both electricity and natural gas, as well as continued investment in demand responses programs for electricity. Changes to EmPOWER should be implemented in combination, starting with, “… a collaborative effort to determine how much energy and demand savings are available for a given level of investment under a cost-effectiveness test that analyzes the true benefits of avoiding the marginal unit of energy supply.” Thus, EmPOWER 3.0 looks to realistically define, analyze, and implement policies based on costs effectiveness of the programs. Accountability to ratepayers and realism regarding the process of increasing energy efficiency has become more focused concerns.

MEA’s recommendations for updating EmPOWER are as follows:

1. Determine the true lifetime value of saving a MWh of electric energy, a MW of electric capacity, and an MMBTU of natural gas (the “avoided cost of supply”).

2. Define the parameters of a cost effectiveness test to be used when analyzing a portfolio of programs.

3. Establish the EmPOWER Planning Group, comprised of state agencies including MEA and the Public Service Commission, electric and gas suppliers and utilities, and other public and private stakeholders, to collectively determine the quantity and cost of achievable savings available in Maryland by fuel type and sector.

4. Set achievable EmPOWER goals that specify minimum annual energy and demand reduction while authorizing the Commission to approve programs up to the cost effectiveness test threshold.

5. Implement programs through standardized offerings following industry best practices to the greatest extent possible.

Projections for demand response programs indicate much slower progress toward energy efficiency goals in the coming years. These projections assume that the program will “continue to achieve reductions beyond 2015 at 50% of the 2015 rate.” The struggle with doing so is that the easy, lowest cost energy reductions may already have been done and the process to achieve the reductions needed to meet the set goals may require aggressive, high cost, and unrealistic
changes. On the other hand, a hope for energy consumption changes could come in the form of an electricity pricing system that more readily follows consumer energy consumption and thus, creates a market-based incentive for reductions.

MEA also recognized the need to focus on commercial and industrial sectors, which will most likely provide the most cost effective way of reducing energy consumption, to standardize utility program offerings, and to change the statute to allow for penalties and incentives for utilities at the discretion of PSC.

**Importance of EmPOWER in Achieving GGRA Targets**

EmPOWER is a significant part of Maryland’s emissions targets under the GGRA. Yet, without coupling the program’s challenges with the realities of electricity markets, the program’s progress towards real emissions reductions is limited.

According to estimates by MDE, EmPOWER can yield a maximum potential CO₂ reduction of 7.27 MMTCO₂e and a minimum reduction potential of 5.4 MMTCO₂e out of the GGRA’s 57 MMTCO₂e by 2020 by implementing a maximum 20% per capita demand reduction by 2020. Each kilowatt-hour of electricity use that is avoided translates to CO₂ reductions. Thus, the compilation of all EmPOWER’s individual programs, whether on a residential, industrial, or countywide scale, pushes Maryland toward GHG reduction goals.

However, according to Tim Welch, author of a University of Maryland PhD dissertation evaluating the State’s GHG plan, Maryland’s actual reductions in CO₂ arising from EmPOWER Maryland may be less than projected. While Maryland’s reduced energy consumption would theoretically mean less power is needed to support Maryland residents, businesses, and other utility-users, not every region of the grid has these energy efficiency initiatives and thus may absorb increased power availability that results from Maryland’s actions.

The PJM grid was not structured to promote efficiency. The utilities on PJM operate on fifteen-year time scales; building power plants to meet the projected demand in this time period. These plans were made before EmPOWER was enacted, so there are already processes underway to expand the power producing capacity of PJM. In addition, when Maryland reduces energy consumption, due to the current infrastructure and low cost of maintaining a certain power supply, utilities may simply move the unused energy of Maryland to areas where demand is growing. Therefore, Maryland’s efforts to reduce energy consumption and CO₂ emissions could be offset by increases in other regions.

Welch thus states,

> While EmPOWER Maryland reportedly has been effective in reducing demand, the goals of the program do not necessarily coincide with the realities of the power generation market. Utilities in Maryland are connected to the PJM network, which coordinate the distribution of power and planning for future needs on a 15-year planning horizon. Most future power plant expansions are connected to the PJM network, which coordinates the distribution of power and planning for future needs on a 15-year planning horizon. Most future power plant expansions and retirements were long since planned beyond 2015 and...
the GHG emission reduction goal of 2020. Thus, any reduction in demand in the home market likely will result not in a reduction of generation and emission but the exporting of power as demand response to other markets on the PJM interconnect.123

Recommendations

1. **Increase Maryland funding for energy efficiency measures.** Spending on energy efficiency improvements offers one of the most cost-effective methods by which Maryland can take actions to reduce future GHG emissions. Improving energy efficiency should therefore be central to Maryland’s overall GHG reduction strategy. Attractive possibilities include local energy efficiency initiatives such as the Maryland Smart Energy Communities program; real-time pricing mechanisms for utilities; advertising of energy efficiency programs and products; greater use of smart grid technologies; increased implementation and enforcement of PSC utility demand reduction plans; and expanded subsidized loan or guaranteed loan programs for energy efficiency improvements.

2. **Commit more of the Strategic Energy Investment Fund (SEIF) revenues (obtained by Maryland from RGGI auctions) to energy efficiency programs, their original purpose.** Maryland has diverted much of the SEIF funds into subsidies for portions of low-income households’ utility bills. This budgetary choice has limited Maryland’s success with energy consumption reductions and in the long run will hinder the potential to achieve future GHG reduction targets.

3. **Maryland’s Public Service Commission (PSC) should strictly enforce EmPOWER guidelines on utilities and streamline the approval process of utility energy efficiency improvements.** PSC has been slow to approve utility plans for energy reductions and has been even less inclined to impose penalties against utilities that do not adhere to its guidelines. PSC must evaluate the cost effectiveness of these programs and move forward to ensure that economically feasible plans are implemented.
PART II – ENHANCING THE ROLE OF THE REGIONAL GREENHOUSE GAS INITIATIVE (RGGI) IN REDUCING GHG EMISSIONS IN MARYLAND AND OTHER RGGI STATES
Chapter 5 – RGGI Auctions

In RGGI, a cap is set by the participating states on total CO₂ emissions. Allowances to emit CO₂ are distributed through auctions, in concept allowing the price of an allowance to be determined by the market. Ideally, the emissions cap and the price of allowances work together in order to achieve the desired emission reductions through the cap-and-trade system. However, in the years since the RGGI auctions began to occur, the system has suffered from an overly high emissions cap, causing excess supply, which has reduced the price of allowances to the administratively permitted minimum. In 2012, RGGI, Inc., the non-profit corporation created to support the implementation of the cap-and-trade system, conducted a review of the program. The review recognized these programs and RGGI has attempted to correct the system by implementing changes to the Model Rule which establishes the auction procedure. This chapter discusses the weaknesses of the RGGI auction system, the changes to the Model Rule that seek to address these weaknesses as well as suggestions for further improvement.

The RGGI Auction System

Under RGGI, electric power generators in RGGI member states (Maryland, Delaware, New York State, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and Maine – New Jersey was an original RGGI member state but has since withdrawn) must hold allowances equal to their permitted CO₂ emissions. Utilities obtain these allowances by purchasing them at RGGI auctions, which began in September 2008 and are held quarterly. Each allowance enables a generator to emit 1 ton of CO₂.

The number of allowances is determined by a gradually reducing carbon dioxide emission cap. The available allowances to be sold at auction during a given year are approximately equal to the current level of the carbon dioxide emission cap. Therefore, as the cap tightens, allowance prices in theory should increase, thereby motivating generators to tighten emissions. States are allocated a certain proportion of emissions allowances based on historic emission levels. States auction off almost all of those emissions to raise funds, most of which are reinvested into energy efficiency measures to benefit citizens, as discussed in Chapter 1.

While each member state retains the authority to determine how the auctions will be run, auctions typically follow the format specified by the RGGI Model Rule that states have adopted. The auctions are conducted using a “single-round, sealed-bid, uniform-price format,” meaning that individual bidders submit confidential bids for a certain number of allowances at a certain price. Bids are accepted starting with the highest bids and acceptances then continue to lower bids until there are no remaining allowances available or all the bids have been accepted. The price paid for allowances is the price bid by the lowest accepted bid. RGGI has a minimum acceptable bid below which no allowances will be sold called the “reserve price bid limitation.” Bids that are submitted below the minimum reserve price will be rejected.

This price floor is currently set at $1.98 and for almost all auctions except the first few and most recent, prices have not risen above the clearing price set at the price floor. Figure 5.1 shows the allowance clearing prices for each of the 19 RGGI Auctions as of the spring of 2013.
For the auction held on March 13, 2013, the first since the RGGI cap and other action procedure changes were made under a new Model Rule in February 2013, the allowances cleared at $2.80.127 Another important statistic for this auction is the fact that bids were submitted to purchase 2.2 times the available supply of allowances. In comparison, at the 18th and 17th auctions, bids were only submitted to purchase 53% and 65% of the available allowances, respectively.128

World Energy Solutions, an energy management services firm located in Washington, D.C., administers the auctions and Potomac Economics acts as a market monitor of the conduct of market participants both in the allowance auctions held by RGGI Inc. and in the secondary market. Market participants’ behavior is observed to identify evidence of market manipulation or collusion. RGGI model rules prevent a single purchaser from purchasing more than 25% of the CO₂ allowances offered at that particular auction. However, anyone can purchase allowances at a RGGI auction provided they meet financial and other qualification requirements.129

After each quarterly auction, the monitor writes reports about the outcomes of each auction. The monitors produce a report for each individual auction and then produce a large final report at the end of the year. The reports provide useful synthesis information about the average clearing price for allowances, the types of bidders who participated, and whether there was any evidence of collusion. Based on experience to date, the RGGI auctions are working well and there is no evidence of gaming or fraud.

RGGI auctions are unique among carbon trading schemes because almost all the participating RGGI member states, including Maryland, auction 100% of available allowances. The one exception to this practice were Early Reduction CO₂ Allowance awards (ERA). The RGGI member states received 2.4 million ERAs as a one-time award to distribute to power generating operators that applied for these allowances by May 1, 2009. To qualify, operators or power plant owners had to demonstrate a reduction in both absolute CO₂ emissions and an improvement in
CO₂ emission rates (lbs CO₂ /MWh) between 2006 and 2008, relative to the baseline period from 2003-2005.\textsuperscript{130}

The revenues from RGGI auctions are distributed among the RGGI member states according to a predetermined formula. New York receives the highest share of the total RGGI auction revenues, equal to 37%, followed by Maryland at 20%. RGGI auctions have generated $1.5 billion through September 2013, meaning that member states have received substantial funds from the program overall.\textsuperscript{131} Maryland alone has received $300 million.\textsuperscript{132}

**The Problem of Excess Allowance Supply**

When RGGI auctions began five years ago, the original Memorandum of Understanding called for a 2012 program review. The review consisted of a comprehensive evaluation of the RGGI program. When RGGI member states conducted the 2012 program review, they identified several main problems, the most significant of which was the excess supply of allowances. Also, while some allowances had no buyers, other allowances that were sold were not used in the year of their sale and were “banked” for use in future years. This has resulted in a large supply of privately held banked allowances that threatened to undercut any future cap reductions RGGI might make to reflect the lower demand for allowances.

During the first 18 RGGI auctions, 20% more allowances were offered for auction than emissions were generated. By 2012, RGGI estimated that there are now 115 million privately banked allowances. This large number of banked allowances has meant that generators could comply with the original cap for at least one year without purchasing any additional allowances. Figure 5.2 shows the original cap in red, the amount of banked allowances as a straight line at 115 million, and the current and projected emissions in the light blue line that changes to purple. The portion in purple is the projected emissions as estimated during the program review.

**Figure 5.2 RGGI Program Review: Current and Estimated Emissions Levels**

![Figure 5.2 RGGI Program Review: Current and Estimated Emissions Levels](source: Maryland Department of the Environment presentation by Diane Franks, March 5, 2013)
While utilities still needed to hold allowances equal to their emissions, the prices were so low that there was no incentive to reduce emissions at the plant level. In effect, because the cap was so much greater than utility needs for allowances, contrary to the original intent, RGGI was actually having little if any effect on total CO2 emissions in the RGGI member states. Utilities needed allowances sufficient to cover their emissions which they bought at the RGGI administratively set minimum price of $1.89, this price thus amounting to a small emissions tax in the absence of any bidding competition.

Figure 5.3 shows the results of another RGGI analysis of auction results during the period from 2009-2011. Although in 2008 and 2009 all of the RGGI allowances offered had been sold, over this period only 69.70% of the 564,230,928 available allowances were sold. Of those that remained unsold, 4.75% were unsold and were not retired; 3.93% were transferred from State set-aside accounts which were designed to encourage renewable energy production; 3.07% remained as non-transferred set-aside allowances; 2.85% were non-transferred set-aside allowances that were retired; and 14.66% were unsold allowances that were retired.

**Figure 5.3 RGGI First Control Period CO2 Allowance Allocation (by Status)**

Between 2009 and 2011, the number of unsold allowances thus significantly increased as auction participants realized there was a significant surplus of allowances being offered in comparison to the emission levels. By 2011, 48% of the 177 million allowances offered for sale at auction went
unsold. In 2012, actual RGGI emissions of CO2 were 45% below the RGGI cap of 165 million tons, thus leaving a large excess supply that left many RGGI allowances unsold, and the price of allowances at the minimum floor.

Factors Leading to Excess Supply

These unsold allowances were the result of an overly high emissions cap as well as emissions reductions within the RGGI system. However, the reductions were mostly due to outside factors rather than the effectiveness of the cap-and-trade system. According to Environment North East (ENE), a non-profit research and advocacy foundation, the unexpected drop in total CO2 emissions within the RGGI states is attributable mainly to “increasing natural gas and renewable energy generation, growing investments in energy efficiency, and decoupling of economic growth and emissions.”\(^{135}\) Reflecting new economic trends, electricity prices dropped in all RGGI states but Vermont, by an average of 10% since RGGI launched in 2008. This was significantly attributable to rising use of natural gas. Natural gas prices have fallen sharply and the energy equivalent price for natural gas has been lower than the corresponding price for oil since early 2006.

Both coal and oil prices have largely increased since RGGI launched. Natural gas emits 44% less CO2 than coal and 33% less CO2 than fuel oil in generating electricity and is more efficient overall. The RGGI cap was set in 2005 and between then and 2011, electricity generation from residual fuel oil dropped 95%, generation from coal decreased 45%, and natural gas generation increased by 45%.

Another significant factor lowering total CO2 emissions in the RGGI member states is overall improved energy efficiency. State data shows that a total of 27,356GWh of electricity has been saved because of energy efficiency programs since the RGGI cap was set in 2005. Funding for electric efficiency grew by almost 350% from $624 million in 2006 to $2.18 billion in 2011. In addition to increased energy efficiency, electricity generation from non-carbon emitting generators like hydropower, landfill gas, biomass, and wind, has increased by 13%. Hydroelectricity is the largest generator in this carbon-free category.

Figure 5.4 shows recent RGGI estimates of the relative significance of the various factors that caused CO2 emissions to decline between 2005 and 2009 much more than had been expected. Fuel switching away from coal and petroleum to natural gas (and nuclear) was responsible for 46% of the decline in CO2 emissions. Improved energy efficiency was responsible for 12%, and increased use of renewable wind and hydro sources of power was responsible for 6%. Surprisingly, RGGI attributes only 4% of the reduced CO2 emissions to overall economic trends. Another surprise is the importance of changes in weather patterns, causing 24% of the decline.
Figure 5.4 RGGI Region: Estimated Factors Causing CO₂ Emissions to Decrease

![Diagram showing factors causing CO₂ emissions decrease]


**RGGI Program Review and Model Rule Amendments**

As a result of the program review, the RGGI state staff developed amendments to the Model which were finalized in February 2013. These model rule changes attempted to address RGGI auction weaknesses. The model rule culminated in significant changes to the RGGI allowance budgets and a reduction of the regional emissions cap. As discussed above, the program review identified two main problems. The first was a large supply of excess allowances and the second was weaknesses in the cost control measures. The amended model rule reduces the Regional Emissions Cap, implements a new strategy to reduce privately banked allowances, and introduces a cost containment reserve (CCR) system of additional allowances available in excess of the cap that can be sold if allowance auction prices reach pre-set trigger prices, and provides for unsold allowances to be retired at the end of the year.

The interim control adjustment for banked allowances was created to attempt to reduce the amount of privately banked allowances. The CCR was developed to avoid price spikes should the new cap become binding. These somewhat contradictory initiatives are a symptom of the inflexibility of RGGI auction tools. Since RGGI is a collaborative effort among nine states, “on the fly” type changes in response to auction feedback is politically difficult and members value stability over more meaningful emission reductions. Therefore, both the price floor and the price ceiling remain extremely conservative and low.
Reduced regional cap to 91 million short tons in 2014

The most significant change was to create a new cap. This new cap was set in response to the significantly lower than projected emission levels in 2012 and effectively reduces the cap by 45%. This was accomplished by reducing the 2014 cap from 165 to 91 million tons, effectively freezing 2012 as the baseline year for the RGGI cap. The original 2.5% annual reduction will continue as originally written for 2015 to 2020. By 2020, the cap will be 78 million tons. However, since the CCR was introduced, the final cap might wind up being larger than 78 million tons, depending on how many of the additional CCR allowances are introduced.

Reducing the regional cap was necessary to allow the market to operate as intended. Figure 5.5 shows the old RGGI cap, the new RGGI cap as of 2014, actual RGGI emissions of CO2 from 2003 to 2012, and projected RGGI emissions from 2013 to 2020 in the absence of an effective cap. As shown there, the new cap brings the future RGGI cap below the otherwise projected level of RGGI emissions for 2014-2020, thus making the cap binding in 2014 for the first time since 2010. By 2020, the new cap will effectively reduce RGGI emissions to 14% below the 2012 level of RGGI emissions, and 26% below what RGGI emissions would have reached in 2020 in the absence of a binding cap.

Figure 5.5 Estimated current and future emissions levels and the effect of lowering the cap

![Figure 5.5 Estimated current and future emissions levels and the effect of lowering the cap](image)

Source: Maryland Department of the Environment presentation by Diane Franks, March 5, 2013

Another action that will likely have the effect of reducing the cap is the new option for states to retire unsold allowances. This will actually help to ensure the cap remains closer to the actual emission levels than in the past. All of the participating RGGI states except for New Hampshire and Maine have agreed to retire unsold allowances. New Hampshire and Maine’s carbon dioxide trading statutes set the number of allowances auctioned and therefore the states cannot retire
unsold allowances without legislative action. However, both states have agreed to place unsold allowances into a special bank that will not be offered again for resale and this will have the same effect as if the states were retiring these unsold agreements.

Interim Control Adjustment for Banked Allowances

In order for the reduced regional cap to have the intended effect, RGGI states needed to address the large stockpile of privately banked allowances. During the amendment process, RGGI Inc. projected an estimated 115 million privately banked allowances amassed during 2009-2013. This meant that the number of privately banked allowances exceeded the new 2014 cap of 91 million tons. If there were no private bank of allowances, RGGI states would distribute emission allowances to RGGI States that roughly equaled the regional cap for the year. However, since the privately banked allowances were actually greater than the cap for 2014, this bank would likely undermine the reduced cap introduced in the 2013 amended model rule.

To address this problem, the amended model rule creates two interim control adjustment periods for banked allowances. They are formally called the First and Second Control Period Interim Adjustment for Banked Allowances. These adjustment control periods were introduced to help “soak up” excess banked allowances that undermine the newly reduced cap and have the potential to destabilize market prices for allowances.

The interim control adjustment for banked allowances are determined using a complicated algorithm and appear to overlap in time. Therefore, it is easiest to view them as two distinct phases that are designed to target different “vintages” of privately banked allowances. The adjustments made in each phase are added together to determine the ultimate allowance budget. A banked allowance purchased in 2009 is referred to as a 2009 “vintage” allowance. A banked allowance purchased in 2010 is referred to as a 2010 “vintage”, and so on. The first adjustment period targets surplus allowances from the years 2009, 2010, and 2011. The second adjustment period targets surplus allowances from 2012 and 2013. The amended model rule defines an allowance as an “excess allowance” if it is held “in addition to the aggregate quantity of first [or second] control period CO₂ emissions from all CO₂ budget sources in all of the participating states.”

Table 5.1 provides an example of how the interim adjustments for banked allowances are calculated using sample numbers.
Table 5.1 Illustrative Example of Interim Adjustments for Banked Allowances

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<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Regional CO₂ Budget</td>
<td>91M</td>
<td>89M</td>
<td>87M</td>
<td>85M</td>
<td>82M</td>
<td>80M</td>
<td>78M</td>
</tr>
<tr>
<td>First Interim Adjustment (49M)</td>
<td>7M</td>
<td>7M</td>
<td>7M</td>
<td>7M</td>
<td>7M</td>
<td>7M</td>
<td>7M</td>
</tr>
<tr>
<td>After First Adjustment</td>
<td>84M</td>
<td>82M</td>
<td>80M</td>
<td>78M</td>
<td>75M</td>
<td>73M</td>
<td>71M</td>
</tr>
<tr>
<td>Second Control Period Interim</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adjustment (60M)</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>After Second Adjustment</td>
<td>84M</td>
<td>72M</td>
<td>70M</td>
<td>68M</td>
<td>65M</td>
<td>63M</td>
<td>61M</td>
</tr>
</tbody>
</table>


RGGI member states used modeling to project that approximately 2/3 of the 115 million privately banked allowances will be used to fill the gap between allowances offered for sale and the current cap between 2014-2017. Then, according to the modeling, the remaining 1/3 will be used thereafter between 2018 and 2020. Table 5.2 demonstrates how the state base budget for allocation of allowances will be lowered based on privately banked allowances.

**Auction Reserve Price**

RGGI has a minimum reserve price in place that acts as a price floor for allowance auctions. If bidders submit a bid below the reserve price, the auction platform will automatically reject the price. The minimum reserve price is adjusted at the beginning of each calendar year for the U.S. Department of Labor, Bureau of Labor Statistics Consumer Price Index. Until recently, this minimum bid was $1.89 for an allowance. As mentioned earlier, allowances largely cleared at the minimum reserve price for most of the RGGI auctions.

Prior to the model rule amendments, the reserve price was adjusted at the beginning of each calendar year by the U.S. Department of Labor, Bureau of Labor Statistics Consumer Price Index. The original model rule also provided an option for a “Current Market Reserve Price” or CMP. This provision was never implemented or utilized, but would have allowed RGGI States to set the auction price floors in accordance with current market prices. The new model rule
Table 5.2 Estimated effect of the interim adjustment for banked allowances on the base budget for allowances offered

<table>
<thead>
<tr>
<th>Year</th>
<th>CAP (millions of tons)</th>
<th>Adjusted base budget for allowances offered due to the Interim Adjustment for Banked Allowances</th>
<th>Estimated number of privately banked allowances used</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>91</td>
<td>84</td>
<td>7</td>
</tr>
<tr>
<td>2015</td>
<td>89</td>
<td>70</td>
<td>19</td>
</tr>
<tr>
<td>2016</td>
<td>87</td>
<td>68</td>
<td>19</td>
</tr>
<tr>
<td>2017</td>
<td>82</td>
<td>64</td>
<td>18</td>
</tr>
<tr>
<td>2018</td>
<td>82</td>
<td>64</td>
<td>18</td>
</tr>
<tr>
<td>2019</td>
<td>82</td>
<td>64</td>
<td>18</td>
</tr>
<tr>
<td>2020</td>
<td>78</td>
<td>62</td>
<td>16</td>
</tr>
<tr>
<td></td>
<td>Total Banked allowances used</td>
<td>115</td>
<td></td>
</tr>
</tbody>
</table>


simplifies the reserve price calculations and eliminates the CMP option. In 2014, the reserve price will be raised to $2.00 and increase by 2.5% each year and rounded to the nearest whole cent. This provision in the rule is still called the “Minimum reserve price.”139 This increase is meant to approximate the effects of inflation.

