ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Analysis of Output-Based Allocation of Emission Trading Allowances

Submitted to:

U.S. Combined Heat and Power Association

June 2003

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Background

Air quality regulatory programs for the power generation sector are increasingly focusing on emission cap and trade programs. These programs can provide greater environmental certainty and lower compliance costs than traditional command and control programs. However, the design of the cap and trade programs can have a significant effect on the long-term outcome of the program and whether it encourages the development of a mixed portfolio of cleaner, more efficient technologies, including combined heat and power (CHP). Appropriate allocation of emission allowances is a critical factor in promoting such a positive program outcome.

Under traditional command and control programs, each plant must meet a specific compliance target. The costs of compliance are borne directly by that plant and passed on to consumers in the price of the product.

Under cap and trade programs, an emission cap is set for the entire affected sector. Emission allowances are created which allow the emission of one unit (e.g., one ton) of pollutant. Each plant must hold allowances equal to its actual emissions at the end of each compliance period. The cap and trade program does not set specific emission limits for each plant as long as the plant holds allowances equal to its emissions. This flexibility and the ability to purchase allowances if they are less expensive than direct control of the plant provide great operational and economic benefits to the regulated facilities. Old plants with a high cost-of-control are among the greatest beneficiaries of the trading program.

On the other hand, the cap provides greater environmental certainty than conventional regulatory programs. In addition, the requirement to retire valuable allowances to cover emissions creates an ongoing economic incentive to reduce emissions. Under a cap and trade program, plant operators are driven to make emissions reductions whenever they can be achieved at a cost below the market price of allowances. The costs of compliance are spread more evenly across the sector, in particular reducing the cost of compliance at the high-cost plants.

One of the key issues in an emissions trading program is the way in which the tradable allowances are distributed to the affected facilities. There are three options that are most commonly discussed in current program designs:

Auction

Under an auction, affected units and others would have the opportunity at periodic intervals to purchase the available allowances in an open auction. Once purchased, allowances could be traded on a secondary market. Under an auction, all generators must pay up-front for all allowances. There is no “free” distribution under a pure auction. All emitters in the program have an equal position in the auction.

Economists generally find that auctions are the most economically efficient distribution mechanism since each participant is driven to make economically efficient tradeoffs between investment in technology, fuels or allowances. Also, the auction generates revenue that the government can redistribute in ways that offset the impacts of the regulation or meet other policy goals.

Despite these analytical benefits, auctions have appeared to be politically unattractive. This may be because they look like a politically unattractive "pollution tax". Also, the controversy over how to distribute the auction revenues is often seen as a problem. There is a common concern that once the money reaches the U.S. Treasury, it will not be used for the positive uses originally postulated. From an industry perspective, the fact that generators must purchase all allowances in an auction rather than receiving any "free" allocation is unattractive. In any case, despite some possible benefits, auctions seem to be a politically difficult solution for allocation.

Grandfathering Based on Heat Input

Under grandfathering or one-time allocation, the allowances are allocated to sources once and forever at the beginning of the program. This is the structure of the acid rain SO_2 trading program. The plants that receive allowances will continue to receive them "forever" regardless of their emissions or operation. They will receive them even if they shut down. New plants, including new CHP plants, will never receive any allocations. The basis for the allocation is historical heat input times a fixed allocation factor.

Grandfathering is simple but it clearly creates arbitrary winners and losers. All those who are in the initial allocation group gain a permanent economic benefit regardless of their emissions, efficiency or other attributes. Those who are not in that group are losers since they never receive allowances. The lack of allocations for new plants puts those plants at a competitive disadvantage. Thus grandfathering tends to preserve the existing generating base and slow the turnover to new, potentially cleaner and more efficient generators, like CHP facilities. This is particularly true for new coal plants, which have more emissions that they must cover through allowance purchases.

Output-Based, Updating Allocation

Under an updating system, the allowances are periodically redistributed, typically every one to three years, based on power generation output from each unit in the few years prior to the redistribution. In each year, each unit's allocation will be proportional to its share of historic generation. For example, if a unit generates 1 percent of the total power generated by affected units, it would receive 1 percent of the allowances in an output-based system. The allocation is typically done several years in advance to provide some certainty. For example, in year four of the program, allowances would be allocated for year seven based on average generation in years one through three.

Updating allocation has several effects. One of the most important is that it brings new sources into the program as they begin to operate. It also phases older plants out of the program as they reduce or cease operation. In this way all plants are included in the program, reducing the arbitrary creation of winners and losers created through grandfathering. Allowances are allocated to the plants that actually produce power.

Under updating, the operation of the plant in any year will affect the next allocation. Thus, the updating allocation creates incentives for certain behaviors. If the allocation is based on heat input, it rewards increased heat input. If it is based on generation, it rewards increased generation (electric and thermal generation in the case of CHP). In effect, an input-based system rewards inefficiency while an output-based system rewards efficiency. It seems preferable from a policy perspective to adopt a system that encourages efficiency.

In addition, an output-based system facilitates the allocation of allowances to renewable and non-emitting generators and end use energy efficiency projects. Allocating to these sources is difficult under an input-based system because they do not have heat input. Under an output-based approach, they can be treated equally to other generators based on the electricity output. Allocation to non-emitting facilities allows the trading program to provide added value for these technologies and potentially encourage increased construction and operation of lower-emitting generation.

Effects of Allowance Allocation

Probably the most important benefit of an updating, output-based allocation is the incentive for increased construction of new, more efficient plants and the retirement of old, less efficient plants. Increased construction of new, cleaner plants and retirement of old, inefficient plants could result in real reductions in the overall cost of compliance with the cap.

This effect occurs because the allocation method affects the asset value of power plants by changing the distribution of the emission allowance value. Grandfathering allocates this value to existing plants, regardless of fuel or emissions level. Under grandfathering, new plants, including new CHP, receive none of this value. This is most negative for new coal plants which require large capital investments but still must retire a lot of emissions allowances in order to operate.

Updating output-based allocation distributes the allowances more evenly and provides some of the allowance value to new plants. This value can be an important factor in encouraging the development of new, cleaner plants. The stream of allowances can be viewed as a capital cost credit ranging in value from $75 to $200/kW or higher depending on the treatment of future allocations.

There is a parallel effect on old, inefficient plants in which the future value is reduced in an output-based, updating program relative to a grandfathering allocation. This negative value could lead to a decision to retire older, less efficient plants. Although it is beyond the scope of this analysis, further evaluation of this effect would be very useful.

Although the allocation method affects the choice of new plants, it does not affect the cost of compliance or the optimum compliance approach for existing plants. The compliance cost is the cost of new equipment, different fuels and higher operating costs related to compliance plus the value of allowances that are retired to cover plant emissions. These allowances have the same market value regardless of the allocation technique and the control costs are not related to allocation so the allocation does not affect the compliance cost. The optimum compliance solution is a function of the cost of control options at different plants and is also not affected by the allocation method.

The cost of allowances retired for compliance is added to the variable cost of producing electricity and is passed on to consumers. In the updating output-based allocation system, however, the operation of the plant affects future allocation. If the plant generates more electricity, it will receive more allowances in a future year. This can be seen as a negative variable cost. That is, for every MWh generated, there is some future value, a credit that can be counted against the current costs of generation.

It is a common misperception that this credit under an updating output-based allocation will give an advantage to lower-emitting plants in the dispatch order and make clean plants more competitive and run more. This turns out to be incorrect. Since the allocation is based on generation, every MWh receives the same allocation value and the dispatch effect is the same for every plant and the dispatch order is not changed[1].

Although the output-based allocation does not change the dispatch order, the implied reduced bid prices does suggest another effect. The value of the allocation associated with incremental generation creates an operating cost credit. In a competitive electric market, the generator might then be expected to reduce the bid price of its electricity. Economic theory predicts that the generator will reduce the bid price by the full value of the allocation. In this case, new generators would be no better off under updating than under grandfathering because they would be "passing through" the full value of the allocation.

The analysis in this report suggests that generators will retain at least some portion of the allocation value, making new generators better off under updating. In addition, new generators will be better off competitively under updating because their treatment and the value they receive from allocation will be the same as their competitors. This is preferable to the situation under grandfathering in which incumbent generators receive all of the allocation value and new generators receive none. This competitive effect is important because new generators may be more likely to construct new, more efficient plants that might displace old plants.

The extent to which a change in bid price affects the price of electricity depends on the market position of the affected units and the status of electric restructuring in the area. As restructuring advances, however, the result is expected to be lower electricity prices to consumers. Essentially this means that the value of the allowances is being passed to consumers rather than being

[1] The exception is plants that do not receive allocations. In a fossil-only output-based allocation, nuclear and renewable plants are disadvantaged since they do not receive this credit. Their variable costs may still be low enough for them to remain competitive but this will depend on the specific technology.

retained by the power companies. Many would see this as an appropriate outcome, since consumers ultimately bear both the cost of pollution control and the environmental cost of the pollution. Moreover, lower electricity prices are generally seen as a positive outcome, particularly in difficult economic times.

However, there is another view in which lower electricity prices have a negative implication. The price elasticity of demand for electricity means that lower prices will cause greater demand for electricity. Increased generation would create additional potential emissions. But since emissions are capped, additional emission controls will be required and the overall cost of compliance will increase. The implication is that output-based allocation will increase the overall cost of compliance compared to a different allocation system. Aside from competitive concerns, this argument is the most significant argument against updating output-based allocation.

Although this effect is theoretically valid, there are a variety of economic and uncertainty factors that reduce the willingness of power generators to reduce their current bid price based on the future allocation. When these factors are taken into account along with the actual elasticity of demand for electricity, the potential increase in generation and compliance cost is almost insignificant, probably less than 1 percent, much less than the likely cost reduction from encouragement of new, more efficient generation.

Implications for CHP

Combined heat and power (CHP) is the sequential generation of electric and thermal energy from a common energy source. By providing electric and thermal service from a common fuel input, CHP significantly reduces the associated fuel use and emissions. CHP is especially attractive because it can be applied with almost any combustion technology and fuel. This means that it can be applied in many different end uses and can use whatever fuels are economically available.

There is about 64 GW of CHP capacity in place in the U.S. today. Yet there is still substantial remaining potential for expansion. The U.S. DOE has set a goal to double the capacity of CHP between 2000 and 2010. The National Energy Policy Development Report also stresses the importance of increased application of CHP.

A highly efficient technology such as CHP should be advantaged in an emission trading program. However, proper recognition of the benefits of CHP depends on recognition of both the thermal and electric output and on appropriate allocation systems. While it is U.S. energy and environmental policy to encourage increased use of CHP, new CHP facilities, like all other new power generators, will be disadvantaged under a grandfathering allocation system by not receiving any allowances.

In order to properly credit the efficiency of a CHP system under an output-based allocation program, the program must recognize both the thermal and electric output of the CHP system. The efficiency of CHP results from the combined generation of both electricity and thermal energy. This efficiency cannot be reflected unless both are recognized. In a cap and trade program that includes both electric generators and large non-electric generating boilers, this can be done by allocating allowances to the CHP unit for its electric output from the electric generator pool of allowances and for its thermal output from the non-electric generator pool of allowances. In a cap and trade program that addresses only electric generators, the thermal output can be converted to MWh equivalent and added to the unit's output for the purpose of calculating allocations.

There is a further difference for CHP under cap and trade programs that only affect power generators: Industrial facilities considering an investment in CHP have a clear choice. They can invest in conventional separate thermal and electric equipment in which they have only a boiler on their site and purchase electricity from the grid. While this is less efficient, it exempts them from a cap and trade program on electric generators. If they choose a CHP approach, they will be subject to the requirements of the cap and trade program. If the cap and trade program is negative for new sources, then potential CHP users will get the clear message not to invest in CHP.

Finally, if an allocation programs does properly recognize CHP, there should be opportunities for all CHP facilities to participate. This means the inclusion of appropriate opt-in provisions for CHP facilities that would not otherwise be included due to size, configuration or other applicability considerations.

CHP is a very valuable technology for meeting energy and environmental goals, however it will only be encouraged by careful design and application of cap and trade programs.

Conclusions

Updating, output-based allocation of emission allowances is an appropriate method of allowance allocation for an emissions cap and trade program. It will encourage the transition to new, cleaner technology, using all fuels and including CHP, without increasing the cost of compliance for existing facilities or increasing the overall system cost of compliance. By encouraging the construction of more efficient new generating technologies, output-based allocation could actually reduce the cost of compliance.

Promoting new generation will allow the development of new, cleaner coal plants that will allow for sustainable future electric generation based on the substantial U.S. supply of coal. It will also promote the development of new gas-based generation that can make more efficient use of U.S. natural gas resources than existing gas-fired plants. The construction of more efficient generation using all fuels and incorporating CHP will assist in reducing U.S. energy demand growth while reducing emissions of all regulated and unregulated pollutants. Updating, output-based emission allocation can promote all of these beneficial outcomes within the design of an emissions cap and trade program.

1 Introduction

The future regulation of air emissions from electricity generators is increasingly focused on the use of emissions cap and trade programs. These programs provide increased environmental security as well as greater flexibility for regulated sources and the promise of lower compliance costs. Experience to date with emissions trading, such as the acid rain SO_2 program and the northeastern NO_x Budget Program, has been very positive. Proposed legislation for multipollutant emission reductions from the power generation sector for either 3 pollutants (SO_2, NO_x and mercury) or 4 pollutants (including CO_2) has emphasized the use of emission trading programs.

One of the most important components of an emission trading program is the way that tradable allowances are allocated. In some past programs, the allowances have been awarded in perpetuity to existing sources. Some programs reallocate the allowances periodically based either on fuel input or generation output from the affected sources. There are also proposals that the allowances be auctioned.

There is great debate over the effect of allocation on the ability of units to comply with the program, the cost of compliance, the effect on energy prices and the competitive or macroeconomic effects. In particular, some analysts have suggested that updating, output-based allocation increases the overall cost of compliance or discourages the construction of new, efficient plants, including combined heat and power (CHP) facilities.

This report analyzes the effect of different allowance allocation systems on the cost of compliance, the cost of electricity and on the value of new and existing power plants. The report uses a hypothetical power system with a mix of new and old plants using different fuels to assess the effects of allocation. These cases do not represent any specific legislative or regulatory proposal but are simplified to focus directly on the allocation issues.

Chapter 2 lays out the basic structure of an emission cap and trade program compared to a conventional command and control program. Chapter 3 addresses the specifics of different allocation approaches. Chapter 4 analyzes the effect of allocation on system dispatch and price of electricity. Chapter 5 analyzes the effect of allocation on asset value and plant construction decisions. Chapter 6 addresses the specific impact of allocation on CHP projects. Several Appendices provide additional information on the analysis.

2 Regulatory Structures

The issue of emission allowance allocation exists in the context of emission cap and trade programs. These programs are typically implemented to effect emission reductions for all of the power plants in a certain sector in a given region. The affected plants include new and existing plants and are typically already affected by a variety of existing emission regulations. The cap and trade program has certain effects on compliance costs and system operation that are independent of the allocation system. There are also effects that are purely a function of the allocation system. This section describes the basic regulatory structure of cap and trade programs and the conventional command and control programs that they replace. It also identifies and describes the basic allowance allocation options.

2.1 Command and Control

"Command and control" is the term used to describe the conventional emission regulation structure that was used prior to the application of emission trading programs and exists as an overlapping requirement to most cap and trade programs. Under command and control regulations, specific emission control requirements are set for each plant or type of plant and each plant must comply individually. Within this basic structure, there are a variety of different structures:

- Plants can be regulated generically or on a unit-by-unit basis.
- The regulation can set emission rate limits or control technology requirements or combinations of the two.
- Emission limits can be set on a fuel or technology-specific basis or they can be constant across fuels and technologies.
- They can be for new units or for existing units.

