Technical Support Document (TSD) for the Transport Rule

Docket ID No. EPA-HQ-OAR-2009-0491

Allowance Allocation Final Rule TSD

U.S Environmental Protection Agency

Office of Air and Radiation

June 2011

Allowance Allocation to Existing and New Units under the Transport Rule Federal Implementation Plan (FIP)

This Technical Support Document (TSD) provides information that supports EPA's determination of unit-level allocations for existing and new units under the final Transport Rule. Section VI.D of the preamble discusses state budgets, and section VII.D discusses how the budgets are apportioned (i.e., allocated) to existing and new units under FIP program structure. This TSD provides additional information in support of unit level allocations and elaborates on the data and methodology used to arrive at the final allocations. The TSD is organized as follows:

1) Overview
2) New Unit Set-Asides and Allocations
3) Allocation Methodology for Existing Units
    a. List of Existing Units
    b. Data and Calculations
4) Appendix A: Effects of Allowance Allocations on the Competition between Power Plants

EPA anticipates that some states will submit State Implementation Plans (SIPs) with revised unit-level allocations to existing units that will replace those defined in the FIP. Section X of the final Transport Rule preamble explains when and how states may replace the FIP allocations, which can occur by vintage year 2013 or later through specific SIP procedures.

1. Overview

As discussed in preamble section VI, each state's budget is comprised of the emissions that EPA estimates remain after the state has made the reductions required to eliminate its significant contribution to nonattainment and interference with maintenance of the relevant National Ambient Air Quality Standards (NAAQS) in downwind states in an average year. EPA finalized the Transport Rule with four limited interstate trading programs. Emission allowances are used in the implementation of these programs. Specifically, EPA creates one allowance for each ton of emissions allowed in each year under each state's budget. Each allowance has a "vintage" year, which is the year for which the allowance is issued. Covered sources are required to submit such an allowance for each ton of the relevant pollutant emitted on an annual basis. To implement the programs, allowances are initially allocated among covered sources within a state.

As discussed in the preamble, under the FIP, EPA allocates allowances to sources in the state equal to that state's total budget. The methodology used to determine states budgets is independent of and not affected by the methodology used to determine initial allowance allocations. In other words, initial allowance allocations in no way impact the state budgets. The state budgets are determined independently through the multi-factor analysis outlined in section VI of the Transport Rule preamble. Regardless of the methodology used by EPA or a state to allocate allowances to sources within the state, all emissions in each covered state that significantly contribute to nonattainment or interfere with maintenance in another state will be prohibited. In sum, the allocation methodology has no impact on the rule's ability to satisfy the statutory mandate of CAA section 110(a)(2)(D)(i)(I) to eliminate significant contribution and interference with maintenance in downwind states.

As discussed in section VII.D of the preamble, under the FIPs, EPA will distribute the entire budget to sources located in the state subject to the FIP. However, this budget would first be divided into three different subgroups listed below (note, amounts vary by state):

1) New source set-aside
2) Indian Country set-aside
3) Existing unit budget

An initial amount of the state budget (92% to 98%, depending on the state) would be distributed to existing sources (i.e. sources online before January 1, 2010) in advance of the vintage year for which they are issued. The remaining amount would be held back for new units in a new source set-aside account. If any of the new source set-aside allowances remained unclaimed two weeks prior to the allowance transfer deadline, then they would be allocated to existing units on the same pro-rata heat input basis as the initial existing unit budget so they will be available to existing units for compliance.

The final Transport Rule identifies potentially covered existing Transport Rule units and allocations for each of those units under the FIP. This TSD details how the list of potentially existing units was determined, how allocations were calculated, and how the quantity of allowance set-asides for new units and Indian Country units were determined. Following these descriptions, an appendix showing each affected EGU's allocation under the final Transport Rule FIP along with the underlying data and calculations used to derive the allocation comprises most of the document.

2) New Unit Set Asides and Allocations

As explained in section VII.D, the final Transport Rule uses January 1, 2010 as the cut-off date to distinguish "new units" from "existing units" for purposes of allowance allocation. Allocations to existing units are based on historic heat input over a five-year baseline as well as historic emissions data. To allocate on this basis, EPA needs at least one full year of heat input and emissions data from an "existing unit" to determine its allocation using this methodology. If a unit did not come online prior to January 1, 2010, it cannot have provided a full year of data at the time of the Transport Rule's finalization. For this reason, EPA could not use a date later than Jan. 1, 2010 for the cut-off date. Units that came online after January 1, 2010 are considered "new units" for purposes of allocation under the final Transport Rule FIPs and will receive their allocations from the new source set-aside. In the proposal, only units that came online after January 1, 2012 were considered "new units". Therefore, "planned" units coming online on or after January 1, 2010 represent a unique subset of units that were considered "existing units" at proposal, but "new units" in the final Transport Rule. EPA recognizes that the final rule's designation of these units as "new units" would, all else held equal, increase the demand for allowances in the new unit set-asides. As a result, EPA's methodology for establishing each state's new unit set aside in the final Transport Rule accounts specifically for the inclusion of units that commenced commercial operation on or after January 1, 2010 as described below.

The new unit set-aside for SO_2, annual NO_X, and ozone-season NO_X for each state is a percentage of the state's total budget. This percentage is the sum of a "base" percentage that all states receive for "potential" new units and a state-specific percentage reflecting emissions from "planned" units. For purposes of this document, the "potential" units on which the new source set-aside base percentage relies are those units that are projected new builds in the IPM modeling of the Transport Rule. In other words, they are units that do not show up in the modeling input, but do show up in the modeling output as surrogate facilities representing potential new EGUs that come online in future years in response to demand increases or other market drivers. "Planned" units, on which the state-specific percentage of the new source set-aside is based, are those units that are already identified in the modeling input (NEEDS) because they are specific plants that already built or are under construction, but that commence commercial operation on or after January 1, 2010. Because the location of these "planned" units is already known and identified in the modeling input, the portion of the new unit set-aside corresponding to these units is state-specific.

