A Patchwork Program: An Overview of State Mercury Regulations

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While a federal Program, implementation of the Clean Air Mercury Rule (CAMR) is left to the states. Some states have decided to opt out of the national trading program and have enacted or are considering more restrictive mercury (Hg) limits, with significant impact on the sources within their jurisdiction. This paper provides an overview of the CAMR State Implementation Plan (SIP) process and the status of state Hg regulations. State-by-state limits and any restrictions on allowance trading are discussed as well as any deviations from the EPA model rule and potential impacts on source monitoring and control strategies.

Background

After determining that its initial decision to control utility Hg emissions using a maximum achievable control technology (MACT)-based standard was "neither appropriate nor necessary,"[1] EPA finalized CAMR on March 18, 2005. CAMR reduces mercury emissions through a national emissions cap for all coal-fired electric utility units. Additional Hg standards are also established for new units under Subpart Da of Part 60.[2]

The national emissions cap for electric utilities will be implemented in two phases as shown in Table 1. The first phase cap represents the anticipated "co-benefits" that are expected through the implementation of the Clean Air Interstate Rule (CAIR) while sources make the necessary preparations and modifications to address the second phase. The second phase cap reflects the Agency's estimates of reasonably achievable Hg emission reductions.[3]

Table 1. National Electric Utility Mercury Emission Cap

Compliance Year	Nation-wide Cap
2010 – 2017	38 tons/yr
2018 and thereafter	15 tons/yr

In many ways, the CAMR approach is very similar to the Acid Rain cap-and trade program for SO_2. However, unlike the Acid Rain Program (or a MACT standard) that is applied uniformly across the country, the final CAMR approach for existing units is based on Section 111(d) of the Clean Air Act and is state implemented. Working within this framework, EPA has established Hg emission budgets for 53 jurisdictions (50 states, two tribes, and the District of Columbia) and each jurisdiction is required to develop a SIP to ensure that their annual Hg emissions budget is not exceeded. The budgets for each jurisdiction are permanent regardless of any potential growth in the electric generation.

[1] 70 Federal Register, March 29, 2005, p. 15994
[2] Any unit that commenced construction after 1/30/04 must comply with NSPS in 40 CFR 60 .45(a).
[3] Even though compliance is not required until 2010, CAMR specifies that Hg CEMS should be installed, certified and operated by January 1, 2009.

The state budgets were determined by apportioning the national cap using on the baseline heat input of each electric utility unit (average of the highest three years during 1998-2002) adjusted for fuel type. The baseline heat inputs were adjusted to reflect the variation in mercury concentrations as well as ease of removal using the correction factors in Table 2. No allocations were assigned to states without existing coal-fired units.[4]

Table 2. Fuel-based Allowance Weighting Factors

Fuel-type	Weighting Factor
Bituminous	1.0
Subbituminous	1.25
Lignite	3.0

Table 3 shows the annual Hg state budgets for electric generating units (EGU) that are defined in 40 CFR §60.24 as well as the baseline heat inputs and weighted average fuel factors used to develop the allocations. For comparison, the table also shows the 1999 Hg emissions estimates that were based on the Agency's mercury Information Collection Request (ICR) data. Nationwide, the allocations represent emissions reductions of 21% for Phase I and 69% for Phase II below the 1999 emission level (representing 49% and 80% reductions based on coal concentrations).[5]

Table 3. CAMR Annual EGU Hg Emission Budgets

	1999 Hg Estimate (tons)	Baseline Heat Input (10^{12} Btu)	Average Fuel Factor	Budget (tons/yr) 2010-2017	2018 -
Alaska	0.007	2.9	1.25	0.01	0.004
Alabama	2.466	842.8	1.06	1.289	0.509
Arkansas	0.506	285.9	1.25	0.51	0.2
Arizona	0.475	253.5	1.24	0.454	0.179
California	0.004	28.3	1.00	0.041	0.016
Colorado	0.255	415.8	1.17	0.706	0.279
Connecticut	0.036	36.7	1.00	0.053	0.021
Delaware	0.104	49.7	1.00	0.072	0.028
Florida	0.961	846.2	1.01	1.232	0.487
Georgia	1.489	818.4	1.04	1.227	0.484
Hawaii	0.008	13.2	1.25	0.024	0.009
Idaho	0	0.0	0.00	0	0
Iowa	0.975	407.7	1.23	0.727	0.287
Illinois	2.995	965.6	1.14	1.594	0.629
Indiana	2.442	1360.4	1.07	2.097	0.828
Kansas	0.825	406.2	1.23	0.723	0.285
Kentucky	1.74	1051.5	1.00	1.525	0.602
Louisiana	0.503	266.2	1.56	0.601	0.237
Massachusetts	0.146	118.8	1.00	0.172	0.068
Maryland	0.91	338.9	1.00	0.49	0.193

[4] Four jurisdictions (Rhode Island, Vermont, Idaho and the District of Columbia) that had no coal fired EGU during the baseline period received zero Hg emission allocations.
[5] EPA-600/R-01-109, *Control of Mercury Emissions from Coal-fired Electric Utility Boilers*, Interim Report, April 2002.