Cost Control Mechanisms

Program reviewers felt that in light of the new, lower cap, that the original cost control measures in place were inadequate and might result in price spikes, should the cap become binding on electricity generators. Therefore the new model rule creates a cost containment reserve (CCR) which is both advertised as a “more flexible cost-control mechanism”140 in RGGI publications and described as a “bizarre price ceiling” by critics. As written, the CCR creates a fixed supply of available allowances. These allowances are available in addition to the cap, so if introduced, these extra allowances could effectively raise the cap. If allowance prices reach certain set price levels during auctions, the reserve CCR allowances will be introduced, thus forestalling further allowance price increases. The levels are $4 in 2014, $6 in 2015, $8 in 2016, and $10 in 2017. The drafters decided that CCR trigger prices will rise by 2.5% beyond 2017 to account for inflation. Tellingly, this price ceiling is actually set at a lower price than California’s price floor. California’s CCR is significantly higher than RGGI’s and increases by incremental amounts and by inflation each year.
Analysis of Changes

The RGGI state’s push to lower the regional cap was impressive. However, the low allowance prices indicate that the cap could be lowered without excessive costs to consumers. The cost of carbon allowances in the RGGI market are very low and do not adequately represent the long term social and environmental costs of continuing to add carbon to the atmosphere. In February 2010, the federal Interagency Working Group on Social Cost of Carbon, issued a report that estimated the current and projected social cost of additional carbon emissions. The group estimated that in 2010, using a discount rate of 3% that the additional cost of a ton of carbon dioxide was around $21.40 per ton.\(^{141}\)

The report also provides a range of estimated social costs that account for different discount rates. The estimate for a 5% discount rate was $4.70 per additional ton of carbon dioxide; for a 3% discount rate, as mentioned earlier, the estimate cost was $21.40 per ton; and the estimate for a 2.5% discount rate was $35.10. The report also provided a “high” estimate of $64.90, which was the estimate should a large number of unexpected disasters occur, with a 3% discount rate.\(^{142}\)

The RGGI cost control measures are in place to help ensure stable pricing. Price stability is important since electricity producers must plan in advance to ensure a continuous and reliable supply of electricity. However, these restrictive measures also mean that there is less income generated for the member states and potentially higher carbon emissions being produced than necessary, at a high cost to society.

Some economists have suggested that for greenhouse gases, a carbon tax would be a more efficient way to accomplish a similar result. Since RGGI’s prices are already so restrictive and narrowly constructed, a carbon tax would look similar in practice and provide electrical generators with complete price stability. However, if a tax were in place, polluters could continue to emit greenhouse gases so long as they paid the price and the prices might be distributed inefficiently. Therefore, the ultimate levels of carbon dioxide emissions would be less stable. A carbon tax might also be difficult to establish politically and it would likely be difficult to raise a carbon tax after it was put in place. However, as seen in Sweden, a high carbon tax can effectively reduce carbon emissions. In the case of Sweden, the Swedish economy has actually grown by 44%, not constricted as some fear.\(^{143}\)

However, cap and trade programs are also complicated and cumbersome to modify, implement, and assess, as is seen with RGGI. The argument in favor of a cap and trade program, like RGGI, is that the carbon cap provides a stronger protection for the environment and allows polluters to reduce in the most efficient ways possible.

**Options for Greater Cap Flexibility**

RGGI would benefit from a more responsive system for setting the cap that could more quickly respond to market cues. Currently, carbon emissions are relatively cheap to reduce because of outside factors like increased use of natural gas, the economic downturn, and investment in energy efficiency and carbon free electricity generators. Therefore, it might make sense to take advantage of relatively lower opportunity costs for reducing carbon emissions and raise both the price floor and the cost containment reserve trigger prices more rapidly in the future. Here are five recommendations proposed to manage the risk of market failure due to price collapse.
Floating Cap Adjustment

Similar to a floating exchange rate, the cap for greenhouse gas emission can be set within a floating range. This gives the regulatory entity more flexibility to adjust for uncertainty in emission forecast. But where the floating range should be set largely depends on how carbon emission (BAU) through a model rule period is estimated. Despite the fact that accurate estimation is difficult, the floating cap can be found by incorporation of various emission scenarios from the bearish to the bullish. For instance, to account for the uncertainty in economic recovery and technological improvement that could cause carbon emission to rise or decline in absence of a cap-and-trade system, the cap for RGGI member states should fall within a range with the minimal pointing to the case of bearish economic outlook plus increased usage of shale gas; whereas the maximum referring to the opposite situation.

Once the floating cap is determined, the regulatory entity will have to devise a trigger mechanism for cap adjustment, i.e. when the cap should float or fix at a certain level. Since the floating range is calculated on a combination of emission scenarios, the assumption for each scenario can function as a trigger condition for the regulatory entity to decide whether to let the cap float and by how much or vice versa. Suppose that a cap is adjusted in the middle of a fiscal year, it would become necessary to make a change in allowance allocation the following months of that year or at the next auction. If the cap rises within a timescale, then the number of allowances available for that period should go up as well.

There are many details to work out for implementing the floating cap. First and foremost, the regulatory entity has to reach an agreement with the regulated industries on a timescale to revisit the cap and see if it is well justified in doing adjustment; second, it must clarify how to coordinated the banked allowances and the allowances at auction such that the total number available to the market will always reflect the updated cap; third, the system manager should develop a set of measures against the price disturbance as a result of frequent cap adjustment.

Allowance Repurchase

The purpose of setting up allowance repurchase is meant to help the market achieve balance and therefore reduce the risk of price collapse when extra allowance supply becomes evident. Specifically, the regulatory entity should monitor the market balance closely to identify any supply or demand shock, such as the oversupplied allowance under the European Trading Scheme. Especially in the presence of oversupply, risk of price collapse will rise and the regulatory entity has to conduct repurchase of the extra allowances from market, including those banked privately. One of the questions that have to be answered before carrying on the repurchase is: at which price level should the allowances be repurchased? Tiered Pricing Scheme

Current cap-and-trade programs under operation employ a uniform pricing mechanism, a single price system for all regulated industries. It might be more efficient in terms of emission reduction if the regulatory entity could introduce a tiered pricing scheme that serves the demand of different consumer groups. For instance, heavy-polluting industries, such as coal-fired power plants, might need more allowances per unit of CO₂ than auto manufacturers. Therefore, the allowance price level should be set higher for heavy-polluting industries but lower for those with less than average emissions. To make sure the tiered pricing scheme work effectively, the model rule drafters have to develop a reasonable market specification, i.e. detailed enough to reflect the difference in demand of various industries but not over-detailed such that implementation becomes infeasible.
Recommendations

In many ways, RGGI has been a successful model for carbon dioxide emissions trading. The program instituted some rather innovative policies including its policy of auctioning, not giving away allowances; implementing and acting upon the 2012 program review and its recommendations; and the programs emphasis on reinvesting in energy efficiency. However, there are also weaknesses that should be addressed to further strengthen the program.

1. Increase the RGGI auction price floor significantly. The current RGGI floor of $2.00 is well below the California floor of about $10 per ton of CO₂. It is even further below most estimates of the social cost of each additional ton of CO₂ such as a recent federal government study finding that this cost is about $20 per ton. If allowances are incapable of generating bids greater than the current low RGGI minimums, the appropriate solution is to reduce the number of allowances offered for sale (and associated CO₂ emissions), and thus sustain higher bid prices.

2. Increase the maximum RGGI auction price – the price at which the cost containment reserve allowances are then made available for sale. The current RGGI maximum prices for allowances in its auctions over the next few years will gradually rise from $4 to $10 per ton of CO₂, far below the California maximum of $40 and above. If additional reserve allowances are so readily supplied to the market at such low prices, the additional allowances made available will work to undermine the positive step achieved by RGGI’s recent sharp reduction in its cap for CO₂ emissions.

3. Implement a way for RGGI to react more quickly to market results by adjusting its cap, instead of using rigid price floors and maximum price levels. The greatest weaknesses of the RGGI program have revolved around RGGI’s inability to react more quickly to changing market indicators and realities. Until very recently, the RGGI cap was not really acting as a cap because the cap was set at levels well above current CO₂ emissions. This was apparent as early as 2010 but it took three years to alter the RGGI cap to reflect this reality.

4. Consider the adoption of a “floating cap.” Perhaps RGGI administrators could be given discretion to alter the cap within certain boundaries in a much shorter time frame. Similar to a floating exchange rate, the cap for greenhouse gas emissions might be set within a floating range. This would give the regulatory entity more flexibility to adjust for uncertainty in emission forecasts. Where the floating range should be set largely depends on how carbon emissions under business as usual through a model rule period are estimated. Despite the fact that accurate estimation is difficult, the allowable range for the floating cap can be established by incorporation of various emission scenarios from the bearish to the bullish.

5. Authorize RGGI to make allowance repurchases. Establishing a program for allowance repurchases would help the market achieve balance and therefore reduce the risk of price collapse when extra allowance supply becomes material. Specifically, the regulatory entity should monitor the market balance closely to identify any supply or demand shock, such as the oversupplied allowances under the European Trading Scheme. Especially in the presence of oversupply, the risk of price collapse might rise and it might then be desirable for the regulatory entity to be able to conduct repurchases of the extra allowances from the market, including those banked privately. The U.S. Federal Reserve System employs such methods in seeking to maintain interest rate stability at the desired levels and RGGI could study the workings of such operations.
6. Consider the use of a tiered RGGI auction pricing scheme. Current cap-and-trade programs under operation employ a uniform pricing mechanism, a single price system for all regulated industries. It might be more efficient in terms of emission reduction if the regulatory entity could introduce a tiered pricing scheme that reflects the varying demands and economic sensitivities to the price of carbon of different consumer groups. Like a perfect monopolist in a conventional market, RGGI administrators might be able in this way to minimize the social adjustment costs of making GHG reductions across different economic sectors. For instance, some heavy-polluting industries, such as coal-fired power plants, might be required to hold more allowances per ton of CO₂ they emit, as compared say with auto manufacturers. This would at least partly reflect the differing elasticities of demand in different sectors for RGGI allowances.
Chapter 6: RGGI Leakage Problems

“Leakage” is a large concern with a wide variety of environmental regulations. Regulators fear that regulation specific to one area will cause harmful activities to shift into an unregulated area. This effect lessens the intended impact of regulations and often shifts regulated economic activities to areas outside the scope of existing regulation. Leakage is a large concern regarding the regulation of carbon dioxide emissions from power generation in Maryland, as well as in all the Regional Greenhouse Gas Initiative (RGGI) states. The concern is that while power plants are participating in the RGGI cap-and-trade program, therefore increasing power generation costs and reducing emissions, power plants outside of RGGI will continue to produce at lower costs. Their power might therefore be imported into RGGI states, resulting in a net increase in carbon dioxide emissions. Maryland, for example, already imports about 30 percent of its electric power, and this percentage could increase as a result of further leakage.

Another type of leakage is contract shuffling. Contract shuffling, also known as resource shuffling, is the practice of receiving credit for emissions reductions that have not occurred by shifting the sources of power to avoid regulatory controls. For example, a power generator in Utah may sell power to both Nevada and California. Before regulation is put in place, this generator might sell power to California that was produced from a mix of 70% coal facilities and 30% natural gas facilities, and sell power that was generated from 50% coal and 50% natural gas to Nevada. Then, after new greenhouse legislation in California is passed, the generator may switch production and distribution so that there is still the same amount of coal and natural gas production occurring and the same amount of greenhouse emissions, but most of coal power would now be sent to Nevada and most of gas generated power to California, thus complying with California’s new stricter regulation without making any actual greenhouse gas reductions or incurring additional compliance costs. Contract shuffling can actually cause an overall increase in GHG emissions in some cases.144

Currently, neither Maryland’s nor RGGI’s regulations explicitly address leakage. A recent study performed by Navigant Consulting on the Western Climate Initiative (WCI) found that if leakage is not addressed in a cap-and-trade scheme eventually as the price of emissions allowances increases, the electricity market would shift so that carbon emissions under such a scheme will simply shift:

The decrease in WCI emissions was offset by an increase in non-WCI emissions in every case, resulting in almost no net change in total emissions. WCI emissions decrease because fossil generation falls when allowance prices are applied. This decrease in WCI generation leads to reduced exports from WCI. Non-WCI generation therefore needs to increase, and since only fossil generation has variable output, this means an increase in non-WCI fossil generation and CO₂ emissions.145

The findings on WCI can be applied to most cap-and-trade programs including RGGI. In Maryland, leakage is especially a concern because of its large existing power imports (18,814,168 MWh in 2009) from surrounding states. Some of this power stems from coal-fired power plants which produce more greenhouse gas emissions than other power sources such as natural gas, nuclear, hydroelectric, wind, or solar.146,147,148
\textbf{Electric Power Regional Grids}

The leakage issue is greatly complicated by the fact that wholesale power sales on large regional grids make tracking and determining the origin of electricity difficult. Once power is generated at a plant, it is sent through high voltage power lines to local power distribution centers where it is then reduced to much lower voltages for retail consumption. These electricity lines and local distribution centers are part of the Bulk Electric System transmission infrastructure. Once generated, excess power cannot easily be stored. This is why supply must be continually balanced with demand. If current demand is not fully met by grid supply, consumers will face shortages and the systems stability can become vulnerable.

Because power must be consumed simultaneous to generation, the electricity market has evolved so that what were once considered local grids have expanded and connected to other grids to increase efficiency by having a larger pool of generators and consumers to help match supply and demand. This arrangement allows a grid with excess supply to ship to a grid with excess demand; interconnection solves both problems economically. The interconnected grids span across state lines, which makes power imports and instant power exchanges between regulated and not regulated areas occur frequently. Although the interconnected nature of the power supply enhances efficiency and reliability, it makes tracking or predicting power exchanges difficult.

Moreover, there are Regional Transmission and Independent System Operators (RTOs and ISOs) that oversee power production and help to ensure the wholesale markets operate efficiently and reliably. Within RGGI, Maryland and Delaware are part of the PJM market while Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont are all part of the New England Independent System Operator (NE-ISO) and New York is part of the New York Independent System Operator (NYISO). These operators connect numerous states and thousands of generators. For example, in 2010 PJM transmitted generated power from 1,340 sources over 56,750 miles of transmission line.

As in most wholesale electricity markets, PJM operators monitor the grid to balance demand with supply. In order to this, electricity producers will bid a marginal cost of operation every 15 minutes which the PJM operators will then rank from lowest to highest. PJM operators will select only as much production as demand, meaning that those plants with the lowest cost of operation are more likely to be selected. In this way, these interconnected grids allow PJM to choose power that is at the lowest cost for consumers rather than in close proximity. The high number of generators and the cost mechanism prevents states from exclusively choosing the origin of their power. This method combines all the generated power places and then ships it to demand. For these reasons, determining the source of leakage is difficult.

\textbf{The Rise of Natural Gas-Fired Power Generation}

Currently, the use of lowest marginal cost as a measure to determine which generators run has the effect of pricing out most leakage that would come from coal-fired power plants, due to the dramatic decrease in the marginal cost of natural gas that has occurred in recent years. According to a study performed by Credit Suisse (CS), the price of natural gas would have to rise by more
than $6 per mcf (1000 cubic feet of gas) before the price of coal and natural gas would be similar for electric generation (shown in Figure 6.1).\textsuperscript{151} This means that coal plants are typically the last to run and while coal fired power generation retains the largest electricity market share, generation from natural gas has been on the rise over the past few years as shown in Figure 6.2. Due to this shift most of the leakage at present stems from natural gas power plants.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure6.1.png}
\caption{Natural Gas Pricing Versus Coal Pricing}
\end{figure}


\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure6.2.png}
\caption{U.S. Monthly Net Electric Power Generation, January 2007 – March 2013}
\end{figure}

\textit{Source: U.S. Energy Information Administration, May 2013}

Natural gas releases roughly about half the amount of carbon dioxide than coal per unit of power produced (See Table 6.1).\textsuperscript{152} The lower price of natural gas and the associated pollution benefits
has allowed Maryland and RGGI to reach emission reduction goals much sooner than expected. For example, as discussed in Chapter 5, emission levels in RGGI states were 44 million tons below the set RGGI cap by 2011. In response to this phenomenon, RGGI recently adjusted future emissions caps; the new cap responds in part to the growing use of natural gas by lowering the RGGI cap by 45% from 165 million tons to 91 million tons.

Table 6.1 Comparison of Emissions Between Natural Gas and Coal (Pounds per Billion BTU of Energy Input)

<table>
<thead>
<tr>
<th></th>
<th>Natural Gas</th>
<th>Coal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Dioxide</td>
<td>117,000</td>
<td>208,000</td>
</tr>
<tr>
<td>Carbon Monoxide</td>
<td>40</td>
<td>208</td>
</tr>
<tr>
<td>Nitrogen Oxides</td>
<td>92</td>
<td>457</td>
</tr>
<tr>
<td>Sulfur Dioxide</td>
<td>1</td>
<td>2,591</td>
</tr>
<tr>
<td>Particulates</td>
<td>7</td>
<td>2,744</td>
</tr>
<tr>
<td>Mercury</td>
<td>0</td>
<td>0.016</td>
</tr>
</tbody>
</table>

Source: America's Natural Gas Alliance

Problems with Possible Future Leakage

Despite the fact that currently leakage in Maryland is not seen as a significant problem, there is no guarantee that leakage will not pose a future threat to carbon reduction goals. One reason is that the markets will adjust to the price shock of natural gas and adjustments in prices for other electricity sources may be made. Also, in a recent review, emissions modeling showed that as emissions caps within RGGI get tighter and the price of allowances increases, leakage will become more of an issue. Again this shift in leakage is due to the competitive generation markets; the addition of a higher compliance cost to only select electricity generators could lead to a shift due to the response to the CO₂ price signal. For example, a study of six RGGI states all on the NEISO power grid (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), showed that when the carbon dioxide allowance price reaches $10 per ton, the cap will cause approximately three million tons of carbon dioxide leakage associated with power purchases in non-RGGI states.

In addition, a higher allowance price will erect a political barrier to other states joining the initiative. It would be difficult to persuade Pennsylvania to join RGGI since this would give a commercial advantage to other states in the same power grid, such as Ohio. RGGI needs to act now and implement leakage control mechanisms because, in addition to being a deterrent for other states to join RGGI, higher allowance prices are likely to trigger leakage and offset the emissions reductions that RGGI has already accomplished.
California’s Leakage Strategy

Under California’s Global Warming Solutions Act (AB32), which led the way to establishing California’s cap-and-trade program, as discussed further in the next chapter, California is required to minimize leakage and the state has taken significant steps to do so. The California Air Resources Board (ARB), the agency responsible for implementing the cap-and-trade program, addresses leakage via several mechanisms. First, to reduce the market incentives for leakage related to marginal cost, California provides free allocations since lower compliance costs are an incentive for facilities to continue operating in California. (See Chapter 7 for more details on California’s allowance allocation process.) Second, Section 95852(b)(2) of AB32 attempts to control contract shuffling by requiring first deliverers to submit an annual attestation promising not to contract shuffle. However, the attestation requirement has been suspended from January to June 2014 pending ARB review of the definition and exclusions to shuffling, and monitoring of the market in 2013.

Third, as a means to mitigate leakage, California includes imported power in its cap and trade market. In order to implement this measure California tracks the transmission path and origin of imported power, by mandating an e-tag on electricity from the California Independent Systems Operator (CAISO, the main power-grid in California). E-tags are electronic documents that can track electricity transmission and help identify the parties with financial ownership of power; the e-tag is able to identify the power source and designated control region. Regulators then use the information provided by e-tags to assign out of state emissions to in-state power consumption of power imports. This information is used as the base measurement to determine the compliance responsibility of the party that is listed on the e-tag document, otherwise known as the First Jurisdictional Deliverer of the power imported to the grid.

Once the first seller has been determined, California holds them responsible for their imported power emissions. Since the exact emission rate of these producers cannot be determined, California establishes responsibility by tracking past power production and imports into control areas. California evaluated past contracts, plants owned by Californian utility companies located outside the state, long term contracts, and renewable sources—which have been reported under the state’s RPS -- and assigned 96% of the power imported to a financially responsible party. California then assumes that the power imported into the state reflects the overall historic emissions profile of the out-of-state supplier of the power.

Legal Challenges to Controlling Leakage

The Interstate Commerce Clause is one of the biggest legal barriers to regulating leakage. This constitutional provision gives Congress the power to “to regulate Commerce with foreign Nations, and among several States, and with the Indian Tribes." This is why states can only regulate energy generation of imports rather than consumption because regulating consumption would constitute discrimination against interstate commerce.

Another legal issue that arises when considering a strategy to regulate leakage is the Federal Energy Regulatory Commission’s (FERC) jurisdiction over electric power transmission and wholesale power distribution under the Federal Power Act. In order to avoid undermining FERC,
a rule regulating leakage must avoid specifically regulating transmission or wholesale transactions. Lastly, states must determine if they have the legal authority to regulate Load Serving Entities; if this is not possible then states should investigate whether state Public Utility Commissions would have that authority on their own or in combination with state environmental agencies.159

Regulating or controlling contract shuffling as type of leakage emission will be more difficult than regulating imported power because one could not claim under the Interstate Commerce Clause that the pollution was harming in state natural resources. Many experts have pointed out that contract shuffling is a large vulnerability in cap-and-trade programs that only involve a few players. This is especially true for RGGI states that operate on multi-state power grids that include non-RGGI states. Power producers can simply sell their dirty power to unregulated regions on their power grids and less carbon intensive power to a state in the RGGI region.

Mechanisms for Tracking Leakage and Associated GHG Emissions

The key challenge to preventing leakage within RGGI is tracking electricity imports and associated GHG emissions outside RGGI. Maryland would need to develop a mechanism to hold power producers responsible outside the cap-and-trade program. An accountability scheme outside RGGI would need to have detailed information on power producers. Maryland regulators would need to know which plants the power came from, exactly how much power from each plant went to Maryland consumers, and what the carbon dioxide emissions rate from the plant were. Then the state -- or RGGI as a whole -- would need to determine if they had the authority to impose such regulations.

Currently, eight of the nine RGGI states have tracking systems. The Generation Attribute Tracking System (GATS) in PJM and the Generation Information System (GIS) in NEISO provide data to states on the energy and attribute transactions within each control area. The attribute could be for example gas, coal, or wind. The systems were developed to track state compliance with RPS and power source disclosure laws from power generators and load serving entities (LSEs) accounts, primarily RECs generated within RGGI or purchased by RGGI states outside of RGGI, which represent a small fraction of energy bought and sold in the region.160 However, GATS and GIS, also generate quarterly reports available to regulators that include information from other energy generation sources, including non-renewable energy (See Figure 6.3).

David Farnsworth and Rachel Terada from the Regulatory Assistance Project have explored adapting GATS and GIS for tracking all energy attributes and CO₂ emissions from energy consumption within RGGI. GIS and GATS characterize electricity commodities in terms of both the power generated in MWhs and the generation “attribute.” For example, GATS takes a MWh of wind power and characterizes it as a renewable energy certificate (REC) equal to one MWh of wind generation and also as one MWh of undifferentiated power.160 Both characterizations are separate commodities that can then be accounted for and traded independently, in other words RECs are traded separately from the MWh of electricity.
Moreover, GATS and GIS can substantiate certificate ownership claims when the certificate and/or attribute is transferred from the power generating facility or control area to the purchasing entity, such as a LSE. GATSS and GIS also enable regulators to track, for each generator, the fuel source, its CO₂ emissions, location of the generating sources, and its status under RGGI. Fransworth and Terada argue that GATS and GIS could be expanded to track CO₂ emissions associated with all energy consumption within RGGI, including imported power.