EPA determined the base percentage of the new unit set-aside by assessing the share of each state's budget that is emitted in 2020 by new capacity build projected by the model (i.e., "potential units"). EPA identified each state's projected net new emissions in 2020 as a percent of the state's total budget. It then selected the maximum percentage among all states for all pollutants at the state level as the "base" percentage for each state's new unit set aside.[1] By selecting the maximum percentage, EPA chose a conservative envelope that would provide a pool of new source set-aside allowances large enough to cover emissions from "potential" new units in any state. EPA chose this basis in order to preserve a reasonable amount of allowances for new unit allocations in every state, as new units may not be sited in the same locations that EPA's modeling assumes for analytical purposes. The maximum percentages of the total emissions represented by the projected net new emissions in 2020 at the state level are:

SO_2:	0.00 %
Annual NO_X:	1.80%
Ozone-season NO_X:	1.76%

In the final Transport Rule, EPA relied on this analysis to establish a "base" percentage for each pollutant as 2 percent of each state's total emissions budget for each pollutant. This base percentage is smaller than the 3 percent share EPA proposed to use in the proposed Transport Rule and is the result of EPA's updated power sector modeling, which projects a lower share of future emissions from "potential" new capacity build that the model projects.

The "state-specific" percentage represents the share of each state budget that EPA projects to be emitted from "planned" units in 2020. As discussed previously, determining the state-specific percentage is necessary given the new unit definition used in the final rule. EPA is determining a state-specific percentage for projected emissions from "planned" units because unlike the location of new capacity that the model projects to be built, the location of planned units is already known.

The base and state-specific percentages were added for each state and each pollutant to determine that state's size of the new-unit set asides, which are shown below in Tables 1 through 3 below.[2]

---

[1] Net new emissions for each pollutant are equal to the projected 2020 emissions from newly built units by IPM (which does not include planned units) less the sum of allocations to units projected to be retire more than 4 years in advance of 2020. As explained in section VII.D of the preamble for the final Transport Rule, after 4 years of non operation, existing units have their allocation redirected to the new unit set asides, thereby offsetting the need for additional allowances to be withheld from existing unit allocations for purposes of the new unit set asides.

[2] The ozone-season NO_X values in these tables reflect EGUs in the 20 states covered by this rule for purposes of the ozone NAAQS and the six states that would be covered for the ozone NAAQS if EPA finalizes its supplemental proposal.

Table 1 - State New Unit Set-Aside Accounts (As % of Total State Budget)			
	Annual SO_2	**Annual NO_X**	**Ozone-Season NO_X**
Alabama	2%	2%	2%
Arkansas	---	---	2%
Florida	---	---	2%
Georgia	2%	2%	2%
Illinois	5%	8%	8%
Indiana	3%	3%	3%
Iowa	2%	2%	2%
Kansas	2%	2%	2%
Kentucky	6%	4%	4%
Louisiana	---	---	3%
Maryland	2%	2%	2%
Michigan	2%	2%	2%
Minnesota	2%	2%	---
Mississippi	---	---	2%
Missouri	2%	3%	3%
Nebraska	4%	7%	---
New Jersey	2%	2%	2%
New York	2%	3%	3%
North Carolina	8%	6%	6%

Ohio	2%	2%	2%
Oklahoma	---	---	2%
Pennsylvania	2%	2%	2%
South Carolina	2%	2%	2%
Tennessee	2%	2%	2%
Texas	5%	3%	3%
Virginia	4%	5%	5%
West Virginia	7%	5%	5%
Wisconsin	5%	6%	6%

Table 2: State New Unit Set-Aside Accounts (tons).*

	SO_2 in 2012-2013	SO_2 in 2014 and Later	NO_X Annual in 2012-2013	NO_X Annual in 2014 and Later	Ozone-Season NO_X in 2012-2013	Ozone-Season NO_X in 2014
Alabama	4,321	4,265	1,454	1,439	635	630
Arkansas	---	---	---	---	301	301
Florida	---	---	---	---	557	557
Georgia	3,171	1,905	1,240	811	559	366
Illinois	11,744	6,206	3,830	3,830	1,697	1,697
Indiana	8,563	4,833	3,292	3,253	1,406	1,385
Iowa	2,142	1,503	766	749	331	324
Kansas	831	831	615	512	271	220
Kentucky	13,960	6,377	3,403	3,090	1,447	1,307
Louisiana	---	---	---	---	403	403
Maryland	602	564	333	331	144	144
Michigan	5,486	2,880	1,204	1,156	515	495
Minnesota	840	840	592	592	---	---
Mississippi	---	---	---	---	203	203
Missouri	4,149	3,319	1,571	1,462	683	632
Nebraska	2,602	2,602	1,850	1,850	---	---
New Jersey	111	111	145	145	68	68
New York	547	372	527	527	250	250

North Carolina	10,951	4,610	3,036	2,494	1,330	1,107
Ohio	6,205	2,742	1,854	1,750	801	756
Oklahoma	---	---	---	---	437	437
Pennsylvania	5,573	2,240	2,400	2,384	1,044	1,038
South Carolina	1,773	1,773	649	649	278	278
Tennessee	2,963	1,177	714	387	298	160
Texas	12,198	12,198	4,008	4,008	1,891	1,891
Virginia	2,833	1,402	1,662	1,662	723	723
West Virginia	10,232	5,297	2,974	2,729	1,264	1,165
Wisconsin	3,974	2,006	1,898	1,823	822	793

*Amounts shown reflect total set aside portion of budget (including set aside for Indian Country new units). Values are approximate, may vary slightly due to rounding. See Transport Rule rule text for final set-aside values.

