OTC Stationary and Area Source Committee, Largest Contributors Workgroup

Comparison of CSAPR Allowance Prices to Cost of Operating SCR controls

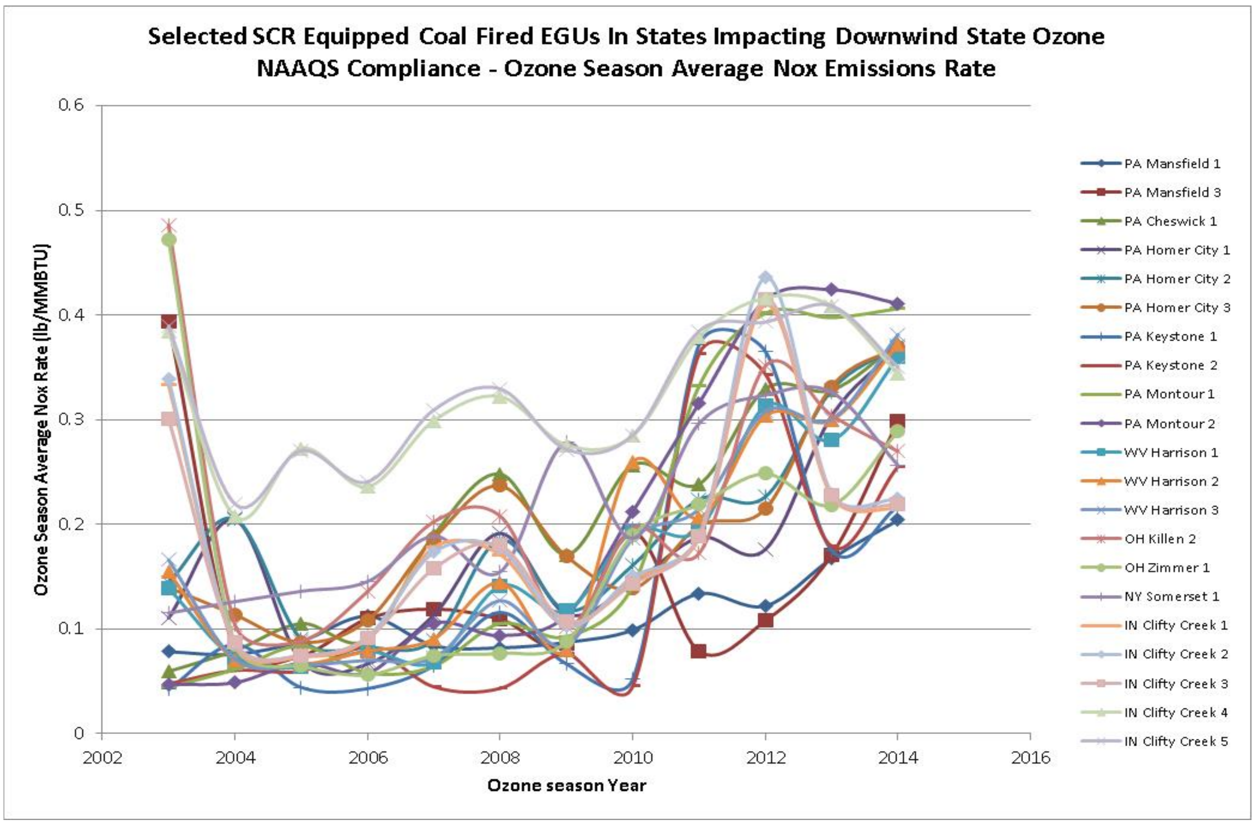
DRAFT 04/15/15

Background

During recent ozone seasons, a number of coal-fired EGU's equipped with SCR post-combustion NOx controls have demonstrated ozone season average NOx emission rates far in excess of levels that those units demonstrated during previous ozone seasons.

Many such SCR equipped coal-fired EGUs are located in states that have been identified as impacting downwind states' ability to attain and maintain the ozone NAAQS. Some of these, subject SCR-equipped coal-fired EGUs have demonstrated average ozone season NOx emission rate increases in excess of 100% from their lowest demonstrated levels, as shown in the following graph:

Graph 1



Many of these specific SCR-equipped coal-fired EGUs were/are subject to seasonal NOx emission control regulations that include ozone season NOx emissions trading programs, such as the NOx SIP Call, CAIR, and CSAPR. These seasonal NOx trading programs allow the subject EGUs to reduce emissions, obtain allowances, or any combination of the two to help comply with the trading program requirements.