Table 3. CAMR Annual EGU Hg Emission Budgets (Continued)

	1999 Hg Estimate (tons)	Baseline Heat Input (10^{12} Btu)	Average Fuel Factor	Budget (tons/yr)	
				2010-2017	2018 -
Maine	0.002	0.9	1.00	0.001	0.001
Michigan	1.541	795.4	1.13	1.303	0.514
Minnesota	0.632	389.8	1.23	0.695	0.274
Missouri	1.372	790.8	1.22	1.393	0.55
Mississippi	0.34	190.2	1.06	0.291	0.115
Montana	0.471	202.5	1.29	0.377	0.149
North Carolina	1.538	784.1	1.00	1.133	0.447
North Dakota	1.024	360.9	3.00	1.564	0.617
Nebraska	0.417	233.4	1.25	0.421	0.166
New Hampshire	0.018	43.6	1.00	0.063	0.025
New Jersey	0.098	105.6	1.00	0.153	0.06
New Mexico	0.564	165.7	1.25	0.299	0.118
Nevada	0.165	197.0	1.00	0.285	0.112
New York	0.514	272.2	1.00	0.393	0.155
Ohio	3.555	1413.7	1.01	2.057	0.812
Oklahoma	0.861	404.7	1.23	0.721	0.285
Oregon	0.084	43.5	1.21	0.076	0.03
Pennsylvania	4.979	1231.8	1.00	1.779	0.702
Rhode Island	0	0.0	0.00	0	0
South Carolina	0.534	401.3	1.00	0.58	0.229
South Dakota	0.056	40.4	1.24	0.072	0.029
Tennessee	1.125	641.0	1.02	0.944	0.373
Texas	5.023	1615.8	1.99	4.65	1.83
Utah	0.14	350.2	1.00	0.506	0.2
Virginia	0.633	409.7	1.00	0.592	0.234
Vermont	0	0.0	0.00	0	0
Washington	0.265	109.7	1.25	0.198	0.078
Wisconsin	1.132	511.2	1.21	0.89	0.351
West Virginia	2.466	965.0	1.00	1.394	0.55
Wyoming	0.914	527.1	1.25	0.952	0.376
District of Columbia	0	0.0	0.00	0	0
Navajo Nation	0.678	372.4	1.12	0.6	0.237
Ute Indian Tribe	0.002	41.4	1.00	0.06	0.024
Total	48.0	22119.7	--	38.0	15.0

SIP Options

The SIP process affords the affected jurisdictions considerable latitude in how to manage their Hg budgets. States may allocate allowances as they see fit and decide whether they want to participate in the trading program. If the state elects to participate in the national trading program, it can determine the basis for distribution, can adjust the frequency of allocations, can establish allowance set asides, and can even auction off allowances based on the needs of the state but must provide unit-by-unit allocation information to EPA at least three years in advance of each control period.[6] If the state decides not to join the national trading program, then the

[6] With the exception of the notification for 2010 – 2012, allocation notifications for each year are due on October 31 "for the fourth year after the year of the notification deadline."

budget allocation represents a firm cap for the jurisdiction and the SIP must include mechanisms that ensure that the emissions allocations will not be exceeded.[7] States may also supplement Hg regulations that are not part of SIPs to address other issues (e.g., additional limitations) that are not required in the SIPs. SIPs must:

- Assure compliance with the state's Hg emission budget for coal-fired EGUs[8]
- Include fully adopted state rules and identify enforceable state mechanisms for implementation
- Demonstrate that it has legal authority

Additionally, in accordance with §60.24(h)(4), state plans "shall comply with the monitoring, recordkeeping and reporting provisions of Part 75."

To assist the states, EPA prepared a model rule that could be incorporated into the jurisdiction's regulations and serve as the basis of the SIP. Key elements of the EPA model rule are that:

- Allocation for existing units are prorated from the state budget based on a one-time historic baseline heat input (weighted by fuel type), which is defined as the average of highest three years of annual heat input from 2000 to 2004 (or the first five years of operation for units commencing operation later). With the exception of the initial distribution block (2010-2014), allocations determinations are made five years in advance.
- For new units, allocations are based on modified output values (using a 7,900 mmBtu/kWh conversion factor). Allocations for new units are provided from a new unit set aside pool until they can establish a five-year baseline (and the five years thereafter since allocations for existing units have already been made). The new unit set aside from the state budget is 5% for 2010-2012 and 3% thereafter. Unused new unit set aside allowances are distributed to existing units in accordance with their baseline heat input.
- There are no restrictions on trading or banking of allowances as long as the source account holds current or past vintage allowances in excess of emissions at time of control period transfer deadline.
- Compliance is determined by facility-level accounting. There is a 3:1 allowance surrender penalty from future year's allocation for excess emissions.
- Retired units continue to receive allowances indefinitely in accordance with their initial baseline heat input.