For each control period, any allowances remaining in a state's new unit set-aside (after allocations are made to new units that requested allowances) are distributed to the existing units in that state in proportion to the existing units' original allocations. This ensures that total allocations to units in the state are equal to the state budget in that year.

Each Indian country set-aside equals a proportion of the "base" new unit set-aside included in this final Transport Rule (the base percentage, as described above, is calculated as 2 percent of the state budget). EPA is reserving allowances for the Indian country set-aside from each state's "base" percentage of the new unit set-aside. EPA is not reserving these allowances from the state-specific percentage of each state's new unit set-aside because that percentage is specifically calculated on the basis of projected emissions from "planned" units, none of which are located in Indian country. EPA is creating Indian country set-asides in each state as a share of that state's base percentage portion of the new unit set-aside, i.e., as a share of the 2 percent portion of the total budget in that state. EPA is determining the size of the Indian country set-aside (within that 2 percent portion of the state budget) on the basis of the percentage of Indian country relative to the entire state. EPA calculates the maximum percentage of Indian country in any state within the Transport Rule region to equal 5 percent, and is using that level as a basis for establishing Indian country set-asides for all states whose geographic boundaries encompass Indian country. Therefore, the Indian country set-aside is 5 percent of the base percentage new unit set-aside, which is equivalent to 0.1 percent of the total state budget (i.e., 5 percent of 2 percent is 0.1 percent). EPA assessed the share of Indian country within each state using the American Indian Reservations/Federally Recognized Tribal Entities dataset, which contains data for the 562 federally recognized Tribal entities in the contiguous U.S. and Alaska. EPA analyzed the share of square miles of Indian country within the total square miles of a state whose geographic boundaries encompass that Indian country. As explained above, EPA then took the highest percentage as the number to be applied across all states with Indian country to determine the Indian country new unit set-aside. The Indian country new unit set-asides in the following Transport Rule states with Indian Country are shown in Table 4.

Table 3: New Unit Set-Aside Allowances for Indian Country (tons)

	For SO2 in 2012-2013, Indian Country	For SO2 in 2014, Indian Country	For NOX Annual in 2012-2013, Indian Country	For NOX Annual in 2014, Indian Country	For Ozone-Season NOX in 2012-2013, Indian Country	For Ozone-Season NOX in 2014, Indian Country
Florida	---	---	---	---	28	28
Iowa	107	75	38	37	17	16
Kansas	42	42	31	26	14	11
Louisiana	---	---	---	---	13	13
Michigan	229	144	60	58	26	25
Minnesota	42	42	30	30	---	---
Mississippi	---	---	---	---	10	10
Nebraska	65	65	26	26	---	---
New York	27	19	18	18	8	8
North Carolina	137	58	51	42	22	18
South Carolina	89	89	32	32	14	14
Texas	244	244	134	134	63	63
Wisconsin	79	40	32	30	14	13

*Values are approximate, may vary slightly due to rounding. See Transport Rule rule text for final set-aside values

New units are allocated allowances from the set aside accounts described above. The final rule provides that a unit's new unit set-aside allocation initially equals that unit's emissions for the control period (annual or ozone-season) in the preceding year. EPA determines whether the total amount of initial allowance allocations for all units in a state for a control period exceeds the amount in the state's new unit set-aside for the control period. If the amount in the new unit set-aside is exceeded, EPA allocates each unit a proportionate share of the new unit set-aside based on the unit's initial allocation amount. Any unallocated allowances in the new unit set-aside are allocated to existing units in proportion to their share of the current existing-unit allocations. Unused allowances in the Indian country set aside are first transferred to the respective state's new unit set-aside. If allowances remain unused in the state's new unit set aside, they are then proportionally distributed, as previously described, to existing units in that state.

3) Allocation Methodology for Existing Units

The allocation methodology bases a unit's allocation off heat input but limits any unit's allocation to its historic maximum emissions. Implementation of this methodology involves identifying potentially covered units and determining appropriate data baselines for each unit. EPA first identified the list of potential TR covered units. Next, it compiled reported data on each unit and calculated its share of heat input. Both stages are described below.

a) List of Potential Existing Transport Rule Units

The list of units to which final allocations are adopted in the final rule is based on final applicability criteria discussed in section VII.B of the preamble and Sections 97.404, 97.504, 97.604, and

97.704 of the final Transport Rule regulations. Existing units are units that are covered under these criteria and that commenced commercial operation prior to January 1, 2010. This cutoff date is used in the definition of existing unit because it assures that at least one full year of historic data is available to determine each existing unit's allocation. The baseline years used in the January 7, 2011 NODA (76 FR 1109) ended in 2009 for similar reasons – at the time, it was the most recent year for which EPA had complete and quality assured data. Since publishing the NODA, the 2010 data has been reported and verified. Because an additional year of data is available, EPA updated it cut-off date for existing units to January 1, 2010, its heat input baseline from 2005-2009 to 2006-2010, and its historic emission baseline to 2003-2010. These final allocation tables available in the docket and on EPA's website contain a list of units that EPA believes, based on best available data, meet the covered and existing unit criteria. As described above, the percent of the state budgets allocated to existing units varies between 92% and 98% for each state depending on the number of planned units in each state.

To identify the potential existing Transport Rule units, EPA relied largely on data reported to EPA. To develop the list of potential existing Transport Rule units, EPA first included any fossil-fuel-fired unit serving a generator greater than 25 MWe producing electricity for sale that is in a Transport Rule state and on line prior to January 1, 2010 and that reported emissions data in 2010 under at least one of the following ongoing EPA trading programs: the CAIR NO_X or CAIR SO_2 annual trading program or the Acid Rain Program. EPA did not include units that were flagged as opt-in units. Data reported to EPA under CAIR and the Acid Rain Program meet the requirements of Part 75 and have been certified as to their accuracy and completeness by the source's designated representative. About 98% of the potential existing covered units listed in the final rule allocation tables were identified in this manner.