The subject EGU owner/operators would be expected to seek compliance using the least costly method, as was a stated goal for the incorporation of the trading flexibility aspects of the cap-and-trade season programs. Therefore, if there is less of an economic impact to obtain sufficient allowances for compliance than reducing the actual emissions, the owner or operator may be expected to comply in that fashion.

A number of events have resulted in a depression of allowance costs. Those events include an economic slowdown requiring lower levels of electric generation, installation of NOx controls on existing EGUs, low-cost natural gas fueled generation off-setting coal-fired generation, and proliferation of renewable resources reducing the levels of required fossil-fueled generation. In total, these events and others have resulted in the reduction of NOx allowance costs as shown in the following table:

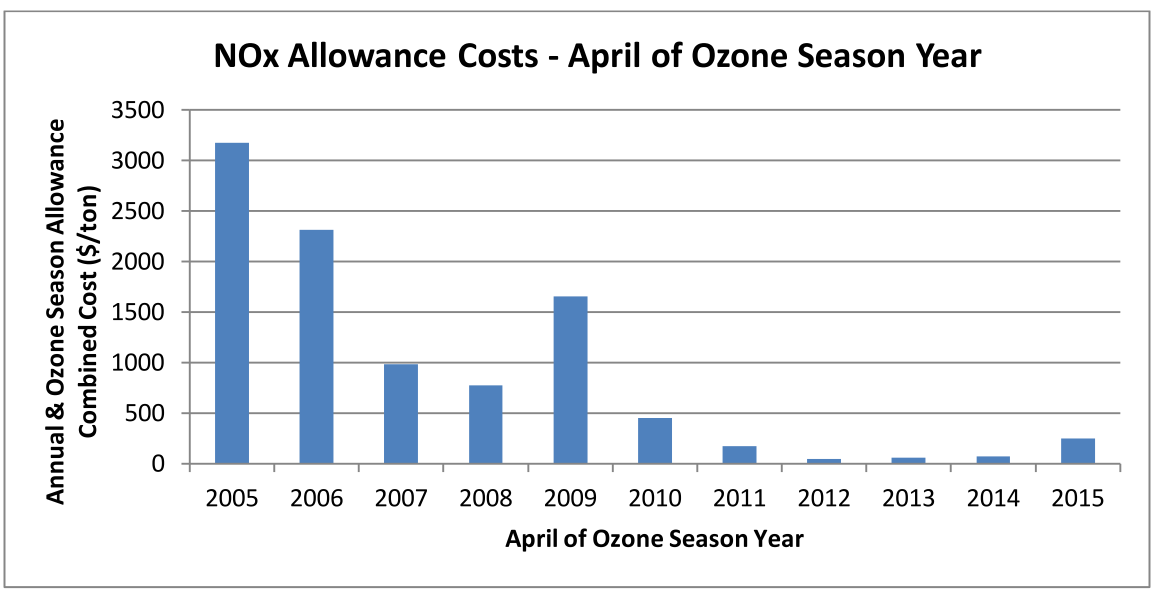
Table 1

Date	Annual Nox Allowance Cost (est $)	Seasonal Nox Allowance Cost (est $)	Combined Annual and Seasonal Cost (est $)	Program
4/28/2005	0	3175	3175	NOx SIP Call
4/28/2006	0	2312	2312	NOx SIP Call
4/30/2007	0	983	983	NOx SIP Call
4/30/2008	0	775	775	NOx SIP Call
4/30/2009	425	1232	1657	CAIR
4/30/2010	420	33	453	CAIR
4/29/2011	150	20	170	CAIR
4/30/2012	35	8	43	CAIR
4/30/2013	40	18	58	CAIR
4/30/2014	52	22	74	CAIR
3/31/2015	125	125	250	CSAPR

*Above data taken from Air Daily for the noted dates

The following graph plots the cost data presented in Table 1:

Graph 2



Comparing the ozone season average NOx emission rates shown in Graph 1 with the allowance costs shown in Graph 2, it can be seen that there is a reasonable correlation between the allowance prices and average ozone season NOx emission rates for many of the EGUs in the Graph 1. The average NOx emission rates are relatively low during the high cost periods for 2005 and 2006. The average NOx emission rates then increase somewhat when the allowance costs drop in 2007 and 2008. Another low in average ozone season NOx emission rate can be seen for most of the EGUs in the chart in 2009 when the allowances prices had a significant upward spike. And then average ozone season NOx emission rates tended to increase for most of the EGUs in the 2010 and beyond ozone seasons as the NOx allowance prices dropped and remained at low levels through the 2014 (and latest) ozone season.