In addition to the EPA model rule, the National Association of Clean Air Agencies (NACAA, formally STAPPA/ALAPCO) developed a model rule to serve as a potential template for states. The NACAA model includes options that depart from the EPA model in a number of ways:

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[7] Even states where trading is going to be disallowed and alternative Hg emissions limits are defined, careful consideration should be given to make sure that allocation procedures are equitable should the future growth make the CAMR budgets critical. Strict emission limits alone are inadequate.

[8] Under CAMR, it is necessary that all emission reductions come from coal-fired EGUs.

- No interstate trading is allowed but intrastate averaging by the same owner is permitted.
- Requires a 80% removal (or 0.010 lb/GWh) during Phase I and 90-95% removal (or 0.0060 – 0.0025 lb/GWh) during Phase II based on a 12-month rolling average
- Accelerated Phase II implementation schedule – Phase I in 2009, Phase II in 2013
- Option allows Phase I limit adjustment with concessions for future SO_2 and NO_X reductions by 2013.
- New units must meet 90-95% removal (or 0.0060 – 0.0025 lb/GWh) limit.

SIP Approval
On December 8, 2006, EPA issued a finding stating that 21 states submitted SIPs by the November 17, 2006 CAMR deadline. The states that submitted on-time plans are Alabama, Arizona, Connecticut, Delaware, Idaho, Iowa, Illinois, Louisiana, Massachusetts, Montana, North Dakota, New Hampshire, New Jersey, Nevada, New York, Pennsylvania, Rhode Island, South Dakota, Texas, Vermont, and West Virginia. EPA has four months to approve SIPs. The Agency must finalize a federal implementation plan (FIP) within six months for states that have been disapproved or have not submitted a plan in a timely fashion. The proposed FIP is essentially the EPA model rule with administration by the EPA instead of the state and a shorter allocation determination period (three years instead of five after the initial distribution).

There is no sanction for states that did not submit a plan. EPA has stated that it will continue to work with states as they submit plans and will continue to work with states as they submit plans and will continue to accept plans in the interim. If the SIP is not completely satisfactory, the Agency may implement part of the plan as a FIP/SIP hybrid. For late SIPs, EPA may also impose transition requirements to minimize disruption and will not reallocate any allowances already assigned under a FIP. Even under a FIP, states have the option of submitting their own stand-alone allowance allocation plan.[9] A state can submit a plan for approval at any time, and a revised SIP can be submitted for approval at the state's discretion.

Generally EPA will implement the emissions trading rule for EGU's on tribal lands unless a tribe obtains treat-as-state status[10] and submits a tribe implementation plan (TIP). Other tribes will be treated on a case-by-case basis to address any future construction but with zero Hg allowance allocations although EPA has requested comments on the potential alternative of a 300 lb/yr set aside for Indian territories (and possibly zero budget states) starting in 2012 but this would require reducing each state's budget.[11]

State-by-State Comparison
The following comparison of state-by-state Hg regulations/SIP provisions was made based on the best information available to the authors at the time that this paper was written. Obviously, no state's SIP had EPA approval by this time and many states had yet to finalize their Hg-related

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[9] EPA has proposed a deadline for allocation method of May 30, 2007 since states must submit first allocation pursuant to an approved methodology by October 31, 2007. EPA has also proposed allocating the allowances for 2010-2014 one-year at a time (albeit three years in advance) to more readily integrate new state allocation procedures.
[10] 40 CFR Part 49; Federal Register, February 12, 1998, p. 7253-7274
[11] If this provision is enacted the Agency has stated that it would not redistribute allowances that are unused.

regulations. The presented information, therefore, reflects state rules in various levels of draft and may or may not represent the final SIP provisions.

Allowance Trading
As shown in Figure 1, it appears that 14 non-zero budget states will be opting out of the national trading program. Only three of these states (Illinois, Michigan and Pennsylvania) will allow intrastate system-wide averaging for compliance demonstrations.[12] Three of 14 states (Oregon, Washington and Wisconsin) will allow trading during Phase I, but trading will be disallowed for Phase II compliance.[13]