Next, EPA supplemented the list of units by using data from the Integrated Planning Model v.4.10 (IPM) to identify potential existing units under the Transport Rule that were not reporting data to EPA under the CAIR NO_X or SO_2 annual or Acid Rain trading program. Specifically, IPM's National Electric Energy Data System (NEEDS) was used to identify units that were potentially fossil-fuel-fired units serving generators greater than 25 MWe producing electricity for sale that are in a Transport Rule state and were not reporting under one of these ongoing EPA trading programs. To identify whether the NEEDs unit potentially met the fossil fuel criteria of a covered unit, EPA identified those units with a capacity greater than 25 MW and a plant type listing of coal steam, combined cycle, combustion turbine, fossil waste, IGCC, landfill gas, Municipal Solid Waste, O/G Steam, tires or biomass. Approximately 2% of the potential existing covered units listed in the final rule allocation tables were identified in this manner.

This subset of units identified through NEEDS was then screened to remove units that were not potential existing Transport Rule units and thus not eligible to obtain allocations. In particular, if the unit was retired or in cold storage in 2010 or is a steam turbine at a combined cycle (CC) plant that was listed as a separate unit in NEEDS but reported to EPA as one CC unit, then it was not included as a unit in the list of potential existing Transport Rule units. The remaining units in this subset of units were added to the list. For instance, there were units in Nebraska and Kansas that were identified through NEEDS as being potential existing Transport Rule units that were not currently reporting under the CAIR NO_X or SO_2 annual or Acid Rain trading program because the units were not Acid Rain Program units and were not in a CAIR state. Finally, a small number of units were added to or removed from the list based on comment and supporting data previously submitted to EPA during the comment period on the proposed Transport Rule and/or the January 7, 2011 NODA by the unit owner or operator.

Units identified using the EPA and NEEDS databases were included in the list of potential existing Transport Rule units if they were in one of the following states covered by the Transport Rule: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

EPA notes that inclusion of a unit in, or exclusion of a unit from, the list of potential existing Transport Rule units presented in the final Transport Rule Allocation tables reflects only a preliminary assessment of the applicability of the final Transport Rule and in no way suggests that EPA has made a determination about the applicability of the final Transport Rule to any unit. As discussed above, the list of units developed for this NODA enables EPA to calculate allowance allocations for potential existing units based on the final allocation methodology. While allocations calculated for the final Transport Rule are based on the best available data provided to EPA by the time of the calculation, the applicability of the final Transport Rule to an individual unit is determined based on all relevant data, whether or not EPA has such data at the time that allocations are calculated. In fact, because any list of units developed for purposes of allowance allocation may not be entirely consistent with applicability determinations made in the future, the final Transport Rule establishes procedures to be applied when the Administrator determines that a unit allocated allowances turns out not to actually be a Transport Rule unit. For example, under these procedures, if such a determination would be made after EPA's recordation of the allowance allocation but before EPA's deduction of allowances for compliance with the requirement to hold allowances covering emissions, the Administrator would deduct the recorded allowances and transfer them to a new unit set-aside for the appropriate state.

b) Data and Calculations

For the 98% of units identified through the process in section 3.a. above because they were reporting under the ARP and/or CAIR programs, EPA used reported heat-input and emissions data from the EPA database for the years 2003 through 2010. For units included in the list of potential existing Transport Rule units that were not reporting under one of these ongoing EPA trading programs, EPA used historic heat input and emissions data from Energy Information Administration (EIA) forms 767, 860, 906, 920, and 923. These data are publicly available at http://www.eia.doe.gov/cneaf/electricity/page/data.html. The heat input based allocation method finalized and described below is used to allocate the existing unit portion of the state's budget (i.e., the state budget less the state's new unit set-aside and, if applicable, the Indian Country new unit set-aside for the state).

The final Transport Rule uses a heat input allocation approach subject to a maximum allocation limit for any individual unit based on its maximum historic emissions. As described in the Transport rule preamble section VII.D, allocations under the Transport Rule FIP are determined by establishing a baseline historic heat input value for each potential existing Transport Rule unit and setting the unit's initial share of available allowances under each Transport Rule trading program equal to the unit's percentage share of the total baseline historic heat input for all potential existing Transport Rule units in the state. This approach is applied to each state separately, using the portion of that state's budget available for potential existing Transport Rule units in that state. In instances where the heat input based allocation exceeds the unit's historic maximum emissions over the baseline period, this historic maximum emissions is used as an upper bound on the allocation and the source's allocation is set equal to this emission level.

Allocations under this approach for each existing unit are determined by applying the following steps.

1. For each unit in the list of potential existing Transport Rule units, annual heat input values for the baseline period of 2006 through 2010 are identified using data reported to EPA or, where EPA data is unavailable, EIA. For a baseline year for which a unit has no data on heat input (e.g., for a baseline year before the year when a unit started operating), the units is assigned a zero value.

(Step 2 explains how such zero values are treated in the calculations.) The allocation method uses a five-year baseline in order to improve representation of a unit's normal operating conditions over time.