The most recent NOx allowance costs associated with compliance with the CSAPR seasonal program are as follows:

CSAPR Allowance Prices*

Annual NOx allowance price = $125/short ton
Ozone Season NOx allowance price = $125/short ton
*Reference: Argus Air Daily Issue 22-49 Friday 13 March 2015 Page 5

Description of Sargent and Lundy (S&L) control cost methodology for calculating Variable Operation and Maintenance (VOM) costs used in IPM V.5.1.3

Operation of existing SCRs on existing EGUs incur incremental variable operating costs due to the need for reagent injection, additional electrical auxiliaries (fans, pumps, controls, etc.), soot blowing, SCR catalyst replacement and disposal, etc. An owner or operator may be able to reduce these variable operating costs if the controls are either not in service or operated at reduced emissions control levels when the EGU is on line, with the degree of potential saving also being variable on a unit specific basis (coal-type, boiler type, initial NOx rate, amount of reduction required, etc.). Additionally, the potential savings would be much lower for units without a full flow SCR bypass than a unit that incorporates an effective full or partial flow SCR bypass capability.

In support of the development of emission control cost estimation capabilities for the its IPM modeling, the EPA worked with Sargent & Lundy to develop an SCR cost estimation methodology that included the capital, fixed O&M, and variable O&M cost aspects of SCR emission controls**. As it is the variable cost estimates that are believed to be associated with potential savings when existing SCR emission controls are not operated or not operated at the highest level of control capability, only the variable cost aspects of the Sargent & Lundy cost estimation methodology will be further discussed.
**Reference: "IPM Model – Updated to Cost and Performance for APC Technologies - SCR Cost Development Methodology – Final, March 2013, Project 12847-002, prepared by Sargent & Lundy, pages 4 & 5.

A review of the Sargent & Lundy methodology included in EPA's IPM technical support documentation indicated that the methodology is applicable to the cost estimation needs of this effort, and it was therefore adopted to estimate potential savings that might be realized by SCR equipped coal-fired EGUs that do not operate their SCRs or operated the SCRs at reduced emission control efficiency.

The Sargent and Lundy (S&L) control cost methodology for estimating Variable Operation and Maintenance (VOM) costs includes the following elements:

- Reagent use and unit costs;
- Catalyst replacement and disposal costs;
- Additional power required and unit power cost; and
- Steam required and unit steam cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent consumption rate is a function of unit size, NOx feed rate and removal efficiency.
- The catalyst replacement and disposal costs are based on the NOx removal and total volume of catalyst required.
- The additional power required includes increased fan power to account for the added pressure drop and the power required for the reagent supply system. These requirements are a function of gross unit size and actual gas flow rate.
- The additional power is reported as a percent of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.
- The steam usage is based upon reagent consumption rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Urea cost in $/ton;
- Catalyst costs that include removal and disposal of existing catalyst and installation of new catalyst in $/cubic meter;
- Auxiliary power cost in $/kWh;
- Steam cost in $/1000 lb.; and
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

- VOMR = Variable O&M costs for urea reagent
- VOMW = Variable O&M costs for catalyst replacement & disposal
- VOMP = Variable O&M costs for additional auxiliary power
- VOMM = Variable O & M costs for steam

The total VOM is the sum of the VOMR, VOMW, VOMP and VOMM.

Analysis of Cost of Operating Controls

For this evaluation 2011 was selected as the "base" year to remain consistent with the previous work that was performed as part of the OTC Largest Contributors Workgroup (LCW) process. The required data was assembled from the EPA Air Markets Program Database (AMPD) and Energy Information Administration (EIA) databases.

The EGUs analyzed have SCRs already installed (and assumed to be in operational condition), the costs associated with operation of the SCRs (as compared to installed and operational but not operated) would be the variable costs. For the SCRs, the variable costs primarily consist of reagent consumption, increase in auxiliary power consumption, increase in steam consumption, and costs associated with catalyst deactivation (replacement of depleted catalyst) with use.