Table 2-1 lists examples of command and control regulations.

Under a rate limit, each individual unit must meet its specific emission limit. Compliance requirements are fixed and certain, though the cost of control varies by plant. Some plants may have much higher control costs than others. In some cases, differential compliance levels are set to limit costs on higher emitting plants, e.g., different limits for plants using different fuels. In some cases there may be provisions for plants to petition for a less stringent limit (an alternative emissions limit) if control costs exceed a certain threshold, however in this case, sector emissions will increase.

Each plant is responsible for its own compliance costs. In some cases these costs can be very high. The costs are passed on to consumers as a cost of operation. There is no transfer of costs within the sector.

Table 2-1
Examples of Command and Control Regulations

Regulation	Applicability	Form	Application
New Source Performance Standards	New and modified sources	Rate limits or technology requirements	Uniform or by fuel and technology
Acid Rain NO_x Limits	All coal boilers	Rate limits	By fuel and technology
New Source Review	New and modified sources	Rate limits or technology requirements	Case-by-case
Reasonably Available Control Technology	All new and existing sources	Rate limits or technology requirements	By fuel and technology
Maximum Achievable Control Technology	Selected new and existing sources	Rate limits or technology requirements	By fuel and technology

Often, new plants are restricted by new source command and control requirements to emissions levels that are more stringent than broad sectoral command and control standards (e.g., new source review limits are more stringent than new source performance or RACT standards). In this case, the new units are essentially unaffected by the broader standard, unless there are additional monitoring requirements.

There are several significant differences between command and control vs cap and trade programs. Although command and control programs set fixed limits on emission rates for individual plants or units, they do not set a limit on total tons of emissions from the regulated sector, since the emissions will vary according to the utilization of the affected plants. In addition, total emissions will increase as new plants are constructed.

2.2 Cap and Trade Programs

Cap and trade programs are a fundamentally different approach to emission regulation. Under a cap and trade program, an overall emission tonnage cap is set for an affected sector or set of plants. For example, the acid rain SO_2 trading program sets a cap of approximately 9 million tons per year for U.S. power plants. Allowances are created which represent the right to emit one unit (e.g., one ton) of the allowable cap. The allowances are distributed to the affected plants. The primary compliance requirement is that each plant must hold allowances equal to its actual emissions at the end of each compliance period. However, there is no fixed emission cap or limit on each plant and each plant's emissions are not limited to the allowances that it receives. It can purchase additional allowances from another plant or it can sell some if it has extra.

There are several benefits from a cap and trade program. The emission cap creates much greater environmental security than a command and control program since the total tons of emissions are held to a specific limit regardless of plant operation or growth in the sector. The trading program also helps reduce the cost of compliance. The trading system allows reductions to be made at the lowest cost plant rather than requiring specific reductions from each plant. Ideally, plants with lower cost-of-control make more reductions while plants with higher control cost make fewer. Through trading, all plants have the option of compliance at essentially the same cost per ton. By levelizing the compliance cost and more efficiently allocating the benefits of emission control, trading programs reduce the overall cost of compliance and the regulatory impact on high-cost plants. (Ellerman and Joskow 2003)

The trading program also monetizes emissions and control investments. Each ton of pollutant emitted requires the retirement of an allowance that has a market value. Thus each ton emitted carries a specific dollar value. In competitive electricity markets, plant operators add this cost to the variable cost that they seek to recover in bidding into the electricity market. This creates an ongoing economic incentive to reduce emissions in order to make each plant more competitive. Ultimately the cost of control is still passed on to electricity consumers through higher cost of electricity.

While the cap fixes the total emissions from the sector, there is no fixed emission limit at the plant level. Each plant can emit more or less each year as long as it can acquire the required allowances. Compliance planning changes from the command and control concept of meeting a specific emission rate at the lowest cost to a goal of minimizing total plant operating cost through the most advantageous combination of emission controls, fuel choice, plant operation and allowance purchases or sales. The cost of compliance under a cap and trade program is the cost of allowances retired to cover emissions plus the capital and operating costs of any control measures that may be installed.

If allowances are inexpensive on the market, the best option for a plant may be to forego emission controls, emit more and purchase allowances. If allowances are expensive, it may pay to install capital-intensive control technology and possibly have allowances to sell. There is no fixed compliance level or solution. The program applies market forces to the broader goal of producing electricity at the lowest cost within a fixed emission constraint rather than on meeting plant-specific emission limits without any overall emission limit or cost-minimization function.

Part of the basic functioning of the cap is that higher-emitting plants will need more allowances to operate while low-emitting plants will need fewer. This creates an economic incentive to reduce emissions, however, the effect of this incentive will depend on other plant costs. For example, a high-emitting plant with an unusually high cost-of-control would likely be better off under a trading program than under a command and control program because it has the option of purchasing allowances at a lower cost than directly reducing its emissions.

A very clean plant with high operating costs may get little advantage from a trading program. It has already paid the cost of emission reductions and would not be affected by a command and control program. However, under a cap program even the very clean new plants must recognize the cost of allowances it must surrender for its emissions as well as the additional monitoring and administrative costs of the program.

2.3 Allowance Distribution

While capping of emissions and the establishment of a value for emissions is inherent to any cap and trade program, many of the effects of the program are a function of how the allowances are distributed. Under an allowance trading program, the allowances must be distributed to affected units in some way. The allocation does not affect the overall level of emissions (the cap) and may or may not affect the dispatch of specific generating assets. However, it does affect the profitability of individual units and possibly the total cost of the program and the future choice of generating technologies. Because of the competitive and profitability issues for individual companies, allocation is one of the most contentious and politically difficult aspects of cap and trade program design.

From a policy perspective, some goals of an allocation program should be:

- Simplicity
- Not arbitrarily creating winners and losers
- Promoting a balanced mix of clean, new generating technologies.

The key design features of allowance distribution can be thought of in three dimensions as in Figure 2-1.

Figure 2-1
Allowance Distribution Design Features

Frequency of Distribution	Distribution Method	
	Allocation	Auction
One time (grandfathering)	Input or	
Updating (reallocation)	Output	

The first dimension is the method of distribution - an allocation to sources without charge vs an auction. The second dimension is the frequency of distribution - one time (grandfathering) or periodically reallocated. The third is the method of allocation – typically either based on heat input or generation output.

2.3.1 Method of Allowance Distribution

There are two primary options for allowance distribution – allocation or auction. Under allowance allocation programs, the government distributes allowances in a "free" allocation to affected sources. This system has been used in emission trading programs to date and is certainly the choice of affected industry. It relieves industry from having to actually purchase allowances up-front and avoids the policy "problem" of what to do with the income from an allowance auction. Allocation can also create advantages for those who receive allowances. Allowances have a market value, so any company that receives them for free has received a valuable commodity. This does not necessarily change current compliance actions or costs but it can change plant profitability, asset valuation and future investment decisions.

Allocation awards allowances to individual plants. If they can reduce their emissions below the allocation level then they can sell the excess allowances. The allocation does not determine the best compliance option or the cost of compliance, but it does affect the profitability and value of each plant under the cap and trade program. It therefore can create incentives or biases. This is discussed further in later chapters.

Under an auction, affected plants and others would have the opportunity at periodic intervals to purchase the available allowances in an open auction. Once purchased, allowances could be traded on a secondary market. Under an auction, all generators must pay up-front for all allowances. There is no "free" distribution under a pure auction[2]. It is clear that allowances have a market value and plant operators must carefully evaluate that market value in making compliance decisions. All emitters in the program have an equal position in the auction. The auction does not create any bias to the market action of the trading program.

Economists generally find that auctions are the most economically efficient distribution mechanism since each participant is driven to make economically efficient tradeoffs between investment in technology, fuels or allowances. Also, the auction generates revenue that the government can redistribute in ways that offset the impacts of the regulation or meet other policy goals. It is also simple in that the government does not have to track and administer the basis for distribution as in an allocation program.

Despite these theoretical benefits, auctions have appeared to be politically unattractive. This may be because they look like a politically unpopular "pollution tax". Also, the controversy over how to distribute the auction revenues is often seen as a problem. There is a common concern that once the money reaches the U.S. Treasury, it will not be used for the positive uses originally postulated. From an industry perspective, the fact that generators must purchase all allowances in an auction rather than receiving any "free" allocation is an unattractive aspect. In any case, despite some possible benefits, auctions seem to be a politically difficult solution for allocation.

2.3.2 Frequency and Basis for Distribution

The second parameter for allowance distribution is whether the allowances are distributed only once or whether they are periodically reallocated and the third is the basis for the distribution. The basis for distribution is an issue only under allocation programs, since the auction takes care

[2] It is possible to adopt hybrid allocation systems that are combinations of the options discussed here. This analysis addresses only the "pure" individual options in order to more clearly illustrate the differences among them.

of the distribution. Auctions can be either one-time or updating programs, though they are usually envisioned as updating programs.

Under grandfathering or one-time allocation, the allowances are allocated to plants or auctioned once and forever at the beginning of the program. This is the structure of the acid rain SO_2 trading program. The plants that receive allowances will continue to receive them "forever" regardless of their emissions or operation. They will receive them even if they shut down. New plants will never receive any allocations. The basis for the allocation can vary. In the acid rain program, allocation was based on historical heat input times a fixed allocation factor. Since there is only one allocation, the allocation basis does not affect future behavior and so is somewhat less important than under the updating approach (see below).

Grandfathering is simple but it clearly creates arbitrary winners and losers. All those who are in the initial allocation group gain a permanent economic benefit regardless of their emissions, efficiency or other attributes. Those who are not in that group are losers since they never receive allowances. The lack of allocations for new plants puts those plants at a financial and competitive disadvantage. Thus grandfathering tends to preserve the existing generating base and slow the turnover to new, potentially cleaner and more efficient generators including CHP. This is particularly true for new coal plants, which have more emissions that they must cover through allowance purchases than some other new plants. (See below.)

Under an updating system, the allowances are periodically redistributed, typically every one to three years. Most auction systems are envisioned as updating systems in which the allowances are auctioned every year.

Under an updating allocation system, the basis for the allocation can vary but is most commonly either the heat input or power generation output from each plant in the few years prior to the redistribution. In each year, each plant's allocation will be proportional to its share of total heat input or generation. For example, if a plant generates 1 percent of the total power generated by affected plants, it would receive 1 percent of the allowances in an output-based system. The allocation is typically done several years in advance to provide some certainty. For example, in year four of the program, allowances would be allocated for year seven based on average operation in years one through three.

Since new plants do not have a history of operation on which to base their allocation when they start up, an updating program typically includes a new source set aside. This is a small pool of allowances that can be allocated to new plants until they have an operating history on which to base continuing allocations at which time they become part of the normal allocation pool[3].

[3] A new source set aside could be used under a grandfathering system but since new plants never enter the main allocation pool under grandfathering, the new source set aside would need to be sized to accommodate all future growth in generation.

The updating system is more work for regulators than grandfathering since the allocation must be redone every one to three years instead of just once at the beginning of the program. The basic calculations are simple but the process can be time-consuming and the heat input or generation data must be tabulated as the basis for allocation, depending on the system.

GPS vs Output-Based Allocation

The terms generation performance standard (GPS) and output-based allocation are often used interchangeably. While they are both ways of relating distribution of allowances to generation output, they operate very differently and have different results on trading and compliance. It's important to understand and distinguish these differences.

Under a GPS, the regulators forecast the expected total generation from affected plants in the upcoming year. The emission cap is divided by this generation forecast to calculate the generation performance standard in lb/MWh. Each plant is required to meet this GPS on average over the coming year. At the end of the year, the total emissions for each plant are divided by its generation to calculate its actual average emissions per MWh. If the average is below the GPS, the difference can be converted into equivalent tons that can be banked or sold. If the average is above the GPS, the difference must be converted into tonnage equivalent and the operator must purchase allowances to make up the difference or it will be in violation. A new generation forecast is done for the next year and the cycle starts all over.

Since the actual generation is unlikely to match the generation forecast exactly, actual emissions will typically be a little higher or lower than the desired cap each year. The "allocation" of allowances does not take place until after the season is over, so plants cannot trade until that time. In reality, it takes several months to gather and check the emissions data and several months to do allocations. This means that the final true-up for each year would not be done until halfway through the next year. Plants would not know their allocations until well after the end of the season and would start each year not knowing how they fared in the prior year. This reduces liquidity of the market and creates increased uncertainty for affected sources. On the other hand, the plant does not need any allowances unless it exceeds the GPS. Thus many plants will not have to retire allowances at all.

Under a GPS, the allocation is much closer to the operation of the plant that drives it. Therefore, the price discounting effect of the allocation is likely to be higher. One advantage of the GPS approach is that there is no need for a new source set aside, since all allocations are retrospective, based on actual operation in the prior year.

Under an output-based allocation, all plants have to retire allowances equal to their emissions so there is much greater liquidity. Allowances are allocated in advance, proportionate to generation in an earlier year. This means that sources know several years in advance what their allocations will be for a future year. This provides greater certainty, opportunity to plan for compliance and greater allowance market liquidity. Because the actual distribution is several years from the nominal allocation, the electricity price discounting effect is probably reduced. This system also ensures that the cap will not be exceeded. One drawback is that the system requires a new source set aside to provide allowances for new plants until they have established a record of actual generation.

Updating allocation has several effects. One of the most important is that it brings new sources into the program as they begin to operate. It also phases older plants out of the program as they reduce or cease operation. In this way the program focuses on plants that actually produce power, reducing the arbitrary creation of winners and losers created through grandfathering.

If reallocation is based on an operating parameter such as heat input or output it can have an effect on the future operation of affected plants. Depending on the program design, this can be used to promote policy goals as discussed below.

The choice of whether to allocate allowances based on heat input or generation output is one of the most contentious allocation issues. It can be an issue for either a grandfathering or updating allocation program, but it is more important for an updating program since the allocation is repeated and continues to affect future actions. In any year, the operation of the plant will affect the next allocation. Thus, the updating allocation creates incentives for certain behaviors. If the allocation is based on heat input, it rewards increased heat input. If it is based on generation, it rewards increased generation. In effect, an input-based system rewards inefficiency while an output-based system rewards efficiency. It seems preferable from a policy perspective to adopt a system that encourages efficiency.

An output-based allocation is needed to provide credit for the thermal output of CHP facilities and recognize the increased efficiency offered by these systems. This is discussed in Chapter 6. In addition, an output-based system facilitates the allocation of allowances to renewable and non-emitting generators and end use energy efficiency projects. Allocating to these sources is difficult under an input-based system because they do not have heat input. Under an output-based approach, they can be treated equally to other generators based on their electricity output. Such allocations could include allocations to nuclear facilities, though this is controversial for some due to non-air impacts of nuclear plants. Allocation to non-emitting facilities allows the trading program to provide added value for these technologies and potentially encourage increased construction and operation of lower-emitting generation. This is addressed in Chapter 5.

2.4 Effects of Allocation

As noted above, compliance planning and costs are different under a cap and trade program than under command and control programs. This section discusses some of those differences and addresses several commonly cited "myths" related to allowance allocation and compliance. There are two important characteristics of cap and trade programs that must be understood in order to address many of these issues:

<u>Allowance allocations are not emission limits.</u> Power plants do not have to limit their emissions to the allocations that they receive. The only compliance limit in the cap and trade program is that each plant must have allowances equal to its actual emissions at the end of the year or other compliance period. This can be more or less than the plant's allocation depending on the plant's

emission level and whether the owner bought or sold allowances. Most plants will emit either more or less than their allocation and bank, buy or sell the difference.