Non-renewable generators also collect attribute certificates into their accounts until the end of the tracking period, but unlike the renewable certificates, the attributes cannot be traded. At the end of the trading period: 1) the non-renewable energy consumed by individual LSEs is characterized and 2) the untraded attribute certificates are removed, retired and put into a residual system mix or average attribute mix. The combined residual attributes are then pooled and assigned to individual MWhs, generating a “residual mix certificate” or a per-MWh average of the aggregate characteristics of all untraded attributes. Each MWh of load in a LSE account that does not already hold a retired certificate is assigned a residual mix certificate.

According to the authors, by making an adjustment to this residual attribute mix it is possible to isolate and track imported CO₂ emissions from power generated outside PJM or NE-ISO. Taking PJM as an example, this adjustment is accomplished by taking the residual mix and then, identifying, and excluding emissions sources that RGGI would not want to include in future GHG policy, specifically: generation within RGGI that is already covered by RGGI; non-RGGI fossil fuel generation that is less than 25 MW; imported generation into PJM, but within RGGI (e.g. from NY), and ‘specified transactions’, meaning sources they are excluded from the rule that they be ‘treated as an unspecified source of power’. The rationale for excluding sources less than 25 MW is that they are currently not included in the RGGI cap.

The result is an adjusted attribute mix composed of the following:
a) non-RGGI fossil fuel generation larger than 25 MW

b) net imported generation from an adjacent non-RGGI systems, such as the Midwest Independent Transmission System Operator

c) non-fossil generation

One complication to this approach is that not all RGGI states operate on the same power grid. This would mean that after a tracking mechanism was developed, as outlined above, RGGI states would have to get their power grids to implement the exact same tracking system and methods. After a tracking method is implemented the RGGI states would need the same information as in the case if Maryland were regulating leakage on its own. RGGI would also need to determine how they were going to incorporate outside states into their emissions reduction scheme.

The final step is estimating the carbon emissions with the attributes of the adjusted mix outlined above, and then assigning the resulting CO₂ emissions rate to each MWh of load that does not already have a certificate associated with it. This is further discussed in the next section. Electricity providers would then need to acquire allowances under RGGI that reflect their CO₂ emissions.

Finally, a key to the integrity of this approach is the quality of data collection. In developing a tracking proposal for RGGI, Farnsworth and Terada urge the importance of assessing the sources and quality of emissions data to determine if they are acceptable or if improvements are needed (see below for more on determining emissions intensity). The authors note that their proposal to mandate CO₂ emissions reporting could generate compliance issues for electric service providers and that using GATS and GIS to track carbon dioxide emissions will raise a number of legal, regulatory, and administrative issues for state regulators.

**Determining Emissions Intensity from Leakage**

After a mechanism is developed to track leakage and the legal hurdles are overcome, emissions intensity must be determined in order to hold producers accountable. Emissions rates may vary from one generating plant to another and, the year the plant was built, the technology being used. In the case of, coal the type of coal being burnt (Figure 6.4) is also an important factor.

For example, lignite (i.e. brown coal) produces approximately 216.3 pounds of carbon dioxide per million Btu, bituminous coal produces 205.3 pounds of carbon dioxide per million Btu, and anthracite produces 227.4 pounds of carbon dioxide per million Btu. Further, a one-percentage point increase in the efficiency of a coal fired power plant results in a two to three percent reduction in carbon dioxide emissions. Modern coal plants that are highly efficient emit also 40 percent less emissions than the average coal fired power plant. In order for data to be accurate, all of this information must be known to calculate emissions rates, placing a large burden on regulators.
RGGI could adopt existing emissions intensity metrics. The European Union’s Emissions Trading System (ETS) and the Australian Carbon Pollution Reduction Scheme (CPRS) have established their own methods of evaluating emissions intensity, and examples can be found in Figure 6.5.

To evaluate carbon emissions intensity California chose to evaluate intensity with the EU ETS metrics, the Australian CPRS metrics, and metrics used by the U.S. Environmental Protection Agency (EPA). Using all of these metrics promotes fairness and reduces the chance of a method skewing results by providing three different methods to arrive at the same conclusion. In fact the results of California’s emissions assessments with all three metrics showed similar orderings. Unfortunately, determining such intensities would require significant amount of effort and different power plants may contest determinations or claim that all of their emissions are not related to power sent to RGGI states.
Figure 6.5 Various Approaches to Assessing Emissions Intensity

ASSESSING EMISSIONS INTENSITY

EU ETS

- Direct and indirect additional costs by the EU ETS are greater than 5% of Gross Value Added, expressed as:
  
  \((\text{Direct emission } \text{tCO}_2 + \text{Indirect emission } \text{tCO}_2) \times 30 \, \text{€/tCO}_2 > 5\%

  \text{Gross value added at factor cost}

The American Clean Energy and Security Act of 2009 (ACES)

- Energy intensity (the cost of electricity and fuel costs divided by shipment) is greater than 5%, or,

- The greenhouse gas intensity ($20 allowance price multiplied by \text{CO}_2 \text{e tons of GHG emissions divided by shipment}) is greater than 5%. GHG emissions are the sum of direct combustion, process emissions and indirect emissions from upstream electricity generation.

Australia CPRS

- A sector is highly emissions intensive if the weighted average emissions per million dollars of revenue is greater than 2,000 \text{tCO}_2 \text{e} (\text{tCO}_2 \text{e}) (Weighted emissions are measured as process emissions + fuel combustion + electricity + natural gas and its components used as feedstock)

- If value added is used in place of revenue, the threshold is 6,000\text{tCO}_2 \text{e}

- A sector is moderately emissions intensive if the weighted average emissions per million dollars of revenue is greater than 1,000 \text{tCO}_2 \text{e} (\text{tCO}_2 \text{e}) (Weighted emissions are measured as process emissions + fuel combustion + electricity + natural gas and its components used as feedstock)

- If value added is used in place of revenue, the threshold is 3,000\text{tCO}_2 \text{e}

*Source: California AB-32-Appendix K, 2010*
Recommendations

1. As allowance prices increase, leakage will become a potential threat to the integrity of the RGGI cap. To help prevent leakage RGGI should follow California’s steps and incorporate imported power into its GHG emissions cap, requiring that allowances be obtained within RGGI for power imported from outside of RGGI. This will also pave the way towards future linkage with California. In order to accomplish this, RGGI should make available additional allowances corresponding to the levels of imported power to RGGI jurisdictions. Power from generators outside RGGI would be subject to yearly decreases in allowances and increases in allowance prices similar to generators within RGGI. This strategy would safeguard Maryland emissions goals from the vulnerabilities presented by leakage and contract shuffling.

2. A key step to incorporating imported emissions into the RGGI cap is for member states to work with their regional power grids to develop tracking systems for imported power and the associated GHG emissions. There are two ways Maryland could accomplish this
   a) Work with PJM to establish a system to track the distribution of power generation sources in the regional grid and the emissions associated with those sources. Then PJM could establish an average emission rate per Btu. Maryland could apply the average emission rate to imported power and require the importers of power from outside the state to hold sufficient allowances. However, establishing tracking systems in three regional power grids will be a daunting task.
   b) As one option, adapt the existing tracking systems (CAPS, GIS) used by the RGGI regional grids, which are already tracking renewable energy certificates, to track imported power as follows. Take the average certificate mix in each grid (from all power sources) and exclude emissions sources that RGGI would not want to include in future GHG policy to obtain a new residual certificate mix of i) non-RGGI fossil fuel generation larger than 25 MWh ii) net imported generation from an adjacent non-RGGI systems, such as the Midwest Independent Transmission System Operator and iii) non-fossil generation. This newly calculated certificate mix would then be assigned to each MWh at individual facilities, from which a GHG emissions rate would be calculated.

3. Seek the expansion of RGGI to include current non-member states such as Pennsylvania and West Virginia. To the extent that RGGI can newly include all current states that supply out-of-state power to RGGI states, the issue of leakage can be most effectively resolved in this manner.
Chapter 7: The California/Quebec Cap and Trade System and the Potential for Linkage with RGGI

For five years, RGGI operated as the only cap and trade program in the United States. In January 2013, however, California began the implementation of its cap and trade program under AB 32, the Global Warming Solutions Act of 2006. Early in development, California identified the potential of linkages with cap and trade programs at the national and international level and built into its program a framework for doing so. In fact, in April 2013, California and the Canadian province of Quebec signed an agreement to integrate the two programs to encompass both jurisdictions. These developments in California demonstrate the feasibility of external linkages as well as represent an opportunity for RGGI, along with California, to help establish a pathway for wider U.S. participation in GHG cap and trade schemes. In the absence of an international or national framework, the potential for linking cap and trade programs provides a bottom-up alternative approach to GHG policy.

This chapter further examines this approach as well as the current opportunities for linkage between the RGGI and California cap and trade programs. As Dallas Burtraw, et al. of Resources for the Future discuss in their April 2013 paper “Linking By Degrees: Incremental Alignment of Cap and Trade Programs,” there are various ways in which programs can link together. However, this chapter is primarily concerned with a formal and binding agreement, such as that between California and Quebec. Burtraw et al. outline three criteria for evaluating cap and trade programs for potential linkage, including: difficulty of administrative alignment, importance for the market to be able to function, and importance for the political economy. According to these criteria, while many aspects of the California and RGGI programs are ready to be linked, there are still some areas of concern that need to be addressed. Despite these issues, however, linkage between the RGGI and California/Quebec programs is a significant opportunity not only to benefit the programs themselves, but also to “reinforce the process of cooperation [in GHG emissions reduction] across jurisdiction.”

An Introduction to the California Cap and Trade Program

As mentioned above, the California cap and trade program was established under the Global Warming Solutions Act of 2006, which required the California Air Resources Board (CCARB), the state agency dedicated to air pollution regulation, to develop regulations and market-based mechanisms to reduce GHG emissions to 1990 levels by 2020, which represents a 25% statewide reduction. As required by the law, one of the strategies adopted by CCARB included cap and trade regulation, which covers the major sources of GHG emissions such as refineries, power plants, industrial facilities, and transportation. Overall, the program covers sources responsible for 85% of the state’s GHG emissions. This is a point of departure from the RGGI system as California has extended the cap to cover other sectors of the economy rather than limit it to electric power plants as in the case of RGGI.

Other components of AB32, not discussed in this chapter, include renewable energy investments, which must comprise 1/3 of the states’ electricity by 2020 and Low Carbon Fuel Standards (discussed in Chapter 2). Figure 7.1 shows the predicted percentage of emissions and reductions
(by 2020) from each of the AB32 program measures. In total, CARB projects reductions of 61.8 MT within the cap and 27.3 MT of reductions from programs outside the cap (e.g. offsets) by 2020.

**Figure 7.1 Projected Proportion of Emissions and Reductions (in MMT CO₂e shown in parentheses) for Program Elements in California’s AB32 by 2020**

![Figure 7.1](image)

Source: Center for Climate and Energy Solutions

AB 32 has and continues to face legal and legislative challenges. Perhaps the most significant was Proposition 23. This ballot proposition, held on November 2, 2010 would have suspended AB 32 until California’s unemployment rate dropped to 5.5% for a full year, but it was defeated by California voters by a margin of 23%. The cap and trade and offsets components of AB32, to be discussed later in more detail, have been particularly contentious and have been challenged in court by numerous stakeholders. Beginning in 2009, in the case of *Association of Irritated Residents et al. v. CARB*, community groups claimed that the legislation would allow unrestricted emissions by certain polluters that would disproportionately impact minority populations, and that the offsets provisions were not sufficiently binding. The courts ruled in favor of CARB in June 2012.

**Sectors included in the program**

California’s cap and trade program works by setting a cap on GHG emissions from “covered” entities, starting in 2013 and declining thereafter. Covered entities are facilities that emit 25000 Metric tons of CO₂e per year, including the electricity sector, oil and gas industry, refineries, cement production facilities, and the manufacturing and food processing sector as shown in Figure 7.2. Like RGGI, these covered facilities need tradable permits called “allowances”, where one allowance is equivalent to one ton of CO₂e. In order to function and track GHG emissions, CARB relies on California’s Mandatory Reporting of Greenhouse Gas Emissions Regulation.
(MRR), which was first adopted in 2007. The program requires facilities that emit more than 1000 tons of CO$_2$e to report their GHG emissions. Under MRR, point sources such as electric generating facilities, fuel and CO$_2$ suppliers were required to report their emissions beginning in 2009.168

![Figure 7.2 2010 California Emissions Inventory by Sector](image)

*Source: California Air Resources Board, “Cap and Trade Program,” 2013.*

The sectors covered by California’s cap and trade program, industrial, electricity generation from within and outside California, and commercial together comprise about 44% of California’s GHG emissions. In 2015, the program will expand to cover transportation fuel distributors, capturing the remaining emitters to encompass 85% of the state’s total emissions.

To regulate the electricity sector, California has adopted a mechanism known as First Jurisdictional Deliverer (FJD), which imposes CO$_2$e charges on imported power, where the first entity delivering imported electricity into the state would have a compliance obligation. This mechanism is one first recommended through the Western Climate Initiative (WCI), a collaboration of several Western states and Canadian provinces to advance GHG emissions reduction. WCI commissioned a study that established the benefits of including imported power in WCI states cap and trade programs; specifically it analyzed the impact of FJD on emissions and generation in Manitoba, Ontario and Quebec, and found that without FJD, emissions reductions in those three WCI provinces would be offset by emissions increases in mid-Western states.169

**Cap Timeline and Compliance Period**

In establishing the California cap and allowance budget, CARB followed the framework previously set through WCI agreements.170 The initial cap was set equal to the expected emissions for the covered facilities in the first year of compliance, in this case 2012, and emissions reductions would be accomplished via a gradual tightening of the cap throughout the
compliance period. To avoid over allocation of allowances and repeating the mistakes of the EU ETS, CARB implemented strict GHG reporting requirements in 2007 through the MRR, aimed at improving baseline and program emissions estimates and ensuring adherence to the GHG cap. The information from the 2007 MRR was used by CARB to improve the initial budget estimates from the Scoping Plan and calculate the final 2020 cap of 334.2 tons. The GHG allowance budget timeline is shown in Table 7.1.

California has three compliance periods. Initially covering only the electric power sector and industrial sources, by 2015, the program will also cover transportation fuels and residential and commercial use of natural gas, hence the increase in the budget from the first to the second compliance period. In estimating the allowance budget, CARB also took into consideration factors such as the economic downturn and other GHG measures within the Scoping Plan.

<table>
<thead>
<tr>
<th>Table 7.1 California GHG Allowance Budget Timeline</th>
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<tr>
<td><strong>Budget Year</strong></td>
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<td>First Compliance Period</td>
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Note: parenthesis indicates % reductions in covered sources relative to 2015


Allocation of allowances

A specific company’s allowances and offsets are also called “compliance obligation.” CCARB manages compliance through the Compliance Instrument Tracking System and Service (CITSS), which records an entity’s allowances and transfers. As a deterrent to leakage, CCARB gives out certain allowances for free. The remaining allowances are either auctioned (see next section) or go into an Allowance Price Containment Reserve, which can also be purchased through the auction process.

The electricity sector receives a significant amount of free allocations, 90% of their 2008 CO\textsubscript{2} emissions, and declining to 85% of that amount by 2020. The allowance allocation of each facility, in tons of CO\textsubscript{2}e, is a function of the cost burden to customers, projected energy efficiency savings, and a facility’s early action in the adoption of renewable energy between 2007 and 2011.\textsuperscript{171} New facilities are subject to the energy based allocation methodology, where a baseline allocation is calculated from a) amount of steam emitted b) amount of fuel consumed and c) amount of electricity sold.\textsuperscript{172}
In the industrial production sector (excluding refineries), CARB allocates 95% of the allowances for free using the “product based allocation methodology.”\textsuperscript{173} Using this method, individual facility allowances are proportional to the amount of product produced, leakage risk, product benchmark, and a factor that declines in proportion to the overall cap decline. Therefore, non-electrical generators’ allowances are also calculated with leakage reduction in mind. In the case of refineries, allowance allocations are a rather complex function of the parameters used in other industrial sectors, with the addition of an “assistance factor.”\textsuperscript{174}

**Leakage**

CARB mitigates leakage via two key mechanisms: 1) in the framework of allowance allocations (see previous sections), in other words by giving out free allowances and 2) by prohibiting reshuffling. Reshuffling occurs when a utility substitutes its own emissions with a lower emission source that have not been reported in the MRR, for the purpose of reducing its own compliance obligations.\textsuperscript{175} For a more detailed discussion of leakage in California and Quebec, see Chapter 6.

**Auctioning and price of allowances**

A percentage of California’s allowances are auctioned. Auctions are open to all who are eligible to register with California’s Cap and Trade Program. Auctions are held quarterly and they are managed through the Western Climate Initiative’s “Green House Gas Allowance Auction and Reserve Sale Platform.”\textsuperscript{176} This platform also hosts the CITSS, and online system that enables participants to indicate their intent to bid. Bids are conducted in a single round and can only be submitted in lots of 1000 allowances. Allowances are distributed beginning with the highest bid and moving successively to lower bids. The settlement price for all allowances is determined by the lowest price at which all allowances are exhausted or the reserve price, the one that is reached first.\textsuperscript{177} The CITSS is also used by to approve bidders and inform bidders of their settlement price. CARB’s first auction was held on November 14\textsuperscript{th}, 2012.

The allowance price floor for California’s cap and trade program is $10.71 per metric ton. CARB states several reasons for setting this price floor, but the primary reason is to avoid an oversupply of allowances.\textsuperscript{178} As discussed in Chapter 5, in concept allowances should not be issued for prices below the social cost of greenhouse gas emissions, suggested by some studies to be around $20 per ton of CO\textsubscript{2}. The agency also conducted an economic analysis that showed market prices would exceed that level under most circumstances. In addition, because CARB believes that the offsets market is an important compliance instrument for the program, a higher floor price was set to encourage offset project developers to seek approval for projects, and thus stimulate the offsets market. The allowance price ceiling was set at $50.

Reserve sales (from the Allowance Price Containment Reserve), which represent 4\% of all allowances, are also purchased via the CITSS. There is a set price per allowance as follows: tier 1 ($40), tier 2 (45), tier 3 (50), and participants can bid for each of the tiers.
**Offsets**

Offsets are an alternative mechanism for reducing GHG emissions under a cap and trade program that are specifically designed to compensate for emissions elsewhere. Most cap and trade programs have a fixed percentage of reductions per facility that can be achieved via the offsets market, 8% in the case of California and Quebec.

In concept, offsets can significantly reduce the cost of achieving any given desired reduction of greenhouse gases under a cap and trade system, by providing reductions at lower marginal costs somewhere else that substitute for reductions within the cap and trade system. For example, it makes more economic sense to make a CO₂ reduction in Mexico for $5 if the price for an equivalent reduction in California is $15. Defining eligible offsets is complicated, however, by the necessity to determine baseline emissions in the absence of the offset payment, and other difficult issues. Offsets are one of the most controversial elements of cap and trade programs.

CARB approved two registries for its offsets program, the American Carbon Registry, based in Sacramento, and the Climate Action Reserve, based in Los Angeles. The Climate Action Reserve is a national offsets program based in Los Angeles that quantifies and verifies GHG projects across the US. Examples of project types include landfill and livestock (methane) capture and ozone depleting substances. The registry has a field that indicates whether projects are CARB eligible. Currently, 227 out of the 779 projects listed in the registry are CARB eligible as follows: projects for destruction of ozone depleting substances in Arkansas, Texas, or Ohio; landfill gas capture in a number of states, and forest conservation projects within and outside California, but primarily within California. The registry also has non-CARB eligible projects for organic waste composting, and reduction of nitrous oxide (N₂O) emissions from agriculture. The registry also includes a few projects in Mexico and India. See Figure 7.3 for a distribution of offset projects.

The American Carbon Registry is the second registry approved by CARB’s offsets program. With 72 registered projects, it is not as large as the Climate Action Reserve, but has a comparable number of eligible project types, and a much larger overall fraction of projects for improving fuel transport efficiency. It generally specializes in the voluntary markets, and accepts most CDM proposed tools. Like the Climate Action Reserve, nearly all registered projects are in the US, with a few in Africa and Latin America.

As noted, the greatest challenge to any offsets project is guaranteeing its additionality, meaning that it must lead to GHG emission reductions that would have not happened otherwise through law or regulation. Thus, an offsets project must be real, verifiable, quantifiable, enforceable and permanent. CARB accepts four types of offset projects: forestry, urban forestry, dairy manure digesters, and destruction of ozone depleting substances. CARB has strict Compliance Offset Protocols for each project type, before they can be approved. Once approved, projects can be listed in one of the two registries for participation in CARB’s cap and trade program via purchase or trading.
California has also been pursuing international offsets via the Reduced Emissions from Deforestation and Forest Degradation (REDD) Offset Working Group, established in February 2011 as a result of a Memorandum of Understanding signed in November 2010 between the Governors of California, Chiapas and Acre (Brazil). Its mission is address the following three questions “(1) what legal and institutional mechanisms are required to enable California to recognize international REDD-based emission offsets for compliance purposes; (2) what are the key policy considerations a sectoral REDD program should address to achieve the level of performance needed for California to recognize the REDD-based offsets for compliance purposes; and (3) what should be the bases for judging the performance of the states in reducing carbon removals from forests? 182

The Western Climate Initiative

As mentioned above, the WCI has been a strong influence on the development of California’s cap and trade system. The WCI, following the creation of RGGI around the same time, was formed in 2007 between the states of Arizona, California, New Mexico, Oregon, and Washington. The purpose of the agreement was to develop a regional plan for reducing GHG emissions. Between 2007 and 2008, Montana, Utah and the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec also joined the WCI. There are also 15 US States, Canadian provinces, and Mexican states with observer status. Together, the initial member states comprised 19% of the population and 20% of US GDP and 79% of the population and 76% of Canadian GDP.

In 2010 member jurisdictions developed a WCI Regional program. 183 The program set a framework and recommendations for a cap and trade market including offset certificates with nonmember states, energy efficiency and renewable energy incentives, and vehicle and fuel emissions standards. Similar to RGGI, under the 2010 WCI cap and trade framework each
province or state develops its own program and issues its own allowances which can be traded among jurisdictions. The plan would encompass 90% of all GHG emissions within WCI member states with a target of 15% reductions in 2005 emissions by 2020. The cap increases in 2015 when it incorporates transportations fuels. In 2011 a nonprofit entity, the Western Climate Initiative, Inc., was created as the administrative vehicle to support the implementation of the individual WCI jurisdictions’ cap and trade programs.

Since the WCI Regional plan was developed in 2010, only five of the jurisdictions have put action plans in place, British Columbia, California, Manitoba, Ontario and Quebec. Thus far, only California and Quebec, as noted above, have reached agreement to formally link their systems. The 2010 WCI Regional Program, however, set much of the framework for the recently established cap and trade programs in California and Quebec. For example, WCI proposed three key elements for mitigating leakage that have been adopted in both California and Quebec 1) giving out free allowances 2) linking with other jurisdictions and 3) including a requirement that imported power must also obtain allowances in its cap and trade program. Additionally, even though many of the original states and provinces have stalled in taking action, the WCI represents a precedent for linkages between jurisdictions to reduce GHG emissions. It is through this program that California and Quebec began exploring options for linking their respective programs, which is detailed further below.

Overview of Quebec’s Cap and Trade Program

In general, Canadians are more supportive of action on global warming including cap and trade, and are more willing to pay for reduced CO₂ emissions than in the United States. More than half of Canadians support a cap and trade program that would add $50/month to their electricity bills, above the price allowance ceiling California and Quebec have implemented.

In 2008, Quebec joined WCI, and established its enabling legislation for the program and GHG reduction goals in 2009. Quebec developed its initial cap and trade regulation, “Regulation respecting a cap-and-trade system for greenhouse gas emission allowances,” in 2011, benefiting from significant cooperation with California. Over the past year Quebec has developed its market design and allowed regulated industries to become familiar with the program. Quebec aims for an ambitious target of cutting GHG emissions by 20% below 1990 levels by 2020. In addition, Quebec also taxes CO₂ emissions. To put the market into operation, Quebec adopted the “Regulation to amend the Regulation respecting a cap-and-trade system for greenhouse gas emission allowances” in 2012. In 2013, Quebec took another major step in climate policy by running the country’s first operational carbon market.