For the Sargent & Lundy SCR cost estimation methodology, the EGU-specific data and/or variables that weigh into the calculations include the EGU's nameplate rating, uncontrolled NOx emissions rate, intended NOx removal capability, type of coal, urea cost, catalyst cost (depleted catalyst replacement), auxiliary power cost, heat rate, atomizing steam usage, and atomizing steam cost.

While the Sargent & Lundy methodologies appear to be a viable means to estimate SCR costs for coal-fired EGUs, the available data from the AMPD and EIA may not be ideally suited for use with those Sargent & Lundy methodologies, and could lead to estimates that are not representative of actual conditions or would otherwise be expected for existing coal fired EGUs. Some of the more significant issues appear to include the following:

- While the Sargent & Lundy methodologies appear to use EGU nameplate rating as a basis, the methodologies in fact rely upon heat input rating as a basis for cost input. (And this would appear to be logical, as the post-combustion controls must be sized to address the steam generator output rating, and not the electric generator output rating, in order to control the emissions from the steam generator.) At first glance the Sargent & Lundy methodologies appear to be based upon electric generator nameplate capacity as the nameplate rating is utilized in many of the calculations. However, in the majority of the calculations the nameplate rating is multiplied by the EGU's heat rate (or heat rate factor) so that the estimations are in fact based upon the steam generator's heat input rating at the electric generator's nameplate rating. This is significant as the EPA AMPD data includes steam generator heat input capacity, but not electric generator nameplate data. In order to obtain the electric generator nameplate capacity related to the subject steam generator, it is necessary to correlate the AMPD data with some other source of data for the electric generator nameplate, such as the EIA Form 860 database. There are a few disconnects between the databases where electric generator nameplate cannot be matched to a given steam generator with absolute certainty. There are also a small number of other discontinuities such as situations where multiple steam generators serve a single electric generator, where a single steam generator serves multiple electric generators, or where multiple steam generators serve multiple electric generators in a header configuration. In these instances, and other similar complexities, the as-published Sargent & Lundy cost estimation methodologies may not be truly representative.
- As noted above, the Sargent & Lundy cost estimate methodologies rely upon a unit heat rate value for certain calculations within the methodologies. The heat rate value is used in the S&L methodologies to calculate heat rate factors and to calculate heat input capacity (electric generator nameplate rating multiplied by the heat rate). The value used in the Sargent & Lundy methodology examples appears to be representative of a full load design heat rate, rather than an "average" heat rate potentially representative of startups and shutdowns, load following, extended low load operation, etc. The "heat rate" value determined using AMPD data (in this case, 2011 ozone season average heat input and gross generation data) for this estimation process would tend to be impacted by any startups and shutdowns, unusual operations, load following, extended low load operation, very high loads, etc. The use of this heat rate calculated using AMPD data is likely not ideal for many or most of the EGUs in the evaluation, even though it seems to be the best data available at this time. (Note also, that in some cases the estimated heat rate using the AMPD data was very high or very low, requiring the use of default values in a fashion similar to that utilized for the EPA's IPM process.)
- Related to the above heat rate issue is that there are some examples in the AMPD database where there is no electric generation data for some of the EGU steam generators. This appears to be true for units where one or more steam generators serve a single electric generator. There may be other examples also. This obviously makes it impossible to calculate a heat rate using the AMPD data. For these types of situations it is necessary to utilize default values for the estimation process.

These issues can impact the cost estimation process using the S&L methodologies. Using the Sargent & Lundy cost estimation methodologies, it is expected that the use of heat rates that are high would tend to increase the estimated costs associated with post combustion NOx controls. The use of any other estimated or default values in the Sargent & Lundy methodologies may also impact the cost estimates, high or low, depending upon any error introduced by the estimated or default values that may be high or low relative to the "real world".

As a modification to the S&L cost estimation methodology, the calculations were revised to utilize steam generator heat input capacity as the basis of the estimation methodology instead of the electric generator nameplate capacity and estimated heat rate. As the AMPD includes steam generator heat input capacity values, the heat input capacity data point is consistently available for the steam generators. (Note: there are some who question the accuracy of the heat input capacity values in the AMPD, at least for some specific steam generators. However, since the heat input capacity value should represent a design value and is a required input, it is anticipated that overall the AMPD's heat input capacity data would be reasonably accurate for the majority of the steam generators.) Use of the AMPD heat input capacity values would seem to result in more accurate, representative, and consistent estimation values than using heat inputs calculated using correlated generator nameplate rating and heat rates calculated using seasonal average values.