The "free" allowance allocation has value. It is a common misconception that allowances allocated by the government have no value whereas purchased allowances have a real cost. However, since unused allowances can be sold, they have real value regardless of their source. If they are not used for compliance, they are worth the market price in cash. If they are used, they can't be sold. Therefore, every allowance has the same value whether it was allocated to the unit or purchased from someone else. The value of either is the market price. Many companies recognize this by "taking" the allowances from the operating units and "giving" them to a trading unit. The plant operators are then required to "buy" the allowances they need from their colleagues at market prices. This ensures that the allowances are properly valued.

With this in mind, we can address common misunderstandings about compliance under a cap and trade program.

Allocation does not determine the ability of a plant to comply. Some companies have suggested that they will be unable to comply with cap programs under allocation systems that give them fewer allocations. However, as noted above, allocation does not set the compliance limit. As long as plants can buy and sell allowances, their direct allocation does not limit their ability to comply. As pointed out above and discussed further below, allocation does not directly change the cost of the allowances or compliance at individual plants.

In the broader perspective, allocation does not change the total number of allowances in the cap. Thus there are always the same number of allowances available for compliance. If the market is efficient at allocating costs, then any plant has the same ability to acquire the allowances that it needs to comply efficiently and cost-effectively regardless of its allocation. The allocation does have other important implications as discussed below.

Allocation does not determine the cost of compliance. The cost of compliance for a plant is the combination of:

- The capital cost of any required new investment in control technology
- The variable cost of compliance options (increased fuel or O&M costs)
- The value of the allowances that need to be retired to cover actual emissions. (The cost of these allowances is the same whether the allowances retired are purchased or allocated by the government.)

The goal of cap and trade compliance planning is to find an approach that minimizes these costs on a $/MWh basis and makes the unit most competitive and profitable in the electric market. The key factor is whether the plant can make reductions at a cost below the market price of allowances. If not, it is more cost-effective to purchase allowances on the market. If allowances are cheap, the best option may be simply to purchase a lot of them. Or the best option could be some combination of capital (technology), fuel, and O&M options. None of these factors is affected by the allocation.

Power generators that are still regulated utilities will pass these compliance costs directly to ratepayers. Even some utilities that have gone through restructuring have negotiated ratepayer coverage of compliance costs as part of their restructuring package. In this case, the utility is insulated from the cost impact of the regulations regardless of the allocation. In contrast, unregulated developers of new plants, must bear all of the compliance costs.

Allowances do have value and the potential total value in a multipollutant program is very large. That value can be used by generators to pay for compliance or it can be used to pay for office supplies or to launch a new business. It is no more tied to compliance than any other source of revenue.

The value of allocated allowances can support all companies and technologies equally or be skewed to benefit only certain companies and technologies. Allocation based on grandfathering gives an advantage to older, generally higher-emitting plants and disadvantages new, cleaner facilities. If allocations are distributed on an equal basis, then plant operators can make economic tradeoffs without the government picking winners. If allowances are distributed on an equal, output basis, they will give more support for the development of cleaner and more efficient plants regardless of the fuel that is used. The next chapter uses a scenario analysis to illustrate these effects.

3 Application of Allocation Programs

With the preceding background on the broader structure of emission trading programs, we can look more closely at the application and implications of emission allocation programs. In order to illustrate these issues, this report uses a hypothetical power system with a variety of old and new power plants. This system is evaluated prior to imposition of new emission control regulations, under a command and control regulatory system and under a cap and trade program with different allowance distribution mechanisms. The operation of the power system is simplified to focus specifically on the impacts of different trading programs. These example programs do not represent any actual cap and trade programs and the compliance scenarios are hypothetical cases intended purely to provide a basis for comparing the effects of alternative allocation approaches. They do not include all of the effects of real regulatory programs on a real power system.

All of the plants are the same size (300 MW) and have the same utilization (75 percent) in all cases. The plants in the system include:

- Existing uncontrolled coal plant with high cost-of-control
- Existing uncontrolled coal plant with low cost-of-control
- Existing controlled coal plant
- Existing conventional gas steam plant
- New conventional coal plant
- New integrated gasification combined cycle plant (IGCC)
- New gas combined cycle plant (NGCC)
- Nuclear plant
- Geothermal plant

The effects of allocation on CHP facilities are discussed in Section 6.

There are three likely options for distribution of allowances in a cap and trade program that are addressed in these examples:

- Updating auction (auction or AU)
- Input-based grandfathered allocation (grandfathering or GF)
- Updating output-based allocation (output-based allocation or OBA) with allocations either to all generators (OBA All) or to fossil-fired units only (OBA Fossil).

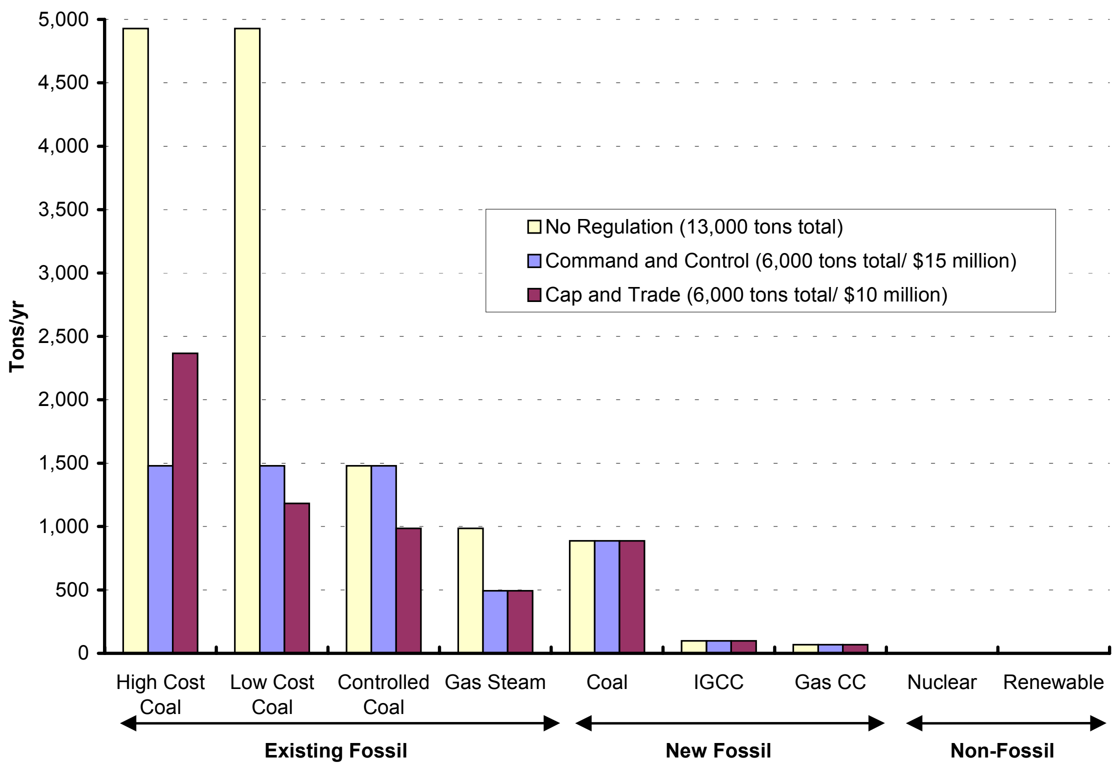
3.1 Basic Cap and Trade

The application of the trading program is expected to reduce the overall cost of compliance with a cap (Burtraw 2003). The allocation, in turn, affects how those costs are distributed. This effect can be demonstrated with the hypothetical power system. The first step of this analysis is to understand how the cap and trade program changes the plant operator's compliance strategy and cost of compliance independent of the allocation method. For simplicity, this comparison is presented for just one pollutant, NO_x.

Figure 3-1 shows the emissions from the plants in the hypothetical system under three different cases:

- Before imposing new regulations.
- Under command and control regulations
- Under a cap and trade program.

Figure 3-1
NO_x Compliance Alternatives



Before new regulations are imposed, the total emissions of the system are over 13,000 tons of NO_x per year. Under command and control, the emissions are reduced to about 6,000 tons per year. Each unit must meet its own emission limit and each unit pays the cost of that compliance. The three existing coal plants all must meet the same emission rate limit. The controlled coal plant already meets that limit. The existing gas plant must also make reductions because the command and control limit for the gas plant is more stringent than for the coal plant. The new plants are built to more recent, more stringent standards and can already meet the command and control retrofit level of control. The total compliance cost under command and control is about $15 million per year. Most of the reductions come from the two uncontrolled coal plants, which also bear most of the cost.

Under the cap and trade program the system emits the same 6,000 tons per year as under command and control but each plant finds the most advantageous combination of control technology investments and allowance purchases. The plants will reduce their emissions wherever the cost of reduction is lower than the cost of purchasing allowances. If the cost of reductions is higher, they will purchase allowances to achieve compliance.

Figure 3-1 shows that the high-cost existing coal plant does less on-site control under cap and trade and purchases allowances to cover its emissions. The low-cost existing coal plant and the controlled coal plant are able to make additional reductions below the market price of allowances to offset the higher emissions from the high-cost coal plant. The new plants are not assumed to make any additional reductions. Because more reductions come from the lower cost plants, the total compliance cost is reduced from \$15 million to \$10 million per year.

Figure 3-2 shows the changes in compliance among the three coal plants between command and control and cap and trade. It shows the tons per year of emissions in each case and the marginal cost of control in dollars per ton. The two uncontrolled coal plants must make investments and incur increased operating costs to meet the command and control limit. One has a very high cost-of-control (\$3,000/ton) and one is relatively lower (\$1,350/ton). The controlled coal plant already meets the limit, so its compliance cost is zero. The total cost of reductions for the system is \$15 million/year.

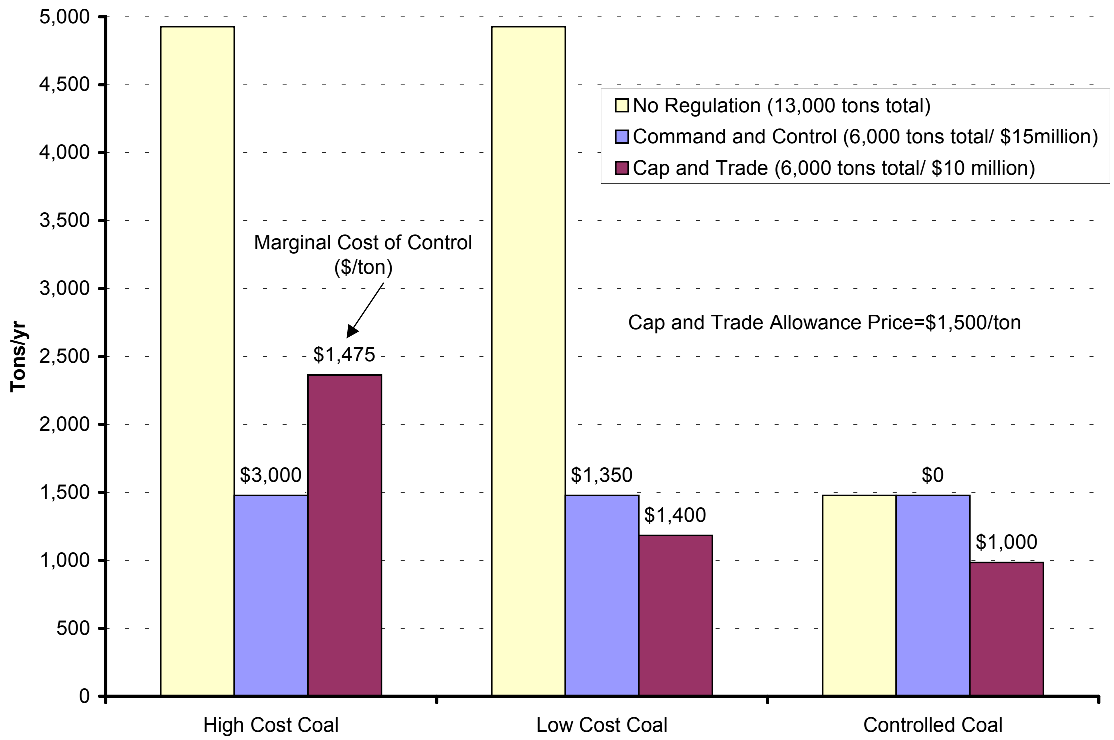
Under the trading program, each plant must retire an allowance for every ton emitted. The allowances have a value set by the trading market. If a plant can avoid emitting a ton of NO_x at a cost less than the market price, it will do so. If avoiding the emissions costs more than the market price, it is cheaper to purchase the allowances. Overall emissions are limited by the cap in all cases and balancing the cap vs the cost of the last required emission reduction sets the market price for allowances. In this case, the price of NO_x allowances is assumed to be \$1,500/ton.

Under command and control, the high cost-of-control plant had to spend \$3,000/ton to reach the compliance level. Under cap and trade, the plant makes only the reductions that can be achieved for less than the market price of \$1,500/ton and purchases the balance of the allowances it needs to comply. Its direct emissions are significantly higher than under command and control but its cost is much lower. The biggest cost reduction benefit of the trading program is to reduce the cost of compliance at high marginal cost plants.

The low cost-of-control coal plant and the controlled coal plant actually invest more to create reductions under the trading program than under command and control. These two plants can reduce their emissions at a cost below the market price for allowances so it is actually cheaper for them to reduce their emissions below the command and control level than to pay for the allowances. The additional reductions at these two plants offset the increased emissions at the high-cost plant so the cap is not exceeded. The low-cost and controlled coal plants actually spend more on controls than under cap and trade but the high-cost plant spends much less. The total direct cost of compliance is $10 million/year, one third less than the command and control case. However, there has been transfer and levelizing of costs between the plants.

The new plants do not make additional investments. Since they already have state of the art controls, the marginal cost for additional reductions would be higher than the market price for allowances to cover their emissions.

Figure 3-2
NO_x Control Strategy and Cost for Coal Plants



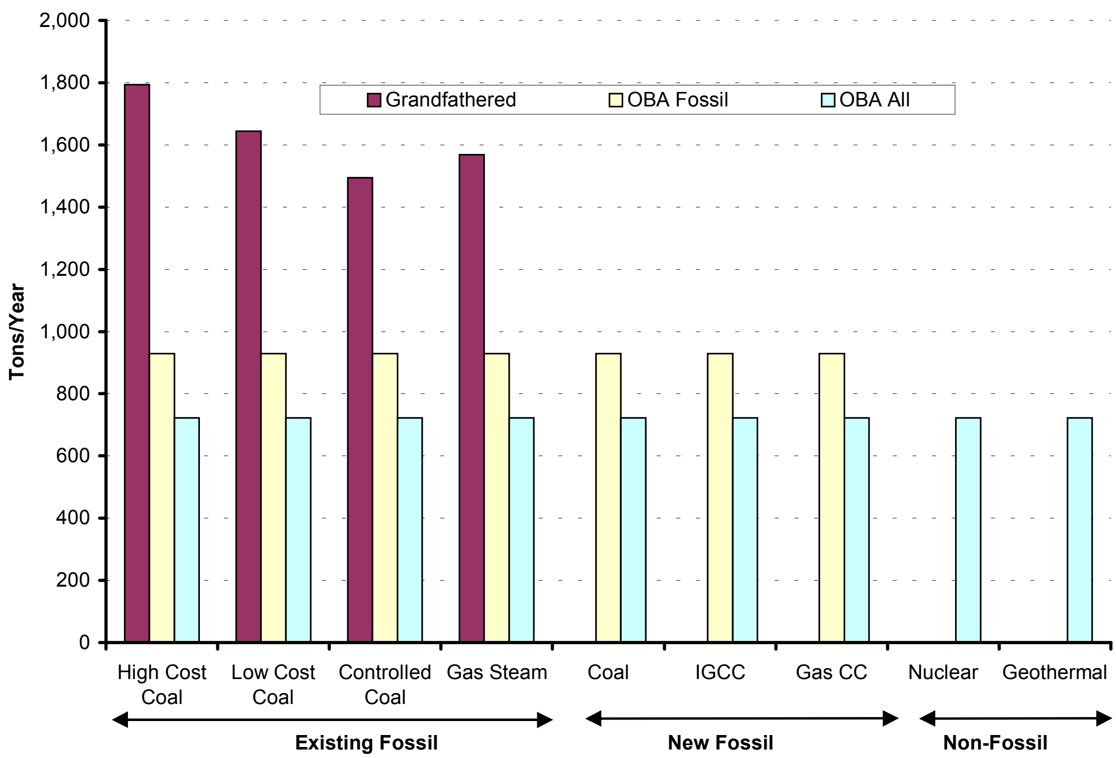
Within the universe of this system, the compliance decisions under the cap and trade program are independent of the allocation system. The number of allowances available does not change and the control options available to each plant and their cost are fixed. The key decision is whether to reduce emissions on-site or retire allowances. Since the value of the allowances is the same whether they are allocated or purchased, there is only one most efficient solution, which is independent of the allocation method. However, the distribution of the allowances can affect the overall financial effect of the program on affected plants and their owners.