2. For each unit, the three highest, non-zero annual heat input values within the 5 year baseline are selected and averaged. Selecting the three highest, non-zero annual heat input values within the five-year baseline reduces the likelihood that any particular single year's operations (which might be negatively affected by outages or other unusual events) determine a unit's allocation. If a unit does not have three non-zero heat input values during the 5 year baseline period, EPA averages only those years for which a unit does have non-zero heat input values. For example, if a unit has only reported data for 2008 and 2009 among the baseline years and the reported heat input values are 2 and 4 mmBtus respectively, then the unit's average heat input used to determine its pro-rata share of the state budget is (2+4)/2 = 3.
3. Each unit is assigned a baseline heat input value calculated as described in step 2 above. This baseline heat input value is referred to in the data tables in the rulemaking docket, and on the website referenced previously, as the "three-year average heat input".
4. The three-year average heat inputs of all potential existing Transport Rule units in a state is summed to obtain that state's total "three-year average heat input".
5. Each unit's three-year average heat input is divided by the state's total three-year average heat input to determine that unit's share of the state's total three-year average heat input.
6. Each unit's share of the state's total three-year average heat input is multiplied by the existing-unit portion of the state budget (i.e., the state budget less the state's new unit set-aside and, if applicable, the Indian Country new unit set-aside for the state) to determine that unit's initial allocation.
7. An eight-year (2003-2010) historic emissions baseline is established for SO_2, NO_X, and ozone-season NO_X based on data reported to EPA or, where EPA data is unavailable, EIA data. This eight-year historic emissions baseline is used in order to capture the unit-level emission before and after the promulgation of the Clean Air Interstate Rule (CAIR) and the NO_X Budget Program (NBP).
8. For each unit, the maximum annual historic SO_2 and NO_X emission amount is identified within the eight-year baseline. Similarly, the maximum ozoneseason NO_X emission amount from the eight-year baseline for each unit is identified. These values are referred to as the "maximum historic baseline emissions" for each unit.
9. If a unit has an initial historic heat-input based allocation (as determined in step 6) that exceeds its maximum historic baseline emissions (as determined in step 8), then its allocation equals the maximum historic baseline emissions for that unit.
10. The difference (if positive) under step 9 between a unit's historic heat-input-based allocation and its "maximum historic baseline emissions" would be reapportioned on the same basis as described in steps 1 through 6 to units whose historic-heat-input-based allocation does not exceed its maximum historic baseline emissions. Steps 7, 8, and 9 are repeated with each revised allocation distribution until the entire existing-unit portion of the state budget would be allocated. The resulting allocation value is rounded to the nearest whole ton using conventional rounding. The table below provides an example application of the steps 1-10 in a hypothetical state.

Table 4 - Demonstration of Allocations Using Final Allocation Methodology in a Three-Unit State With a 80 Ton State Budget			
	Step 1-6	Step 7,8,9	Step 10
	Historic Heat-input-based Initial Allocation	Maximum Historic Baseline Emissions	Final Allocation
Unit A	20	16	16
Unit B	30	50	32
Unit C	30	50	32

Where can I find this data?

The unit level allocations can be found in the separate file titled "Final Transport Rule Unit Level Allocations under the FIP" published as a PDF and an Excel file and available in the Transport Rule Docket and on EPA's website www.epa.gov/airtransport under technical information. The PDF file displays each unit and its final allocation under each of the trading programs The Excel file contains two worksheets. The first, titled "Final Allocations" is identical the PDF document. The second worksheet, titled "Underlying Data", shows all the data and calculations that are numerated above. Each of the ten steps are color coded and displayed in sequential order moving from left to right across the worksheet. The formulas to derive any calculated values are explained directly beneath the column header. The final column in the second worksheet labeled "commenter data substitution" identifies units for which some commenter-provided data corrections were incorporated for the underlying heat input and emissions data.

Rounding

EPA uses conventional rounding for its allocation purposes and applies rounding at the unit level for existing unit allocations. For example, if State A has a 500 ton budget with a 5% new source set-aside, than its existing unit allocation would be 475 tons. If there are only two covered existing units in the state with equal heat inputs and a historic maximum emissions above 500 tons, than the steps described above would result in an allocation of 237.5 tons for each unit. This unit level allocation for each of these units would round to 238 allowances, which would sum to 476 allowances. The difference between the sum of the rounded existing unit level allocations and the state budget (i.e., 500-476), would be the actual new source set-aside budget for the state. EPA notes that because of rounding, the actual number of allowances in the new source set aside will sometimes sum to a total value whose percentage of the state value is marginally greater or less than the percentage identified in the tables above. In other words, the percentage approximated for the new source set aside in the tables above may be 5% in a particular state, but the actual total new source set-aside allowances may equal 5.01% or 4.99% of the state budget. Because EPA does not issue allowances nor require compliance using fractional tons, this type of rounding is necessary.

Appendix A: Effects of Allowance Allocations on the Competition between Power Plants

Introduction

This paper addresses a question about the potential effects of the allocation system set up by the Transport Rule. The question is: if the owners of a given power plant are granted a permanently larger stream of allowances, will that advantage lead to their plant gaining a larger share of the electricity market than would otherwise have occurred? The analysis presented below shows that the answer to this question is no. Careful consideration of the incentive effects of initial allowance allocations at the outset of a trading program, as well as a review of the extensive literature on this topic, will show that all generators must factor in the price of emitting a ton (as reflected by the allowance price) under a trading program when selling power no matter the original pattern of initial allocations.

We begin with a very brief review of cap-and-trade regulations and the need for a mechanism for distributing the emission allowances that serve as the "trade goods" in the markets set up by these regulations. Then, we show why freely allocated allowances under the Transport Rule's programs do not change the economic equation of how much to generate – first in the simpler context of a deregulated competitive market, and then in the somewhat more complex case of a "cost-of-service" (COS) market.

Allocation of Allowances for "Cap-and-Trade" Regulations

"Cap-and-Trade" is a common term for flexible, market-based environmental regulations that aim to limit total emissions from an industry or region to a specified maximum (the "cap"). This approach recognizes that, if the environmental goal can be met by controlling the total level of emissions in a given region rather than emission levels at specific sources, regulated sources can realize significant cost savings by working out among themselves the most convenient and efficient way to reach the cap. Coordinating all the competing economic interests across a large set of sources, in a way that ensured that the emissions cap was not exceeded, would be virtually impossible without a decentralized market-based system for spreading around a fixed quantity of emissions. To make this market work, the total cap is divided into "allowances," each of which constitutes a permit to emit one ton of the regulated substance. Environmental protection is ensured by the limited number of allowances, and flexibility is provided by the sources' right to transfer or trade allowances to other sources as they see fit.