This alternate heat rate based estimation methodology (based on the Sargent & Lundy methodology) was utilized to estimate the variable costs of SCR post combustion NOx control. For the fleet of coal-fired EGUs that, as part of the OTC LCW process, were judged to be candidates for installation of SCR post-combustion NOx controls, the SCR variable operating cost estimates are summarized in the following table:

	Variable O&M - Urea ($/ton NOx Removed)	Variable O&M - Catalyst ($/ton NOx Removed	Variable O&M - Incremental Power ($/ton NOx Removed)	Variable O&M - Steam ($/ton NOx Removed)	Total Variable O&M ($/ton NOx Removed)
Hi	433	4947	38934	6	44321
Low	433	128	100	6	688
Average	433	653	942	6	2035
Median	433	487	500	6	1424

Note: Values are in 2012 dollars

The range of the variable O&M values for the catalyst and incremental power are very large. The highest costs are associated with coal-fired EGUs whose 2011 average ozone season (base year) NOx emission rate was relatively low (close to but not at or below the "floor" SCR NOx emission rate capability of 0.06 lb/MMBTU that was assumed for the initial OTC evaluation process). The lower costs are associated with those coal-fired EGUs whose 2011 average ozone season (base year) NOx emission rate was high relative to the assumed SCR "floor" value of 0.06 lb/MMBTU.

The following table contains a comparison of the avoided cost of operating SCRs calculated using the Sargent & Lundy standard method to the modified Sargent & Lundy for three specific EGUs. As can be noted from the table in general the modified Sargent and Lundy method shows lower avoided costs than the standard Sargent & Lundy methodology. As can also be noted in both cases, the avoided costs of operating SCRs are lower than the CSAPR NOx Allowance prices.

CSAPR NOx Allowance Prices vs. Avoided Cost of Operating SCRs
2011 Ozone Season Basis (2012 dollars)

	Sargent & Lundy Standard Method*	Modified Sargent & Lundy Method**	Sargent & Lundy Standard Method*	Modified Sargent & Lundy Method**	Sargent & Lundy Standard Method*	Modified Sargent & Lundy Method**
Unit	Unit 1		Unit 2		Unit 3	
Boiler Size	153.1 MW	---	403.7 MW	---	958.8 MW	---
Capital Cost ($/ton)	$29,770	$46,045	$19,776	$31,140	$10,281	$12,129
Fixed O&M ($/ton)	$1,682	$2,335	$614	$888	$279	$324
Variable O& M ($/ton)	**$748 -$1,985**	**$439 - $1,598**	**$744 - $2,118**	**$440 - $1,785**	**$529 - $1,755**	**$439 - $1,680**
Total Operating Cost ($ ton)	$32,200 - $33,437	$48,819 - $49,978	$21,134 - $22,508	$32,468 - $33,813	$11,089 - $12,315	$12,892 - $14,133
2011 Ozone Season Steam Generator Heat Input Capacity (MMBtu/hr)	---	2,322	---	6,372	---	11,107
2011 Ozone Season Capacity	23.7%		35.1%		73.9%	

Additionally, there is another variable that is operational in nature and impacts the number of the above values that may be applicable to any particular. It appears that there are some existing coal-fired EGUs that do not incorporate full capacity SCR flue gas bypass capacity, such that even when the SCRs are "taken out of service" the flue gas continues to flow through the SCR. For these EGUs that do not incorporate full flow bypass capacity, the estimated savings from an SCR “out of service” would be limited to only the values reflected in the above table’s values for Variable O&M – Urea and Variable O&M – Steam. This is because the incremental auxiliary power costs (primarily due to additional fan capacity to overcome the draft loss of the SCR) and SCR degradation (due to deactivation caused by elements in the flue gas that continues to flow over the catalyst) will continue to be incurred as long as the flue gas continues to pass over the catalyst. For those coal-fired EGU’s that incorporate full flow flue gas bypass capability for the SCRs, the estimated savings would be the total of the four variable O&M categories (Variable O&M – Urea, Variable O&M – Catalyst, Variable O&M – Incremental Power, and Variable O&M – Steam) shown totaled in the column titled Total Variable O&M in the above table.