January 1st marked the beginning of Quebec’s first compliance period, which will operate separately from California’s until linkage in 2014. For the first few months of the compliance period, Quebec has been allowing covered entities to adjust to the system, running auction workshops and a pilot auction. Emitters will receive their allocations on May 1, 2013.
Cap Timeline, Allocation of Allowances and Leakage

Like California, Quebec’s emissions trading market will become operational in several phases. In 2013, Quebec’s electricity sector and 75 industrial facilities producing more than 25kt of CO$_2$e, including aluminum, cement, lime, mining, and pulp and paper production will enter the cap and trade program. In 2015, the cap increases as businesses that distribute fuel including gasoline, propane, and natural gas, as well as transportation, building and all other industry are added to the program.\textsuperscript{191} Quebec’s GHG emissions by sector are shown in Figure 7.4.

As shown in Figure 7.5, 96% of Quebec’s electricity comes from hydropower. The province is a net exporter of electricity and offers consistently low prices for residential customers.\textsuperscript{192} As a result, the Quebec cap and trade program is expected to have a small effect on the province’s electricity prices, a fact that has contributed to its public support. In RGGI, however, residential electricity prices have been a point of contention in the formation of the program.

\begin{center}
\textbf{Figure 7.4 Quebec’s 2009 GHG Emissions by Sector}
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Like California, and unlike RGGI, Quebec takes a mixed approach to distributing initial allocations in its market, with some industries receiving free allowances and others purchasing them at auction. Both the electricity and transportation sectors will have to purchase emission credits at auction.\textsuperscript{193} Some allowances go into a reserve account with 1% being placed in reserve for the first compliance period, 4% for the second, and 7% for the third.\textsuperscript{194}
Free allowances are distributed based on industry specific historic emissions and emissions intensity targets. Equations designating these allowances are established clearly in the Quebec system operating rules. Industries that sell products on an international market will receive free allowances to help them be more competitive on the market. These industries include aluminum, lime, cement, pulp and paper, mining and others. Thermal energy producers may also receive free auctions, if they have long-term pricing contracts that were agreed to before 2008.

**Linkage between California and Quebec**

Linkage between California and Quebec was originally scheduled for June 2012. However, last minute legislation (SB 1018) and public opposition in California required CARB to produce an additional study analyzing the implications of linkage and consideration of four findings, before the Governor of California would make a final decision on the findings. The Governor officially approved the linkage on April 19th, 2013. The four findings analyzed by CARB pertaining to approval of a linked jurisdiction were 1) equivalent or stricter than in terms of emissions reductions achieved 2) continued enforceability of California’s AB 32 3) enforceability of the linked program and 4) linkage does not impose liability on California. CARB’s analysis in comparing the two programs supported the four findings and concluded that both programs had equal rigor in the caps and other operating methods.

Linkage was facilitated by the fact that, as discussed earlier, the WCI provided a common framework in the development of the California and Quebec’s cap and trade programs. To streamline the linkage process, both jurisdictions worked collaboratively in developing
regulations governing their respective programs. Staffs from both jurisdictions parties have worked closely through working groups by exchanging market model proposals on topics like reporting, program scope and market regulations. In addition, both CARB and Quebec’s Ministry of Sustainable Development, Environment, Wildlife and Parks, have examined Quebec and California’s regulations for line-by-line comparisons.197

Aligning the two Cap and Trade Programs

Quebec and California outlined what elements of the market needed to be aligned for linkage and determined that auctions, reserve sale, and floor price should be identical – requirements that might be difficult for RGGI to meet. Early reduction policy, and allowance distribution in noncompetitive markets can vary between jurisdictions. Variables like registration requirements, reporting, and competitive industry allowance distribution should be consistent across jurisdictions, but do not have to be identical. Canadian representatives assert that this is an adaptive iterative process, and through the market’s operation, regulators may find evidence to restrict or relax alignment between the markets.198

Still, California’s Air Resources Board has established that offset requirements are equivalent between Quebec and California. Both jurisdictions limit offsets to 8% of an entity’s compliance obligation and annual reporting. Additionally, although each jurisdiction enforces offsets differently, they both account for all offsets and verify the number of offsets claimed by purchasers.199

To align the two programs, Quebec made several changes to its draft regulation that were later adopted in its final 2012 regulation (see Table 7.2). The most significant change was the price floor. Quebec’s original proposal set a $15 price floor for the auction, yet the final regulation lowered the floor to $10. This critical change in Quebec’s market is likely due to pressure from California. Ultimately, Quebec’s final rule, which was released the day following California’s, changed the price floor, allowance reserve price, allowance allocation, and holding limits from Quebec’s original regulatory proposal (Table 7.2). That same month, the “Regulation respecting the delegation of management of certain parts of a cap-and-trade system for greenhouse gas emission allowances” authorized funding for the Western Climate Initiative Inc., to operate the market on behalf of the Government of Quebec.200

According to CARB’s published amendments to the cap and trade regulation, linkage with Quebec benefits the program by expanding the market of allowances and the opportunities for achieving low cost compliance.201 According to the same document, some additional investment will flow into California as a result of Québec paying for lower cost reductions in California.

From the Quebec perspective, linking with California was a top priority in the creation of its cap and trade market. The linkage was perceived as vital to Quebec’s market because the increased competition in a broader cap and trade system makes the program more efficient, lowering the cost of GHG reductions. As an early leader in the WCI, Quebec also hoped that linking with California from the beginning of the system would encourage other jurisdictions, specifically other WCI states and provinces, to join the market.
Table 7.2 Key Changes from Draft to Final Rule for Quebec’s Cap and Trade Program

| Auction Floor Price | Draft: Starting at $15/tonne, increasing 7% per year  
|                     | Change: Starting at $10/tonne, increasing 5% per year (plus inflation) |
| Allowance Reserve Price | Draft: Fixed price between $40-50/tonne  
|                      | Change: Starts between $40-50/tonne and increases 5% per year (plus inflation) |
| Allowance Allocation | Change: Select importers of electricity may now be eligible to receive free allowances in final regulations |
| Holding Limits      | Change: Introduction of holding limits in final regulations |


Differences Between California’s and Quebec’s Programs

Although California and Quebec’s cap and trade programs have undergone substantial harmonization, they have permitted some key differences in the programs, particularly in the offsets market:

1) Quebec has limited the number of offsets that can be generated by Quebec for sale to California, but not vice versa.

2) The allowed offset project types are not identical. California permits forest projects in its offset criteria, but excludes waste (see Table 7.3).

3) CARB and Quebec have different rules for qualifying and invalidating offsets. In Quebec, offsets are required to be “additional, permanent and accurately and conservatively quantified.” To meet such provisions, Quebec limits approved projects to livestock waste digesters, small landfill gas recovery, and ozone depleting substances destruction in Canada. Quebec also provides a methodology for evaluating the offsets for these credits. In contrast, California employs a “real, additional, permanent enforceable, verifiable, and quantifiable” standard.

4) If credits are later deemed invalid, the Quebec government takes recourse with the offset provider. Every offset provider is required to place 3% of its offsets into a government-operated buffer account. If a provider cannot replace the invalid offsets, the Government withdraws replacement offsets from the buffer account. However, in California, the offset purchaser is held responsible for the offset credits, and the purchaser must replace the invalid offsets with new offsets.

5) Unlike California, Quebec does not grant any free allocations to the electricity or transportation sectors.
In terms of percentage emissions reductions for covered sources relative to historical emissions, Quebec’s target of 20% below 1990 levels is more strict that California’s target of achieving 1990 levels themselves by 2020. When considering the fraction of emissions reductions relative to 2015, when all covered sources in California and Quebec will be participating in their respective programs, the percentage reductions in GHG emissions are comparable, 15% for California and 16% for Quebec. Looking at each sector separately, both California and Quebec have substantial transportation and industrial emissions. However, while electricity generation accounts for 23% of California’s GHG emissions (Figure 7.1), Quebec’s electric grid consists mostly of hydroelectricity, and as a result, electricity is only a small fraction of Quebec’s GHG emissions (Figure 7.4).

Moreover, due to changes in both production and consumption, electricity emissions dropped 60% between 1990 and 2009 in Quebec. At the same time, transportation emissions increased 30%. Industrial emissions dropped 25% over the same time period, though this was due in part to temporary and permanent facility closures. While California will be able to achieve some GHG reductions by replacing current fossil fuel generation with cleaner energy, most of Quebec’s emissions reductions must come from industry and transportation, which according to CARB makes Quebec’s cap and trade program equivalent to or more stringent than California’s.

Potential Linkage between RGGI and California

In a publication from Resources for the Future (RFF), Burtraw et al. recently developed a two tiered framework for linking carbon market programs, and specifically analyzed the potential case of California and RGGI. Quebec’s program, due to be linked to California in early 2014, was not analyzed. The first tier discusses the program elements needed for alignment, and the second tier discusses the benefits of a gradual alignment approach.

The California and RGGI cap and trade programs have already adopted elements from each other and according to Burtraw et al., the process of linkage is essentially already underway. The study describes in general terms the political, economic, administrative, and policy benefits of linkage and the differences between unilateral versus bilateral linkage. The authors contend that carbon trading mechanisms can be linked gradually and that the process of alignment of program elements prior to formal linkage is in itself beneficial and reduces the chance of unanticipated consequences.

The RFF study identifies ten key program elements and evaluates them in the context of RGGI and California linkage according to three criteria: difficulty of administrative alignment, importance for the market to be able to function, and importance for the political economy. If an element is characterized as important but not yet aligned, a recommendation is made to align it prior to linkage. The ten program elements identified mirror the key carbon market components discussed in this and other chapters for California and RGGI: 1) measurement, reporting and verification 2) allowance tracking 3) emissions cap 4) scope and timing of coverage 5) allocation 6) auction coordination 7) banking 8) offsets 9) price collars (floor and ceiling); and 10) legal contingencies.
Regarding the comparability of the emissions cap between California and RGGI, the authors argue that the best way to evaluate the relative stringency of the caps is by examining the response of industry to the cap levels and the cost needed to achieve a given emissions target. Such an analysis, beyond the scope of this paper, would need to evaluate contributing factors such as co-existence of other GHG policies such as a renewable portfolio standard, the allocation mechanisms (i.e. free allowances versus auctioning), etc.

Finally, the potential linkage options between RGGI and CARB were explored via modeling analysis with and without an allowance exchange rate (1 CARB offset or allowance = 3 RGGI offsets or allowances). In both scenarios, and in particular in the scenario without an exchange rate, allowance prices in RGGI would increase, increasing the risk of leakage. Assuming that RGGI does not expand its market beyond the electricity sector, the highest risk of leakage would be to other coal states that already export electricity to RGGI states on the PJM grid, such as Pennsylvania and Virginia. For more information on leakage, see Chapter 5.

In terms of the impact of RGGI and California formal linkage on combined emissions levels from the electricity generating sector only, the model analysis found that when linked without an exchange rate, overall emissions would decrease by 26%, as compared to 17% without linkage with almost no impact on electricity prices. When using an exchange ratio of 1 to 3, linkage between California and RGGI leads to an overall emissions increase of 14% as compared to an increase of 17% without linkage, and only a very small increase in electricity prices in RGGI states.

An overview assessment of linkage potential

Starting with the working hypothesis that linkage between RGGI and California is feasible, this section examines the advantages and disadvantages of linkage, and near term recommendations. A good starting point for evaluating the benefits and disadvantages of linkage between RGGI and CARB is to detail some of the key differences between the two programs:

1) California’s AB32 requires “the maximizing of GHG emission reductions through coordinated sub-national efforts by enhancing individual jurisdictions’ actions through a collaborative effort.” While CARB built-in a framework to allow future linkage with other cap and trade programs, RGGI did not. The implication for harmonization is the political barriers within RGGI states if they were to “upgrade” their program components to become suitable for linkage. Joint agreements and action among the RGGI member states is inevitably complicated by the fact of nine political jurisdictions, as compared with one in the case of California (or two if we think of it as the California/Quebec cap and trade system).

2) CARB promotes economy wide reductions, while RGGI is limited to the utility sector. However, this is not necessarily an impediment to a functioning linked market Error! Bookmark not defined. or likely to be at odds with EPA federal regulation, which currently only applies to the utility sector (see Chapter 9).

3) There is a considerable difference in the minimum and maximum allowance price between RGGI and California that is often cited as a key impediment to linkage. The floor price of
allowances is much higher for CARB, at $10.70, than for RGGI, only about $2.00 at present. In 2014, the maximum allowance price for RGGI under the new system adopted in February 2013 will be $4.00, rising to $10.00 in 2020. California already has a maximum in the $40 to $50 range, as discussed above.

4) California and RGGI have different governance structures, a topic to be discussed later in greater detail, and also covered in previous chapters. California’s cap and trade market is part of a broad climate change mitigation program and has been explicitly linked to other efforts to reduce GHG emissions in California. This integration across GHG emission reduction initiatives has not occurred in the case of RGGI states.

5) CARB has already built in a mechanism to prevent leakage, inherent in the way it allocates its allowances (see previous section). Although reportedly, leakage within RGGI has not been a problem, as RGGI’s cap tightens over time, leakage could well become a problem, yet RGGI does not have protocols in place for mitigating leakage.

6) RGGI, California, and Quebec’s offsets program types are not identical (see Table 7.3). In addition, RGGI’s offset program is essentially dormant and constrained to RGGI states, while California has a fully developed offsets market for the entire US. In addition, CARB is actively pursuing international offset linkages via the REDD Offsets Working Group. CARB and Quebec have separate energy efficiency incentives. Likewise there are differences in the scope of each project type across the three jurisdictions.

| Table 7.3 Comparison of offset project types between California, Quebec, and RGGI |
|---------------------------------|------------------|------------------|------------------|
| Project Type a                  | California       | Quebec           | RGGI             |
| Forestry                        | YES              | NO               | YES              |
| Urban Forestry                  | YES              | NO               | NO               |
| Landfill Gas capture            | NO               | YES              | YES              |
| Dairy Manure                    | YES              | YES              | YES              |
| Ozone Depleting Substances      | YES              | YES              | YES              |
| Energy Efficiency (Buildings)   | NO               | NO               | YES              |

\(^a\) RGGI added energy efficiency offsets because there is no other public fund available.

**Benefits of Linkage**

CARB’s published amendments to the cap and trade regulation discuss how linkage between California and Quebec is beneficial by providing “*a framework for additional partners to join and demonstrating a workable template for urgently needed action at the national and international levels to address climate change.*” From this statement, it would seem that California would be amenable to working with RGGI to develop a linked common system.

In addition, California’s regulation grants CARB with the authority of linkage, provided there is a public comment period, thus providing the regulatory framework for external linkage beyond...
Quebec, such as potentially RGGI. Thus, adding partners to California’s cap and trade program beyond Quebec, could initiate the process towards a wider US cap and trade program.

**Disadvantages to Linkage**

When linking cap and trade programs, there is uncertainty and potential risk introduced if for example RGGI were to implement program changes or link to a third jurisdiction with weaker compliance mechanisms, because there is no clear mechanism for California or Quebec to enforce their own cap and trade regulation on RGGI states. This concern was expressed by multiple stakeholders during the public comment period on the 2012 amendments to California’s cap and trade regulation. Several stakeholders in California have requested amendments to the regulation that would outline explicit protocols in the event of modification of cap and trade program elements by a linked jurisdiction, such as for example the ability for CCARB to review program changes proposed by Quebec, and a public comment period in California for changes to protocols in linked jurisdictions.

**Recommendations**

1. **RGGI should move forward in discussions with California and Quebec with the objective of linking their two cap and trade systems, thereby forming a newly international and transcontinental integrated GHG cap and trade system.** Combining the California/Quebec and RGGI cap and trade systems into one integrated cap and trade system would significantly expand the potential geographic scope of trading, thus increasing the efficiency of GHG reductions in the combined area, and lowering the total GHG reduction costs. In addition, RGGI could benefit from the experience and expertise that California and Quebec have developed in implementing their cap and trade systems – as they might benefit from RGGI experience and expertise. The additional recommendations below would facilitate the linking process.

2. **Develop a RGGI plan for phasing in transportation and other economic sectors besides electric power generation.** California’s cap and trade system is scheduled to include the transportation sector as of 2015. At present, RGGI is limited to the electric power sector. Expanding the scope of RGGI to also encompass transportation, while perhaps not a requirement for linkage, would facilitate the process, and would also have GHG benefits internal to RGGI.

3. **Develop a RGGI mechanism to phase in allowance price increases more rapidly:** California has a minimum allowance sales price of about $10, much higher than the RGGI minimum sales price. If California GHG emitters could buy RGGI allowances for much lower RGGI prices, it would reduce their incentive to make GHG reductions – an undesirable form of leakage. In order to facilitate linkage, RGGI should raise its minimum price to correspond to the California minimum. Alternatively, it might be sufficient at first for RGGI to reduce the cap enough to drive up the price of RGGI allowances. RGGI’s cap is set to be reduced by 2.5% per year. A decrease of 5% per year or more would bring it closer to CARB’s allowance price and facilitate linkage.
4. **Link RGGI’s and California’s offset programs:** RGGI should take steps to link its offset program with California’s as a vehicle for promoting less costly GHG reductions by RGGI GHG emitters, and invigorating RGGI’s offset program. In California, industry is already enthusiastic about an expanded offsets market, and some power utilities have expressed concern that CARB’s offset market is not sufficiently large and will be further strained by linkage with Quebec. Given the more advanced development of the California/Quebec offset program, RGGI might agree to accept offsets that have met California offset requirements.

4) **Implement changes to RGGI’s Governance Structure:** RGGI cannot adapt to changing circumstances or modify its programs without consent from 7 states, a major barrier to program effectiveness and linkage opportunities, since the harmonization process would likely necessitate multi-state approval. Conversely, California is able to adapt more quickly, since only one state is involved in decision-making, although future linkage with Quebec may slow down that process. RGGI should seek an alternative mechanism for decision making that shifts decision-making power towards RGGI administrators in at least some policy areas, thus reducing the need for multi-state legislative and/or regulatory approval.

5) **Seek Congressional ratification of RGGI as an interstate compact:** RGGI has felt constrained in pursuing governance reforms and other actions by the legal concern that an actual treaty compact among the RGGI states might not be constitutionally valid, unless blessed by Congress. This concern could be addressed by seeking formal Congressional approval for RGGI. There are many precedents in interstate water compacts and other formal agreements among states that could be drawn upon.
Based on the analysis of this report, it is likely that Maryland will find it difficult to fulfill its Greenhouse Gas Reduction Act (GGRA) commitment to a 25% greenhouse gas emissions reduction goal by 2020. One way that Maryland might increase its overall contribution to greenhouse gas reductions would be to allow GHG emitters in Maryland to purchase offsets outside the state. These offsets might then be counted as part of Maryland’s GGRA commitment to reduce GHG emissions within the state by 25%, as compared with 2006 emissions.

Since the GHG emissions of electric power producers in Maryland are regionally controlled by RGGI, offsets obtained by Maryland GHG emitters in the power sector would have to be obtained through the RGGI system of accepting offsets. If RGGI and California officially formed an integrated system, as examined in Chapter 7, Maryland electric power producers might obtain their offsets by directly purchasing allowances in the California cap and trade market. California GHG emitters might similarly purchase needed allowances in the RGGI cap and trade market.

In the absence of such integration, RGGI might still act on its own to permit electric power producers within the RGGI area to “offset” their GHG emissions by purchasing California allowances (although this would be unlikely at present because California allowance prices are considerably higher than RGGI allowance prices). If California did not reciprocate in allowing California GHG emitters to purchase allowances from RGGI sources, this would be known as a “one-way” offset relationship between the RGGI and California cap and trade systems. One-way relationships could potentially also exist with other cap and trade systems other than California’s, including, in concept, cap and trade systems outside the United States.

Both the California and RGGI cap and trade systems also, and as discussed in Chapters 5 and 7, allow the use of GHG offsets purchased from individual parties outside their own systems. These are by definition “one-way” transactions, as one GHG emitter in the California or RGGI systems pays for an offset project somewhere else, in lieu of making a purchase of an allowance within its own cap and trade market.

**The Clean Development Mechanism**

The best known system of individual offsets is the Clean Development Mechanism (CDM), created by the Kyoto Protocol. The Kyoto Protocol is an international treaty under the United Nations Framework Convention on Climate Change (UNFCCC) that sets binding GHG emissions targets for 37 industrialized countries and the European Community, which together are known as the Annex I countries. The CDM, as defined in Article 12 of the Kyoto Protocol, generates offsets (Certified Emission Reduction credits) through investments in GHG reduction and sequestration projects in developing countries. CERs can be traded to meet emission commitments under the Kyoto protocol.
CDM was designed to enable Annex-I countries to reduce global GHG emissions in a more cost-effective way through investments in less expensive offset projects in non-Annex I countries (developing countries without binding targets). The first CDM project was registered in 2004 and the scheme has grown rapidly and now dominates the offsets market. Since September 2007, the CDM has self-financed its regulatory functions through project fees, instead of grants from Annex-I countries. Over one billion CDM credits have been issued to date, each representing one ton of CO$_2$ equivalent reductions. As of March 2010, more than 80 countries have financed CDM projects. About 63% of the projects are in China and India with future projections of 71% of annual CERs. Brazil, China, and India are the three largest CDM markets in the world, both in terms of the number of projects and the amount of CERs generated.

The Kyoto Protocol defined the baseline for a CDM project activity in 3/CMP,1, Annex Paragraph 44: “The baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases that would occur in the absence of the proposed project activity.” This means that the baseline is a reference case representing the volume of greenhouse gas that would have been emitted if the CDM project had not been implemented. The baseline is an important factor in determining whether a CDM project is “additional” and the claimed volume of additional GHG emissions reduction is actually achieved by a CDM project activity. The baseline should be derived using a methodology approved by the CDM Executive Board.

High quality offsets must meet the following performance standards: additionality, measurability, independently audited, unambiguously owned, able to account for leakage, and permanent. Table 8.1 evaluates CDM offsets based on these six standards.