3.2 Distribution of Allowances

The next step of the analysis is to look at which plants get allowances under different approaches and how that affects the distribution of the value of the program. Under the command and control program, there are no allowances to be distributed. Each plant must comply directly and bear the costs on its own. There is also no direct allocation under the auction. Instead, under the auction each plant must purchase the allowances it needs to comply, either directly in the auction or in the secondary market. There is likely to be relatively little actual allowance trading between plants under the auction since they will purchase approximately the allowances they need to comply. However, the flexibility of the trading program will still minimize the overall compliance cost of the program.

Figure 3-3 shows the results of different allowance allocation systems in the hypothetical system. Under the input-based grandfathering approach, allowances are allocated once and forever to the plants based on their heat input in the historical base period. The existing fossil-fired plants receive allowances and the new plants and non-fossil plants receive none. All the plants in this system are the same size and generate the same amount of electricity so the variation in allocation to existing plants in this case is only due to differences in heat input caused by varying efficiency. The less efficient plants receive more allowances because their heat input is greater for the same generation.

Figure 3-3
NO_x Allocation Comparison



It is often suggested that grandfathering is most favorable to coal plants. This is only partly true. Grandfathering differentiates only by vintage, not by fuel. The input-based allocation does not address fuel type or the actual emissions but only the heat input. The conventional gas-fired plant, the controlled coal plant and the uncontrolled coal plant all have about the same heat input. Therefore they receive about the same allocation, even though their emissions and compliance issues would be quite different. Most of the grandfathered allowances go to coal plants but that is simply because most of the existing generation is coal-fired.

Because all of the plants in the hypothetical system have the same generation output, the output-based allocation distributes an equal number of allowances to each plant. Because the same total number of allowances is distributed over a larger number of plants (including the new plants), the allocation to existing plants is smaller under the output-based allocation. This is even more true under the output-based allocation to all generators. This effect is exaggerated in the hypothetical system because the new plants and the non-fossil plants make up an unrealistically large portion of the total in this small system.

Figure 3-4
Comparison of Weighted NO_x Allocation

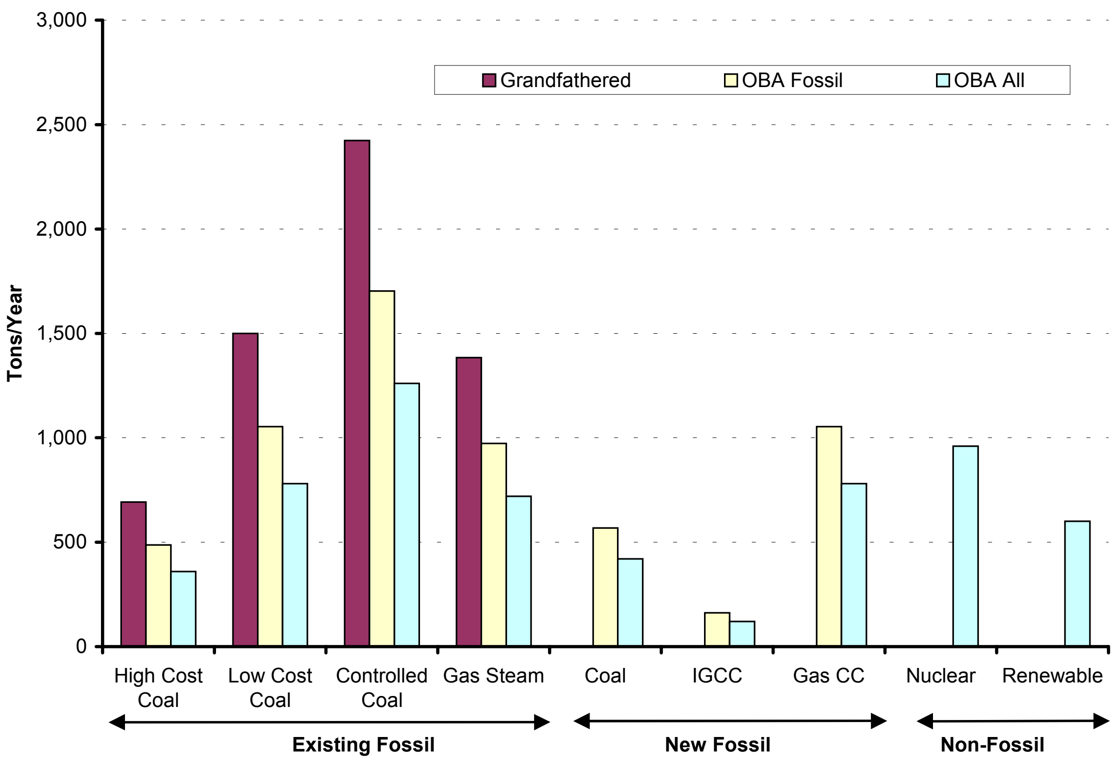


Figure 3-4 shows a similar allocation comparison in which the plant types are weighted by the current and projected total U.S. generating mix. (The mix of existing coal and new plants is an approximation of recent modeling results for 2010. Renewable includes large hydro generation.) This figure compares grandfathered and output-based allocations based on 2000 heat input (GF) and forecast 2010 generation (OBA). It shows that a grandfathering program carried out today or in the near future awards most of the allowances to existing coal plants. However, this is simply because most of the fuel burned by fossil-fueled plants (72 percent) is coal. An output-based program based on existing operation would also award a majority of the allowances to coal plants since coal accounts for over 70 percent of fossil generation. Even in 2010, the output-based allocation awards the majority of the allowances to coal plants.

Output-based allocation favors more efficient plants. It is often suggested that output-based allocation will excessively favor gas plants over coal plants, however this is not true, at least not in the current inventory. Most of the generation today (approximately 70 percent) is from coal plants, so they will get most of the allocations in an output-based allocation. Moreover, the difference between input and output-based allocation is related to efficiency not fuel choice. Most of the fossil generation today is from conventional steam plants. Many of the most efficient of these plants are large, base-loaded coal plants and these coal plants will get a larger share of allowances under an output-based approach than they would under an input-based approach. (See Appendix A.)

3.3 Allowance Distribution and Cost Impacts

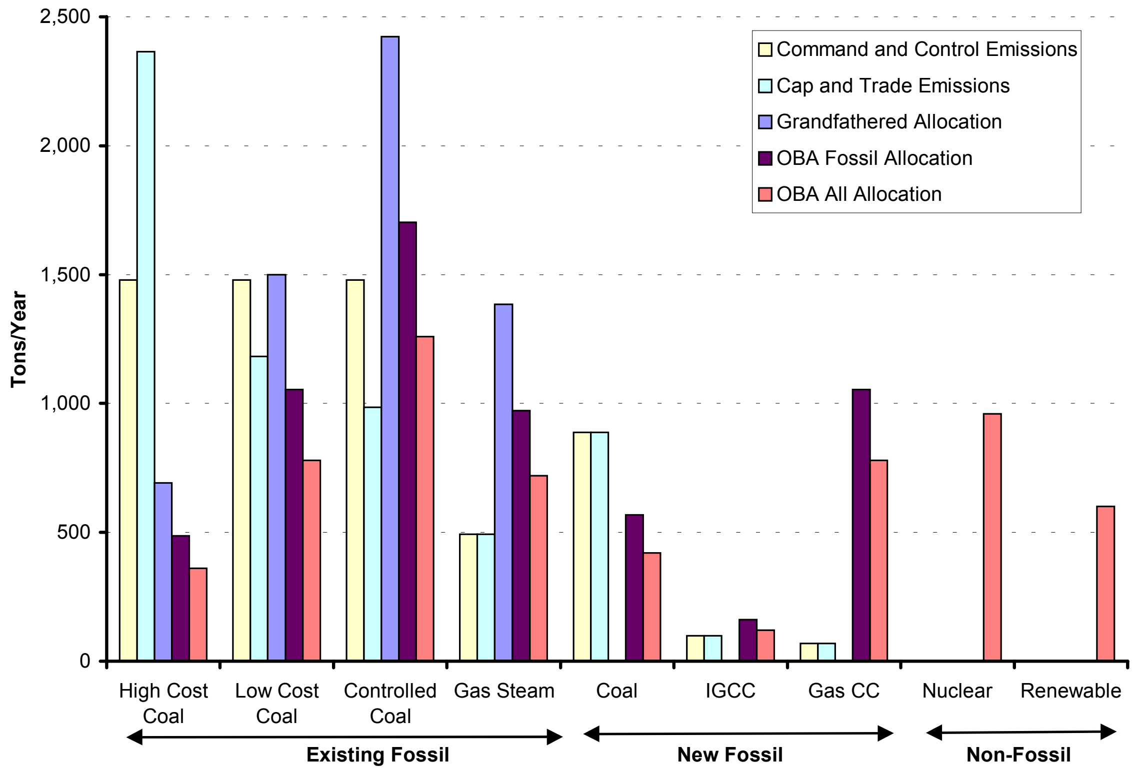
Combining the allocation data from Section 3.2 with the compliance cost information from Section 3.1 shows the economic effect of allowance allocation. This is done by adding the direct compliance cost, the cost of allowances retired for compliance and the value of allowances allocated to the plant. While the allocation does not determine the compliance approach, it does determine which plants receive the economic value of allowances.

Figure 3-5 shows the annual emissions from the plants under command and control and the emissions under cap and trade compared to the tons of allowances allocated under the various allocation methods. The auction case is not shown because all plants must purchase allowances to cover their emissions under the auction. Under grandfathering the existing plants get all of the allowances while they receive progressively fewer under the two output-based approaches.

Under cap and trade, the high-cost coal plant emits much more than under command and control even though it must purchase most of its allowances under all allocation scenarios. Purchasing the allowances is much less expensive than directly making the reductions at the plant. The low-cost coal plant and the controlled coal plant "overcontrol" under cap and trade because it is less expensive to do so than to retire the equivalent allowances. The other plants don't change their compliance approach from command and control to cap and trade because they are already highly controlled. While the allocation method does not change the compliance approach, it affects whether the plant will have net allowances to purchase or sell, i.e., it determines how the wealth of the allowance program is distributed to the affected plants.

Figure 3-6 shows the direct cost of compliance, the cost of the allowances that must be retired for compliance, how many of those allowances are directly allocated vs purchased and the net value of allowances that are available for sale by each plant under the different allocation approaches. The direct compliance cost is the same for all of the cap and trade cases for each plant. The total value of allowances retired is also the same for each plant but the number that must be purchased or that are available for sale varies according to allocation method.

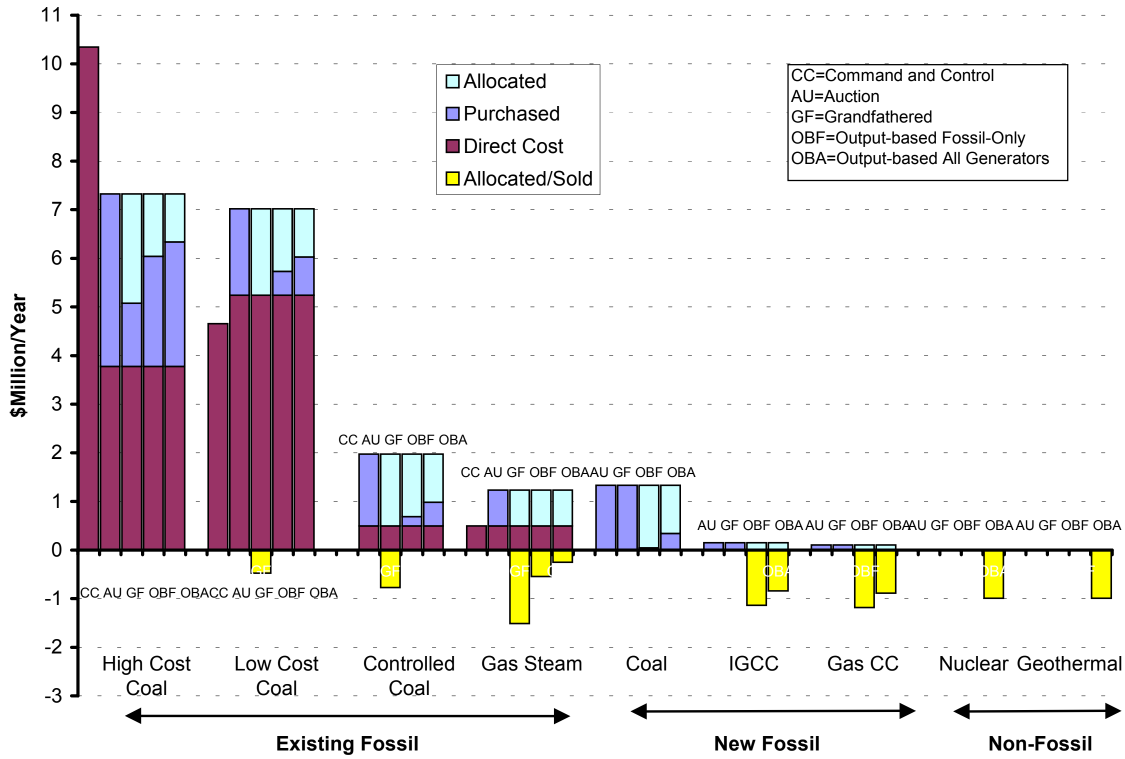
Figure 3-5
NO_x Emissions and Allocations



The high cost-of-control coal plant is the biggest beneficiary of cap and trade. Under cap and trade, it installs less control technology and purchases a lot of allowances but the total cost is still much less than under command and control, even under the output-based allocation approaches. The low cost-of-control and controlled coal plants actually have higher direct control costs under cap and trade than under command and control but this cost is lower than the cost of making reductions at the high-cost plant, so it reduces the overall system cost of compliance. This approach is also lower in cost than purchasing additional allowances, so it is a net benefit for these plants as well under the trading program.

However, the total net value for the low-cost and controlled coal plants individually depends on the allocation method. Under an auction, their total compliance cost is significantly higher than under command and control because they must directly purchase allowances to cover their emissions, whereas the controlled coal plant had no expenditure at all under command and control. Under grandfathering, however, both the low-cost and controlled coal plants have allowances leftover to sell. Thus, all of the existing coal plants are better off under grandfathering than under command and control; the high-cost-of-control plant because it can purchase allowances less expensively than direct compliance and the other two plants because they receive enough allowances to sell some to the third plant. This is also true for the controlled plant under output-based allocation though the low-cost plant must purchase some allowances under the output-based allocation approaches. The existing gas plant is in a similar situation to the controlled coal plant, though it has some compliance costs under command and control.