Analysis of Cost Savings Incurred from Not Running Controls

The OTC Largest Contributor workgroup identified certain plants which might not be fully running their NOx Controls. Using the Sargent & Lundy methodology on those power plants resulted in the following Ozone Season Cost Savings. As in the Avoided Cost table above a range of cost savings is presented for each state.

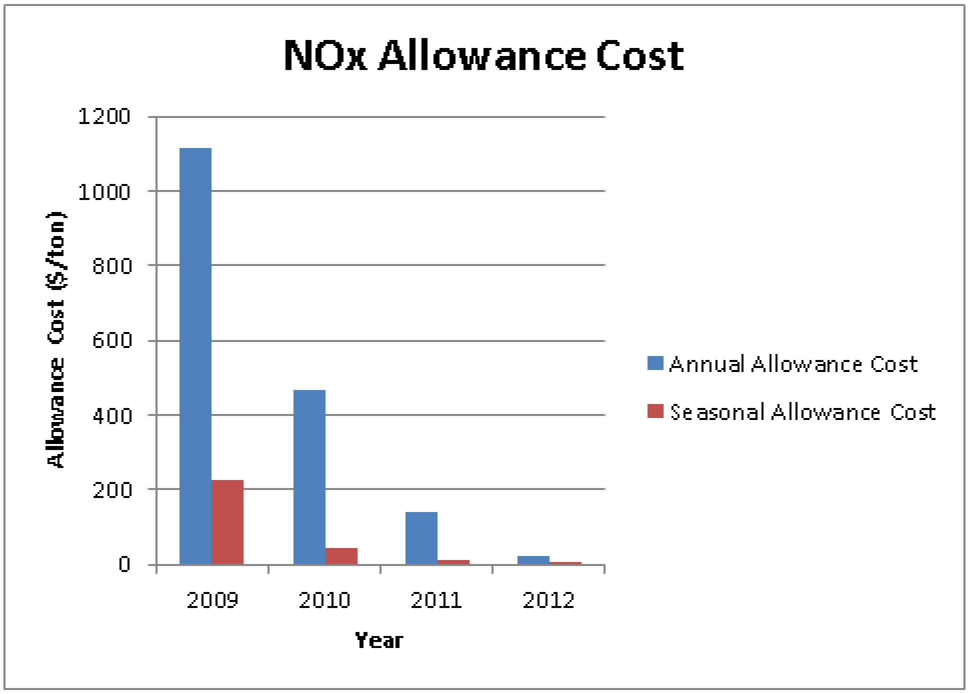
A calculation was done based on 2014 emission rates compared to the lowest emission rate experienced by these plants to calculate control utilization which is summarized by state in the following table.

Avoided Cost of Operating SCRs and Ozone Season NOx Pollution Control Utilization

State	Avg 2014 OS NOx emission Rate Lb/mmBtu	Lowest Ozone Season NOx emission Rate 2003-2012 Lb/mmBtu	NOx reduced if operated at Lowest level - Tons	NOx Pollution Control Utilization (how close to 100% are they running controls %	Money saved by not running controls millions $
PA	0.31	0.06	21,374	46%	9.7 – 38.8
NY	0.25	0.12	150	81%	0.0
WV	0.18	0.05	14,240	69%	7.4 – 29.6
OH	0.16	0.07	12,485	83%	6.7 – 26.8
KY	0.18	0.07	9,257	76%	6.4 – 25.6
IN	0.17	0.09	8,635	85%	4 - 16
NC	0.14	0.06	5,646	81%	3.2 – 12.8
IL	0.09	0.06	1,470	93%	0.6 – 2.4
TN	0.07	0.05	359	97%	0.2 – 2.4
VA	0.04	0.03	99	98%	0.0
MI	0.06	0.07	0	100%	0.0
MD	0.07	0.07	0	99%	0.0
		Total	73,715		

NOx Allowance Cost Comparison

In order to see the significance of the relatively high variable cost of SCR NOX removal, some representative NOx allowance cost data was collected for the years 2009 through 2012. That data indicates that the NOx allowance costs have dropped significantly during that period and are well below the cost of NOx removal utilizing SCR technology. The NOx allowance costs (taken from Air Daily for early July of the respective year) are show in the following graph:



As shown in the above chart, the NOx allowance prices are significantly lower than the estimated variable operating costs for SCR NOx controls on coal-fired EGUs. This is true for both coal-fired EGUs that incorporate full flow SCR flue gas bypass capability and those coal-fired EGUs that do not incorporate full flow SCR flue gas bypass capability.