To set up this market for trading allowances, though, there must be an initial allocation of the allowances comprising the cap. That allocation can be made through an auction (requiring sources to compete in a bidding process for their initial allocation) or through free allocations directly awarded to sources. Free allocation procedures may determine the number of allowances received by each source in proportion to various metrics, including its capacity, its output, or its inputs. Furthermore, the metric could be something fixed (like its recorded fuel input in a particular time period), or something dynamic (like its fuel input in the previous year on an updating basis). The Transport Rule programs freely allocate allowances to existing sources in proportion to annual fuel input in a specified period not to exceed annual maximum emissions at each source during that specified period. This allocation pattern is fixed once-and-for-all (henceforth referred to as grandfathered allocation), though actual allocations can change over time (e.g., due to new unit set-asides) and still fall under the definition of "fixed" as long as they do not depend on the actions of the affected industry.

The amount of freely allocated allowances does have an impact on the financial well-being of the *owners* (i.e., shareholders) of the emission sources; however, as explained below, freely allocated allowances to sources do not have any impact on any source's marginal cost of producing electricity. For example, Williams-Derry and Drake (2008) quotes CBO testimony to show, "Giving allowances away to companies that supply fossil fuels or that use large quantities of fossil fuels in their production processes could create "windfall" profits for those firms."

Therefore, while the imposition of caps on sulfur dioxide and nitrogen oxides clearly provides a broad incentive shared across the fleet for cleaner generation, the Transport Rule's provision of free allowances to existing units (based on a fixed, or grandfathered, allocation pattern) does not affect incentives and competition among individual power plants. To understand why, we need to consider the economics of power production.

The Dispatch Problem

At any point in time, for a given price of electricity, there will be a particular demand for electric power (measured in megawatts (MWs)). Many power plants will be available at that point in time, with an aggregate capacity that is usually well above the amount demanded. Thus, a decision needs to be made as to what combination of plants, contributing how much power each, will be used to meet the demand. This decision is termed the "dispatch problem." It is well known that the most efficient way to solve this problem is to rank the plants in order of efficiency, and, choosing the most efficient one first, continue choosing the most efficient of those that remain, until the aggregate output of the chosen plants reaches the demand. Choosing the plants in this way ensures not only that the demand is met but that none of the plants that are not used is more efficient than any of the plants that are used. Thus, there is no way to add any of the unused plants into the mix without either over-producing power or displacing a more efficient plant.

For a simplified description how electricity generation and dispatch works, see, for example, Palmer et al. (2006), which explains how the Resources for the Future (RFF) operationlizes dispatch in their Haiku model. Similarly, see http://www.eia.gov/oiaf/servicerpt/ceca/appd.html, which explains the same process as it is used in the Department of Energy's NEMS modeling system. Finally, EPA's IPM base case (v4.10) documentation explains how EPA conducts dispatch modeling in its policy analysis (see IPM documentation, Section 2.3.6).

The measure of efficiency used in solving the dispatch problem is the short-run marginal cost of generation, meaning the increase in variable cost of a small increment in output, per unit of additional output, for an existing facility. Fixed costs do not factor into this equation because they are already incurred over the long run and do not vary with the amount of generation selected. For example, see Shu et al. (2008), which argues, "...dispatch calculation does not directly consider the impact of these fixed costs. Dispatch involves variable and marginal costs of the power plants." Similarly, Palmer et al. (2009), describe the logic behind dispatch modeling in Haiku as follows: "Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation, including fuel costs, variable operating and maintenance costs and the costs of operating pollution control equipment plus the opportunity costs of using emission allowances…" (page 11-12). In other words, the short-run marginal cost of generation for a particular power plant will be the cost of buying enough additional fuel to generate an additional MWh, plus any additional maintenance costs necessitated by increasing output by an additional MWh, plus any costs associated with the additional emissions that result from generating an additional MWh. The emission-related costs are particularly important in the context of a cap-and-trade program, in which additional emissions must be covered by surrendering additional allowances. Because the allowances are tradable in a market, they have an explicit monetary value: if burning the fuel needed to generate another MWh releases another 2 pounds of NOx, and the market value of NOx allowances is $2,000 per ton, or $1/pound, then generating another MWh has an emission-related cost of 2 pounds x $1/pound or $2.

Note that these emission-related costs will be the same whether the allowances were freely allocated or bought at auction, or whether the allowances were part of the initial allocation or have to be purchased from another power plant's owner. This independence of the origin of allowances from the cost of generation stems from the fact that all tradable allowances that have to be used have an *opportunity cost.* Even if an electricity generating unit (EGU) or its parent company received more allowances than it could use in a free allocation, the use of one more allowance means the firm has one fewer allowance to sell in the market. Thus, because the firm loses the opportunity of selling an unneeded allowance when it emits another ton of NOx, even the emission of a ton covered by a "free" allowance causes the generator to incur the cost of that allowance's market price, which the owner must forego by emitting that ton and using that allowance.

The concept of the opportunity costs of allowances is explained in several studies, including Mannaerts and Mulder (2003), which states: "the cost of using a permit is the opportunity cost of not selling the permit on the permit market. This opportunity cost exists no matter whether the emitter has received the permits by grandfathering or by auctioning." Also, Wrake et al. (2010) argues, "… economic theory indicates that retail prices will increase [when entities receive free allowances], reflecting the economic value of permits whether polluting entities received them for free or not, because economic costs include the *opportunity cost* of using a permit that otherwise could be sold in the permit market." Williams-Derry and Drake (2008) provide a simple analogy to make this point. They argue that even if a scalper obtained a World Series ticket "on the ground" without having to pay for it, he will not sell that ticket for any less than those he had to pay for, because the "street price of World Series tickets is based on supply and demand," which is the same irrespective of how the scalper obtained the tickets. Thus the value of the commodity is determined by its opportunity cost (or what it could be sold for in the market), not by whatever previous cost may have been incurred to obtain the commodity.