Figure 3-6
Total Value of Allowances and Compliance Cost



The new fossil plants had no additional compliance cost under command and control but they have compliance costs under cap and trade because they must purchase allowances to cover their emissions. Under the auction and grandfathering, they do not receive any allocations so they are always worse off than under command and control. The new conventional coal plant is particularly damaged by this effect. The new IGCC and NGCC plants also are worse off under grandfathering but less so because their emissions are lower. The new plants do better under output-based allocation, because they receive more allowances.

It is often suggested that the older plants have the higher compliance burden and therefore they should have the benefits of greater allowance allocation. This assessment does not hold up for several reasons. First, Figure 3-6 shows that it is the high cost-of-control plant that is the biggest beneficiary of trading, even under output-based allocation.

The existing controlled coal plant has no additional control burden under command and control. It makes additional reductions under the trading program because they are economically advantageous but it does create some new control costs. In addition, the plant must purchase all of its allowances under the auction. Under grandfathering, however, the plant has a surplus of allowances to sell. Under the output-based allocations it must purchase a smaller number of allowances.

On the other hand, a new coal plant will have made the same capital investment in control technology as the old controlled coal plant but will receive no allowances. Though both have to retire the same number of allowances, the old plant is able to sell allowances while the new plant is always purchasing. Compliance cost is not affected, but profitability is. This is not a fuel issue but a vintage/ownership issue. Owners of existing plants receive the value of allocation under grandfathering while builders of new plants do not. This creates a disincentive to build new plants, especially new coal plants.

3.3.1 Transfer of Costs

Allowance trading minimizes costs by always applying the lowest cost reductions. The compliance outcome is always the same. However, the choice of allocation system can create some systematic economic transfers between types of generators. For example, under grandfathering, the new plants are always buyers of allowances from the existing plants because the new plants receive no allocations. That is, the cleanest plants are paying the higher emitting plants and thereby reducing the latter's compliance cost. Compared to the command and control cost, the cleaner plants have higher compliance cost and the higher emitting plants have lower costs. The cleaner plants are paying for part of the compliance cost for the highest emitting plants. Under output-based allocation, the situation is more even. The cost of compliance is still reduced for the highest cost/emitting existing plants but the cleanest plants are able to get economic benefit for their low emissions.

4 Economic Implications of Allocation

Thus far the analysis has assumed that the allocation method does not change the operation of the electric system. In fact, there are two primary ways that different allocations could change the system's operation. One is by changing the dispatch of the available units, the other is by changing the mix of units operated or built in the future.

4.1 Dispatch Issues

In a competitive power market, plant operators bid the price at which they will sell electricity. The bid price is typically near the total variable cost for the plant. This is the cost of fuel, consumables and variable operation and maintenance costs (VOM) required to operate the unit, not including fixed costs such as capital charges and fixed labor costs. The lowest cost units are dispatched first and run the most.

Table 4-1 shows a typical variable cost "stack" sorted with the lowest cost unit at the bottom. The hydroelectric plant has the lowest variable cost and is the most baseloaded plant in the system. It is followed by two coal plants. The controlled coal plant has higher VOM than the uncontrolled coal plant but also a higher efficiency and therefore lower fuel cost, so it is lower in the dispatch stack than the uncontrolled plant. The fuel cost for the two gas plants is much higher than for the coal plants, which puts them higher in the dispatch stack despite their lower VOM costs. The cost differential column shows the difference in variable cost between each unit and the preceding unit in the stack.

Table 4-1
Variable Cost Stack Without Emission Allowances

Technology	VOM ($/MWh)	Fuel ($/MWh)	Total Cost ($/MWh)	Cost Differential ($/MWh)
Conventional Gas	$2.00	$25.00	$27.00	$8.00
Gas Combined Cycle	$2.00	$17.50	$19.50	$3.85
Uncontrolled Coal	$2.50	$12.65	$15.15	$0.15
Controlled Coal	$3.50	$11.50	$15.00	$14.70
Hydro	$0.30	$0.00	$0.30	---

Under a cap and trade program, plant operators will add the cost of consumed allowances to their bid price. The cost of the allowances is a cost that must be recovered through the bid. The cost will be passed on to consumers as higher electricity prices[4]. Higher electricity prices are usually seen as a negative, though electricity price can help encourage end use efficiency and can make alternative generation technologies more competitive.

4.1.1 Effect of Allowances on Bid Prices

Table 4-2 shows how the cost of allowances, in this case for CO_2, affects the variable cost of operation. The coal plants have higher CO_2 emissions than the gas plants due to the difference in fuel carbon. In addition, the low efficiency of the uncontrolled coal plant and the higher efficiency and lower CO_2 potential of the gas combined cycle are sufficient to move the combined cycle ahead of the uncontrolled coal plant in the dispatch order compared to Table 4-1. This allowance cost effect is independent of the method of allowance distribution, it is simply a reflection of the value of allowances that are used, regardless of their source, and the plant efficiency and fuel.

Table 4-2
Effect of CO_2 Allowance Cost on Dispatch/Bid Price

Technology	VOM ($/MWh)	Fuel ($/MWh)	Emission Rate (lb/MWh)	CO_2 Emission Adder ($/MWh)	Total Cost ($/MWh)	Cost Differential ($/MWh)
Conventional Gas	$2.00	$25.00	1,170	$2.93	$29.93	$8.53
Uncontrolled Coal	$3.00	$12.65	2,299	$5.75	$21.40	$0.41
Gas Combined Cycle	$2.00	$17.50	819	$2.05	$20.99	$0.76
Controlled Coal	$3.50	$11.50	2,090	$5.23	$20.23	$19.93
Hydro	$0.30	$0.00	-	$0.00	$0.30	---

In the updating output-based allocation system, however, the operation of the plant affects future allowance allocations. If the plant generates more electricity, it will receive more allowances in a future year. This can be seen as a negative variable cost. That is, for every MWh generated, there is some future value, a credit that can be counted against the current costs of generation. Calculating the value of this allocation raises some questions that are discussed below, but for the moment it is assumed that there is a credit of $2.50/MWh associated with each additional MWh of generation.

There is a common perception that this credit under an updating output-based allocation will give an advantage to lower emitting plants in the dispatch order and make clean plants more competitive and run more. This perception turns out to be incorrect as shown in Table 4-3. Since the allocation is based on generation, every MWh receives the same allocation credit and

[4] This assumes a restructured competitive power market. In traditional regulated utility markets, the bidding will be similar but the treatment of allowance cost may be very different.

the effect is the same for every plant so the dispatch order is not changed compared to other allocation methods[5].

Table 4-3
Effect of Output-Based Allocation on Dispatch/Bid Price

Technology	VOM ($/MWh)	Fuel ($/MWh)	Emission Rate (lb/MWh)	CO_2 Emission Adder ($/MWh)	CO_2 Credit $/MWh	Total Cost ($/MWh)	Cost Differential ($/MWh)
Conventional Gas	$2.00	$25.00	1,170	$2.93	($2.50)	$27.43	$8.53
Uncontrolled Coal	$3.00	$12.65	2,299	$5.75	($2.50)	$18.90	$0.41
Gas Combined Cycle	$2.00	$17.50	819	$2.05	($2.50)	$18.49	$0.76
Controlled Coal	$3.50	$11.50	2,090	$5.23	($2.50)	$17.73	$19.93
Hydro	$0.30	$0.00	-	$0.00		$0.30	

Although the output-based allocation does not change the dispatch order, the implied reduced bid prices has other potential effects. The value of the future allocation associated with incremental generation creates an operating cost credit. In a competitive electric market, the generator would then reduce the bid price of its electricity as shown in Table 4-3 compared to Table 4-2. If power producers subtract the allowance value from their bid price in an updating output-based system then the price of electricity will go down. In effect, the value of the allowance allocations is being passed on to consumers rather than being retained by the power generators. Lower electricity prices are usually seen as a positive factor, particularly for electricity-intensive industries. In addition, many see it appropriate for the allowance value to pass on to consumers who are also the recipients of air pollution, while power generators still benefit from the flexibility of trading.

However, lower prices at least theoretically can also create negative outcomes. Three potential negative outcomes that are largely refuted in the following sections include:

- While updating output-based allocation is generally seen as positive for new generators and renewables, some argue that new generators will pass through the full value of allowances as lower bid prices and be no better off than under grandfathering.
- As discussed above, lower electricity prices may encourage increased electricity consumption and discourage end use efficiency, which would be a negative outcome.
- The price elasticity of demand means that lower prices will cause greater demand for electricity. Increased generation would create additional potential emissions. But since emissions are capped, additional emission controls will be required and the overall cost of compliance will increase. The implication is that updating output-based allocation will

[5] The exception is plants that do not receive allocations. In a fossil-only output-based allocation, nuclear and renewable plants are disadvantaged since they do not receive this credit. Their variable costs may still be low enough for them to remain competitive but this will depend on the specific technology.

increase the overall cost of compliance compared to a different allocation system. (ICF 1999)

All of these outcomes depend on generators reducing their bid price based on the future allowance allocation and creating lower electricity prices, often referred to as an "output subsidy." The concern over increased compliance cost further hinges on the lower price resulting in higher demand and increased potential emissions. Although these outcomes are theoretically plausible, it's not clear whether they would occur in the real world or if the effect would be significant except under extremely high allowance prices. While the concept of the price reducing response is credible, its extent is likely to be mitigated by several factors, discussed below.

4.1.2 Factors Affecting Bid Price Reduction

Under the scenarios described above, generators would be reducing the current price of their product on the expectation of the value of an allowance that they will not receive for several years in the future. In order to calculate the appropriate reduction in the current bid price, the value of that future allowance must first be reduced for the time value of money. Allowances are typically allocated three years in advance based on the average of two to three years of past operating data. This means that the allocation could be six to seven years after the generation takes place, even in an annual updating program. In a program that reallocates every three years, the lag between generation and actual allocation could be closer to 10 years. This creates a significant discount just based on time value of money.

In addition, however, there are a variety of uncertainty factors that could cause companies to further reduce the current value of future allocations in their bidding strategy:

- The value of the future allowances cannot be precisely known. Allowance markets can be highly volatile.
- Companies could use various financial instruments to lock in the future value but recent trading scandals have resulted in credit guarantee requirements that require current cash outlays that reduce the attractiveness of this option.
- Some companies may be reluctant to recognize the value of future allocations due to the fallout of "Enron-type" business practices.
- In some companies, allowance allocations are funneled to a central trading desk and must be "bought" internally by the plants. Under this structure, the allocation might not be credited to the generating unit.
- The allocation is not a direct per MWh allocation. It is a function of the plant's share of overall generation in a future year based on average generation over several years. Calculating the value of an incremental MWh requires forecasting the total system generation 6 to 10 years out and each plants share thereof. This is another source of uncertainty.

For all of these reasons, the value of the future allowance for bidding purposes might be reduced for the uncertainty of the future value of allowances and the market risk associated with their use. Companies are reluctant to leave current operating costs uncovered based on an uncertain future allowance value. Thus the actual impact on the bid price will be lower than might be expected or than estimated by some studies. Power generation planners and asset managers quizzed on this topic have suggested a risk factor reduction of at least 50 percent of the future value.

4.1.3 Allocation Effect on Demand

We can estimate the potential effect of updating output-based allocation on electric demand by looking at the potential value of the allocations and their effect on demand elasticity. In order to do so, we must estimate the:

- Amount of allocations per incremental MWh.
- Value of allowances.
- Cost of money for 7 to 10 years.
- Discount for market uncertainty and risk aversion.
- Demand elasticity for electricity.

Table 4-4 shows a calculation of these factors for three and four pollutant programs of output-based updating for fossil generators and all generators.

The first step is to estimate the value of the future allocations. The allocation per MWh is simply the total cap divided by the future generation, either fossil-only or all generation. In this case, we use typical emission caps proposed for 2010 divided by generation estimated by EIA for a three pollutant (3-P - SO_2, NO_x and mercury) compliance case. The allocation is multiplied by the projected allowance values to calculate the projected future value of allocations for an incremental MWh in 2010. This value ranges from $1.86/MWh for a 3-P all-generation allocation to $5.40/MWh for a four pollutant (4-P - including CO_2) fossil-only allocation. The CO_2 factor is equal to or greater than the sum of the other three pollutants[6].

The next step is to discount for the time value of money. As noted above, the discount period could be as long as 8 to 10 years, but in this case we are using a more conservative 5 years. At an internal cost of capital of 11 percent, this comes to a 69 percent discount factor.

The next step is the discount for uncertainty. This is difficult to project. However, discussions with several power generation planners and asset managers yielded a common assumption of at

[6] A much higher CO_2 allowance value would increase the future allocation credit but it would also increase the current price of electricity so the percentage change would not be large. In addition, this analysis assumes that the U.S., for political reasons will not adopt CO_2 mitigation policies that result in such high compliance costs.

least a 50 percent uncertainty factor, which is applied here. This leaves an allocation value ranging from \$0.55 to \$1.60/MWh.

There are many estimates of demand elasticity for electricity spanning a wide range of values. Based on the references cited here (Wade 1999, Miller 2001), we estimate a value of -0.15 for residential/ commercial and -0.5 for industrial consumption or an average value of -0.35. Assuming a baseline price of retail electricity of \$60/MWh, this yields increased demand of only 0.3 to 0.7 percent. Estimating the compliance cost effect of this increase in generation is beyond the scope of this analysis, however we can project that the emissions of the marginal generating units will be less than the average and the compliance cost increase will be small. Given all of the uncertainties, it is not clear that this result of an updating output-based allocation system is a significant change from a policy perspective.

Table 4-4
Estimate of Demand Elasticity Due to Output-Based Updating Allocation

			All Fossil	All Output
Allowance Value	Allowances	Price	Price	Price
		(\$/Allowance)	(\$/MWh)	(\$/MWh)
NO_x (MMTons)	2.25	\$1,500	\$1.07	\$0.79
SO_2 (MMTons)	4.5	\$800	\$1.15	\$0.84
Hg (Tons)	10	\$50,000	\$0.32	\$0.23
3-P Total			\$2.54	\$1.86
CO_2 (MMTons)	1,800	\$5	\$2.87	\$2.10
4-P Total			\$5.40	\$3.95
	Years	Disc Rate		
Cost of Money	5	11%	69%	
3-P			\$1.51	\$1.10
4-P			\$3.21	\$2.35
Uncertainty	50%			
3-P			\$0.75	\$0.55
4-P			\$1.60	\$1.17
		Retail Price		
Elasticity	-0.35	\$60	/MWh	
Change in Demand				
3-P			0.4%	0.3%
4-P			0.7%	0.6%

There is one other mitigating factor on the potential increase in generation. If increased generation caused by lower prices causes the cost of compliance to increase, the price of allowances will increase and cause an increase in the cost of electricity, reducing the effect of the allocation credit. While assessing the specific impact is beyond the scope of this study, the effect of updating is self-limiting as well as small.

Finally, one can ask whether any of this is actually happening in the markets. Massachusetts, Connecticut and New Jersey have allocated NO_x allowances for the 2003 season wholly or in part based on generation in the past few years. Generators in these states should have been incorporating this effect for these years. However, in discussions with companies operating in these states, EEA did not find any who have been doing so. Those who are even aware of the issue were of the opinion that the uncertainty is too great and the value too small to have an effect. They also felt that covering current costs is more important than accounting for uncertain future income from allocations. This supports the conclusion that the effects of output-based, updating allocation on electricity price will be limited and the effects on electricity demand and compliance cost will be insignificant.