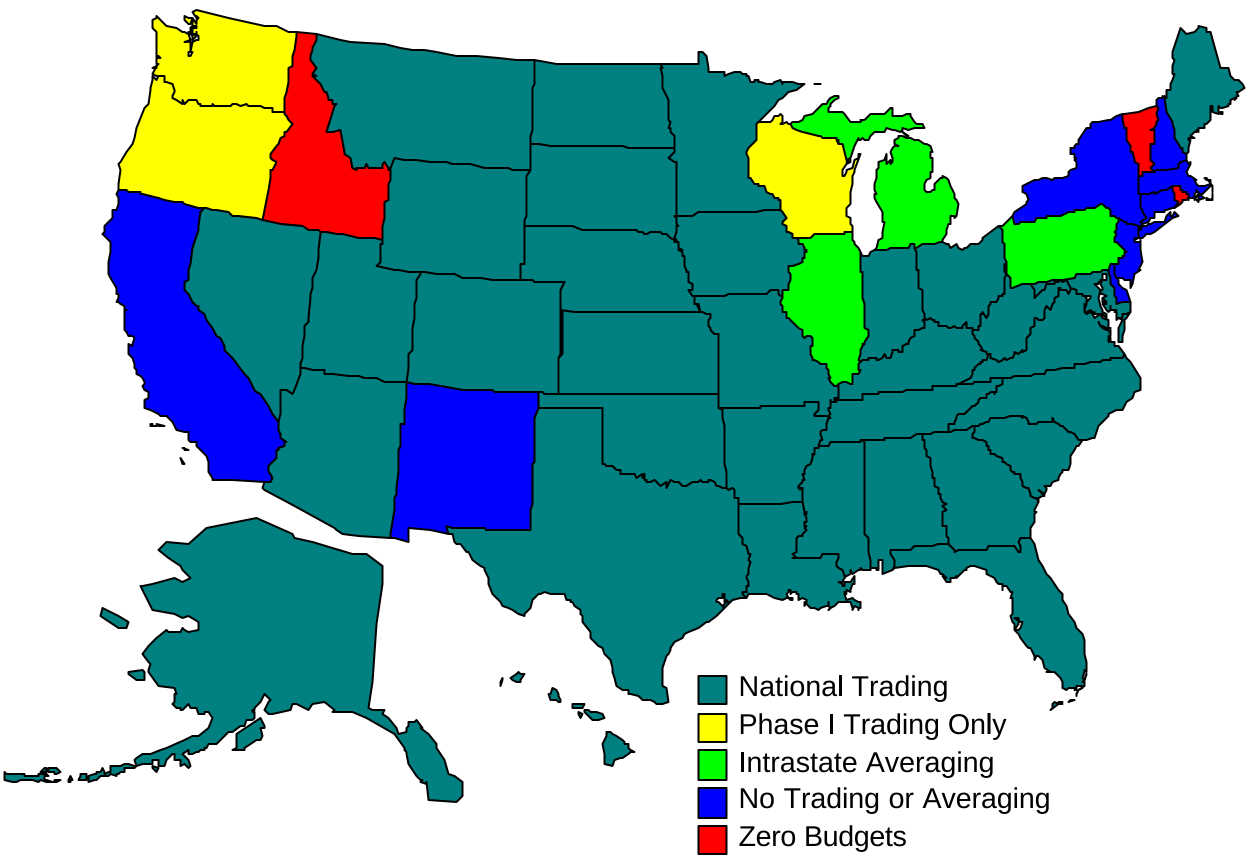

Figure 1. State-by-State Hg Trading or Averaging Details

Virginia is unique in that it will participate in the national trading program, but will also issue its own state issued allowances to address a provision established by its legislature.[14] In Virginia, small EGU operators may demonstrate compliance via trading, but companies with large in-state coal-fired capacity can demonstrate compliance only using system-wide allowances. Depending

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[12] In addition, Maryland, which allows sale of surplus allowances via national trading, permits system-wide intrastate averaging to demonstrate compliance with its state Hg limit.
[13] Oregon will allow trading through 2017 although allocations will be reduced starting in 2013. In Washington, trading will be phased out in 2013. Wisconsin proposes to allow trading through 2017.
[14] Code of Virginia §10.1-1328.

on the amount of in-state generation, a company may also include emission credits from out-of-state sources that it owns but only if the sources are within 200 km of Virginia's border.

Stringency and Acceleration

As shown in Table 2, twenty-one states have proposed or finalized state mercury limits or allocation procedures which are either more stringent than CAMR or are more quickly implemented.