Note also that the short-run marginal cost of electricity generation *does not* include any offset for the value of the allowances allocated to that power plant's owners, if that allocation does not change at all when the electricity output is increased (i.e., allocations are not updated). Again, short-run marginal cost is the *change* in total costs resulting from a change in output – so if the allocation is grandfathered before the program starts, it will not enter into the calculation of marginal cost, as it does not affect the variable costs. Certainly, the free allocation of a stream of valuable allowances does offer firms a subsidy that affects the overall corporate balance sheet. As Mannearts argues, "the transfer of wealth [under grandfathering] to the emitters can be seen as fixed subsidy, independent of future production." But a fixed stream of allowances affects fixed costs (i.e., the portion that is insensitive to output), not the variable costs (the portion that changes when output is increased). In making short-run economic decisions, changes to the fixed costs are properly treated as "sunk costs" (or sunk benefits) and are ignored when making operational decisions (as the saying goes, "let bygones be bygones").

This reasoning can be made clearer with a concrete example. The table below shows the inputs that might be needed to operate a plant at various levels of output. (Note that the values used for these illustrations are hypothetical, and do not represent any particular plant in the real world.)

Table 1: Illustrative Resource Requirements for Generating Electricity: Grandfathered Allocation of 1 NOx Allowance (in tons)

Output (in MWh)	Fuel Use (in MMBtu)	Fixed O&M (in labor hours)	Variable O&M (in labor hours)	Emissions of NOx (in pounds)	Allocated allowances (in tons)
97	970	20	10	194	1
98	980	20	10.05	196	1
99	990	20	10.1	198	1
100	1,000	20	10.15	200	1
101	1,010	20	10.2	202	1

These inputs can be translated into dollar values. Suppose fuel costs $3 per MMBtu, labor hours cost $50 each, and NOx allowances are sold on the market for $2,000 per ton (or, equivalently, $1 per pound). Then, Table 1 becomes Table 2:

Table 2: Cost Components for Generating Electricity

Output (in MWh)	Fuel cost	Fixed O&M cost	Variable O&M cost	Cost of Emissions of NOx	Value of Allocated allowances	Total Cost Minus Value of Allocation (Total Net Cost)	Change in Total Net Cost to Add One MWh
97	$2,910	$1,000	$500.0	$194	$2,000	$2,604.0	
98	$2,940	$1,000	$502.5	$196	$2,000	$2,638.5	$34.5
99	$2,970	$1,000	$505.0	$198	$2,000	$2,673.0	$34.5
100	$3,000	$1,000	$507.5	$200	$2,000	$2,707.5	$34.5
101	$3,030	$1,000	$510.0	$202	$2,000	$2,742.0	$34.5

Note: the table above excludes fixed costs because they do not affect marginal cost calculations, but are part of the cost schedule faced by EGUs.

Note that the last column shows the change in the total cost as output is increased by one MWh – e.g., the last row shows the increase in cost (which we can call the 'incremental' or 'marginal' cost) as ($2,742-$2,707.5), or $34.5 per additional MWh.

Table 3 below presents the same cost structure for a utility, with the only difference that the plant is now awarded twice as many allowances than in the previous case.

Table 3: Illustrative Resource Requirements for Generating Electricity: Grandfathered Allocation of 2 NOx Allowances (in tons)

Output (in MWh)	Fuel cost	Fixed O&M cost	Variable O&M cost	Cost of Emissions of NOx	Value of Allocated allowances	Total Cost Minus Value of Allocation (Total Net Cost)	Change in Total Net Cost to Add One MWh
97	$2,910	$1,000	$500.0	$194	$4,000	$604.0	
98	$2,940	$1,000	$502.5	$196	$4,000	$638.5	$34.5
99	$2,970	$1,000	$505.0	$198	$4,000	$673.0	$34.5
100	$3,000	$1,000	$507.5	$200	$4,000	$707.5	$34.5
101	$3,030	$1,000	$510.0	$202	$4,000	$742.0	$34.5

Notice that the allocation of additional allowances does not change the marginal cost (i.e., change in total net cost to add one MWh) at all, because the additional allowances do not depend on or change with output.

The foregoing exercise has clear implications for competition between power plants. If dispatch (the choice of which units operate to what extent) is decided using cost minimization, the provision of freely-allocated allowances to various firms does not affect competitiveness because grandfathered allowances do not change the marginal costs of electricity generation, which is instead affected by the market price of any emissions subject to the cap. Firms that get larger grandfathered allowance allocations end up with a subsidy to offset their costs, but that does not mean those firms run inefficient plants any more than they would have if they had received smaller allocations.

Effects of Allowance Allocations under Cost-of-Service Rules

As shown above, grandfathered allocations are expected to have no effect on freely competitive electricity markets: prices, outputs, and competition among the power plants would be driven by the marginal cost of emitting under the programs' emission caps. The value of surrendered allowances would be factored into the marginal cost of generation whether or not they were originally received through free allocations.