4.2 Allocation Effect on Asset Value

While allocation may have relatively little effect on dispatch and current compliance choices, it does greatly affect the asset value of plant and the choice of which plants to retire, retain or build. The value of a generating asset is the net present value of its:

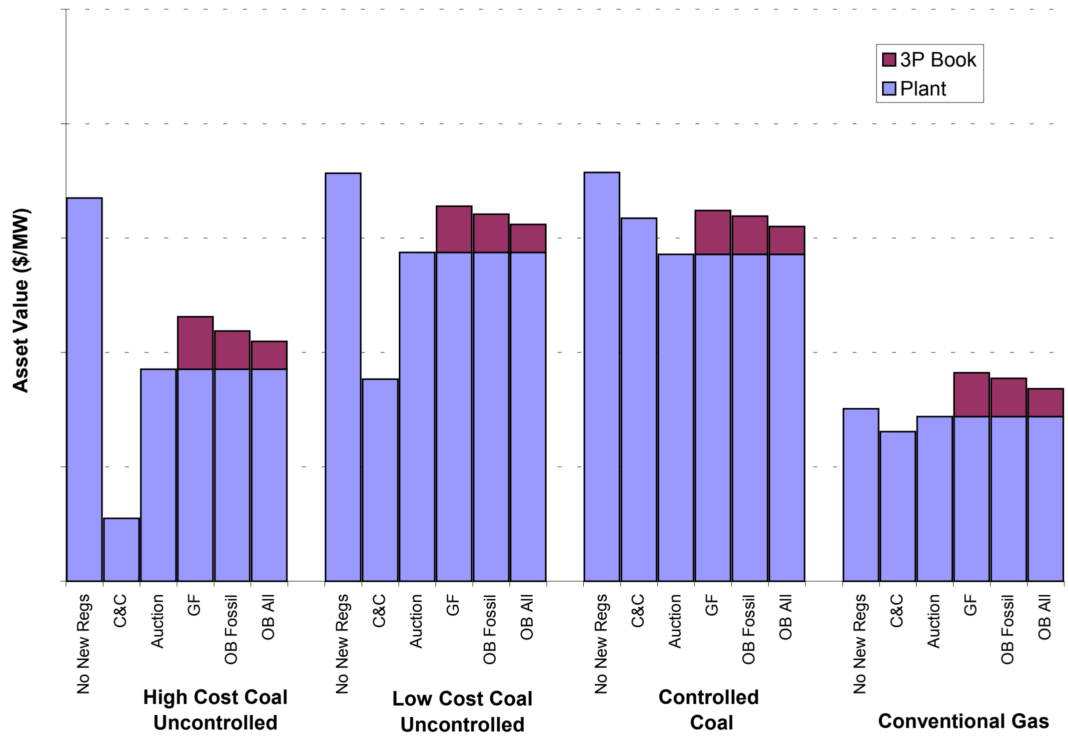
- Future revenues (value of electricity sold)
- Minus variable costs including emission allowances consumed
- Minus new compliance investments (going forward costs)
- Plus the value of emission allocations (the allowance book)

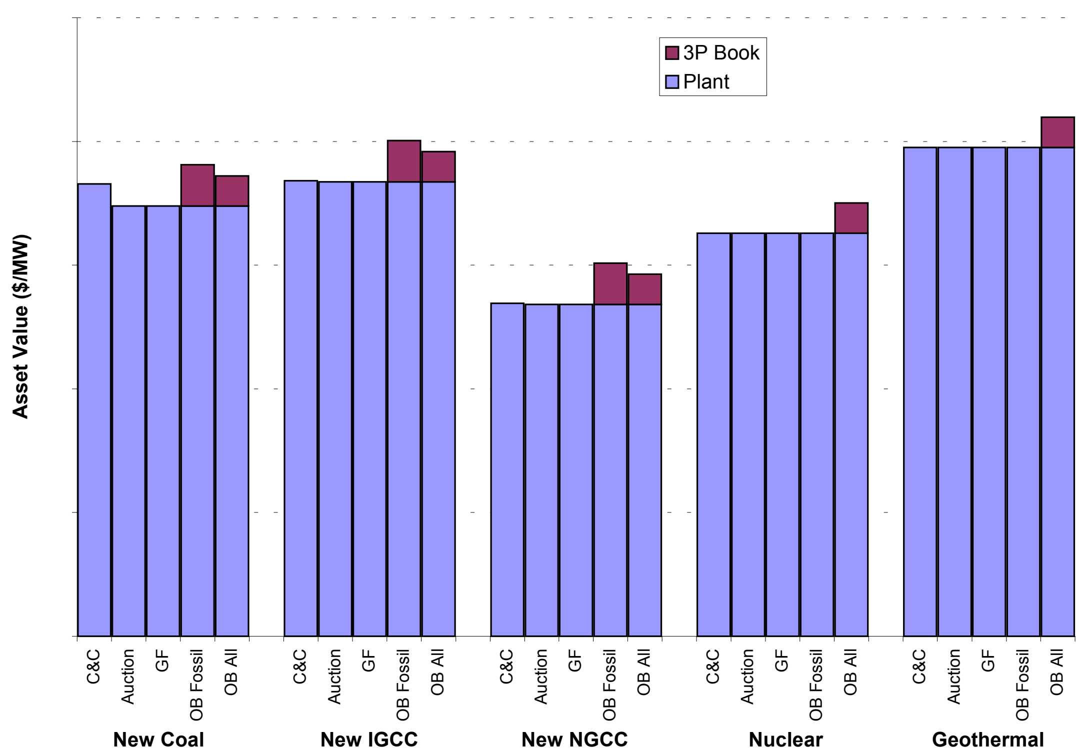
Changing the allocation approach changes the allowance book and can cause a significant change in asset value. We can compare the asset value for the hypothetical electric system under several scenarios to evaluate this effect. For simplicity, this analysis is based on a one year snapshot rather than the present value of a stream of years, however, the relative effects are the same.

Figure 4-1 shows the changes in asset value for the system starting with a no regulation baseline and moving to command and control and then trading with allocation by auction, grandfathering, and output-based allocation to fossil-only and all plants. All of these are for a 3-pollutant program. The asset value is broken into three components:

- The plant value based on the revenue minus variable and going forward costs and the cost of allowances required in a cap and trade program.
- The value of SO_2, NO_x and mercury allocations (3P book).
- The value of CO_2 allowances (CO_2 book).

Figure 4-1
Asset Value Under 3-P Programs





The asset value with no emission control program primarily shows the profitability of the different plants in the absence of regulation. For example, the conventional gas plant has a lower value due to its lower efficiency and the higher price of gas. The new plants have higher asset values due to higher efficiency.

Under command and control, each plant must take individual action to reduce emissions, so the asset value of all of the existing plants is lower due to the added costs of control. The effect depends on the required level and cost of control. The high-cost uncontrolled coal plant is the most affected due to the high cost-of-control. The controlled coal plant is only controlling for mercury and has only a small loss of value. The existing gas plant also has compliance costs under command and control so its asset value is lower as well. The new plants are assumed to already meet the command and control levels so their asset value is the same as the no new regulation case.

Under cap and trade, the compliance costs are lower for the uncontrolled coal plants and the conventional gas plant so their asset value is higher than under command and control, even including the allowances that must be retired. As shown earlier, the uncontrolled plants get the greatest benefit in compliance cost from the trading program. The value for the new plants is lower under the trading case because they must purchase allowances even though their emissions are very low. This effect is most noticeable for the new conventional coal plant. The 3-P emissions of the NGCC and IGCC are too small to change the value significantly. Since the compliance approach is the same for all of the cap and trade cases, the plant asset values for each plant are the same for the different trading cases.

However, the value of the asset book does change based on the value of allowances that are allocated to each plant. Under the auction, there is no allocation, so the asset value is not changed. Under grandfathering, the existing plants get the value of allocation but the new plants do not. This allocation further increases the value of the uncontrolled coal plants compared to command and control. It also improves the position of the controlled coal plant relative to command and control. The uncontrolled coal plant benefits because its compliance cost is lower than under command and control. The controlled coal plant benefits because it has only a small compliance cost but receives a large amount of allowances. Only the new plants do not benefit under grandfathering. Although their emissions are quite low, they do not receive any allowances, so their value is lower relative to the no new regulation/command and control cases, most notably for the new coal plant.

Under the output-based allocation, all plants receive an equal allocation (since they all have the same generation). The allocation is larger in the fossil-only cases because the allowances are spread out over fewer plants. The output-based allocation provides some value to the new plants and improves their position, especially for the new coal plant. Of course, the nuclear and renewable plants are unaffected[7] except in the output-based allocation to all plants, in which they get increased value.

Figure 4-2 shows the changes in asset value under a 4-P program that includes CO_2. It also assumes a different treatment of the allocation value. The 4-P analysis includes the potential effect of lower electricity prices under an updating, output-based allocation. The revenue decrease is based on a 50 percent uncertainty factor as shown in Table 4-4 above. It does not include an offsetting increase in allowance prices caused by increased generation.

One of the concerns about output-based updating allocation is that the negative revenue effect for new plants and renewables will be greater than the positive effect of the allowance allocations. Figure 4-2 shows that this is not a problem, however. The new plants are better off under updating than under the auction or grandfathering since the revenue-reducing credit is always some fraction of the allocation. While the revenue reduction can offset some of the allocation value, it can never exceed that value. The new and non-emitting plants are better off under an output-based, updating system than under grandfathering in these scenarios. The only exception is the value of the non-emitting plants in the output-based fossil allocation in which they do not receive allocations.

Under the 3-P program, the additional compliance costs for the gas and IGCC plants are almost negligible. Under a 4-P case including CO_2, this picture changes. The change in asset value under the cap and trade program is much increased under the 4-P program due to the cost of CO_2 emission allowances. The general trend remains the same, however[8]. This is particularly noticeable for the controlled coal plant and the new plants, which had relatively little decrease in value under the 3-P case but are much more affected under the 4-P case. The cost of CO_2 allowances makes the negative effect of grandfathering much more significant for the new plants, especially the new coal plant.

The effect of allowance allocations on asset value can also affect the decision as to which plants to retire and which plants to build. For new plants, the present value of the stream of allowances can be viewed as a credit against the capital cost of a new plant[9]. Under the assumptions used earlier in this chapter, the net present value of a 30 year stream of output-based allocations for a new plant would range from about $100/kW for a 3-P all generation case to $300/kW in a 4-P fossil-only case. If updating causes a revenue reduction, some of this value would be lost. Under the 50 percent uncertainty assumptions used above, the value would still range from $75 to $215/kW for new plants. The effect of a $200 to $300/kW reduction in capital cost could be a significant factor in the decision to build new, clean plants, especially in a 4-P program.

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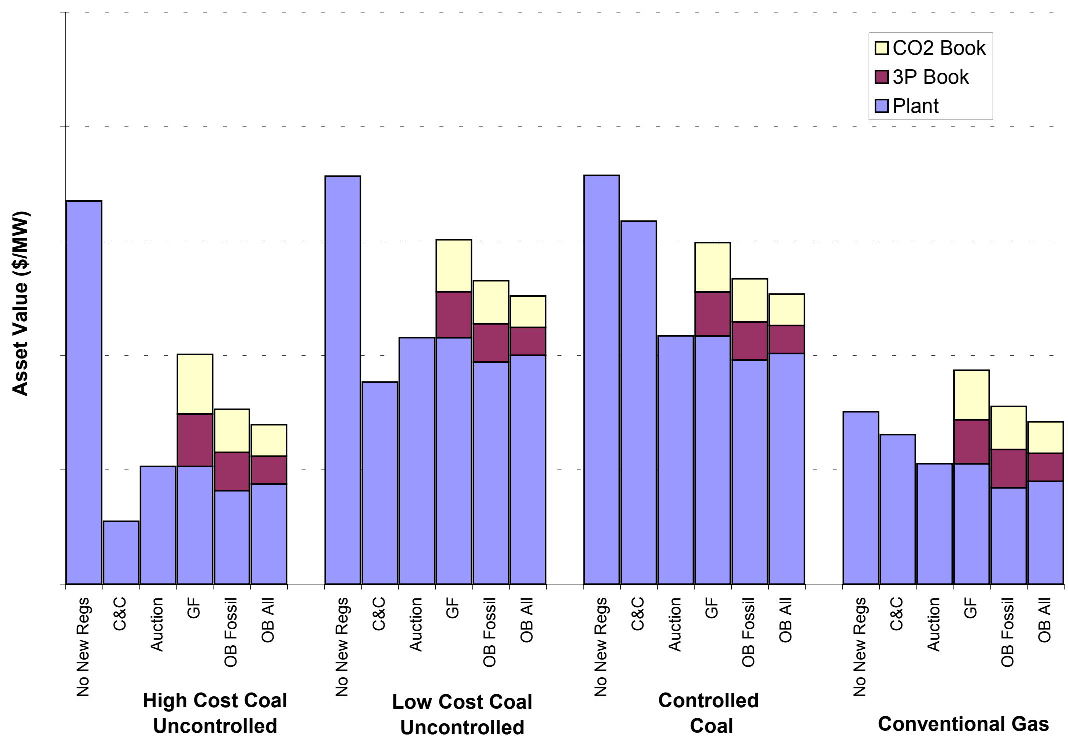
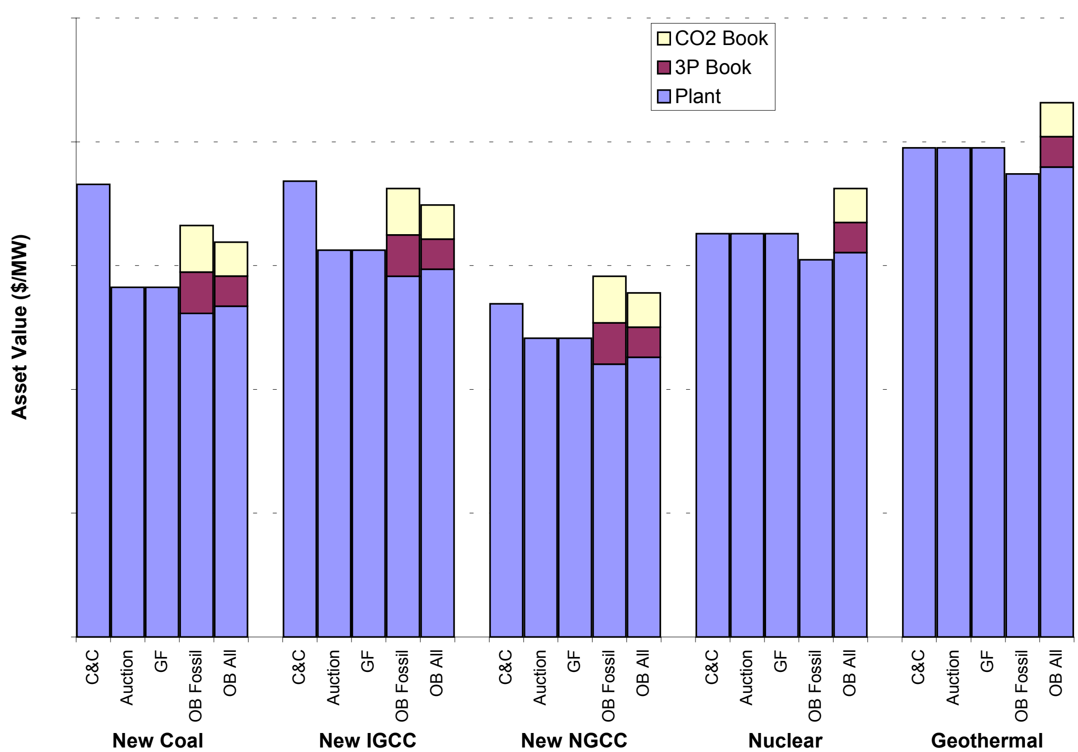
[7] This example does not address changes in dispatch or system operation that would be caused by the imposition of new compliance costs.
[8] The command and control program does not include CO_2. It is unchanged from the 3-P case.
[9] This calculation assumes that there is a new source set aside in which new plants are treated similarly to the main program. Also, there is no "uncertainty discount" in this calculation.