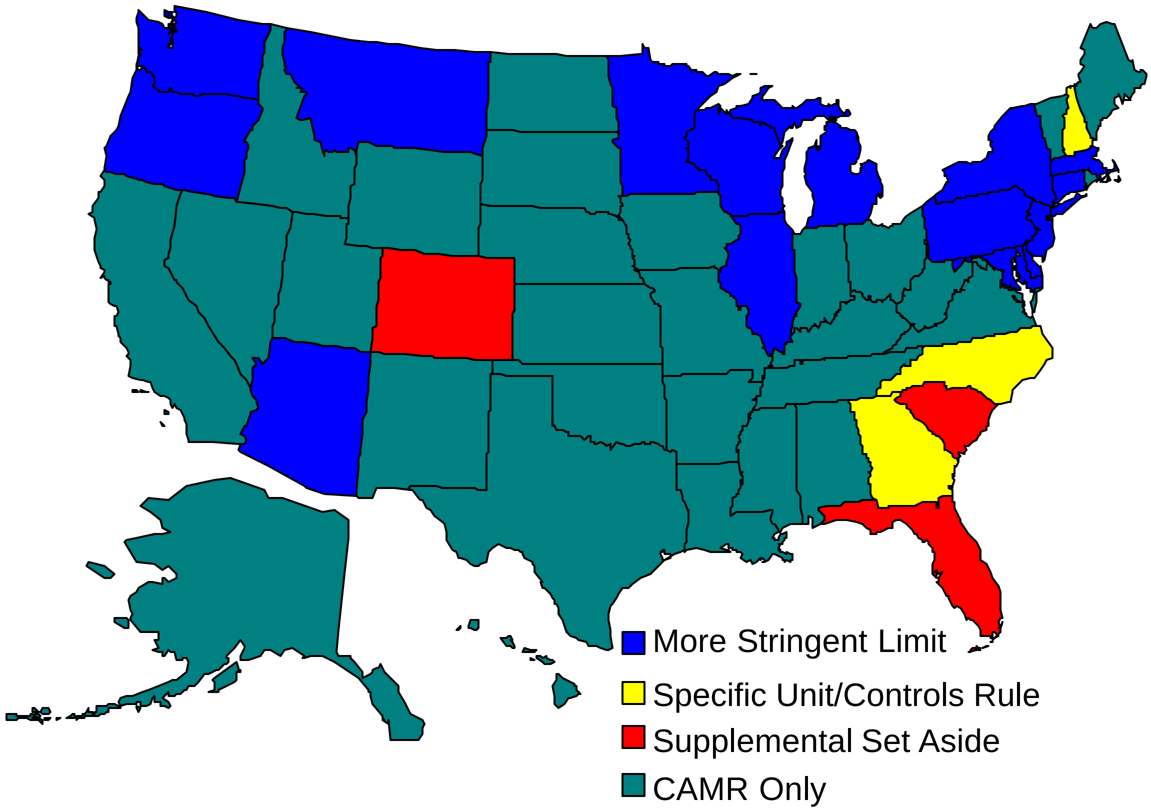

Figure 2. State-by-State Hg Limitations or Restrictions

Most restrictions are based on performance standards (e.g., 0.6 lb/TBtu or 90% reduction) but North Carolina and Georgia employ specific unit/controls-based rules. Four states (Colorado, Florida, South Carolina and Washington) have reduced Phase I allowance allocations to restrict banking.[15] Most of the limits are expressed in terms of a rolling-12 month or calendar year average. One notable exception is New York, which specifies compliance on a 30-day rolling basis. In addition to a current proposed limit, Montana requires a best achievable control technology (BACT) evaluation for every unit at least once every ten years.

Table 4 highlights the supplemental mercury restrictions that have been finalized or proposed by various states. To allow easier comparison, the state mercury limits (and allocation limitations) have all been converted to lb/TBtu (lb/10^{12} Btu) values based on an assumed gross heat rate of

[15] These supplemental "health" set asides will be retired, although there are some provisions to allow sources to receive some of these allowances for compliance in exchange for concessions in South Carolina and Colorado.

9,500 Btu/kWh and are presented along with the CAMR allocations translated in terms of lb/TBtu based on the baseline heat inputs for each state.[16]

Table 4. Comparison of Supplemental State Hg Restrictions[17]