The situation is slightly different in the case of regulated electricity markets, which make up roughly half of all markets in the US (see Burtraw and Palmer, 2007). In regulated markets, the electric utility acts as a monopolist (in that it faces no competition within its own service area), but its prices and operations are controlled or overseen by an authority (e.g., a Public Utilities Commission or PUC) to ensure that it serves its customers' needs and does not profit unduly. Electricity prices in these markets are set not at the *marginal* costs of generating and supplying power but at the *average* costs, including a reasonable return on invested capital. An important contrast with the competitive case is that, though changes in grandfathered allocations have no effect on marginal costs, they do change the average costs, because the value of the allocated allowances offsets other long-run costs for the utilities. To put this in another way, in a regulated market, if allowances are allocated for free, they are not included in the PUC's rate base calculations, since the utility "will not have spent anything to acquire its permit holdings" (Hahn and Stavins, 2010).

Higher allocations, then, lower a utility's average costs, and lower average costs translate into lower electricity prices in cost-of-service regulated markets. Lower prices, in turn, lead to a higher quantity of electricity demanded. Thus, other things being equal, giving a utility a higher allocation can be expected to result in it producing more electricity.

But this fact does not imply that changes in grandfathered allocations to various units changes the competitive balance among those units. First, though a regulated utility as a whole may see a small increase in its output if it is given a larger allocation vis-à-vis another regulated utility, the choice within that utility of which units to dispatch will still be made on the basis of marginal costs, not average costs. For example, Massey et al. (2006), argue, "For years, utility system operators have used an integrated least cost dispatch model that matches generation and load in real time… The utility system operator, in a purely cost-of-service world, dispatches the mix of generation units necessary to achieve both reliability and least cost" (page 346).

So as described above, retail electricity pricing in a cost-of-service market is determined by regulators on the basis of average cost, which can be affected by freely allocated allowances to that market's regulated utility. However, this impact only affects how much money consumers are required (through the rate base) to pay to the utility for electricity generation overall; in other words, the freely allocated allowances act as a subsidy *to consumers*, which is why electricity demand for that particular utility may rise. Whatever the electricity demand to be met, the regulated utility still makes the dispatch decision on the basis of marginal costs among the units in its fleet, which is not affected by the amount of allowances that any particular unit in that fleet was initially allocated.

Thus, within a monopolistic regulated utility in a cost-of-service market, a unit whose characteristics resulted in a large allocation for its utility would not be advantaged in producing more output, under a grandfathered allocation. The relative outputs of two different regulated utilities, where one is given a large allocation and the other is given a small allocation, will be expected to change. Electricity prices in the former utility's service area will fall relative to prices in the latter's, and this change in relative prices will lead to small changes in relative output as different consumer bases receive a different degree of subsidization through freely allocated allowances to the regulated utilities in their respective cost-of-service territories. But because regulated utilities in two separate cost-of-service areas are not competitors, it cannot be said that one has a competitive advantage over the other.

References:

Alpha-Gamma Technologies, Inc. Market Mechanisms and Incentives: Applications to Environmental Policy. A Workshop Proceeding, Session Four, US-EPA, Center for Environmental Economics, and National Center for Environmental Research. Washington, D.C. May 2003.

Burtraw, Dallas and Karen Palmer. Compensation Rules for Climate Policy in the Electricity Sector. RFF Discussion paper DP 07-41. Resources for the Future. July 2007.

Hahn, Robert and Robert Stavins. The Effect of Allowance Allocations on Cap-and-Trade System Performance. RFF Discussion paper DP 10-21. Resources for the Future. March 2010.

Mannaerts, Hein and Machiel Mulder. Emissions Trading and the European Electricity Market. CPB Netherlands' Bureau for Policy Analysis. January 2003.

Massey, William, Robert Fleishman, and Mary Doyle. Reliability-Based Competition in Wholesale Electricity: Legal and Policy Perspectives. *Energy Law Journal.* Volume 25:319. 2006.

Montgomery, D.W. "Markets in Licenses and Efficient Pollution Control Programs." *Journal of Economic Theory*. 5,395. 1972.

Neuhoff, Karsten, Kim Martinez, and Misato Sato. Allocation, Incentives, and Distortions: The Impact of ETS Emissions Allowance Allocations to the Electric Sector. *Climate Policy.* 6, 73-91. 2006

Palmer, Karen, Dallas Burtraw, and Danny Kahn. Simple Rules for Targeting CO2 Allowance Allocations to Compensate Firms. Discussion paper 06-28. Resources for the Future. June 2006.

Palmer, Karen, Dallas Burtraw and Anthony Paul. Allowance Allocation in a CO2 Emissions Cap-and-Trade Program for the Electricity Sector in California. RFF Discussion paper 09-41. Resources for the Future. October 2009.

Schulkin, J., Benjamin Hobbs, and Jong-Shi Pang. Long-Run Equilibrium Modeling of Alternative Emissions Allowance Allocation Systems in Electric Power Markets. *Electricity Policy.* Cambridge Working Papers in Economics. September 2007.

Schwyzer, Diana. The Potential of Wind Power and Energy Storage in California. Energy and Resources Group. University of California, Berkeley. 2006(?).

Shu, Gary, Mort Webster, and Howard Herzog. Scenario Analysis of Carbon Capture and Sequestration Generation Dispatch in the Western U.S. Electricity System. *Energy Procedia.* 2008.

US EPA/OAR. Economic Analysis of Alternate Methods of Allocating NOx Emission Allowances. Prepared by ICF Consulting. October 1999.

Wals, Adrian and Fieke Rijkers. How will a CO_2 Price Effect the Playing Field in the Northwest European Power Sector? *Research Symposium European Electricity Market.* September 2003.

Williams-Derry, Clark and Eric de Place. Why Free Allocation of Carbon Allowances Means Windfall Profits for Energy Companies at the Expense of Consumers. Sightline Institute. February 2008.

Wråke, Markus, Erica Myers, Svante Mandell, Charles Holt, and Dallas Burtraw. Opportunity Cost for Free Allocations of Emissions Permits: An Experimental Analysis. *Environmental and Resource Economics.* Vol. 46, No. 3. 331-336.