<table>
<thead>
<tr>
<th>Table 8.1 Criteria for Valid CDM Offsets</th>
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<tr>
<td><strong>Additionality</strong></td>
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<tr>
<td>CDM’s additionality process has evolved and improved over recent years. Initially the program focused on expanding market liquidity. Some non-additional projects were approved due to lack of thorough review procedures. Over 80% of projects during 2005 to early 2007 were registered with little Board review. Since 2007, CDM enhanced scrutiny of the registration process by putting in place more rigorous methods and performance standards. Still, developing methodologies and quantitative metrics for the wide array of CDM projects and countries takes significant resources, time, and expertise.</td>
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<tr>
<td><strong>Measurability</strong></td>
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<td>Since the start of the CDM, over 140 standardized baseline and monitoring methodologies and tools have been approved to monitor emissions, calculate reductions and estimate emission leakage for various kinds of projects. CDM is project-based so in early days there were few standardized methodologies available. Project developers came up with new methodologies to quantify emission reductions and similar methodologies were consolidated. CDM methodology library has laid the technical</td>
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</table>
foundation for other mandatory and voluntary GHG emission reduction programs around the world. The Western Climate Initiative (WCI) conducted comparative study of offset methodologies and found that CDM methodologies were consistently the highest quality for each type of project considered.

| Auditing | The CDM requires two specific types of auditing, one for validation and the other for verification. Validation is a process to ensure projects meet all CDM’s eligibility requirements prior to implementation. Verification audits projects’ GHG emission reduction periodically. Designated Operational Entities (DOEs or auditors) are independent third parties to perform audits, accredited by the CDM Executive Board. Once a CDM project has been implemented, the project should undergo verification before credits are issued. Different auditors are responsible for validation and verification to reduce bias or errors. Under the CDM scheme, auditors take significant responsibilities to review projects. Conflicts of interest have the potential to reduce the rigorousness of auditing. CDM requires a great degree of quality assurance oversight, instead of completely relying on private sector auditors or rating agencies. The Board released a detailed Validation and Verification Manual (VVM) in 2008 to help improve the quality and consistency of CDM project auditing. |
| Ownership | Offsets can be both used for compliance with GHG emissions reduction goals and as a tradable commodity with a market value. The creation of offsets should avoid disputes on settling ownership and it should also prevent double counting. Offset credits are individually counted in a CDM registry. The CDM registry assigns a unique account number to each market participant and each CER can only be held in one account at any given time. For example, if CERs are submitted for compliance in the EU, their account number will exist in the EU registries, thus they could not be used again in EU ETS. |
| Leakage | Under the CDM, leakage is defined as the “net measurable change in GHG emissions that occur outside a project’s boundary”. A deforestation project in one area could lead to harvesting of trees in another area. Leakage occurs in many types of CDM projects but is especially challenging for forest projects, which are not eligible under the CDM Specific methods for defining project boundaries and calculating leakage must be included in each project methodology. Project developers must deduct the leakage from their total credited reductions. |
| Permanence | Emission reduction effects could be reversed. Carbon sequestered by a forestry project could be released back to the atmosphere if there is a forest fire or insect infestation. The CDM addresses this problem by issuing temporary credits (tCER) that |
The emissions trading system (ETS) of the European Union (EU) began allowing entities to use CERs from the CDM in 2005 and Emission Reduction Units (ERUs) from the Joint Implementation (JI)\(^1\) in 2008. However, partly reflecting concerns about the ability of CDM projects to meet the above criteria, the EU has more recently limited the use of certain types of projects such as land use change, forestry and nuclear power. Industrial gas destruction projects will be terminated after 2013 (European Commission, 2011b)\(^2\). Most recently, in 2011, the EU ETS announced that it will only recognize CERs from the U.N.’s least developed countries, most of which are located in Sub-Saharan Africa, after 2013. This means that CDM offset projects from China and India, the two biggest past generators of such offsets, will no longer be accepted within the EU ETS.

EU ETS members have also set limits on the use of offsets as a percentage of total allowance compliance obligations by each nation within the EU. These limits range from 0 % in Estonia to 20% in Lithuania and Spain.

**Other Offset Systems**

Another example of an offset system is the program for “reducing emissions from deforestation and forest degradation” (REDD) proposed by the Coalition for Rainforest Nations including around 30 southern forest countries. This mechanism aims to reduce greenhouse gas emissions from deforestation and forest degradation after 1995. It was excluded from the Kyoto Protocol because of the complexity of measurements and monitoring for the diverse ecosystems and land use changes.

However, at the 11\(^{th}\) Conference of the Parties (COP 11), REDD+ was put up on the table again and included in the international agreements. REDD is an “offset” mechanism of industrialized countries. The basic idea of REDD is to finance projects in developing countries to reduce deforestation over a given period. Credits generated by REDD, which are fungible, are integrated into the market so that industrialized countries and entities could acquire them to meet their obligations and to be traded in the market. However, REDD has been hotly debated due to the risk of “leakage,” in other words that projects lead to a simple geographical shift in deforestation rather than a global reduction in deforestation. Moreover, it is hard to choose the reference period or the baseline to measure the reduction in deforestation. Should the deforestation level during the commitment period be compared with a past period level or a projected business-as-usual scenario? The way to choose the baseline has different implications depending on countries.\(^2\)\(^1\) For example, if a country has had a low deforestation rate in the past is now

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1 Defined in United Nations Framework Convention on Climate Change: “Joint Implementation, defined in Article 6 of the Kyoto Protocol, allows a country with an emission reduction or limitation commitment under the Kyoto Protocol (Annex B Party) to earn emission reduction units (ERUs) from an emission-reduction or emission removal project in another Annex B Party, each equivalent to one tonne of CO2, which can be counted towards meeting its Kyoto target”.

http://unfccc.int/kyoto_protocol/mechanisms/joint_implementation/items/1674.php
expected to build more road infrastructure, this will favor a baseline business-as-usual scenario instead of a past period.

Besides the CDM and REDD, a third source of offsets are credits for GHG reductions that are certified by private third parties that can be bought and sold voluntarily. The brokers in such systems sell credits to large companies and other parties seeking projects to mitigate their emissions. The greatest concern in such voluntary carbon offset schemes is the actual achievement of additionality. It can be difficult to guarantee that the “net” GHG effects of private or public projects represent actual reductions in the emissions of total worldwide GHGs.

Discussion of Possible One-Way Linkages in RGGI

The following section discusses five possible options for RGGI to establish one-way linkages.

Linkages with other domestic cap and trade systems

So far RGGI has not created any specific policies addressing potential linkages with other domestic cap and trade systems -- such as the number of offsets allowable within RGGI from allowance purchases in another domestic cap and trade system. Other possible issues relate to permissible types of allowances purchased from other domestic cap and trade system and the verification process. This section provides recommendations for mechanisms to facilitate one-way linkage between RGGI and cap and trade programs within the US. (See chapter 7 for specific recommendations on full two-way linkage between RGGI and California’s cap and trade system.)

In discussions with officials in the MDE and consultants from RGGI, they hold a positive view of potential linkages with other domestic cap and trade systems. If the market price of allowances in both Maryland and RGGI goes up, Maryland and RGGI are more likely to see entities wanting to buy allowances outside of the RGGI market to fulfill their GHG obligations.

Recommendations

1. RGGI should develop a policy that allows the purchase of allowances from other domestic cap and trade systems. These allowances would be tradable and acceptable for meeting the RGGI cap. The policy would also specify the permissible allowances, such as what kinds of allowances could be bought as offsets.

2. Similar to individual offsets, RGGI should establish a short run quantitative limit on the total number of allowances from another cap and trade system that can be used as RGGI offsets.

3. In the long term, entities within RGGI should not be limited in the number of offsets they can buy in this fashion. They should be free to make a choice between the RGGI market and the other domestic cap and trade system in seeking a lower allowance price. The offsets would be tradable and fully verified.
4. A reporting and verification agency is needed for RGGI as a whole. This agency could be used for administering one way or two linkages with other cap and trade systems. The RGGI verification agency should also provide advisors for each state’s verification agency to make sure that every state’s verification process is consistent with that of RGGI.

**Linkage with international cap and trade systems**

Besides linkage with domestic U.S. cap and trade systems, RGGI could potentially link to cap and trade systems in the EU, South Korea, New Zealand, and even China. Compared to linkages with other domestic cap and trade systems, linkages with international cap and trade systems would be more challenging because of political, legal issues and specific technical issues. For example, the possibility of a RGGI one-way linkage with the EU ETS raises a variety of challenges:

- **Kyoto parties and non-parties**: RGGI allowances are not acceptable for EU countries under the Kyoto Protocol, so any RGGI relationship with the EU would have to be one-way – RGGI could recognize EU ETS allowances as acceptable offsets for purposes of RGGI compliance but not vice versa.
- **Measurement Units**: RGGI allowance permits one short ton of CO\(_2\) emission and EU allowance permits one metric ton of CO\(_2\) emission. The differences in measurement units would have to be addressed by setting a ratio at which EU allowances are accepted for RGGI compliance.\(^{215}\)
- **Allowance tracking system**: RGGI would need a technical mechanism to transfer allowances purchased in the EU ETS. Protocols should be built into the tracking systems to ensure that purchased allowances transferred from EU ETS conform to RGGI’s administrative rules.
- **Monitoring, Reporting and Verification (MRV)**: Without rigorous emission MRV standards, the environmental integrity of the linked programs might be compromised. Unsynchronized emissions reporting could undermine the smooth functioning of the allowance market.\(^{216}\) EU ETS and RGGI have both developed detailed MRV procedures and they should be comparable across these two programs.

Allowance prices in the EU ETS were $30 a ton in 2011 but had fallen to $7 a ton in early 2013. Partly because the economic downturn has reduced industrial demand for allowances, and partly because the EU gave away too many allowances in the first place, there is a surplus of 1.5 billion-2 billion tons, equal to about one year of EU emissions. To address this problem the European Commission developed a plan to take 900 MMT of carbon allowances off the market now and to reintroduce them a few years later (the plan is referred to as “backloading”). The European Parliament, however, recently rejected this plan. The price then fell further to around $3 per ton in mid-April. It might be a good time for Maryland and RGGI to consider linkage with the EU ETS due to the low EU market price of allowances.

Australia’s greenhouse gas strategy is now in flux, owing to the recent election of a new government. Maryland and RGGI, however, might learn from the past efforts to establish a one-way linkage between Australia and EU. In 2012, Australia and the EU agreed to start a full two-way link between their two cap and trade systems no later than 2018.\(^{217}\) Under the planned system, from July 2015 to July 2018, an interim link would be created enabling Australian
parties to purchase EU allowances for future compliance in Australia. European Unit Allowances (EUAs) would be usable in Australia as “eligible international emissions units” under the Clean Energy Act of that nation.

In other words, under the planned system, beginning in July 2015, a GHG emitter in Australia would have been able to surrender EUAs to partially satisfy its obligations under the Australia’s carbon pricing mechanism (CPM). Australia planned to allow such EU offsets to satisfy up to 50% of its obligations under the CPM. The government also considered introducing other limits on classes of eligible international emissions units. One such limit might be is a 12.5% maximum for the number of Kyoto CDM units that can be used for compliance purposes in Australia.

Australia also repealed its $15 price reserve. However, to enhance price discovery and to ensure that the auction price of Australian Carbon Units (ACUs) did not diverge from the secondary market price too much, the Minister still would have had the power to set a reserve price any time necessary. With such a direct one-way linkage with the EU, Australia would be indirectly linked with other trade systems and offset credit systems. If RGGI were to link to Australia, it would indirectly link to others with which Australia might be linked.

**Potential RGGI links to China’s provincial cap and trade systems**

Linkages with China might be particularly challenging but might also offer high rewards for RGGI. Before 2011, China relied heavily on the Clean Development Mechanism (CDM) and on voluntary carbon credit markets for reducing its greenhouse gas emissions. China has 1,273 CDM projects, making up 47.3% of global CDM projects. Six types of greenhouse gas are targeted including CO₂, CH₄, N₂O, HFCs, PFCs, and SF₆.

In January 2012, the Chinese government announced pilot cap and trade programs for the provinces and municipalities of Beijing, Tianjin, Shanghai, Chongqing, Shenzhen, Hubei and

**Figure 8.1 Approved Pilot Carbon Trading Schemes in China**

![Image of China with marked regions for approved pilot carbon trading schemes]

Guangdong (see Figure 8.1). The scheme is intended to benefit from the past experiences of the EU-ETS. The provinces were required to submit proposals for carbon emissions targets, establish a dedicated fund to support the carbon emissions market, and provide implementation plans for approval by the end of 2012.\textsuperscript{219}

The first cap and trade systems were the China Beijing Environment Exchange (CBEEX), the Tianjin Climate Exchange (TCX), the Shanghai Environment and Energy Exchange (SEEE), and the Shenzhen Climate Exchange. Beijing and Guangdong have gone further than any other of the five pilots in developing their cap and trade systems. These exchanges are responsible for allocating allowance permits to achieve the caps. China’s government expects that these pilot exchanges will be the first steps towards establishing a full scale national cap and trade system in the next five years.\textsuperscript{220} More details about the current provincial progress are shown in Table 8.2 as follows:

<table>
<thead>
<tr>
<th>Provinces/Cities</th>
<th>Policy</th>
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<tbody>
<tr>
<td>Beijing</td>
<td>Fuel Efficiency Standard for vehicles and buildings&lt;br&gt;Ended key fuel subsidies&lt;br&gt;Investment in renewable energy and reductions in industrial emissions&lt;br&gt;Established China Beijing Environmental Exchange</td>
</tr>
<tr>
<td>Tianjin</td>
<td>Established the Tianjin Climate Exchange&lt;br&gt;Targeted at high energy consumption industry</td>
</tr>
<tr>
<td>Shanghai</td>
<td>Established the Shanghai Environmental and Energy Exchange&lt;br&gt;Allowances will be distributed free first then auction in key sectors: industry over 20K CO\textsubscript{2} emission; non-industry over 10K CO\textsubscript{2} emission</td>
</tr>
<tr>
<td>Chongqing</td>
<td>The Carbon Exchange Center will be built by April 2013 and start to run by the end of 2013</td>
</tr>
<tr>
<td>Shenzhen</td>
<td>Established the Shenzhen Environmental Exchange (2010)&lt;br&gt;800 companies from 26 industries including power plants over 20 K tons, manufacturing, and electronics industry</td>
</tr>
<tr>
<td>Hubei</td>
<td>Seeking collaboration with Guangdong after 2014&lt;br&gt;In March 2012 it invested $1.34 million to set up 13 research groups on the carbon emissions trading study&lt;br&gt;Mandatory reduction for energy consumption over 60K standard coal equivalent.</td>
</tr>
<tr>
<td>Guangdong</td>
<td>Covers nine industries&lt;br&gt;Companies that emit more than 20,000 tons of CO\textsubscript{2} a year will be required to participate in the trading program&lt;br&gt;2013 Jan. 29 first voluntarily carbon trading case</td>
</tr>
</tbody>
</table>
Some observers have suggested that it might not be feasible to link China’s provincial pilot programs in the foreseeable future with any international cap and trade systems – including RGGI.²²¹ This may be true because the short-term priority for China is not to link with other systems but simply to make each program operational. Moreover, a top priority of China is to establish a national cap and trade market. Therefore, the use of emissions trading in China must be much further developed before considering linkages with cap and trade programs outside China.

Yet, many international experts from EU and Australia are helping China to establish its provincial cap and trade programs and national trading system. According to recent news reports, Australia and China have been working in concert to develop carbon markets as a first step to a broader Asia-Pacific carbon market.²²²

It would make sense, therefore, for RGGI to begin preparations for international linkages such as with China in the future. Like potentially Australia, RGGI could provide technical expertise to the China pilots so that it will be easier and more feasible to link in the future. Based on the current status of cap and trade in China, several RGGI measures could be taken to prepare for international one-way linkages with other cap and trade systems.

**Recommendations**

1. In the near term, both Maryland and RGGI may not be able to resolve the complex issues involved with establishing one-way linkage with international cap and trade systems but in the long term, Maryland and RGGI should allow parties to buy allowances from where they are available at the lowest price.

2. A new verification rule should be set by Maryland and RGGI to establish an international allowance verification reflecting the complexity of international allowances. RGGI should provide expert support to help one of the Chinese provincial pilots design their cap and trade system. If the basic approach of RGGI’s model rules could be applied and accepted by such pilots, future linkage will be more feasible.

3. The Guangdong province is a good choice for a RGGI collaboration because it has a favorable outlook towards linkage.²²³ Moreover, the pilot will cover over 40% of the province’s total power consumption and around two-thirds of its industrial energy use including steel, iron and manufacturing.²²⁴ RGGI could define acceptable transferrable allowances from a variety of allowances sources there.

4. The most urgent help needed for China is to boost emission trading liquidity. Some of the pilots have already established exchanges. Yet, there have been few trades in the past two years. So Maryland and RGGI could assist in this area.

**Linkage with domestic individual offset projects**

In 2012, CARB approved offset protocols for four types of offset projects – forestry, urban forestry, dairy manure digesters and destruction of Ozone depleting substances. Each offset
credit is equal to one metric ton of CO₂ and can be used by entities in California to comply with the cap and trade target for up to 8% of their own compliance obligation. The offsets can be freely sold and traded.

Approved offset project registries are allowed to provide their services under the CARB compliance protocols. CARB trained and certified more than 60 independent, third-party verifiers to evaluate the quality and quantity of offset. In addition, 11 verification bodies have also been certified. After projects are verified and approved by CARB they are listed in the registry, where they can be used to comply with entities’ compliance obligations.²²⁵

Currently, covered sources in RGGI may use emission reduction credits generated from qualified types of offset CO₂ projects located in one of the RGGI states or other jurisdictions within the U.S (note: The Revised MOU among RGGI states also allows offset credits from non-RGGI U.S. states with cap-and-trade systems according to RGGI 2006b.).²²⁶ RGGI participating states currently allow regulated power plants to use a carefully chosen group of qualifying offsets to meet up to 3.3% of their CO₂ compliance obligation. At most, no more than 10% of emissions can be covered by offsets. Five eligible offset project categories are listed below²²⁷:

- Capture or destroy methane from landfills;
- Avoid methane through agricultural manure management operations;
- Reduce emissions of SF₆ from electricity transmission and distribution equipment;
- Sequester CO₂ through afforestation;
- Reduce emissions of CO₂ through non-electric end-use energy efficiency in buildings

Covered sources may use the offsets or buy allowances subject to quantitative limits that depend on the prevailing RGGI allowance price. Two stages of RGGI price triggers based on one-year averages are applied in RGGI. If the RGGI average annual allowance price is over $7 (stage 1), then the offset limit will increase to 5% of allowances. If the RGGI average annual allowance price exceeds $10 (stage 2), the offset limit will increase to 10% of allowances. Moreover, at this point the compliance period increases by one year. The price trigger mechanism is not only applied to linkage with offset credit systems but is also used as a benchmark when considering linking with other cap and trade systems in the U.S.

Potential RGGI offset project sponsors first submit a Consistency Application to RGGI participating states to demonstrate that the project complies with relevant state regulations. Then if approved, the project needs to submit ongoing Monitoring and Verification Reports to demonstrate emission reduction. Like California, independent, state-accredited verifiers monitor and verify all RGGI CO₂ offset projects after each state regulatory agency review. If the report is approved, the projects can be used to meet RGGI participating state compliance.

As of the spring of 2013, no applications for approval of offset projects or allowance purchases from other cap and trade systems had been submitted to RGGI, partly due to the low RGGI allowance price. However, based on interviews with Maryland Department of Environment officials, both Maryland and RGGI hold favorable views concerning the potential for use of domestic offsets in RGGI.
The Maryland GGRA contains some language for the Final Plan (due originally in 2012) to include the use of offsets and early voluntary action project credits as ways to achieve compliance with the GHG reduction goal. The original language in GGRA is as follows: “…Provide for the use of offset credits generated by alternative compliance mechanisms executed within the state, including carbon sequestration projects, to achieve compliance with greenhouse gas emission reduction required by this subtitle…”

Basically it only seems to allow offsets from alternative compliance mechanisms occurring within the State, including carbon sequestration projects and “early voluntary reduction actions”. One policy that GGRA mentioned is Nutrient Trading with Carbon Co-benefits. Because many of the agronomic, land use, etc. promoted by the Maryland Nutrient Trading Program also store carbon and other GHGs, this nutrient market provides a platform for the addition of a voluntary carbon component.228

Recommendations

1. To help fulfill Maryland 25% GHG reduction goal and meet the challenges resulting from the lower cap of RGGI, Maryland should allow statewide offsets within Maryland through the platform of Maryland Nutrient Trading Program.

2. The verification process should be separated from linkage with other cap and trade system verification. A separate verification office should be established that parallels the allowances verification office. Independent, third party verification agencies should be encouraged but have to register and operate under the regulation of the Maryland offset verification office; and RGGI offset verification office.

3. The standards of a high quality offsets should be consistent in Maryland and RGGI. The verification of offsets should consider the actual additionality provided by offsets. To meet the emission goals within a cap and trade system, high quality offsets should meet the following standards:\n
   ✓ Additional: offset projects should lead to additional emission reduction compared with baseline scenario if the projects would not have occurred.
   ✓ Measurable: there are reliable data to verify the emission reductions.
   ✓ Independently audited: the eligibility of the projects and emission reduction calculations should be audited by independent third parties.
   ✓ Unambiguously owned—rights to the credits should comply with laws and mission reductions must not be double counted.
   ✓ Able to account for leakage: offset projects should account for the emissions outside of a project’s boundary.
   ✓ Permanent: credits represent a permanent removal of GHGs from the atmosphere and there is a way to account for non-permanence.
Linkage with international individual offset projects

There are two types of current international offset systems for individual projects that RGGI could consider accepting. One is the Clean Development Mechanism (CDM); the other is the Joint Implementation (JI). As described earlier in this Chapter, CDM is the largest international offset system in the world. The EU ETS, Australia’s Carbon Pricing Mechanism (ACPR) (under previous plans) and New Zealand’s Emissions Trading Scheme (NZ ETS) have unilateral links to CMD offset markets.

Like the CDM, Joint Implementation is a project-based mechanism under the Kyoto Protocol. Yet JI applies to emission reduction projects carried out in an Annex I country. JI produces emission reduction units (ERUs). When ERUs are generated, countries must also meet their own emissions target under the Protocol. This ensures that in addition to ERUs, host countries have a net reduction to cover increased emissions in other countries.

The use of one-way linkage with an offset credit system in reducing emission is controversial because of the large concerns about “additionality:” as Judson Jaffe and Robert N. Stavins explain, “some emission reduction credits offered by a credit system may not represent truly additional emissions reductions because of the difficulty of establishing a baseline against which reductions can be measured.” Some analyses have estimated that 75% of claimed GHG reductions would have occurred in the absence of a CDM program. Another concern of CDM is the destruction of HFC-23, a greenhouse gas that is a by-product of the manufacture for refrigerant gases. It is easy to destroy HFC-23, and as a result, some plants in China were built merely for destroying HFC-23 and generating CERs.

Currently, Maryland does not allow international offsets and there is little guidance concerning future prospects. In RGGI, only when the allowance price reaches $10 per ton are international offsets recognized for fulfilling compliance obligations. Acceptable offsets are CDM credits or any allowances from any other international cap and trade system, such as EU ETS. RGGI thus does not currently encourage individual international offsets or linkages with international cap and trade systems. Since Maryland and RGGI had such little experience in this area, it is useful to look at other countries and regions that have relevant experience.

As mentioned earlier, California’s cap and trade system allows up to 8% of any approved type of offsets of their compliance obligations. In 2011, California developed a framework for possible future linkage to CDM, JI and other ERC program. California has also completed “a joint memorandum of understanding with Chiapas, Mexico, and Acre, Brazil that could allow use of avoided deforestation offsets from these two states as soon as 2015.”

Recommendations

1. Given the lack of political will within RGGI and the additionality concerns with international offsets, in the near term RGGI should focus on increasing its participation in the domestic offsets market. In the long term, RGGI could accept emissions reductions from international offsets such as the EU, which have offset limits between 0 and 20%.
2. Develop and expand international offsets within Annex I countries through the JI credit system. Since CDM has not worked as originally planned, Maryland and RGGI could use more reliable project offsets in Annex I countries.

3. Similar to the EU and California, RGGI offsets should be verified by an independent third party, in order to ensure that the reduction claimed by the offset project is real. The third party should be authorized by Maryland government or RGGI. RGGI should also implement an offset protocol with detailed provisions such as standardized methods for quantifying emission reductions, criteria for determining additionality, and monitoring requirements for each type of offsets.

Key Chapter 8 Recommendations

1. Consider establishing a policy by which GHG emitters in Maryland (but outside the electric power sector over which RGGI exercises GHG control) can purchase GHG offsets as a means of contributing to compliance with the Maryland GGRA emissions reduction goals set by the GGRA of 2009. The GGRA sets a goal of a 25% reduction in GHGs emissions in Maryland, relative to 2006 levels. It has been assumed that this goal should be met by GHG reductions within Maryland itself. It would be possible in concept, to allow Maryland GHG emitters to purchase offsets outside of Maryland, and then have these offsets count towards the Maryland 25% reduction target set by the GGRA. A similar approach is used for compliance with Maryland’s renewable energy standards in which Maryland electric power distributors can purchase Renewable Energy Credits (RECs) either inside of Maryland or outside of Maryland to achieve compliance with Maryland’s renewable energy standards.

2. Study the possibility, as part of further Maryland Climate Action Planning to achieve the Maryland GGRA targets for 2020, of creating an inventory of all GHG emissions in Maryland, and then require specific GHG percentage reductions by 2020 for appropriate categories of (non-power) GHG emitters. For those Maryland GHG emitters included in these mandatory reduction categories, the required GHG emission reductions could be made either by making the GHG reductions directly or by purchasing GHG credits from some other source.

