Testimony of ARIPPA
before the
House Committee on Energy and Commerce,
Subcommittee on Energy and Power
in Support of H.R. 3797 (the SENSE Act)
February 3, 2016

Mr. Chairman, Members of the Committee:

Good morning. On behalf of ARIPPA, I would like to thank the Chair and Committee for holding this hearing today on the SENSE Act (H.R. 3797).

My name is Vincent Brisini and I serve as Director of Environmental Affairs for Olympus Power, LLC. Today, I am testifying on behalf of ARIPPA, the trade association representing the coal refuse energy industry. By way of background, and in terms of my perspective on the issues before you today, I have 37+ years of experience in air resources management, in both public service and the private sector. From 2011 to 2015, I served as Deputy Secretary for Waste, Air, Radiation, and Remediation in the Pennsylvania Department of Environmental Protection; and prior to that worked for 33 years as an air quality and environmental manager in the electric generation sector, principally in Pennsylvania.

ARIPPA is the trade association of a very special and unique group of electricity generation facilities which simultaneously serve as environmental remediation facilities. What makes the ARIPPA member facilities special is that we remove unsightly and polluting coal refuse piles from the environment, use that coal refuse as the primary fuel in producing alternative electrical energy and then remediate and reclaim these and other mining affected lands with the resulting beneficial use ash. The coal refuse to energy process is invaluable because it permanently eliminates the substantial and harmful impacts to air, water and other environmental media, as well as the safety and health impacts, of coal refuse piles. ARIPPA member facilities are located in or near the anthracite or bituminous coal regions of the United States. In the Pennsylvania-West Virginia region, ARIPPA member plants generate approximately 10% of the total electricity produced. The vast majority of these coal refuse to energy facilities are located in Pennsylvania. The attached **ARIPPA Map** of coal refuse-energy facilities demonstrates how these coal refuse-energy facilities are co-located within the abandoned mine lands in Pennsylvania and ideally situated to remediate the environmental harm caused by the coal refuse piles to the numerous watersheds that carry acid mine drainage flowing south and west to the Mississippi River basin and south and east to the Chesapeake Bay.

As noted in the Pennsylvania Department of Environmental Protection's Citizens Advisory Council's 2015 Transition Report, Pennsylvania faces a cost to recover abandoned mine lands of approximately $16.1 billion. Of that amount, reclaiming coal refuse piles alone represents a burden of approximately $2 billion or more in Pennsylvania alone. These types of costs can be expected for other coal producing states in the eastern portion of the United States as well.

Because of erroneous assumptions in certain federal environmental regulations, coal refuse-fired power plants are threatened and may lose the ability to continue to provide these publicly-important environmental, safety and health benefits. This is especially true for those coal refuse-fired electric generating units that operate in wholesale electric markets.

Importantly, the coal refuse-fired facilities located in Pennsylvania:

- Include 1500 MW of electrical generation capacity
- Remove and use as fuel 11 million tons of coal refuse annually
- Have used over 205 million tons of coal refuse for fuel, to date

- Have remediated and reclaimed thousands of acres of PA mining affected lands
- Have eliminated acid mine drainage and improved hundreds of miles of PA streams
- Provide over 1200 direct jobs with payrolls in excess of $84 million per year
- Provide over 4000 indirect jobs in project management, engineering, operations, transportation, logistics and skilled trades
- Provide property tax revenues to support local schools and communities, and;
- Provide over $10 million per year of business per facility into their local economy – collectively, over $150 million per year into PA's economy

H.R. 3797, the proposed "Satisfying Energy Needs and Saving the Environment Act" or "SENSE Act," seeks to address the sulfur dioxide (SO2) allowance allocation errors contained in the Cross-State Air Pollution Rule (CSAPR) and the erroneous assumptions in the Mercury and Air Toxics Standards (MATS) rulemaking with respect to these facilities. Without the SENSE Act, vastly more local and state taxpayer dollars will be required to reclaim the areas blighted by coal refuse and to address the associated environmental, health and safety problems – money that is not available in our states and communities. Federal funding for abandoned mine reclamation is already drying up due to the greatly reduced amount of coal that is being mined, and state and local budgets are simply unable to tackle this daunting challenge. Absent the SENSE Act, the end result would be the death of a private solution to a public problem and the preservation of the coal refuse piles and the continuation of health, safety and environmental harm associated with these sites!