Additional Review of Variable O & M Costs in EPA IPM Base Case v.5.13 Data vs. EPA IPM v.5.14 Data

An additional review of twenty seven (27) EGUs listed in the table contained in Section 5.2 of the "*Incremental Documentation of EPA Base Case v.5.14 Using IPM"* March 25, 2015. The comparison was between the parsed results for these 27 plants in IPM v.5.14 versus IPM v.5.13.

Of the 27 units, 6 units had identical summer electrical generation (GWH) for the 2018 base year in both IPM v.5.13 and IPM v.5.14. These units were Harrison Power Station Unit 1, Homer City Units 1 & 3, Pleasants Power Station Unit 2, Bruce Mansfield Unit 3 and East Bend Unit 2.

The projected 2018 summer emissions from these 6 plants increased from 9,246 tons of NOx to 21,322 tons of NOx and the projected 2018 summer variable operations and maintenance costs for these six plants dropped from $67.8 million dollars $62.10 million dollars.

Since the only difference in input for these 6 units appears to be the summer NOx emission rate it is assumed that all cost differential came from reductions in the cost of running the emissions controls.

Thus on a per ton reduction basis the cost savings from reduced operation of the controls ranged from $360 to $720 per ton NOx ($466/ton NOx Avg). Based on a review of the Sargent and Lundy March 2013 cost methodology it is apparent that only VOMR (Variable O&M costs for Urea) and VOMM (Variable O&M costs for Steam) were modified for these six plants. Thus EPA anticipates no change in VOMP (Variable O& M for additional auxiliary power required including additional fan power) or VOMW (Variable O&M for catalyst replacement and disposal). Of the remainder of the plants,

- Parsed data for Alcoa for the 2011 ETS is reported as Warrick
- 15 units exhibited additional or less fuel use / summer generation,

- 2 units with same summer GWH showed no change in summer VOM (Amos and New Madrid)
  - Amos is operating its SCR in both IPM v.5.13 and IPM v.5.14 however at a rate of 0.061 lb NOx/MMBtu in v.5.13 (2011 CEM data) and 0.10 lb NOx/MMbtu in IPM v.5.14 (2014 CEM data)
  - New Madrid is running it SCR since CSAPR is binding in Missouri IPM v.5.14 will be revised to indicate this requirement.
- 3 units with same summer GWH but with an increase in VOM. (Elmer Smith and Thomas Hill)
  - Elmer Smith has a NOx emission rate of 0.26 lb. NOx/MMBtu in IPM v.5.13 and a NOx emission rate of 0.99 lb. NOx/MMBtu in IPM v.5.14 with estimated VOM of 4.54 mills/kWh and 4.77 mills/kWh respectively.
  - Thomas Hill shows the SCR as "off" in the initial setup for IPM v.5.14. Since CSAPR is binding in Missouri IPM v.5.14 will be revised to show that the SCR is "on" to indicate this requirement, resulting in slightly higher VOM costs.
  - IPM v.5.13 and IPM v.5.14 indicate that both Thomas Hill units will be installing dry sorbent injection (DSI) and activated carbon injection (ACI). These two units were aggregated differently in IPM v.5.14 resulting in slightly different total VOM cost (IPM v.5.13 – 6.89 mills/kWh and 6.88 mills/kWh vs. IPM v.5.14 7.08 mill/kWh and 7.12 mills/kWh, respectively

While Section 5.2 identified 27 units which increased their NOx rates by at least 45% from 2011 to 2014 it is hoped that this same methodology could be used in future IPM runs with 2011 expanded to include a range of years to (2003 – 2012).