3. Expand the range of acceptable offsets within RGGI and the numbers of offsets that can be purchased in lieu of purchasing an allowance in a RGGI auction. If the RGGI cap is tightened sufficiently to increase significantly the sale price of allowances in RGGI auctions, the wider purchase of offsets would be encouraged. This will have the added benefit that the total costs of complying with the RGGI cap will be reduced to the extent that the price of an offset is below that of a RGGI allowance.

4. Allow Maryland (non-power) offsets and RGGI electric power offsets to be obtained either by purchasing allowances in cap and trade systems outside of RGGI or by purchasing offsets generated by individual GHG reduction projects. The purchase of an allowance in another cap and trade system amounts in practice to the reduction of the cap in the other system. RGGI offsets thus might consist of allowances purchased in the EU, China and other future locations of GHG cap and trade systems.
5. **Create a RGGI system for recognizing and certifying acceptable GHG offsets.** RGGI already includes limited provision for offsets but the minimal price of RGGI allowances has in practice meant that there has been no demand for RGGI offsets. If offsets are to become an important part of the workings of the RGGI system, new procedures will needed for defining the characteristics of an acceptable RGGI offset and then establishing certification procedures that such characteristics have in fact been satisfied. If Maryland has a separate GHG offset requirement under the GGRA for non-power sectors, it might simply accept RGGI verification determinations.

6. **Consider adopting the California/Quebec system for recognizing and certifying offsets.** California has already invested considerable resources in developing its own offset system. RGGI might be able to profit by simply accepting California approved offsets for acceptance also in RGGI.

7. **Consider adopting the EU system for recognizing and certifying acceptable CDM credits as also meeting RGGI requirements for acceptable international offsets.** The EU cap and trade system has been exercising a leadership role in addressing the many problems that have developed with the CDM system. Under recent policy changes, for example, CDM projects in many countries such as China and India will no longer be accepted by the EU ETS. Here again, RGGI might be able to profit by accepting EU determinations with respect to internationally acceptable CDM projects.
PART III – THE ROLE OF EPA IN FACILITATING A

NATIONAL STATE-BASED GHG REDUCTION STRATEGY
Chapter 9 – GHG Regulation of Existing Power Plants under the Clean Air Act: Encouraging EPA to Facilitate Bottom-Up Emissions Credit and Cap-and-Trade Programs and Linkages

In the absence of comprehensive legislative action from Congress on greenhouse gas reductions, the United States Environmental Protection Agency (EPA) has become the leading player in regulating GHG emissions at the national level. In the past few years, the Clean Air Act (CAA) emerged as the most viable alternative to regulate U.S. greenhouse gas emissions. Regulators, policymakers, and industry representatives are familiar with the CAA because it is an established federal regulatory tool that has long been used to regulate conventional pollutants. However, as can be expected, the application of the CAA framework to greenhouse gas emissions is controversial.

The CAA, enacted in 1970 and significantly amended in 1977 and 1990, authorizes the EPA to regulate air emissions from mobile and stationary sources. The Act mandates the regulation of emissions the EPA deems “pollutants.” The EPA, under previous administrations, did not consider greenhouse gases to be pollutants. In 2007, in its opinion in Massachusetts v. EPA, 127 S.Ct. 1438, the Supreme Court ruled that greenhouse gases in fact are pollutants and required the EPA to determine whether greenhouse gas emissions from mobile sources endanger public health or welfare. Subsequently, in 2009, the EPA confirmed greenhouse gases as dangerous to human health and the environment through a formal endangerment finding.

This endangerment finding was made after considering the scientific evidence of the risks and impacts of climate change caused by greenhouse gases emitted from vehicles and whether these present a danger to public health or welfare. The Agency concluded that the “risks associated with changes in air quality, increases in temperature, changes in extreme weather events, increases in food- and water-borne pathogens, and changes in aeroallergens” provided “strong and clear support” for an endangerment finding, including serious adverse health effects and increases in morbidity and mortality.

Once the endangerment finding was determined, the Supreme Court’s holding from Massachusetts v. EPA, required the EPA to regulate emissions from mobile sources. While the Court holding did not specifically declare an equivalent mandate for stationary sources, the Court’s decision and the EPA’s finding allow the EPA to regulate stationary sources and has thus led to its current action. EPA finalized fuel efficiency standards for mobile sources as well as rules for permitting new construction on stationary sources (known as New Source Review), but the most far reaching and controversial regulations will be for new and existing large power plants and industrial facilities. EPA proposed rules for such new sources in September 2013.

In the absence of Congressional leadership, several states have initiated state-level greenhouse gas emissions regulations. Most states have chosen state and regional cap-and-trade programs, as discussed in previous chapters with respect to RGGI and California. The emergence of these cap-and-trade programs raises questions of how the EPA will treat state and regional efforts in its consideration of regulations for existing sources. In particular, there is interest regarding whether these programs could be used to meet a state’s obligation under such regulations. These questions contribute to the overall uncertainty surrounding EPA’s greenhouse gas emissions
regulations, though many have advocated for the inclusion of an emissions trading system in the existing source regulation. Given that some states have already begun regulating existing sources under cap-and-trade based on the assumption that this approach yields greater reductions at lower cost than traditional command and control regulations, it seems possible that many states would prefer this market-based approach in the face of direct EPA regulation of individual sources.237

This chapter addresses the viability of existing cap-and-trade programs as a method of compliance in the EPA regulation of greenhouse gas emissions from power plants and industrial facilities. In particular, there has been some speculation that insofar as existing programs offer an option under EPA regulation, more states will join or adopt similar programs. In the absence of national legislation, this could lead to the expansion of cap-and-trade programs, gradually creating a widening trading system through a bottom-up approach. In general, expanding the area covered by cap-and-trade increases flexibility and reduces the cost of reductions, so there is an incentive to states in existing programs to seek new members. As the most coal-intensive member of RGGI, Maryland would benefit from a RGGI expansion. The state could provide leadership in a bottom-up approach by making its preferences clear to EPA.

The Political Landscape of U.S. Greenhouse Gas Regulation

In the first two years of President Obama’s presidency, comprehensive climate and energy reform was at the top of his list of legislative priorities. Action on climate change in the 111th Congress seemed possible because democrats controlled the White House, the U.S. House of Representatives, and the U.S. Senate. Representatives Henry Waxman (D-CA) and Edward Markey (D-MA) introduced the American Clean Energy and Security Act, also known as the Waxman-Markey bill, in early 2009. The bill, contained renewable energy and energy efficiency provisions and proposed an economy-wide cap-and-trade program that called for reducing greenhouse gas emissions from covered sources by 83 percent of 2005 levels by 2050. Interim targets were set as 3 percent below 2005 levels by 2012, 17 percent below 2005 levels by 2020, and 42 percent below 2005 levels in 2030.

The EPA would have been responsible for administering the program, including establishing a registry for covered entities, distributing emission allowances, and creating a program for issuing and authorizing offset credits. Interestingly, the bill also included a provision for purchase of offsets from qualified international cap and trade programs.238 Also of note is that the bill would have suspended existing state cap-and-trade programs from 2012 through 2017, meaning that implementation of the CA AB32 program would have been delayed five years, though given the similarities in scope, at least, it is possible California would have abandoned CA AB32 in preference for the federal program.239

Republicans largely opposed the bill, arguing that the proposed cap-and-trade program would create an undue burden on U.S. industry and damage the already-fragile economy. The Heritage foundation, a conservative think tank, led criticism of the bill by releasing a report that detailed what it considered the likely economic impacts of the Waxman-Markey bill. These impacts included economic losses of $7.4 trillion, over 1 million jobs lost, and an “energy crisis” leading to higher electricity and gasoline prices.240
After an intense round of negotiations, the House passed the bill by a narrow vote of 219 to 212 in June 2009. The bill was passed largely along partisan lines, with 44 Democrats voting against and only 8 Republicans voting for the bill. Similar to the healthcare reform of that year, Republicans felt that President Obama’s liberal agenda was being forced on them. In any case, the bill’s Senate counterpart, introduced by Senators John Kerry (D-MA) and Barbara Boxer (D-CA), died in the Senate without coming to a vote. Then, in November 2010, the Republicans won control of the House in the 112th Congress, leaving little hope of comprehensive climate change legislation as long as Republican control of the House continued.

Political partisanship has deepened since 2009 and any mention of a carbon emissions trading system elicits strong negative reactions from Republicans. While EPA now pursues reductions in greenhouse gas emissions through regulatory action, its authority for establishing a national trading program is legally untested and politically risky as “backdoor cap-and-trade.” Indeed, EPA, in proposing new greenhouse regulations for new coal-fired and natural gas-fired power plants under its CAA authority, has triggered several Republican attempts to divest the Agency of its greenhouse gas authority. Many of the arguments against EPA greenhouse gas regulation are the same as those elicited by the Waxman-Markey bill, though some argue that the CAA is “ill-suited” to handle greenhouse gases and that Congress should be the policymaker rather than EPA. While such arguments have some truth in that greenhouse gases are unlike traditional air pollutants and require some maneuvering within the CAA statute, many see the attacks on EPA as thinly-veiled attempts to stall any type of controls over GHGs.

President Obama has stated that he will veto any bill that seeks to strip EPA greenhouse authority, so such an outcome is unlikely, but greenhouse gas emissions regulation, and particularly emissions trading, are politically vulnerable to attack. Additionally, some opponents will seek to challenge EPA regulations through the courts. A June 2012 decision by the U.S. Court of Appeals for the District of Columbia Circuit upheld EPA authority to regulate greenhouse gases but its opponents, which included 12 states led by Texas and several industry associations, appealed the decision to the Supreme Court in April 2013. Therefore, EPA will likely expend a lot of valuable resources fighting legal and political battles regardless of how it ultimately regulates greenhouse gas emissions. EPA, under the Obama Administration, must create a careful balance between legal and political considerations in the design of its greenhouse gas emissions regulation while also addressing the necessity of such regulation. As will be discussed in the following sections, through its current path, EPA should have the legal authority to block challenges even including emissions trading, though this has been untested as of yet. However, its ability to withstand political challenges is somewhat less certain.

**Regulating Greenhouse Gas Emissions through the Clean Air Act**

The following section further describes EPA’s statutory authority to regulate greenhouse gas emissions through the CAA as well as the agency’s attempt to do so thus far.
Tools under the Clean Air Act

Within the CAA statute, EPA has the authority to use three different tools to regulate greenhouse gases, as illustrated in Figure 10.1. First, with regard to mobile sources, EPA has the ability to set emissions standards for new vehicles. These standards, known as the corporate average fuel efficiency (CAFE) standards, took effect in January 2011, covering vehicles in the 2012 to 2016 model year period. The standards are projected to result in an average industry fleet-wide fuel efficiency of 35.5 miles per gallon (mpg) by 2016. In August 2012, the EPA released its final rule for vehicles in the 2017 to 2025 model year period. By 2025, the projected average industry fleet-wide fuel efficiency rises to 54.5 mpg. The EPA estimates that these stricter standards will reduce greenhouse gas emissions from light-duty vehicles by 50 percent from models in 2010 for a total reduction of 2 billion metric tons.

Figure 10.1 Clean Air Act Tools for Greenhouse Gases


The regulation of pollutant emissions under any CAA program automatically triggers permit requirements for new construction and major modifications to existing sources under CAA §165, or New Source Review, and Title V, which deals with industrial permitting. NSR permitting requires that the facility requesting a construction permit show its design uses best available control technology (BACT). Permitting is usually done at the state level with EPA oversight. While most large emitters are already subject to NSR under other pollutants, the addition of greenhouse gases is somewhat problematic for EPA. Sources subject to the two permitting regulations are those that emit 100 to 250 tons per year, respectively. Because greenhouse gases are emitted in greater volume than other pollutants, this threshold would require 82,000 and 6,000,000 new permitting actions each year. For this reason, EPA has instituted a “Tailoring Rule,” which will set thresholds for greenhouse gases at 75,000 and 100,000 tons per year,
limiting the number of annual permit actions to 900. In *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (2012), Plaintiffs challenged this new rule and other EPA greenhouse gas provisions, but the D.C. Circuit court holding, mentioned above, upheld it.

The third tool of CAA authority covers existing stationary sources. As shown in Figure 10.1, EPA had several regulatory options under the CAA to address existing stationary sources of greenhouse gas emissions. These included the following:

- Treating greenhouse gases as a hazardous pollutant under CAA §112 such as it does for mercury, for example;
- Regulating greenhouse gases with national ambient air quality standards (NAAQS) under CAA §108-110;
- Implementing regulations based on the impact of U.S. emissions on the international community under CAA §115;
- Setting performance standards for new and existing sources under CAA §111.

Regulating greenhouse gas emissions from stationary sources is a unique challenge. First, unlike traditional criteria pollutants whose atmospheric concentrations generally vary regionally, greenhouse gases disperse globally. This makes measuring local or regional concentrations, which EPA uses to determine compliance, meaningless. Second, as mentioned earlier, the typical EPA pollutant threshold, at least for new sources, is 100 or 250 tons. While this is a significant amount of emissions for some pollutants, it is a relatively minuscule amount for carbon dioxide (CO₂) emissions. A typical coal plant with a generation capacity of 600 megawatts (MW) emits about 3.5 million tons of CO₂ per year. For these reasons, any of these options would need to be adapted to the specificities of greenhouse gases.

The first approach to treat greenhouse gases as a hazardous pollutant is not useful since this section is designed for pollutants that are highly toxic and emitted in low quantities. The second approach is to regulate under NAAQS, which is the best-known program under CAA. However, given the global nature of greenhouse gases is unlikely to be useful. Under NAAQS, EPA sets a national air quality standard for a given pollutant. States are then responsible for creating a State Implementation Plan (SIP) to regulate and monitor air quality with EPA oversight to ensure compliance.

EPA may create a model plan that states can adopt, although states generally have significant flexibility in how they plan to comply with the standards as long as the SIP is as stringent as the EPA standard. Once SIPs are in place, states and regions are either in attainment or non-attainment of the standard based on ambient concentration levels. As stated earlier, such a classification poses particular difficulty for EPA in regards to greenhouse gases because atmospheric concentrations are global by nature. In order to make the standard effective, it would need to be set below current global greenhouse gas concentrations, but by doing so, all states would be in non-attainment and have little ability to achieve attainment status under their own efforts. Not only would their non-attainment status trigger strict federal regulations, defeating the purpose of SIPs in the first place, but their status would depend on emissions from other states and indeed even foreign countries. Finally, the third approach using CAA §115, relating to
emissions regulations based on their international impact is rather vague and has never been used.²⁵³

Given these realities, the most effective approach, and the one the EPA chose, is to regulate stationary sources with performance standards under CAA §111. Standards under §111(b) apply to new sources, termed New Source Performance Standards, or NSPS, while standards under §111(d) apply to existing sources. The following section explains the §111 process in more detail.

An Overview of Section 111 of the Clean Air Act

The steps for establishing performance standards are detailed in Figure 10.2. As shown, the first step is for EPA to establish source categories, which lists emissions sources by class, type, and size within these categories. Most large emitters are already represented in the existing list of source categories, including power plants and industrial sectors. Within a year of listing a source category, EPA must establish performance standards for that category.²⁵⁴ In a rather controversial move, EPA’s initial proposed NSPS, released in March 2012, created a new source category, TTTT, which combined coal-fired and natural gas-fired power plants into one category with uniform standards for different types of fossil fuels. EPA has grouped different technologies into a single source category in the past, the Agency previously included further distinctions by creating subcategories for different fuel types or generating technologies, which it did not do in this case.²⁵⁵ Concerned about its legality, the March proposal was never finalized. A new proposed rule was released in September 2013 that treated coal and gas fired power plants differently.

To establish NSPS, EPA must determine an emissions limitation that is “achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reductions and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” In other words, EPA determines an emissions cap based on technological options that consider cost as well as health, environmental, and energy impacts. The “best system of emission reduction” (BSER) must either be adequately demonstrated in practice, or EPA must have a reasonable basis for assuming that it will be within the compliance period.²⁵⁶ Thus NSPS do not necessarily mandate specific control technologies, but may in practice cause widespread adoption of a technology by identifying the BSER.”²⁵⁷
As a case in point, EPA’s latest proposed NSPS for greenhouse gas emissions sets the emissions limitation for new coal plants at at 1,100 lbs. CO$_2$ equivalent per megawatt-hour (CO$_2$e/MWh) and for large new gas fired plants at 1,000 CO$_2$e/MWh. The average emissions rate for U.S. coal-fired power plants is currently 2,249 lbs. CO$_2$e/MWh, which means that the development of new coal-fired power plants is essentially precluded by EPA’s proposed standard, at least without the installation of carbon-capture-and-storage (CCS) technology. On the other hand, natural gas-fired power plants emit an average of 1,135 lbs. CO$_2$e/MWh. However, newer plants are more efficient than the average, so large natural gas-fired power plants can easily meet EPA’s proposed standard.\textsuperscript{258}

Creating an Existing Source Performance Standard

NSPS apply only to new and modified sources, although what modifications qualify is somewhat controversial. EPA must set separate guidelines under §111(d) to cover existing source categories of greenhouse gas emissions. Unlike the NSPS, performance standards for existing sources are developed and enforced at the state-level, similar to the SIP process under the

NAAQS program. The CAA statute calls for a SIP-like process in covering existing sources under §111(d), specifically referencing §110, which pertains to state plans to attain NAAQS or to Prevent a Significant deterioration (PSD) of air quality in the state if it is already in attainment.  

As described in the previous section, EPA issues emissions guidelines for the states to use in developing their plans first in draft form. After the public review and comment period ends, EPA will issue the final rulemaking in accordance with the comments it receives. States must then develop and submit their plans to EPA, ensuring that they are no less stringent and that the compliance times are also no longer than those outlined in the federal guidelines. While plans must comply with these requirements and are subject to EPA approval, the process ultimately gives the states discretion on how to regulate emissions sources within their territories. However, if a state fails to submit a plan or EPA finds the plan inadequate, EPA must impose a federal plan on the state. 

**EPA Options for Structuring an Existing Source Performance Standard**

Applying the SIP process to regulating greenhouse gases is problematic. The SIP is designed as the mechanism for compliance under NAAQS and it will be difficult for states to demonstrate compliance through the traditional mechanism of reducing regional pollutant concentrations. Therefore, EPA has two main options for structuring the standard: a traditional performance standard or a market based mechanism. There are various structural alternatives within these two options.

**Traditional Performance Standard**

Traditionally, performance standards are interpreted as a uniform source category-wide standard based on technological assessment. The standard must be met at each source that falls within the regulated category. This approach therefore requires pollutant regulation on a plant-by-plant basis with relatively little flexibility in compliance. If EPA chooses to issue guidelines along this traditional performance standard pathway, there are two forms the standard could take. The first form is a maximum emission rate (i.e. lbs. CO₂e/MWh) that must be met at each source such as the Agency has proposed in the NSPS. Under this approach, EPA would need to set an emissions limit. The Agency does have the authority to identify subcategories within the source category, often by technology or fuel type, and thus create separate standards within the category. Another form EPA could choose is to require a certain percentage in emissions reduction, such as a 5 percent reduction in emissions from current levels. Under this approach, EPA would need to determine the percentage reduction and importantly, the level from which reductions will be required.

**Market-Based Mechanism**

The other option for EPA is to issue guidelines that allow for greater flexibility in compliance by incorporating market-based mechanisms. Again, EPA has a couple of choices as to how to structure these mechanisms. The first, as has been discussed, is a cap-and-trade program through which EPA would set a fixed aggregate limit on emissions, the “cap.” The cap would then be
enforced by allocating allowances for each unit of greenhouse gas emissions and permitting these allowances to be traded among sources, creating a market.

The second market-based form, as Burtraw et al. (2012b) of Resources for the Future point out, is a tradable standard. Similar to a traditional standard, EPA sets a rate-based performance standard for covered sources, but instead of requiring that each source meet this standard independently, sources have the flexibility to comply either through efficiency upgrades or the purchase of credits from sources that emit less than the standard. This means that on average, the standard is met across the sector rather than at each source.

State Involvement

Another choice EPA will have to make is how much of the implementation to leave to the states. Under any of these approaches, EPA could design a model rule, which would include a complete program that states could adopt wholesale, essentially creating a top-down regulation. Otherwise, the Agency could leave the program design to the states, which would create more of a bottom-up approach to regulation. Regardless of how EPA ultimately decides to structure its standard, because of the discretion the SIP process grants to the states, they will play an important role in regulating greenhouse gas emissions. The approach EPA takes should accommodate state policy preferences as much as possible by acknowledging that various states may prefer different compliance options while also ensuring overall effectiveness of the standard.

Evaluating EPA’s Performance Standard Options

There are several criteria that are useful in evaluating the various options EPA has to structure its standard, including effectiveness in reducing emissions, cost-effectiveness, linkages to other policy mechanisms, and the possibility of legal issues. These criteria are discussed further in this section.

Effectiveness in Reducing Emissions

Ostensibly, each of the above options would be effective in reducing emissions, depending on the stringency of the standard EPA sets. EPA has found, however, that by incorporating market-oriented policies into the standard, it would be reasonable to expect emissions reductions of 2 to 5 percent for individual plants without major changes in plant utilization. Burtraw et al. (2012b) state that a reasonable expectation for the traditional standard based on fleet-wide rate reduction on a plant-by-plant basis would be at the lower end, near 2 percent.

Of the various options, only a cap-and-trade program includes a binding limit on greenhouse gases whereas the traditional standards and the rate-based tradable standard regulate the intensity of emissions. Thus, the total emissions reductions from covered sources could be more or less under cap-and-trade depending on the fuel makeup of the electricity generation fleet and the overall electricity demand.

Cost-Effectiveness
The widely-held view is that market-based mechanisms are more cost-effective because they provide regulated entities with an incentive to pursue the lowest cost reduction option. An important point that Burtraw et al. (2011) discuss is the effect the regulatory approach has on innovation. The authors find that typically, a regulatory approach is “less likely to lead to innovation, and different innovation, that would occur under a flexible incentive-based program.” This is because a regulatory agency may not do as well as private decision-makers at identifying low-cost opportunities for emissions reductions because the agency does not have access to the same information, particularly in the long-run.267

On the other hand, prescriptive regulation such as a performance standard has also been shown to be a powerful driver of technology innovations that could reduce the cost of emissions reductions. Edward S. Rubin of Carnegie Mellon University states that prescriptive technological standards can create sizeable new markets for certain technologies that are stimulated by private-sector investments in research and development and can substantially reduce costs. Some studies of regulatory standards also saw economic advantages in the form of increased employment and sales for the innovating firms.268 On a strict cost per unit of emissions reduced, however, market-based approaches will likely be more effective.

Linkage with Other Policy Mechanisms

As previously discussed, several states already have existing programs that address greenhouse gases, including California and RGGI’s cap-and-trade programs. It is likely that these states will seek to leverage existing programs to meet the state’s obligations. If EPA does not intend to preclude state and regional programs that are both as stringent and meet EPA’s timeline from being adequate means of complying with federal regulations, EPA will need to consider these programs when developing its emissions guidelines.

Regarding the options listed above, it is unlikely that EPA regulations could preempt state and regional emission reduction programs given the CAA provision for the retention of state authority.269 However, states would need to establish “equivalency” with the federal standard. As will be discussed in a later section, there are various considerations for compliance that EPA will need to resolve with existing regional and state programs, such as scope, treatment of offsets, and international trading.