Figure 4-2
Asset Value Under 4-P Program with Revenue Reduction





There is a parallel effect on old, inefficient plants in which the future value is reduced in an output-based, updating program relative to a grandfathering allocation. This negative value could contribute to a decision to retire older, less efficient plants.

The incentive to build new, cleaner plants and retire old, inefficient plants could result in accelerated change in the generating mix over time. By substituting new, cleaner and more efficient plants for older, less efficient plants, this change could result in real reductions in the overall cost of compliance with the cap. Building cleaner new plants is a more efficient use of capital than adding controls to old, less efficient plants. This is particularly true for coal plants. The economic value that updating provides for new, clean coal plants is an important incentive to maintain and expand the efficient use of coal for power generation. Without it, the coal option becomes much less likely.

This potential increase in construction of new plants and retirement of old plants may be the most important outcome of an updating, output-based allocation. Further evaluation of this effect would be very useful.

In summary, this analysis shows that:

- Generators will not pass through the entire value of allocations under an updating allocation system. Some value will be retained.
- The value of allowance allocations to new generators is always greater than any revenue reduction effect of output-based allocation compared to a grandfathering approach.
- The potential increase in electricity generation due to output-based allocation is likely to be too small to affect overall compliance costs.

Even if the allocation value retained by generators under updating is relatively small, new generators will be better off competitively under updating than grandfathering because their treatment and the value they receive from allocation will be the same as their competitors. This is preferable to the situation under grandfathering in which incumbent generators receive all of the allocation value and new generators receive none. This competitive effect is important from a policy perspective because new generators may be more likely to construct new, more efficient plants that might displace old plants than incumbent generators. In this way, updating can help the turnover to a cleaner, more efficient generating mix.

5 Allocation Implications for Combined Heat and Power

Combined heat and power (CHP) is the sequential generation of electric and thermal energy from a common energy source. CHP is recognized as a highly efficient and environmentally beneficial technology. It has been specifically singled out for encouragement by the U.S. Environmental Protection Agency and Department of Energy, which have committed to doubling U.S. CHP capacity between 2000 and 2010. CHP was also highlighted in the Presidential National Energy Policy Document in 2003. While it is often assumed that CHP will do well in allowance trading programs due to its efficiency, new CHP facilities will suffer under grandfathering, like all new plants. In addition, appropriate trading credit for the efficiency of CHP systems requires the application of an expanded, output-based allocation system to account for both the thermal and electrical output of the system. This chapter provides some background on CHP technology and benefits and addresses the allocation issues particular to CHP.

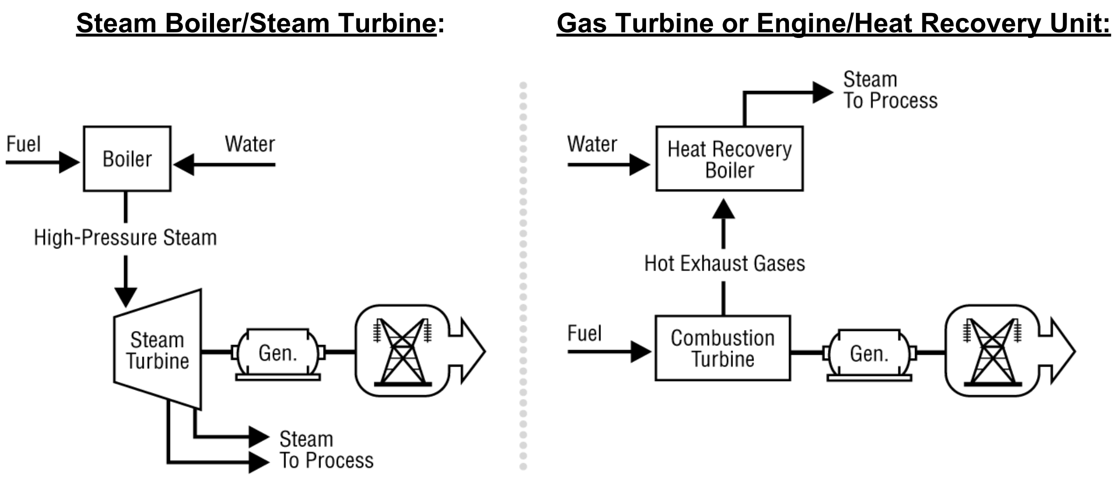
5.1 CHP Background

There are two common configurations for CHP system, shown in Figure 5-1. The steam boiler/turbine approach has been the most widely used CHP system to date. In this approach, a boiler makes high-pressure steam that is fed to a turbine to produce electricity. However, the turbine is designed so that there is steam left over to feed an industrial process. Thus, one fuel input to the boiler supplies electric and thermal energy by recovering waste heat from the steam turbine electric generator. Typically, two thirds of the energy in a conventional power plant is lost when waste steam is condensed in the cooling tower. This type of system typically generates about 5 times as much thermal energy as electric energy. Steam boiler/turbine systems are widely used in the paper, chemical and refining industries, especially when there is waste or byproduct fuel that can be used to fuel the boiler.

In the other approach, a combustion turbine or reciprocating engine is used to generate electricity, and thermal energy is recovered from the exhaust stream to make steam or supply other thermal uses. The application of these systems has been more recent as the prime mover technologies have developed. These types of CHP systems can use very large (hundreds of MW) gas turbines or very small (tens of kW) microturbine, engine, or fuel cell systems. In these systems, the thermal energy is typically 1 to 2 times the electric energy.

CHP is especially attractive because it can be applied with almost any combustion technology and fuel. This means that it can be applied in many different end uses and can use whatever fuels are economically available. It is a well-known and well-demonstrated technology. There is about 64 GW of CHP capacity in place in the U.S. today. Yet there is still substantial remaining potential for expansion. The U.S. DOE has set a goal to double the capacity of CHP between 2000 and 2010. The National Energy Policy also stresses the importance of increased application of CHP.

Figure 5-1
Typical CHP Configurations



Why Encourage CHP?

By providing electric and thermal service from a common fuel input, CHP significantly reduces the associated fuel use and emissions. Figure 5-2 compares the efficiency and fuel use of a CHP facility to the efficiency and fuel use from conventional systems providing the same service.

In the conventional system, electricity is provided by the central grid from a power plant that averages 30 percent efficiency, considering turbine generator losses and the transmission and distribution losses (8 percent). Thermal energy is provided by an on-site boiler that may be as high as 80 percent efficient. Combined, the two systems use 168 units of fuel. The combined efficiency to provide the thermal and electric service is 49 percent.

In the CHP system, one system provides the same combined thermal and electric service by recovering the waste heat from the prime mover used to generate electricity. The CHP system satisfies the same energy demand using only 100 units of fuel. This system is 83 percent efficient.

Figure 5-3 shows the emissions benefits of the CHP system. Because it uses nearly 50 percent less fuel, the CHP system has much lower emissions, even if the combustion process has the same emission input-based rates as the conventional equipment. Because new CHP systems often replace old conventional systems, the emission rate for the new system is often lower, further reducing emissions. In the case shown, the CHP system emits about half as much as the conventional system.

Figure 5-2
Efficiency Benefits of CHP

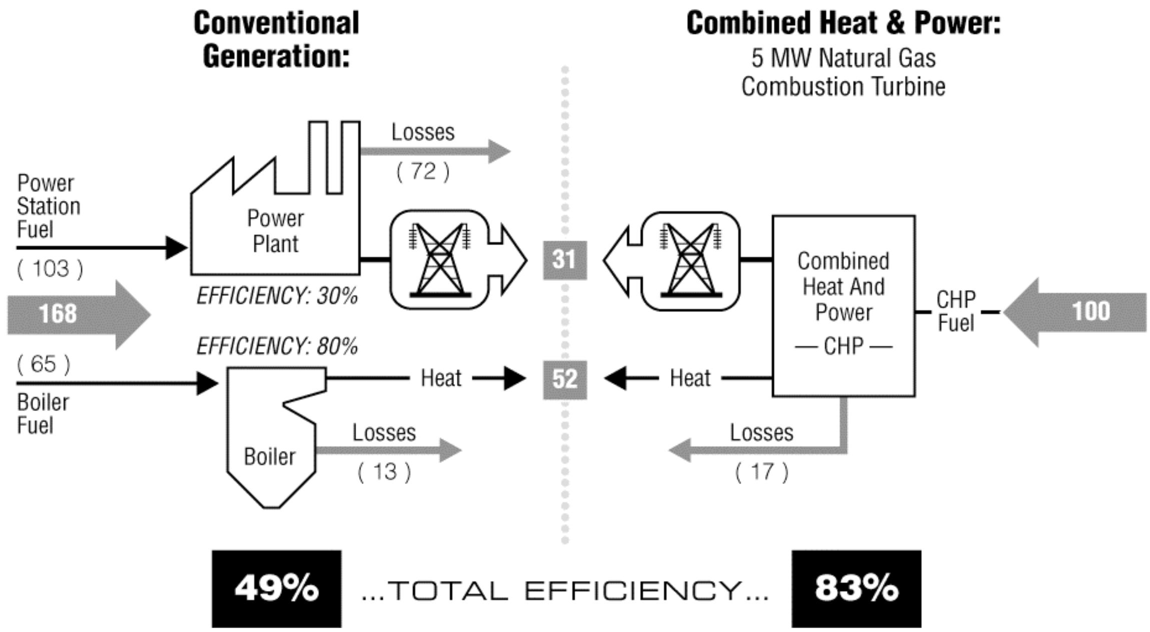
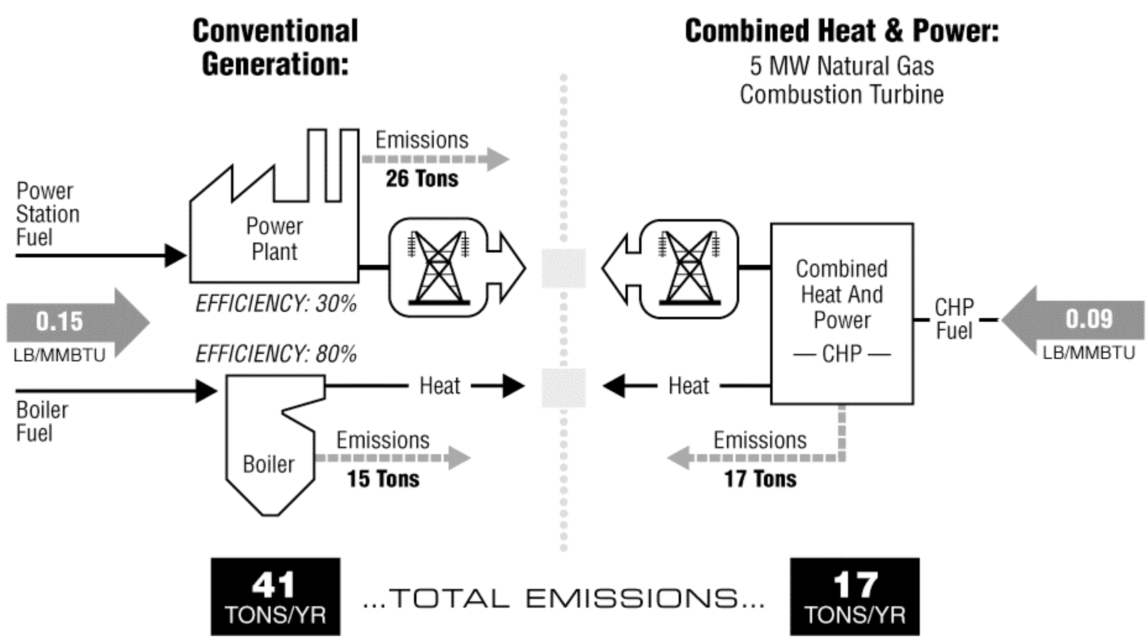


Figure 5-3
Emissions Benefits of CHP



In this case, a significant portion of the avoided emissions are from the off-site power plant. The on-site emissions from the CHP system are slightly higher than the original on-site boiler because more fuel is burned. Depending on the characteristics of the boiler and CHP prime mover, the on-site emissions could be higher or lower with CHP than with a conventional system, though the total regional emissions are always lower.

5.2 Trading and Allocation Impacts on CHP

These examples illustrate the significant energy and environmental benefits that are achievable through the application of CHP. However, current environmental regulations typically do not account for these benefits. This omission is largely because CHP systems replace two separate conventional systems, one part of which (power generation) is typically at an off-site location in a conventional system. Any recognition of the benefits of CHP requires a comparison of the emissions and energy output between the CHP system and both the thermal and electric components of a comparable conventional power system. This requires explicit consideration of the output of both systems.

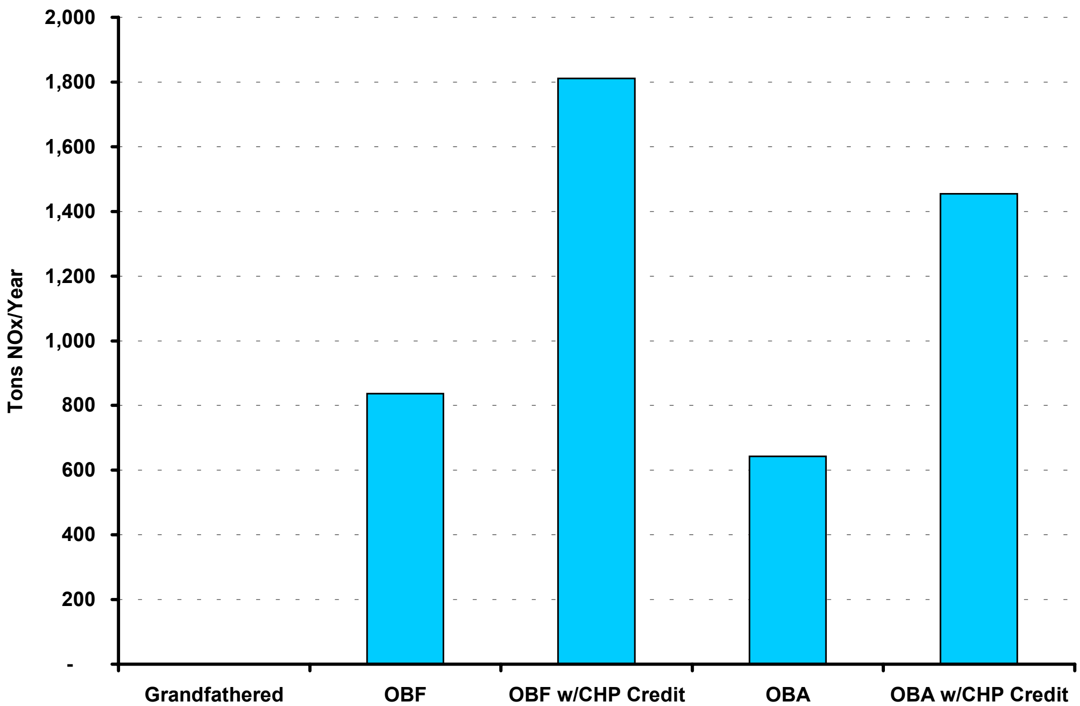
While it is U.S. energy and environmental policy to encourage increased use of CHP, new CHP facilities, like all other new power generators, will be disadvantaged under a grandfathering allocation system by not receiving any allowances. A highly efficient technology such as CHP should be advantaged in an emission trading program. However, proper recognition of the benefits of CHP depends on recognition of both the thermal and electric output and on appropriate allocation systems that recognize the system output.