	CAMR Budget (lb/TBtu)		Additional State Limits (lb/TBtu)		Notes
	2010-2017	2018 +	Phase I	Phase II	
Arizona	3.58	1.41	NA	0.92	0.0087 lb/GWh or 90%, whichever is greater by 2013
Colorado	3.40	1.34	2.15	NA	36.6% set aside 2010-2017
Connecticut	2.89	1.14	0.60	0.60	0.6 lb/TBtu or 90% by 7/1/08 (may tighten on 7/1/12)
Delaware	2.90	1.13	1.00	0.60	1 lb/TBtu or 80% by 1/1/09, 0.6 lb/Tbtu or 90% by 1/1/13
Florida	2.91	1.15	2.04	NA	70% allocation for Phase I
Georgia	3.00	1.18	NA	0.86	Specific unit/controls-based rule (~90% reduction)
Illinois	3.30	1.30	0.84	0.84	0.0080 lb/GWh pr 90% by 7/1/09
Massachusetts	2.89	1.14	0.79	0.26	0.0075 lb/GWh or 85% by 1/1/08, 0.0025 lb/GWh or 95% by 1/1/12
Maryland	2.89	1.14	1.72	0.86	80% reduction in 2010, 90% reduction by 2013
Michigan	3.28	1.29	NA	0.84	0.008 lb/GWh or 90% by 2015
Minnesota	3.57	1.41	NA	0.57	90% by 2014 (phased based on controls)
Montana	3.72	1.47	0.91	0.91	0.9 lb/TBtu except 1.5 lb/TBtu for lignite, AEL phase out in 2018, BACT Every 10 years
North Carolina	2.89	1.14	NA	0.86	Specific unit/controls-based rule (~90% reduction)
New Hampshire	2.89	1.15	NA	1.72*	80% removal by 7/1/2013
New Jersey	2.90	1.14	0.70	0.70	3 mg/HWhr or 90% annual based on stack tests (12/15/07)
New York	2.89	1.14	NA	0.60	0.6 lb/TBtu by 2015, 30-day rolling average
Oregon	3.49	1.38	NA	0.60	0.6 lb/TBtu in 2013, reduced allocation 2013-2017 (0.04 tons), no trading 2018
Pennsylvania	2.89	1.14	2.53	1.26*	0.024 lb/GWh or 80% by 2010, 0.012 lb/GWh or 90% by 2015
South Carolina	2.89	1.14	2.17		25% 2010-2017 health set aside
Washington	3.61	1.42	2.71	0.93	25% initial supplemental "health" set aside, 0.0088 lb/GWh in 2013
Wisconsin	3.48	1.37	3.75*	1.56* 0.57(90%)	Current law (40% by 2010, 75% by 2015) less strenuous than CAMR – Proposes 90% by 2020

* State limit appears less restrictive than CAMR

[16] Effective CAMR lb/TBtu values vary from state-to-state based on fuel factors. Using baseline heat input would not account for potential EGU growth, which would make the effective CAMR budget "limit" more restrictive.
[17] Maine has a broad, non-industry specific rule that limits Hg emissions from facilities to 25 lb/yr by 2010. This limit, however, was excluded from Table 4 because it is far greater than the 2 lb/yr allocation for the state and the current emissions from Maine's single affected source.

In initial draft rules, Arizona was inclined to prohibit trading during Phase II. However, in the preamble to the final state rule, Arizona acknowledges that even with strict limits it will be unable to satisfy its budget without outside allowances due to growth constraints.[18] Arizona has decided to allow interstate trading but is imposing a 2:1 surrender requirement starting in 2012 for purchased allowances needed to cover any deficit (over allocated or banked allowances).[19]

Allocations Procedures

In general, states that are participating in the national trading program are following the EPA allocation model with only minor modifications. Most appear to be basing the allocation on a five year one-time historic baseline although some states are disallowing allocations for retired units (e.g., Nevada and Indiana). Indiana is considering an eight year initial baseline period (1998-2005) for existing units because some of its sources were under-utilized while installing control equipment during the CAMR proposed baseline period and is planning to update the baseline to reflect changes in unit operation. Some states (Iowa, Kansas, Missouri, North Carolina and New Mexico) are creating permanent allocation rates for existing units with or without new unit set asides.[20]

With regard to new unit set asides, most appear to be following the EPA model and are establishing set asides of 5% for Phase I and set asides in the 2-4% range for Phase II. Wyoming and Oregon are opting for 10% new unit set asides.[21] West Virginia has a 5% set aside that will be sold at auction and Kentucky, likewise, plans to auction off its 2% set aside. In addition to a new unit set aside, South Dakota also has, also set up a "mercury reduction account" (5% through 2014, 4% thereafter) to reward sources that can meet 90% removal.

Monitoring Issues

Most state rules incorporate Part 75 by reference but some appear to limit the options. For example, in accordance with Massachusetts regulation 7.29(5)(a)(3) requires Hg continuous emissions monitoring systems (CEMS) and would seem to disallow sorbent trap or low mass emission test-based options.[22] Massachusetts also specifies adjustments for particulate-bound Hg[23], Part 60 data validation (with no missing data substitution) and data validity requirements (75% of hours/day, 75% of days/month, 90% of hours/quarter). On the other hand, the draft

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[18] State estimates the need for 3021 MW of new coal-fired generation by 2018.

[19] The Arizona rule also specifies that no permit will be granted for units with heat rates less than 8250 Btu/kWh (bituminous), 8320 Btu/kWh (subbituminous), or 8740 (lignite) starting in 2015.

[20] With permanent allocations, new units are not folded into the existing unit pool. Under this approach new units would not receive any allowances unless there is a new unit set aside. Even if there is a new unit set aside, several new sources could be competing for the small pool.

[21] Especially with large set asides, a significant consideration is whether any unused portion of the account is allocated to existing (e.g., Wyoming), banked (e.g., South Dakota) or retired (Oregon). Without adequate reallocation procedures, set asides can simply become budget reductions.