One issue to discuss here is how EPA will credit early action, meaning steps taken by regulated entities, often through state regulation, in advance of federal regulatory requirements. In particular, a performance standard in the form of a percentage reduction may also pose problems for states that have taken early action to regulate greenhouse gases depending on what level EPA decides on as its baseline. For example, in 2010, the Colorado Public Utilities Commission approved an emissions reduction plan for the utility Xcel Energy under the state’s Clean Air, Clean Jobs Act, which mandates certain provisions for reducing greenhouse gas emissions from the utility’s generating fleet.270 How EPA credits this action if the reduction is set to current levels remains uncertain, but in this case, Colorado is at a disadvantage for reducing emissions before federal regulations as further reductions will cost more compared to states that have not made similar reductions.271 RGGI states and California, as discussed in the next chapter, would also be at a disadvantage. In general, regardless of which approach EPA takes, the Agency will
need to define what constitutes early action, including eligible actions and the timeframe during which actions should qualify. The Agency must avoid creating disincentives for emission reductions prior to regulation.\textsuperscript{272}

\textit{Legal Issues}

Performance standards have traditionally meant a technological standard uniformly applied to covered sources within a regulated category and as such, the traditional standard approaches would likely be the least risky, legally. However, the prevailing view of EPA and independent legal analysts is that the CAA statute does not necessarily require these rigid standards and that in fact, the adoption of a trading program is likely permissible.

As mentioned earlier, the statute in §111(d) references §110, which outlines the SIP process. The section lists a broad array of policy mechanisms that are allowable in a state’s SIP, including “economic incentives such as fees, marketable permits, and auctions of emissions rights.”\textsuperscript{273} While §111(d) does not expressly list acceptable policy mechanisms such as in §110, the statute calls for establishing the “best system of emission reduction.” There is nothing further in the statute that would preclude an interpretation of “system” as including an emissions trading program.

In regards to other pollutants, EPA has previously interpreted §111 to allow the adoption of a trading program such as for NO\textsubscript{x} emissions and for mercury emissions from coal-fired electric utility facilities in the Clean Air Mercury Rule (CAMR) under the Bush Administration in 2005. This interpretation of cap-and-trade as a “standard of performance” was contested in a legal challenge to CAMR. The Federal Circuit Court of Appeals overturned, or vacated, CAMR on grounds other than the cap-and-trade program, but never decided the challenge to emissions trading under §111. This could mean that the Court did not object to the cap-and-trade program itself or it could mean that it had not yet considered the issue. The current Administration has not yet stated whether it agrees with the interpretation promulgated under President Bush.

Since §111 does not specifically address the issue of cap-and-trade it is assumed that the EPA will continue this interpretation and Courts will give EPA’s interpretation deference. Under the Supreme Court decision in \textit{Chevron v. Natural Resources Defense Council}, 104 S.Ct. 2778, the Court ruled that if the statute is silent or ambiguous regarding a specific question, the court will defer to EPA’s interpretation as long as it is “reasonable.”\textsuperscript{274}

Unfortunately, it is highly probable that any approach EPA takes to regulate greenhouse gases will invite legal challenge given the controversial nature of the regulations. Traditional performance standards have the most legal and practical precedent of the various approaches and Burtraw et al. (2012b) argue that tradable standards are consistent with the statute and Agency practice and thus are unlikely to be seen as incompatible with the CAA by the courts.\textsuperscript{275} They also allow for a larger flexibility for states and covered entities, which is likely to yield favor. There is decidedly less precedent for cap-and-trade under §111 and thus, this approach is the least legally certain.
Policy Options for Addressing Market-Oriented Approaches

Allowing for market-oriented approaches for reducing greenhouse gas emissions from stationary sources under the CAA offers the opportunity to achieve these reductions more cost-effectively and allow more compliance flexibility than traditional command-and-control regulations. The following section explores some of the stances EPA could take towards market-oriented programs in its emissions guidelines.

Option 1: Reliance on State Initiatives

While it may be possible to create a national greenhouse gas cap-and-trade system under §111, such an approach is unlikely. Understanding the legal and political scrutiny EPA currently faces, the Agency is unlikely to take such a bold approach and in fact, several leaders at EPA have already rejected a national cap-and-trade program. A safer option from a legal and political perspective may be to allow states acting on their own initiative to pursue market-oriented emission reduction policies for existing sources under §111(d).\textsuperscript{276} Under this option, EPA’s emission guidelines would not specifically require the use of market-oriented approaches and issues regarding existing regional and state programs would be addressed as they came up.

This option is outlined in the Pew Center on Global Climate Change’s 2011 report on regulating greenhouse gases under §111(d). In Pew’s analysis, this option is the least politically vulnerable since it does not propose any program resembling a cap-and-trade. By allowing states a high level of discretion, this also places a greater burden on state regulators to design compliant programs or prove equivalency of existing programs. The lack of guidance from EPA makes an interstate trading system more difficult to design and requires more coordination among the states. For this reason, it is possible that the gains from market-oriented regulation may be left to states with existing or nascent trading programs.\textsuperscript{277}

On the other hand, faced with the prospect of prescriptive federal regulation, more states may be willing to create or join cap-and-trade programs as an alternative. Even without EPA guidance, there are strong incentives for states to choose such a market approach, including cost advantages for programs that cover a larger geographic area and the reduction of problems with existing programs like leakage. Leadership from states such as Maryland or California could also help drive more states to adopt cap-and-trade programs to reduce the learning curve.

Given that states like Maryland and California have expended a lot of time and resources to design and implement these state and regional cap-and-trade programs and many states will prefer this option over prescriptive regulation, EPA and states should consider the ways in which existing programs can meet states’ obligations under the CAA.

In 2011, the World Resources Institute (WRI) considered this question in its report \textit{What’s Ahead for Power Plants and Industry? Using the Clean Air Act to Reduce Greenhouse Gas Emissions, Building on Existing Regional Programs}. The report identifies several specific areas that are important in reconciling state and regional cap-and-trade models with §111, including stringency, timing of reductions, scope, offsets, international trading, temporal compliance.
flexibility, and cost containment measures. Each of these issues is discussed further in this section.

**Stringency and Timing**

The stringency and timing of the EPA standard is a major source of uncertainty in the incorporation of state and regional cap-and-trade programs. Depending on these aspects, the regional programs could either have to tighten the emissions cap or timeline, or they could help lead to additional reductions exceeding the federal requirement. Inconsistencies in these features may be easy to identify, but they are not likely to be easy fixes. First, stringency and timing are the most visible features of a cap-and-trade program and therefore changes will necessarily engender a lot of stakeholder input. Second, changes to the emissions cap often need agreement from the various stakeholders. As in the case of RGGI discussed previously, some member states require legislative approval for changes to the program. For example, the recent review of RGGI’s cap-and-trade was a two-year process of gathering stakeholder input, meeting with state officials, and winning legislative approval.278

**Scope**

The scopes of RGGI and CA AB32 differ substantially as RGGI covers only the power sector and CA CB32 covers several sectors to be phased in over time. The scope of the program would need to correspond to the source categories established by EPA. In the NSPS, EPA established categories covering coal-fired and natural gas-fired power plants. A broader definition would allow for different treatment of segments within the category, which would make it easier for states with a broad cap-and-trade scheme, such as CA AB32. However, if EPA continues this category definition, there is nothing in the statute that would preclude EPA or the states from using trading allowances across the various regulated sectors. In this case, programs such as CA AB32 could propose covering other sectors for which EPA did not set standards as long as emissions reductions for the covered sector met EPA’s guidelines.

**Offsets**

Offsets are perhaps the most complicated features of existing programs and there has been little experience in crediting offsets as yet because the price of allowances has remained too low to make the purchase of offsets economically viable. Still, the purchase of offsets may increase as the price of allowances rises, so it is necessary to reconcile this aspect with EPA guidelines. WRI and RFF both agree, however, that offsets are unlikely to be permissible under EPA guidelines because reductions must come from covered sources.279 Thus EPA will not be able to give credit for existing state measures such as investment in renewable energy through RPS, demand-side energy efficiency programs. As mentioned earlier, these are tools that states already have and while they demonstrate willingness on the part of the state for emissions reductions, reductions under EPA guidelines will likely have to be above reductions resulting from such programs.280
**International Trading**

Similarly, allowances obtained through linking with international programs will likely not be able to apply for reductions under EPA guidelines. While §111 does not specifically mention reductions from international sources, it seems counterintuitive that international allowances would qualify as compliance under a federally-administered program. Like offsets, allowances gained from international trading may act as a mechanism to lower the cost of emissions reductions, but they will likely only qualify as reductions above EPA guidelines. WRI suggest periodic state review to ensure that in-state reductions meet those required by EPA standards. This may also be required regarding trading between states unless EPA allows a system of emission averaging between regional programs.

**Compliance Periods and Banking**

Both RGGI and CA AB32 allow covered sources to bank allowances as well have compliance periods that span several years. This allows for greater flexibility in compliance and greater cost reduction but raises the question of whether emissions reduction will meet the EPA standard in a given year.

**Cost-Containment Measures**

Both RGGI and CA AB32 also include some form of cost-containment mechanism, which seeks to keep allowance prices down, usually triggered when allowance prices reach a certain level. For example, RGGI has instituted such a mechanism in its recent review. As a certain allowance price is reached, additional allowances will become available to regulated sources in order to contain cost. However, states participating in RGGI will need to show that this short increase in allowances does not prevent the state from achieving its emissions reductions requirements.281

**Option 2: A Tradable Standard**

This option, as proposed by Burtraw et al. (2012b), would allow the trading of credits similar to a cap-and-trade program, but with several distinct differences. The authors argue that tradable standards are more similar to traditional performance standards than cap-and-trade, which is likely to reduce the legal uncertainty as well as help states and EPA feel more comfortable administering the program. They also do not require an emissions cap, which means that EPA need not go through the process of allocating allowances.282 Given the political controversy surrounding cap-and-trade that causes setting the cap and allocating allowances to be such a contentious processes, a tradable standard may reduce the political obstacles to an EPA greenhouse gas emissions standard.

The way that a tradable standard works, as discussed earlier, is that EPA would set a standard based on the emissions rate (or average heat rate) of a regulated entity. Covered entities then have a choice to either: comply with the standard; over-comply and accrue tradable credits to bank for future compliance or sell to other covered sources; or to under-comply and buy credits from other sources. Figure 10.3 illustrates a trading example with an emissions rate set at 1,980
lbs/MWh. How each plant complies with the standard will depend on the cost of upgrades and the market price of credits.

**Figure 10.3: Credit Trading to Achieve Compliance with a Performance Standard**

<table>
<thead>
<tr>
<th>Plant A</th>
<th>Emissions Rate</th>
<th>Performance Standard</th>
<th>Compliance Status (Before Trading)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1880 lbs/MWh</td>
<td>1980 lbs/MWh</td>
<td>In compliance. Excess credit of 100 lbs/MWh for each MWh generated.</td>
</tr>
<tr>
<td>Plant B</td>
<td>2080 lbs/MWh</td>
<td>1980 lbs/MWh</td>
<td>Out of compliance. Need credit of 100 lbs/MWh for each MWh generated.</td>
</tr>
</tbody>
</table>


Similar to cap-and-trade, tradable standards allow for flexibility among covered entities in their compliance with EPA standards. This approach provides an incentive for emissions reductions by imposing a cost on those emissions as well as a monetary benefit for those firms that do reduce emissions beyond the standard. Burtraw et al. (2012b) find that a tradable standard is in fact effective at providing this incentive for emissions reduction, resulting in a 60 percent smaller increase in retail electricity prices and a two-thirds reduction in overall costs compared to a traditional performance standard.

** Tradable Standard Policy Design**

EPA would need to take into account several considerations regarding the design of a tradable standard, including the type of standard (i.e. emission-based or heat-rate based), the scope of the standard such as geographic area and covered sources, and whether to set a predictable schedule for tightening the standard in the future. In regards to the geographic area of the standard, in contrast to the previous option, the tradable standard could be a national program as opposed to an opt-in program relying on states’ initiative. As trading across a broad group of sources provides more opportunity for emissions reductions and cost savings, this is an advantage of the tradable standard option. A national standard also provides certainty and relative uniformity in state markets for industry, which could help defray some industry opposition. Uniformity is important to industries such as automakers, which have consistently supported EPA greenhouse gas regulations for vehicles, stating that having a common standard provides greater ease of business than leaving regulation piecemeal to states.

The standard should also be tightened periodically over the years in order to continue to achieve increasing emissions reductions and incentivize cost-effective measures. A phased program that sets future targets over a specific timeline is an effective way to do this, reducing uncertainty for industry and possibly offering an incentive for early adoption. For example, in previous rules,
EPA implemented phased standards in a way that allows voluntary early adoption of measures more stringent than the requirement to qualify for delayed compliance with the requirements in subsequent phases. This approach also addresses states’ current actions, allowing various efficiency measures to count towards compliance, which is likely to be favored by the states.

In the case of creating a national tradable standard, it makes sense for EPA to publish the program as a model rule in its guidelines. As stated before, states may choose not to adopt the model rule when creating their SIPs, but overall, an EPA guideline would make a trading system easier to design and would better facilitate coordination among the states in contrast to Option 1 in which EPA does not issue a guideline outlining any such national program. The uncertainty that remains in this option, however, is how states with existing cap-and-trade program will choose to act. While EPA could design the standard itself to be flexible enough to accommodate existing trading programs, state and regional programs that are more stringent than the standard may create problems for overall emissions reductions. For example, assuming California’s AB32 program was more stringent than the EPA standard, California sources would be in overcompliance of the federal standard and could use this to generate credits to sell to sources based elsewhere and thus California would essentially be exporting its emissions, ultimately diminishing overall national emissions reductions. States and EPA would need to determine how to avoid this possibility, including the state opting-out of the national tradable standard.

**Option 3: NRDC Proposed Performance Standard**

In December 2012, the National Resources Defense Council (NRDC) released its report *Closing the Power Plant Carbon Pollution Loophole* that outlines the organization’s proposal for EPA’s performance standard for existing sources. The proposal sets an emissions rate limit (i.e. lbs. CO₂e/MWh) for existing power plants that are state-specific, taking into consideration national average emission rate benchmarks and the state-specific energy generation mix. The proposal also allows the use of emission rate averaging across fossil fuel-fired sources while creating a credit system for emission reductions, which can be traded among sources. Of note is the ability of states to combine generation fleets into multi-state regions in which emission credits can be traded, thus creating a regional credit marketplace. Also of note is the creation of a system through which demand-side energy efficiency efforts would be certified as compliant credits under the exchange program and available for trading. Of the three options, the NRDC proposal is the only option through which energy efficiency, through the establishment of a certification system, would explicitly count as compliance.

NRDC envisions that the EPA guidelines it proposes would serve as a template for approvable plans from states, demonstrating compliance provisions that are allowable under EPA’s standard. The proposal will also serve as a yardstick for alternative plans. Since states may choose various options for compliance as long as they are approved by EPA as equally or more stringent than the federal standard, states could use the NRDC-proposed EPA guideline to measure existing programs or proposed policy designs, signaling whether EPA would approve it or not. Finally, NRDC sees the guidelines as giving states advance notice of the contents of a federal implementation plan (FIP) if states fail to submit a plan or the submitted plan is rejected. In this way, similar to Option 2, EPA would provide states more guidance in terms of how to shape
their SIP, even proposing a model rule which states could adopt knowing it would be approved by EPA. This lends more certainty to the SIP process than there would be if EPA chose Option 1.

There are several key principles that guide NRDC’s proposal. First, the NRDC took into consideration that states will have different starting points regarding their emissions because of the differences in the mix of energy generation fleets. The NRDC also considered that providing sources with compliance flexibility decreases the cost of emission reduction and that in many cases, end-use efficiency measures can be achieved in a cheaper and faster way than making efficiency improvements to existing power plants or building new plants. With these in mind, the NRDC made the following proposal for deriving each state’s fleet average emission rate:

Each state’s baseline fossil fuel generation mix (of coal-fired and natural gas-fired power plants) is calculated based on CO₂ emission rates from the period 2008 to 2010. Based on EPA data, the baseline national CO₂ emission rates are 2,063 lbs/MWh for coal-fired power plants and 1,065 lbs/MWh for natural gas-fired power plants.

Nominal emission rate targets for coal- and natural gas-fired sources are then established for each compliance year. The NRDC has proposed targets of 1,800 lbs CO₂e/MWh for coal-fired sources and 1,035 lbs CO₂e/MWh for natural gas-fired sources for the period of 2015 to 2019; 1,500 lbs CO₂e/MWh from coal-fired sources and 1,000 lbs CO₂e/MWh for natural gas-fired sources for the period 2020-2024; and 1,200 lbs CO₂e/MWh for coal-fired sources for 2025 and after. For the period after 2025, emission rate targets for natural gas-fired sources remain the same (1,000 lbs CO₂e/MWh).

Each state’s emission rate standard is calculated by weighting the average emission rate limit from the nominal targets by the state’s generation mix during the baseline period. For example, if a state generates 90 percent of its electricity through coal-fired power plants and 10 percent through natural gas-fired power plants, then the emissions rate standard for the state in the period 2015 to 2019 is calculated as follows: (1,800 lbs CO₂e/MWh * 0.90) + (1,035 lbs CO₂e/MWh * 0.10) = 1,723.5 lbs CO₂e/MWh. Consequently, states which have a more carbon-intensive fleet of electricity generation units will have higher target emission rates, but they will also have greater differentials between their starting emission rates and their targets.

To achieve this emission rate, EPA will allow each source to meet compliance by any of the following options:

- Meeting the target emission rate on its own;
- Averaging emission rates with a set of other sources so that the total emissions of the plants divided by their combined electricity output meets the applicable state standard;
- Acquiring qualifying credits produced by low- or zero-emission electricity generation sources such as a wind farm. For example, a wind farm would earn credits for each lb CO₂e saved per MWh produced, which it could then sell to an entity in undercompliance;
- Or acquiring qualifying energy efficiency credits that reflect incremental reductions in energy demand as certified by NRDC’s proposed national program.
In order for energy efficiency savings to count as a compliance option, NRDC has also proposed the implementation of a credit system that would ensure energy savings are permanent, quantifiable, surplus, and enforceable. The system relies on state or local energy regulators to approve energy efficiency programs and report electricity savings to the state air regulator, which converts those savings into CO\textsubscript{2} credits that can be used as compliance. The state regulator issues and tracks these credits to avoid double counting. States would then need to determine their own process for distributing the emission credits to electricity generators that wish to use them for compliance, though the NRDC recommends auctioning the credits. This energy efficiency program would not apply in states that adopt cap-and-trade programs for compliance since the effects of energy efficiency programs are ostensibly accounted for in the emissions cap and thus would result in double-counting.

The NRDC finds that this proposal would reduce CO\textsubscript{2} emissions from the fossil fuel generating fleet by 26 percent from 2005 levels by 2020 and 34 percent by 2025 with annualized costs of approximately $4 billion in 2020 and benefits of $25 to $60 billion.

Interestingly, because emissions credits can be achieved either through demand-side energy efficiency programs or by incremental electricity generation from renewable sources, shifts towards the greater utilization of low-emitting sources, such as reducing dispatch of higher-emitting sources, would be accounted for in this proposal. Under a traditional performance standard scheme, it is unlikely that efforts outside of supply-side efficiency improvements such as these options would count for compliance, but would rather be above EPA emission limit compliance.

The NRDC proposal also allows for, but does not require, trading among covered sources. In addition, states are not required to average emission rates across their generation fleets nor are they required to join with other states to create a multistate exchange region. Similar to Option 2, this then provides guidance for states to do so, but leaves the burden largely on the states as to whether to incorporate EPA’s proposed compliance options into their SIPs or not.

By allowing for, but not requiring, the various methods of compliance, this option is likely to be palatable to many states given that they are granted a great amount of flexibility and also retain a high amount of discretion in choosing how to comply with EPA guidelines. As stated earlier, from a legal and political perspective, this approach to the pursuit of market-oriented emission reduction policies is the safest of the three options. Option 3 is by far the most prescriptive in that EPA would outline a fairly extensive model rule for an energy efficiency credit system as well as regional trading programs. Therefore, this option may be the most politically risky.

As compared with a cap and trade program, Option 3 raises potentially difficult equity and efficiency issues in that it rewards states that have depended more heavily in the past on coal-fired power generation. These states will have higher state emission rate standards under the NRDC plan than states which have relied more heavily on nuclear power, natural gas or renewables. Ohio, for example, will have a considerably higher emission rate standard than say California or Vermont. As a result, new gas or renewable facilities in different states will be able to sell credit for significantly different prices. Taking account credit sales, a new natural gas plant will therefore be less expensive to build in Ohio than Vermont, even when the actual
construction costs are the same. This will create greater incentives to build a new gas plant in Ohio than in Vermont, altering the geographic distribution of gas power facilities in the United States. This may be objectionable in terms of inequitable treatment of states such as California and Vermont. It may also be objectionable in distorting the national distribution of locations of new natural gas power plants.

**Conclusion**

Under §111 of the Clean Air Act, EPA has a variety of options as to how it can regulate greenhouse gas emission from the power sector. EPA must choose whether to take a traditional performance standard approach that regulates on an individual plant basis or to take an approach that recognizes market-oriented programs as options for compliance. In somewhat of a reversal of past decades, a traditional performance standard may actually be less vulnerable to political attack than the incorporation of a market-oriented approach, at least on the national stage, particularly if this approach is seen to be a tacit endorsement of cap-and-trade.

States, however, are much more likely to favor a market-oriented approach that provides flexible compliance options with lower costs. States like California and RGGI members are interested in having their existing programs qualify as compliant and other states may be interested in linking with these programs as a method of compliance as well. Given that the focus in this report is on how Maryland can meet its greenhouse gas emission targets, we have assessed EPA’s options in terms of their interaction with Maryland’s existing goals. If EPA recognizes existing state and regional programs it will enhance Maryland’s ability to meet its targets and strengthen its current programs in order to do so. Thus, from Maryland’s perspective, EPA should structure its performance standard in such a way that permits existing RGGI programs to qualify. EPA’s standard will also likely benefit from doing so because as a result, the Agency is more likely to have the support of the states, which will serve to strengthen the Agency’s case in defending the standard to Congress.

EPA has several additional options for its performance standard guidelines in regards to market-oriented approaches. Under option 1, EPA could choose a non hands-on laissez-faire approach that is silent on market-oriented approaches, relying on states’ initiatives to create or join viable trading systems. EPA could instead choose a more proactive approach that outlines a set emissions standard and a model rule that creates an interstate trading program, whether that is a simple tradable standard (Option 2) or a more complex credit trading program such as proposed by the NRDC (Option 3). In choosing between these options, EPA will need to balance its statutory obligations, states’ willingness and ability to comply with the federal standard, and the inevitable political backlash that will result with any kind of EPA action. Therefore, EPA’s choice will need to be solid legally and politically defensible as well as hold the support of the states. The option that is most likely to meet these criteria is Option 3. While it is the most politically risky, it also provides the greatest flexibility in compliance.

Option 3 provides several explicit means of compliance for states, including emission rate averaging, energy efficiency, increased use of renewable energy, and trading among covered sources. Option 3 does not create a strict cap-and-trade program but it does create a tradable standard with additional means of compliance that would likely allow many existing state and
regional programs, including cap-and-trade but also other types, to comply. However, for RGGI
and CA AB32 to comply, there would be areas of concern, similar to those outlined in Option 1,
in showing equivalency.

An advantage to Option 3 is that it offers greater certainty to states and industry regarding
compliance and the ability to use market-based, cost-effective measures, however given that
uncertainty still exists especially as it relates to existing cap-and-trade programs, EPA will need
to be more specific in its proposed standard. EPA should include specific language that addresses
existing programs. The following section includes recommendations for EPA and for Maryland
as to how to reduce these uncertainties and thus strengthen the proposal for existing source
performance standards.

Recommendations

1. **EPA should establish a set of alternative model compliance methods for CAA GHG
   regulation of existing power sources among which states could voluntarily choose.** One
   such model would be a standard cap and trade system with a set GHG cap, such as found in
   RGGI and California. Another model might be a market-oriented approach through a tradable
   performance standard for existing power sources. As proposed by NRDC and discussed
   above, this would incorporate demand-side efficiency, state generation fleet averaging,
   trading, and credit banking as well as establishing state authority to combine fleets into
   multistate regions. By outlining a detailed set of alternative CAA model rules, EPA would
   reduce overall uncertainty and provide guidance for state planning as well as a signal to
   industry of possible methods of compliance.