According to additional information received from EPA:

- Each IPM modeling platform uses the corresponding NEEDS database input. Both v.5.13 and v.5.14 use the unit level NOx rates obtained from 2011 reported CEMs data, except where EPA has reflected 2014 behavior in 27 units in v.5.14 (and in some cases if EPA has received comments requiring EPA to update the rates different than 2011 values). Please note that in 2011 there were a number of units with existing SCRs that were not running. EPA did not need to adjust modeling behavior for those, since they do not run their controls in the model projections either. While EPA is relying in part on a NOx emission rate data set from 2011, EPA recognizes that some units have substantially changed their pollution control removal performance since that time. For those units, EPA have adopted more recently reported (2014) emission rates as a better proxy for business-as-usual (base case) emission projections regarding these units. For those units EPA has also confirmed they have no reason (settlement, etc.) to change their rates in the future.

It should also be noted that for Pennsylvania 70% of the units which are not running their controls (7 of 10 units) are missing from the table in Section 5.2 (see chart below).

PA plants	Average of lowest 2003-2012 O.S. NOx Rate Lb/mmBtu	Average of 2014 Ozone Season Emission Rate	% increase	In 5.14 as a plant with disables controls
Mansfield 1	0.08	0.22	175%	N
Mansfield 3	0.07	0.31	343%	Y
Cheswick 1	0.06	0.4	567%	N
Homer 1	0.07	0.37	429%	Y

Homer 2	0.08	0.38	375%	N
Homer 3	0.09	0.38	322%	Y
Keystone 1	0.04	0.2	400%	N
Keystone 2	0.04	0.24	500%	N
Montour 1	0.04	0.41	925%	N
Montour 2	0.05	0.41	720%	N
% of PA plants included in IPM 5.14 as Disabled				30%

According to additional information received from EPA:

Regarding the 7 out of 10 PA units that didn't make the list in Section 5.2, during the 2011 ozone season, the NOx rates for these units were already elevated meaning they already had the SCR turned off or down. Therefore, there was no significant change from 2011 to 2014 rates. In the parsed file they are shown as not running their controls.

- Mansfield 1 – 2011 OS NOx rate (and therefore 2018 rate) was already at 0.15 lb/mmBtu
- Cheswick 1 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.25 lb/mmBtu
- Homer 2 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.22 lb/mmBtu
- Keystone 1 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.37 lb/mmBtu
- Keystone 2 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.38 lb/mmBtu
- Montour 1 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.33 lb/mmBtu
- Montour 2 -- 2011 OS NOx rate (and therefore 2018 rate) was already at 0.28 lb/mmBtu

It should be noted that the 2014 ozone season average NOx emission rates are higher than the 2011 ozone season NOx emission rated for Mansfield 1, Cheswick 1, Homer 2, Montour 1 and Montour 2 indicating potentially higher future NOx emission rates for these units than those currently included in IPM v.5.14.

Summary

Current CSAPR ozone season NOx allowance prices are approximately $125/short ton.

Estimated variable operating costs for SCR NOx controls on coal-fired EGUs ranged from $439/ton of NOx reduction (for a coal-fired EGU without SCR by-pass capability) to $44,321/ton of NOx reduction (for a coal-fired EGU with full bypass SCR capability with an already low pre-SCR average NOx emission rate).

Current CSAPR ozone season NOx allowance prices are significantly lower than the estimated variable operating costs for SCR NOx controls on coal-fired EGUs.

The estimated cost for allowances under the initial phase of CSAPR also appear to be below the value necessary to be a strong factor in discouraging coal-fired EGU owners and operators with existing SCRs from heavily relying on the purchase of allowances instead of operating the SCR at high levels for purposes of compliance with NOx emission trading programs. It is interesting to note the Air Daily 3/31/2015 NOx allowance estimate of $125 for annual allowances and $125 for seasonal allowances are far below the $1,500/ton that EPA had estimated for the 2014 ozone season as part of the initial CSAPR proposal. (It is also interesting here that the EPA's earlier $1,500 allowance cost estimate is similar to the actual 2009 ozone season cost of $1,657, which produced a decent reduction in ozone season NOx emission rate from most of the units shown in the above NOx Allowance Cost chart.)

The data suggests that the most recent, and near-projected, costs associated with the purchase of NOx allowances for trading program compliance are insufficient to cause owners and operators to consistently operate SCR NOx controls on coal-fired EGUs at high control levels instead of relying on the purchase of allowance for compliance. Additional requirements should be considered to provide the incentive for coal-fired EGUs to operate their NOx controls in accordance with good pollution control practices at all times, such as stringent emission rate standards and short term compliance averaging periods.