[22] Deciphering monitoring requirements is complicated by the fact that most state plans and regulations incorporate the definition from the model rule. On its face, the model rule definition would appear to require that Hg CEM concentrations be reported on a dry basis (µg/dscm) and require moisture monitoring, which is inconsistent with Part 75. Further many states cite specific revisions of Part 75 (e.g., Arizona), which could be problematic if strictly applies, particularly given the state of flux in mercury monitoring technology.

[23] Although Massachusetts may be the only state that specifically requires particulate adjustment based on test data, the Hg definition for several states include both gaseous and particulate forms.

Michigan rule (R 336.2510) would seem to allow a variety of non-Part 75 monitoring options (e.g., mass balance, fuel sampling) provided that they are approved by the state Department of Environmental Quality.

In addition to emissions testing and monitoring requirements, some states also require other information. In New Jersey, for example, optimization testing is required for sorbent injection system and operators must subsequently maintain the injection rate at or above approved levels.

Impacts/Implications

One might expect, given the number of states that have imposed their own limits as well as those that have decided to opt out of the trading, that the nature of the final program would significantly altered. But, while the emissions and trading restrictions will have significant repercussions within the affected jurisdictions, the cap-and-trade based performance standard envisioned under CAMR would appear to be relatively intact.

The effect of states opting out of the national trading program as well as the relative impact of health set asides during Phase I is shown in Figure 3. The size of the national trading program has been reduced by about 16% during both phases of the program.

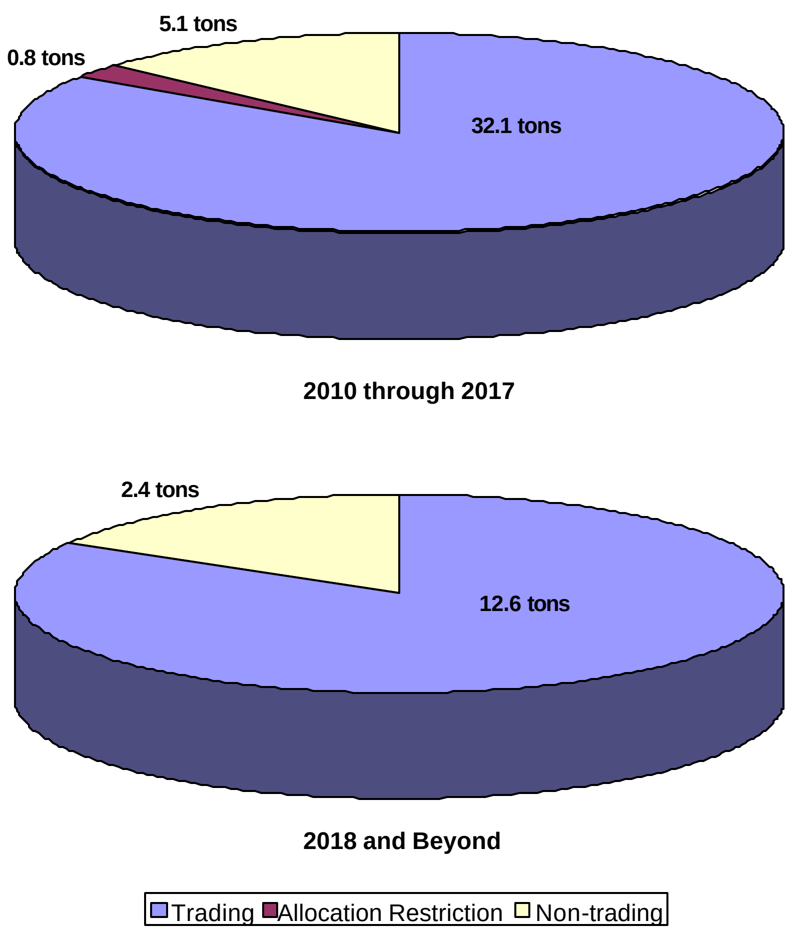

Figure 3. Effective National Trading Program Size

Naturally, the various state limitations will be superimposed with the CAMR budgets starting in 2010. To assess the total potential national emissions, the values in Table 4 were multiplied by the baseline heat input and were substituted for the annual budget values for states that disallow trading. For states that incorporate a strict mercury limit but allow trading, no adjustments were made to the total budget since the allowances are fungible and would presumably be purchased by sources in other states. Adjustments were also made to reflect the supplemental allowance set asides in Colorado, Florida, South Carolina and Washington. While this analysis is simplistic[24], it suggests (as illustrated in Figure 4) a total effective reduction of the national cap of about 7% during Phase I and about 5% during Phase II.