2. **To ensure that trading across covered sources is encouraged and as cost-effective as
   possible, EPA should keep its definition of source categories broad.** A single category of
   “electric power plant” – as opposed to “coal plant,” “gas plant,” etc. -- lays the groundwork
   for including greater trading and other compliance flexibility in its performance standard and
   leads to lower-cost emission reductions. It also leads to greater efficiency in regulating
   sources.

3. **EPA should clearly state that existing state and regional cap-and-trade programs may
   serve as methods of CAA GHG compliance under its existing source performance
   standard.** Maryland and the rest of RGGI would thereby benefit in terms of the ease of
   CAA GHG compliance. The RGGI states can avoid the superimposition of federal CAA
   GHG regulation on top of existing RGGI regulations. This might encourage other nearby
   states such as Pennsylvania or West Virginia to join RGGI in order to comply with EPA
   GHG standards which would offer advantages in dealing with leakage and other matters.

4. **EPA, in its upcoming proposed rule for existing sources, should address criteria for
   establishing equivalency in state programs, including scope (i.e. trading across sectors),
   offsets, and international linkages.** Under the NRDC proposal, while additional means
   other than direct emission reductions such as energy efficiency programs would count as
   compliance through credit certification, existing state and regional cap-and-trade programs
   would still likely not be able to take advantage of such additional means as well as others like
offsets. EPA needs to assess the legal ability of offsets and international linkages to count as compliance under its performance standard and specifically address this in its proposed rule.

5. **EPA, to the extent possible at this stage in the process, should discuss existing source performance standards in its upcoming NSPS rulemaking in order to reduce uncertainty regarding existing sources.** This includes a discussion of how to integrate new and existing sources in a trading program. By including new sources as eligible for trading among sources, EPA could easily incentivize early action in the form of fuel-switching to low-carbon sources.
Chapter 10: Assessing the Stringency of State and Regional GHG Caps

Cap and trade programs for controlling emissions of greenhouse gases (GHGs) from existing sources are attractive at the state and regional level for several reasons, including: 1) applying market incentives to curb GHG emissions helps minimize the total cost of compliance for emitters; 2) a cap sets a clear and transparent policy for the amount of GHG reduction that will be achieved; 3) compared to a carbon tax, a cap and trade system typically has different distributional consequences that can improve its political prospects for actual implementation; and 4) a state or regional cap and trade system offers the possibility of linkage among different cap and trade systems and thus “bottom up” movement towards the goals of a wider or potentially even approaching a national cap and trade system.

In addition, a cap and trade system has the advantage that a wide range of factors can be taken into account in setting the cap. A tradable credit system such as proposed by NRDC and discussed in Chapter 9 is similar to a cap and trade system but where the cap must be set exclusively on the basis of historic GHG emissions rates. This has the disadvantage, as discussed in Chapter 9, that it effectively assigns a higher GHG emissions cap – with associated economic advantages derived from this higher cap – to states that have had historically high GHG emissions (relative to total power production). Depending on the reason for the historically high GHG emissions, one might say that it rewards the “bad actors” and penalizes the “good actors.”

As a result, even if a tradable credit system may be adopted initially, it might be desirable to regard it as a transitional step, making provision for a gradual shift to a cap and trade system, in which the same standards are applied everywhere in the United States in determining the acceptable magnitude of a cap. Rather than historic GHG emissions, an “acceptable” cap might be based as well on more “objective” factors such as energy geography, total GDP within the area of the cap, total population, and others. The issues raised are admittedly complex, similar to the past Kyoto discussions of possible long run national GHG emission targets for various nations such as the United States, China, and India.

In the US, there is already a state-level cap and trade system, California’s, and one regional cap and trade system, RGGI. As discussed in the preceding chapter, the application of the CAA to existing sources of GHGs may take a form of deeming an “acceptable” cap and trade system as complying with the existing source standard of the CAA. This might also encourage more states and regions to create cap and trade systems, and potentially new linkages among such systems. A combination, however, of tradable credit systems and cap and trade systems across the United States might create its own administrative complications and complexities. In effect, once again, a tradable credit system in a state with historically high GHG emissions in the power sector might amount in practice to a preferentially high “cap,” relative to an actual cap in a working cap and trade system (set, for example, in California on the basis of seeking to return to 1990 GHG emission levers, about a 25 percent reduction from 2006).

If a cap and trade system is accepted as a form of compliance with the CAA existing source requirements, it will be necessary to have some policy or standards for EPA to determine an “acceptable” GHG cap for the purposes of the CAA. If the cap is too high, it may not be binding
and thus the cap and trade system would be ineffective in controlling GHG emissions. That was the case, for example, with the RGGI cap from 2010 to 2012, when RGGI auctions left significant numbers of allowances unsold, and those that were sold went for the low reserve price that was not enough to induce power producers to alter their behavior. Similarly, the numerous caps set by the European Union have not been low enough to consistently keep the prices of EU ETS allowances at levels anywhere near the estimated social costs of GHG emissions.

Setting a standard for cap “stringency” or “tightness” thus will be a critical component in the potential design of any future EPA policies that may allow state or regional cap and trade systems to comply with the CAA for the purposes of regulating existing power plant or other sources. There are a variety of different approaches that could be used to evaluate different caps. These approaches raise significant issues of both economic efficiency and equity, as illustrated by an assessment of the California and RGGI caps.

**The California and RGGI Caps**

Table 10.1 shows a comparison between RGGI and the California cap and trade systems. California’s system is more ambitious in terms of its scope of coverage. Phase one (2013-2014) is limited to electric power plants and heavy industry and sets the cap at 25,000 metric tons of CO\textsubscript{2} per year. The scope of coverage will expand to the transportation, refinery and heating fuel sectors in 2015. RGGI’s scope is limited to electric power plants that have 25MW of installed capacity or above.\textsuperscript{287}

In its recent February 2013 revisions to the program, RGGI lowered its emission cap to 91Mt of CO\textsubscript{2} in 2014, reflecting the problems discussed in Chapter 5 with the old cap and the associated auction results. Another prominent difference is the price floor set at auction. California has a much higher floor price of $10 for each ton of CO which will rise by 5% each year, starting from 2014. The current floor price for RGGI is $1.93 per ton of CO\textsubscript{2} and the sale price of allowances in the most recent auction was $2.8 per ton.\textsuperscript{288} However, how the California model compares with RGGI in terms of stringency requires further information and assessment.

<table>
<thead>
<tr>
<th>Table 10.1 Cap and Trade Programs in Comparison – California vs. RGGI</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Population</strong></td>
</tr>
<tr>
<td>---------------------------------------------------------------</td>
</tr>
<tr>
<td>38 million</td>
</tr>
</tbody>
</table>

| **Gross Regional Product** | California | RGGI |
|---------------------------------------------------------------|
| $1.9 trln | $2.3 trln |

| **Sector Covered** | California | RGGI |
|---------------------------------------------------------------|
| Electricity, Industry, Transportation, and Heating Fuels | Fossil Fuel-fired Power Plants |

| **Emission Threshold** | California | RGGI |
|---------------------------------------------------------------|
| Emitters of at least 25,000 metric tons CO\textsubscript{2} e annually | Fossil fuel-fired power plants generating 25 MW or greater located within the RGGI States |

| **Target** | California | RGGI |
|---------------------------------------------------------------|
| Approximately 17% below 2013 emissions by 2020 | 45% below 2005 emissions by 2020 |

| 2013 Allowance Budgets (Millions) | California | RGGI |
|---------------------------------------------------------------|
| 162.8 | 165 |
|--------------------------|-------------|-------------|
| Emissions Target in million metric tons of CO₂ equivalent (Target Year) | 334.2 (2020) | 154 (2018) - Target may become more aggressive through Program Review |
| Allocation Method | Compliance obligations began January 1, 2013 | Approximately 90% available for sale at auction, remainder up to states |
| Price Floor at Auction | $10 per metric ton for both 2012 and 2013 before rising 5% per year (plus inflation) starting in 2014. | $1.93 in 2012; increasing with consumer price index (CPI); current clearing px is $2.8/t |
| Linkage Status | Linked to Quebec’s cap and trade program. Also setting up a forum with Australia to share experiences | No current plans to link with other cap and trade programs |
| Offset Limit | Can amount to 8% of a regulated entity’s compliance obligation | Can amount to 3.3% of a regulated entity’s compliance obligation; higher if certain price triggers are hit |
| 2013 Offset Use Limit (Millions) | 13 | Depends on price triggers |
| Types of Offsets | 1) Forestry; 2) Urban forestry; 3) Dairy digesters; 4) Destruction of ozone-depleting substances | 1) Landfill methane destruction; 2) Reduction in emissions of SF6 in the power sector; 3) Sequestration of carbon due to afforestation; 4) Reduction of CO₂ emissions from natural gas, oil, or propane end-use combustion in buildings; 5) Avoided methane emissions from agricultural manure management |

Source: Center for Climate and Energy Solutions, “California Cap-And-Trade Program Summary,” January 2013

Cap Adequacy Evaluation

RGGI’s original model rule specified an annual allowance budget – a cap – of 165MtCO₂e. The limit was set based on 1990 emission levels whose composition was dominated by coal-fired plants. For instance, in 1990, coal-fired power plants generated in combination more than 52% of the U.S. electricity. By the end of 2009, however, that number had already declined to 44% and
it dipped further to 37% by 2012. The declining share of coal in U.S. energy production was significantly motivated by environmental protection concerns as coal emits large amounts of both conventional air pollutants and GHGs. It was also significantly accelerated by the rapid growth of shale gas production and associated declines in natural gas prices. The financial crisis and consequent recession in 2008 and after also dampened energy demand.

As discussed in Chapter 5, all these factors, plus warmer weather, resulted in large declines in CO₂ emissions, leaving total CO₂ emissions in the RGGI states well below the original cap. In 2012, actual CO₂ emissions were about 45% below the cap. The original RGGI cap thus had virtually no positive GHG reduction effect and would fail almost any EPA test of adequate “stringency” in a cap and trade system.

The European GHG cap-and-trade program provides another case of an ineffective cap that caused allowance prices to plummet. The ETS is estimated to have a cumulative market surplus of 2.7 billion tons of allowances in 2013/14. Carbon prices fell early this year to $3.75 per metric ton (CO₂ equivalent), far below the $30-$50 range necessary to prompt polluters to invest in emission-reducing measures. Causes of such a deviation from actual allowance demand are similar to the RGGI case but this time the economic downturn that slowed down industrial activities played a larger role. Some EU nations were also politically unwilling to impose a cap that would have significantly raised the prices of ETS allowances in such economic circumstances.

Setting the Cap

Cap-and-trade systems usually set their caps at a percentages below benchmark emission levels. For instance, the EU ETS aims at a 21% GHG reduction below 2005 emission levels by 2020. Before the update this year, the original RGGI model rule set a goal of 10% CO₂ emissions below 2009 emission by 2018 and the new model rule sets the cap at a 45% reduction from 2005 levels by 2020. The California cap is more ambitious, a 17% reduction by 2020 from 2013 levels, which is equal to 163Mt.

In setting a GHG emission cap, a state or region has to assess at least three factors: the original benchmark emission levels from some current or past year, the percentage of reduction sought, and the deadline set to complete the reduction. Though the caps defined in the programs introduced above considered all three factors, limited information is available as for how exactly those factors were taken into account in each individual case.

In the EU ETS, for instance, two principal criteria were employed in setting the emissions cap. Firstly, the total number of allowances to allocate should be lower than the business-as-usual projections. Secondly, member EU nations must prove that the intended allocation will be sufficient to achieve the GHG emission targets accepted by the EU burden-sharing agreement under the Kyoto Protocol. Nevertheless, the criteria are rather general and give no answer to key questions, such as how far the number of allowances should fall below the business-as-usual scenario. It is also difficult to justify a particular year over another as the benchmark year because structural changes either in the economy or in energy consumption do not occur at a particular time but instead represent a continuous process spread out over a longer-term period.
Therefore, any differences identified from year to year can be too subtle to function as selection criteria.

To sum up, current cap and trade programs by and large set their exact caps almost arbitrarily and in compliance with guidance from grander climate policy frameworks, such as the Kyoto Protocol or California’s state climate policy. The precise stringency of the caps first depends on the expectation of regulators or lawyers overseeing the cap and trade system and their perception of the state’s maximum willingness to accept GHG emissions reductions. The final emissions cap is thus a compromise among various influences including government officials, industry groups, environmentalists and science organizations. Whether the compromise is tilted more towards environmental protection or steady economic growth hinges on the cost-benefit analysis carried out within each interest group and their relative influences on the process.

**Allocating Allotments Under the Cap**

The GHG allowance allocation method can also make a large difference to the distribution of the burdens from a cap and trade system, as well as the cost to the overall economy, providing economic incentives of different degrees for industries to install emission-reducing technologies. Most of the current cap and trade programs use mixed allocation methods, i.e. including both free allocation and auction. For example, RGGI normally puts 90% of its allowances at auction whereas ETS anticipates only 50% for auction this year. The remaining allowances in ETS will be allocated freely amid manufacturing industry to award highly-efficient producers. Free allocation of 100% of allowances is seen as overcompensating existing GHG emitters and damaging the effectiveness of cap and trade programs by causing market surpluses; on the other hand, 100% auction could raise the cost of compliance so high that strong opposition is stirred up among regulated entities.

Allowance allocation methods usually affect program effectiveness in two ways. The number of total allowances allocated freely significantly affects potential trading program revenue and private compliance costs. Moreover, how those free allowances are distributed could either add to or reduce the effectiveness of cap and trade programs, largely dependent on policy innovations. Research conducted by Goulder et al. (2010) suggests that industry profit would be preserved if about a third of the allowances were given out for free, enabling the firm to enjoy a third of the potential rents.

The implication for regulators is that the higher the energy efficiency, the more rents that industry groups will collect from free allowances. The way in which free allowances were distributed during Phase 1 and 2 of the EU ETS aroused wide concern over the distributional equity, environmental effectiveness and economic efficiency of National Allocation Plans (NAPs) within each member state. Econometric evidence has found a negative correlation between free allocation of allowances and the marginal price incentive to reduce emissions.

To avoid similar controversial outcomes in the future, the EU ETS adopted a brand new approach in distributing free allowances in its Phase 3. Formulas are now provided to quantify the relation between the number of free allowances and the emission-intensity of a certain product from an installation. Connection with performance benchmarking suggests that some
facilities will receive more free allowances than others but the total number of free allowances will decline in Phase 3.

In addition to allowance distribution, offsets as an alternative to emission reduction can hurt program stringency as well if there are too many offset categories. In comparison, both RGGI and California’s cap and trade programs have more efficient offset management when compared to the EU ETS which sets no limit for offsets though it states the possibility post 2020. Offset projects covered under RGGI are also GHG-specific, such as landfill methane destruction and carbon sequestration while the coverage extends slightly when it comes to California’s model. As discussed in Chapter 8, use of CDM as an offset source in ETS led to controversy for two reasons: 1) international offsets do not directly contribute GHG reductions in Europe; 2) many CDMs do not actually reduce GHGs globally as they are administered, due to problems such as additionality, project verification protocols, and others.

Relative State and Regional Caps within an Overall National Cap

The U.S. is now on track to almost reach the 17% reduction GHG target proposed by President Obama at the international Conference of the Parties (COP) in Copenhagen in December 2009, even though the Waxman-Market national cap and trade bill failed to pass in 2010. The discussion above indicates that the final cap would have a significant influence on the effectiveness of a cap and trade program. Suppose that the 17% GHG cut were revised to a more stringent national cap (25% reduction vs. 2006 GHG emission levels is used in the model below), it would then require greater reductions from GHG emitters in the United States or larger increases in energy efficiency to ensure a cumulative reduction above the 16.3% (calculated by Burtraw and Woerman) that would occur under business as usual.

Assuming that the United States were hypothetically to commit to a 25% reduction in GHG emissions in 2020, relative to 2006 levels, it raises the question of how responsibility might be assigned to further limit GHG emissions among U. S. states and regions, assuming they all had caps in place. Several approaches could be adopted in concept for setting the relative state and regional caps that cumulatively would sum up to a 25% reduction in U.S. GHG emissions in 2020.

This hypothetical scenario could then be applied to determine whether any actual caps in place – such as at present only in California and RGGI – would represent a sufficiently “stringent” curtailment of GHG emissions. In particular, one would ask: are the California and RGGI caps now in place sufficiently stringent that EPA could accept them for the purposes of regulating existing GHG sources under the Clean Air Act, as discussed above in this chapter, and in greater detail in Chapter 9? If new state or regional cap and trade programs beyond California and RGGI were created in the United States in response to EPA actions under the Clean Air Act, one could also ask: are the new caps in these new cap and trade programs sufficiently stringent that EPA could accept them as discussed above?
Distributing 2020 State and Regional Caps in Proportion to 2020 State and Regional GDP

The overall framework of this approach to measuring cap stringency involves three calculations: a total U.S. GHG emission projection in 2020 for the United States under the assumption of a 25% reduction from 2006 levels; state forecasts of state GDP in 2020, and a cap distribution of the total U.S. GHG emissions among states and regions in proportion to state and regional GDP in 2020. The underlying theory thus assumes an ideal goal of an evenly distributed carbon intensity (CO₂ emissions per GDP unit) among states and regions in the U.S. emission per capita and overall greenhouse gas contribution. Actual proposed caps could then be measured against this ideal goal.

Table 10.2 shows the first calculation, the total U.S. GHG target for 2020 under the assumption of a 25% U.S. reduction from 2006 (the needed further reductions are assumed to be evenly spaced out from 2013 to 2020). Similar calculations could be made for a 30% total U.S. gas reduction by 2020. Figure 10.1 shows how this would work out, relative to a baseline case of current business as usual.

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In the next step, the relative shares of state GDP are forecast for all 50 states to 2020, as shown in Table 10.3. Arizona, for example, is projected to generate 1.66 percent of US national GDP in 2020, while Pennsylvania would generate 3.88 percent. The highest percentage of national GDP in 2020 is projected to come from California, equal to 12.5 percent.

As a method for assessing the stringency of the existing California cap for 2020, we compare California’s cap under its current cap and trade program with the hypothetical cap California would have in 2020, if its cap relative to total national GHG emissions were in the same direct proportion to its share of national GDP. If the California cap for 2020 were greater than 12.5% of total U.S. GHG emissions in 2020 (under the 25 percent GDP reduction scenario), then the California cap is insufficiently stringent. If the 2020 California cap were less than 12.5% of total U.S. GHG emissions in 2020, then the California cap satisfies this particular stringency test.

**Table 10.3 State GDP/National GDP Ratios**

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Under the current cap and trade program, California’s GHG cap in 2020 will be about 7 percent of the projected U.S. GHG emissions in 2020 (a reduction in emissions of 25 percent from 2006). Thus, the California cap for 2020 easily passes this stringency test based on relative state GDP. This reflects the fact that, as described in Chapter 1, California is already much more greenhouse gas efficient (its GHG emissions per unit of GDP are much less) than the U.S. national average.

A similar assessment can be made for the RGGI cap for 2020 by adding up the projected 2020 GDPs of the RGGI states, and then allocating a hypothetical RGGI cap based on the RGGI share of total U.S. GDP in 2020. The forecast total RGGI share of national U.S. GDP in 2020 is 6 percent. Like California, the RGGI cap for 2020 meets this GDP-based test, since RGGI’s cap will be 6% of total U.S. GHG emissions in 2020, assuming a 25% reduction in total US GHG emissions.

If other states or regions proposed to create a new cap and trade system as part of their GHG compliance with the existing source requirements of the CAA, their level of cap stringency could be assessed in a similar fashion according to the state’s share of national GDP.

_Distributing 2020 State and Regional Caps in Proportion to 2020 State and Regional Population_

A second way of assessing 2020 cap stringency would follow a similar approach but would substitute projected relative shares of state and regional populations in 2020, relative to projected total U.S. population, instead of the projected shares of state and regional GDP above. This would reflect the idea that reducing GHG levels is a national obligation of every citizen, and that citizens should all do their part. Thus, the goal should be that GHG emissions per capita should eventually equalize across states across the United States – or that states with higher GHG emissions per capita should incur a financial penalty for their “excess” emissions by having to purchase “extra” emissions allowances (which might then be reflected in part in the prices of exported goods to other states). Table 10.4 shows projected relative shares of U.S. population by state in 2020. California, for example, has a smaller projected share of population in 2020, 12.05%, compared with its projected share of GDP of 12.51 in 2020.

Again, the California and RGGI caps pass this population-based test of cap stringency because they have significantly lower greenhouse gases per capita at present and as projected to 2020, as compared with the U.S. national average.

Table 10.4: State Population/National Population Ratios

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Distributing 2020 State and Regional Caps in Proportion to Actual 2006 GHG Emissions

This test of cap stringency would hypothetically distribute state and regional caps in 2020 in proportion to actual 2006 GHG emissions in states and regions. The concept here would be that the states and regions should share a cumulative cap for 2020 in proportion to the difficulty of the task of getting from actual 2006 GHG emission levels to the required 25 percent reduction by 2020. In other words, each state and region would be expected to make at least the same 25% reduction from 2006, as shown by their established caps for 2020. By this test, both California and RGGI caps would be sufficiently stringent. The California cap represents a 25 percent reduction from California GHG emissions in 2006, as required by AB 32. The RGGI cap for 2020 represents an even larger reduction of about 50 percent from 2006, as established by the 2013 Model Rule, now feasible because of the large historic reductions that had already occurred within RGGI since 2006.

Recommendations

1. EPA should define “sufficient stringency” for the purposes of a cap and trade system that will qualify as an acceptable alternative for meeting the existing source regulatory requirements for electric power plants of the CAA. As suggested in Chapter 9, EPA should allow states the option to comply with the CAA if its existing power plants are included in an acceptable state (or regional) cap and trade system. In order to make this an operational approach, some definition of “acceptable” system will be required. The concept of the “sufficient stringency” of the cap would usefully serve this purpose.

2. For the purposes of calculating “sufficient stringency,” EPA (or the President by executive authority, or both the President and Congress by legislation) should set a desired GHG reduction target for the United States for some future date. This GHG reduction target is needed as a critical element of assessing whether any actual state or regional caps are tight enough to come within the CAA GHG policies of the United States. One possible such target might be a 25% reduction in total U.S. GHG emissions by 2020, as compared with 2006 levels. This would likely fall below the business as usual level of GHG emissions for 2020, but would hopefully not be so tight a national GHG target as to potentially impose undue economic burdens. If the target date were instead set at 2030, a larger GHG reduction could be sought, perhaps a target of 40% below 2006 levels.

3. In deciding how the total GHG reduction target should be allocated within the United States, EPA should determine the appropriate criteria to be applied. Among many possibilities, such criteria might include state and regional GHG targets for 2020 (and corresponding caps in 2020) that reflected proportional GHG reduction responsibilities from

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<td>Wisconsin</td>
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<td>Wyoming</td>
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2006 based on state and regional GDP, population, or on equi-proportionate reductions from historic past levels of GHG emissions (say in 2006). These and potentially other such criteria might be applied and then a final assessment of “sufficient stringency” made by weighting the criteria to produce an acceptably tight cap.

4. EPA should encourage forming greater linkages among state and regional cap and trade systems in the United States in order to increase the geographic area of the resulting final cap and trade systems for the purposes of CAA GHG compliance. The need to distribute overall GHG reduction responsibilities in the United States among states and regions would be avoided to the extent that the geographic scope of the ultimate cap and trade systems is enlarged. If, for example (and hypothetically), there were a single cap and trade system for the United States, no distribution of GHG reduction responsibilities within the United States would be necessary. The only question would be the total magnitude of the U.S. GHG reduction sought, as would be reflected in the magnitude of the cap proposed for future years.
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