There is a further difference for CHP under cap and trade programs that only affect power generators: Industrial facilities considering an investment in CHP have a clear choice. They can invest in conventional separate thermal and electric equipment in which they have only a boiler on their site and purchase electricity from the grid. While this is less efficient, it exempts them from a cap and trade program on electric generators. If they choose a CHP approach, they will be subject to the requirements of the cap and trade program. If the cap and trade program is negative for new sources, then potential CHP uses will get the clear message not to invest in CHP.

In order to properly credit the efficiency of a CHP system under an output-based allocation program, the program must recognize both the thermal and electric output of the CHP system. In a cap and trade program that includes both electric generators and large non-electric generating boilers, this can be done by allocating allowances to the CHP unit for its electric output from the electric generator pool of allowances and for its thermal output from the non-electric generator pool of allowances. In a cap and trade program that addresses only electric generators, the thermal output can be converted to MWh equivalent and added to the unit's output for the purpose of calculating allocations. (EPA 2000).

Figure 5-4 illustrates the effect of crediting the thermal output in allocating NO_x allowances to a new CHP facility. The example facility is a simple-cycle combustion turbine with heat recovery. This facility generates 1.7 units of thermal energy for each unit of electricity (power-to-heat ratio=0.6). In this example, the trading program is assumed to apply only to electric generators and not industrial steam-only boilers.

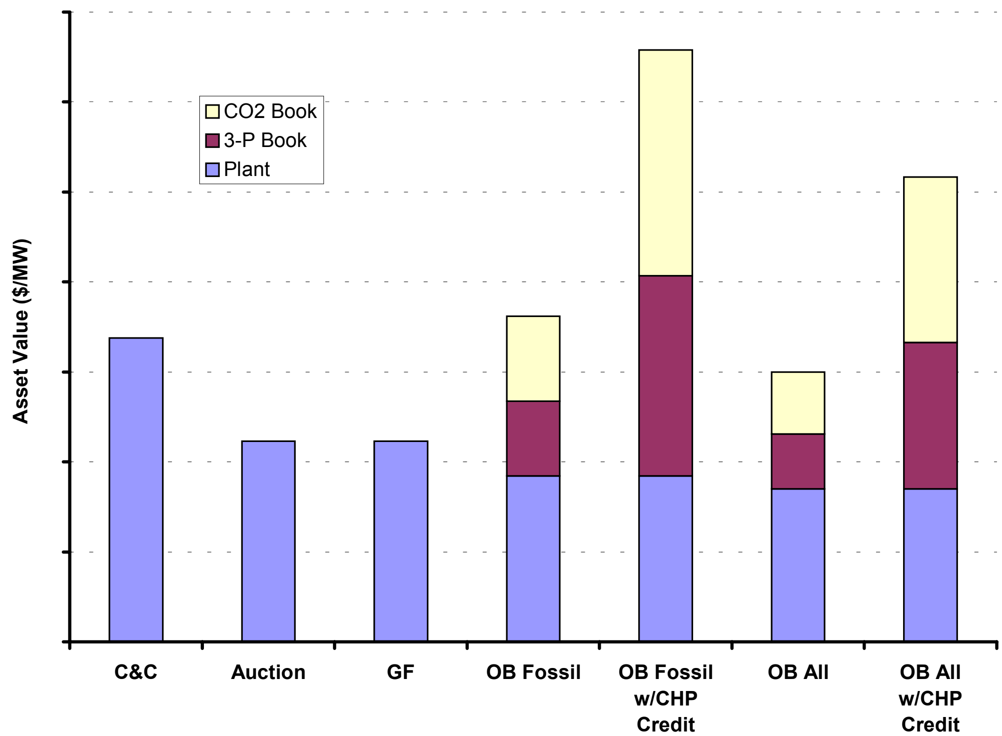
Figure 5-4
Application of CHP Credit in Output-Based Allocation



As in the earlier examples, this new facility has been built to meet more stringent emission limits than the older plants so it does not have to apply additional controls to meet the command and control requirements. Under an auction or grandfathering the facility receives no allocation and must purchase all of the allowances required to cover its emissions. Under standard output-based allocation, the facility receives allowances based on its electric output only. In the case of NO_x emissions, this allows the facility to sell some allowances after retiring allowances for compliance.

If the allocation process recognized CHP, the allocation would be based on the sum of the electric and thermal output. For this facility that would be 2.7 times the electric output only (1 unit electricity+1.7 units thermal=2.7). The allocation in this case is substantially higher, providing a greater surplus of allowances to sell and improving the profitability of the facility. This provides a greater incentive to develop this highly efficient technology. This value is also shown in Figure 5-5, which shows the asset value of the CHP facility under the different allocation approaches including with recognition of the CHP thermal output. Again, it is clear that recognition of the thermal output increases the asset value and promotes the application of CHP while grandfathering reduces the asset value and the attractiveness of developing the facility.

Figure 5-5
Effect of CHP Allocation on CHP Plant Asset Value



CHP is a very valuable technology for meeting national energy and environmental goals, however cap and trade programs must be carefully designed to fully promote CHP. These examples show that output-based allocation can be used to promote the application of CHP within a cap and trade program.

Appendix A
Analysis of Allocation Effects on Existing Generators

Output-based allocation of allowances is increasingly being accepted as the most appropriate method of allocation for emission cap and trade programs. Output-based allocation recognizes and encourages higher efficiency, rather then rewarding inefficiency as input-based allocation does. Energy efficiency is increasingly recognized as a critical component of our energy and environmental policies. Efficiency improvement is a key aspect of a long-term energy security policy. Energy efficiency is the only pollution control measure that reduces all pollutants and reduces operating costs. In any CO_2 mitigation program (including voluntary programs), encouraging increased efficiency is even more important.

On factor that has slowed the acceptance of output-based allocation is the belief by large coal-based utilities that their allocations would be significantly reduced under output-based programs compared to input-based allocation programs, causing them a significant economic disadvantage. A recent analysis of U.S. power companies based on government data for 1999 and 2000 shows that this concern is unfounded and that *many of the coal-based generating companies actually receive more allowances on an output basis than they do on an input basis*.

Methodology

In an allocation program of this kind, each plant receives allowances in proportion to its share either of heat input or electricity generated. In this case, we are evaluating a national cap and trade program, so the allocation is proportional to each plant's share of national heat input or generation. Electricity from nuclear and hydroelectric plants was excluded on the assumption that they would not receive allowances. The analysis was based on the heat input and electric generation data from:

- EIA Form 767
- EPA Title IV CEM data
- EIA Form 906

The set of plants in the EPA database was taken as the starting point for the analysis because it was believed to be a good surrogate for the set of plants that would be affected by a future multipollutant program. The analysis then used generation and heat input data from whichever data source was available for a given plant, roughly in the priority order listed above.

Results

Each plant's allocation is equal to its share of heat input or generation depending on whether an input or output-based system is used. This share was calculated for each company based on the data described above. Table A-1 summarizes the results for the largest companies that do better under an output-based system. It shows each company's share of total electric generation (as an index of size) and the ratio of its allocation under output vs input. A ratio greater than 1 shows the percentage increase in allowances that the company would receive under output vs input.

Most of the largest electric generators fall into this category including: Southern Company, AEP, TVA, Reliant, Duke, Allegheny, Cinergy, First Energy, etc.

Table A-2 shows the results for the largest companies that do better under an input-based system. A ratio less than 1 shows the percentage decrease in allowances the company would receive under output vs input. These companies are generally smaller, as indicated by the share of total generation.

Comments

Although the outcome of the analysis may be surprising to some, there is a relatively simple explanation. The determinant of allocation for a plant between an input and output-based approach is simply the efficiency or heat rate. If a plant or company is more efficient than the average on a generation-weighted basis then it will do better on the output system. If it is less efficient, it will do better on the input system.

Almost all of the combustion-based generation today is from conventional steam turbine power plants. For these plants, the choice of fuel does not make a huge difference in efficiency. The average heat rate based on the data is around 10,300 Btu/kWh. Many large, base-loaded coal plants are more efficient than this and constitute a large share of generation. Owners of these coal plants will do well under an output-based system. The companies that do better under output-based allocation are, overall, more efficient. This is most often because they have larger, base-loaded, more efficient power plants.

There is not a strong correlation between the companies that do well under output and those that use gas vs coal. Many existing gas plants run at intermediate load and are less efficient than the base-loaded coal plants. While much has been written about new gas-fired generation, not that much base-load combined cycle gas generation has gone on line as yet and many of the plants that are on line are not generating a lot of power yet. Also, much of the new capacity installed in recent years is simple cycle peaking capacity that is not much more efficient than conventional power plants and doesn't generate enough power to affect the average very much.

The bottom line is that the large, base-loaded coal plants operated by these power companies are relatively efficient and generate a lot of power, which puts them in good condition for an output-based allocation. In addition, many of these companies are also building or purchasing new, high efficiency plants that contribute favorably to their allocations. Doing better under an output-based allocation is less related to fuel choice than it is to plant size, utilization and age.

Caveats

Although this analysis is believed to be an accurate indication of the outcome of input vs output-based allocation, there are a number of caveats that must be stated:

- The data are not perfectly accurate. In particular for non-utility plants and for the electric generation data, the data are based on different data sources and may involve some estimations. Nevertheless, they are generally accurate and are typical of what the EPA would use for an actual allocation, particularly in the early years of a trading program.

- Data from some plants are missing. They are typically the smaller or less utilized plants and therefore have less impact on the results. Due to restructuring and divestiture, the analysis may have missed or misallocated ownership of plants in some cases. Again, these errors are unlikely to sufficient significantly change the outcome.
- Only two years were used for the analysis. Generation at individual plants can change significantly from one year to another. This variation is less evident over a company as a whole. A more complete analysis, like an actual allocation program, should address several years of data. Nevertheless, this initial data point is believed to be indicative of the outcome of a more complete analysis.

Despite these cautions, the analysis shows that output-based analysis is not necessarily an economic threat to efficient coal-based companies and could actually improve their position in a trading program.

Table A-1
Largest Companies That Do Better Under Output-Based Allocation

Plant Name	1999		2000	
	Percent of Total Generation	Output vs Input	Percent of Total Generation	Output vs Input
The Southern Company	8.6%	3.1%	8.5%	3.2%
American Electric Power Co	8.0%	2.5%	7.7%	2.2%
Tennessee Valley Authority	4.1%	1.1%	4.2%	1.7%
Reliant Energy, Inc	4.0%	1.2%	4.1%	1.5%
Cinergy Corp	2.8%	0.7%	2.8%	1.7%
Progress Energy	2.7%	16.5%	1.8%	4.0%
Duke Energy Corporation	2.3%	7.9%	2.4%	9.0%
Allegheny Energy, Inc	2.0%	3.2%	2.0%	4.0%
DTE Energy Company	2.0%	3.1%	1.8%	0.3%
FirstEnergy Corporation	1.8%	1.2%	1.7%	4.2%
FPL Group, Inc	1.7%	4.9%	1.7%	5.6%
PPL Corp	1.6%	0.6%	1.6%	2.6%
Salt River Proj Ag I & P Dist	1.1%	1.9%	1.1%	1.4%
AES Corp	0.9%	2.9%	1.2%	2.3%
CMS Energy Corporation	0.9%	2.6%	0.8%	0.8%
DPL Inc	0.9%	3.8%	0.9%	5.2%
Los Angeles City of	0.8%	5.3%	0.9%	6.6%
South Carolina Pub Serv	0.8%	5.3%	0.8%	4.9%
PG&E Corporation	0.7%	4.6%	0.6%	4.8%
Associated Electric Coop	0.7%	1.1%	0.7%	3.2%
Constellation Energy	0.7%	0.3%	0.6%	1.4%
Lower Colorado River	0.7%	1.2%	0.7%	0.9%
San Antonio Public Service	0.7%	-0.9%	0.6%	-0.4%
Cardinal Operating Co	0.4%	2.6%	0.5%	4.8%
Seminole Electric Coop Inc	0.4%	10.4%	0.4%	8.7%
Indiana-Kentucky Electric	0.4%	-0.3%	0.4%	1.5%
Hoosier Energy R E C Inc	0.4%	-0.4%	0.4%	-0.7%
Ohio Valley Electric Corp	0.4%	2.7%	0.3%	1.8%
Orlando Utilities Comm	0.3%	3.7%	0.3%	4.3%
UniSource Energy	0.3%	1.9%	0.3%	1.9%
CH Energy Group, Inc	0.3%	-0.2%	0.2%	1.8%

Table A-2
Largest Companies That Do Better Under Input-Based Allocation

Plant Name	1999		2000	
	Percent of Total Generation	Output vs Input	Percent of Total Generation	Output vs Input
Xcel Energy Inc	4.3%	-2.2%	4.3%	-0.7%
TXU Corporation	3.4%	-5.4%	3.3%	-4.1%
Entergy Corporation	3.2%	-4.5%	3.1%	-2.5%
Edison International	2.2%	-3.6%	2.3%	-2.3%
ScottishPower PLC	2.1%	-4.0%	2.1%	-3.2%
Ameren Corp	1.8%	-2.9%	1.9%	-1.8%
Dominion Resources, Inc	1.8%	-0.2%	1.9%	-1.1%
LG&E Energy Corporation	1.5%	-1.8%	1.4%	-2.6%
Wisconsin Energy Corp	1.1%	1.2%	1.1%	-4.4%
Pinnacle West Capital	1.0%	-1.7%	1.0%	-1.7%
OGE Energy Corporation	1.0%	-1.6%	1.0%	-4.8%
Alliant Energy Corp	0.9%	-6.5%	0.8%	-5.9%
Western Resources, Inc	0.8%	-7.2%	0.9%	-7.6%
Dynegy Inc	0.8%	-1.9%	0.8%	-2.5%
NiSource, Inc	0.8%	-6.5%	0.7%	-6.6%
SCANA Corporation	0.7%	5.0%	0.7%	-4.0%
Ipalco Enterprises, Inc	0.7%	-3.5%	0.7%	-2.5%
Kansas City Power & Light	0.7%	-5.1%	0.7%	-2.8%
KeySpan Corp	0.7%	-3.5%	0.7%	-4.0%
TECO Energy, Inc	0.7%	-4.6%	0.7%	-1.3%
Orion Power Holdings Inc	0.7%	-2.8%	0.5%	-4.8%
San Antonio Public Service	0.7%	-0.9%	0.6%	-0.4%
Public Service Co of NM	0.5%	-2.5%	0.5%	-3.7%
Tri-State G & T Assn Inc	0.5%	-2.6%	0.5%	-1.5%
Vectren Corporation	0.5%	-3.0%	0.5%	-2.1%
Basin Electric Power Coop	0.5%	-5.3%	0.5%	-4.9%
CLECO Corporation	0.5%	-3.2%	0.5%	-8.5%
Great River Energy	0.4%	-4.7%	0.4%	-5.7%
Nebraska Public Power	0.4%	-3.6%	0.4%	-4.3%
East Kentucky Power Coop	0.4%	-0.6%	0.4%	-1.6%
Transalta Co	0.4%	-2.0%	0.4%	-1.1%
Conectiv	0.4%	-1.2%	0.3%	-13.8%
Electric Energy Inc	0.4%	-1.3%	0.3%	0.1%
Public Service Enterprise	0.3%	-1.8%	0.4%	-0.3%
WPS Resources	0.3%	-10.1%	0.3%	-9.9%
Omaha Public Power	0.3%	-4.6%	0.3%	-3.2%
Otter Tail Power Co	0.3%	-4.8%	0.3%	-5.4%
ALLETE	0.3%	-5.9%	0.3%	-2.8%
Grand River Dam Authority	0.3%	-3.0%	0.3%	-3.9%
Northeast Utilities	0.3%	-3.8%	0.2%	-5.3%
Minnkota Power Coop Inc	0.2%	-10.9%	0.2%	-10.9%

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