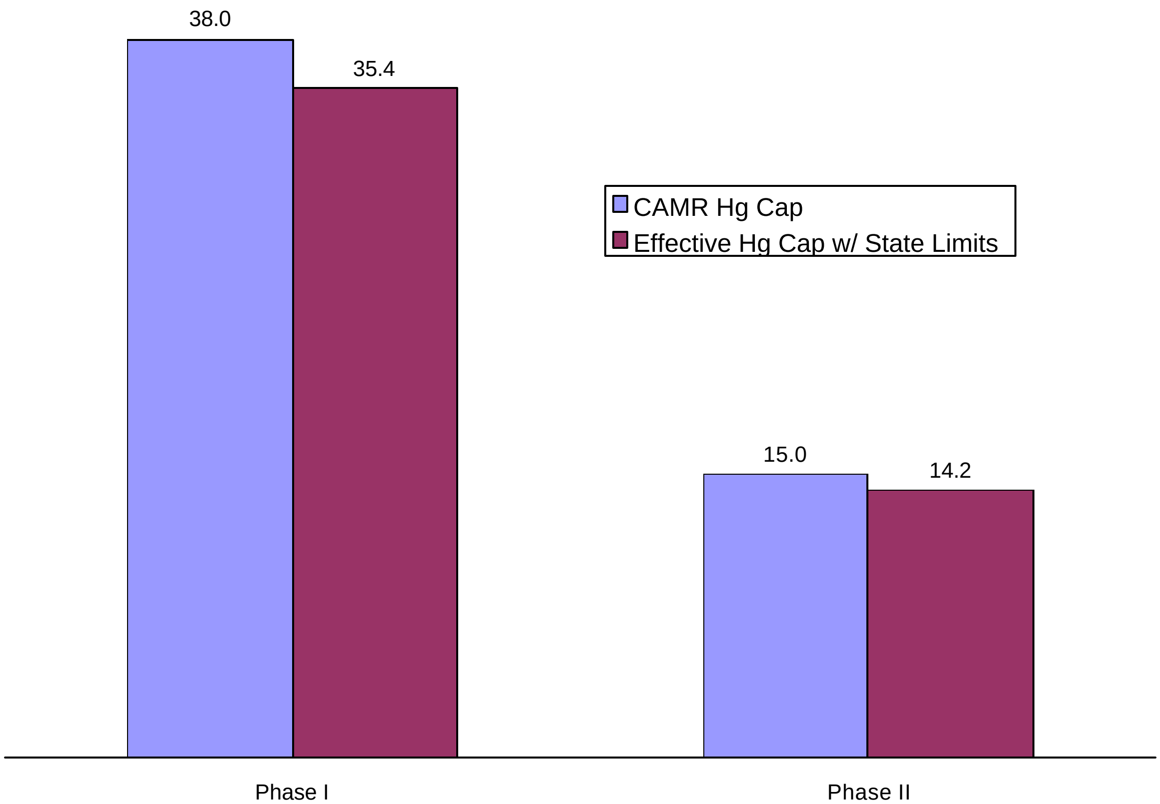

Figure 4. Effect of State Hg Limits on the Effective National Hg Cap

Based on the ICR data, some units that burn bituminous coal and that have baghouses and wet or dry scrubbers may be able to satisfy the 90% reduction requirements posed by a number of states. Most, however, will have to add additional controls (e.g., activated carbon injection) to meet 90% reduction and many to meet the 80% reduction levels reflected in CAMR. States that have decided to accelerate Hg reduction requirements will make the construction market for power plants and emission control systems even tighter. The acceleration will further contract an

[24] For example, this approach does not reflect potential allowance losses due to unallocated new unit set asides and the necessary margins that sources have to employ to assure compliance with the state limits, which would lower the effective cap. However, it also does not reflect the potential alternative limits allowed by some states or potential growth in states that prohibit trading, which would increase the total emissions from those states.

already bubble market and will likely result in significantly higher costs[25] and greater delivery problems. Many of these states have also precluded trading as a potential backstop.

For states that are still considering their SIP options, in addition to control costs, future potential electric generating needs should also be considered. The CAMR state budget approach has built in inequities. For some states, there is insufficient margin for EGU growth without trading. Mechanisms that allow sources to trade and bank allowances should not be discounted offhand.

The implementation of the CAMR is further complicated by the fact that many monitoring issues have yet to be resolved. On-going field testing of commercially available Hg CEMS equipment still reveal difficulties in meeting the Part 75 requirements. Even when the QA requirements are satisfied, there remains significant uncertainty in not only the CEMS but also the reference method measurements, particularly at low levels. Monitoring may prove to be the weakest link in the program. The impact of monitoring issues and the potential use of missing data substation could make compliance with tight limits even more tenuous.

[25] Some recent utility construction projects have seen cost estimates rise by 40-50% (e.g., Duke Cliffside Project).