Cross-State Air Pollution Rule (CSAPR) - Sulfur Dioxide (SO2) Allowances

In Phase 2 of CSAPR, sulfur dioxide allowance allocations to electric generating units that burn coal refuse from the historic mining and processing of bituminous coal are reduced to levels that cannot be achieved by these coal refuse-fired units. Absent the ability to economically decide whether to control or purchase allowances from other units, a seller's market for more expensive SO2 allowances will likely develop which could result in these coal-refuse fired units becoming unable to continue to operate economically.

The SENSE Act mandates that in Phase 2 of CSAPR or in any future revised emissions budget under CSAPR, the bituminous coal refuse-fired electric generating units only be allocated SO2 allowances at the level provided in Phase 1 of CSAPR. This will ensure that these units aren't unnecessarily forced into retirement because of this error.

To assure that the Phase 2 annual sulfur dioxide emissions budget that has been established by EPA is not compromised, the SENSE Act provides that the Administrator must "re-allocate" sulfur dioxide allowances from the allowance allocations to electric generating units which have been or will be permanently retired or fully converted to burn only natural gas. This will result in a proportional reduction in sulfur dioxide allowance allocations to those units consistent with the number of allowances needed for the re-allocation specified in the SENSE Act.

At the same time, The SENSE Act includes provisions that prevent bituminous coal refuse fired plant owners receiving these CSAPR emission allowances from gaining an economic windfall. It prohibits qualifying plants from transferring any unused CSAPR allowances to other facilities; and, while allowing unused CSAPR allowances to be "banked" for future compliance periods, it requires the surrender of such allowances if a unit permanently retires or switches to natural gas.

<u>Mercury and Air Toxics Standards (MATS)</u>

Although we anticipate that all coal refuse-fired plants can meet the mercury standard under MATS, most of the bituminous coal refuse-facilities cannot meet the rule's standards for hydrogen chloride

(HCI) or its surrogate sulfur dioxide (SO2). The problem meeting the SO2 limits arises from the high variations in sulfur content between anthracite and bituminous coal refuse fuels. The SENSE Act addresses this oversight in the regulation by establishing an additional alternative compliance option for coal refuse facilities burning high sulfur coal refuse tied to the removal and control of SO2. Absent this provision, all but one (which burns low sulfur bituminous coal refuse) of the existing bituminous coal refuse generating plants will be non-compliant and forced to shutter their plants. Along with the closure of these plants would be the loss of the multimedia environmental benefits that the plants provide by combining the generation of energy with the removal of coal piles and restoration of land and water resources.

To ensure the continuation of the multi-environmental benefits that the coal refuse fired plants provide through the continued removal, remediation and reclamation of coal refuse piles, the SENSE Act legislation mandates that an alternative, performance based standard be provided for these units to demonstrate compliance with MATS. Specifically, under the SENSE Act, these units would be able to demonstrate compliance with the MATS acid gas requirement by demonstrating a 93% removal of potential sulfur dioxide emissions based on as-fired fuel sampling and continuous emissions monitoring systems measurements. This performance level is consistent with the concepts established by EPA's New Source Performance Standards (NSPS) for SO2 emissions for new coal refuse plants by providing a similar standard for existing coal refuse units.

This alternative standard must be demonstrated on the same boiler operating day basis as the other acid gas standards in MATS.

Conclusion

The SENSE Act is a reasonable, and well-targeted effort to address the errors that EPA has made in CSAPR and the MATS rule, and is a very important part of ensuring that coal refuse-fired facilities remain able to conduct their business of reclaiming and recovering these mining affected lands and providing high quality family sustaining jobs in the communities in which these facilities are located. ARIPPA urges you to support the SENSE Act and its passage in this session of the US House of Representatives.

As part of my testimony, and for your records, I am providing to you certain white papers prepared by ARIPPA that more clearly describe the problems associated with Coal Refuse sites (**Annex A.**) and the impacts of the finalized CSAPR (**Annex B.**) and MATS (**Annex C.**) rules on the coal refuse-fired industry.

Thank you again for the opportunity to testify today.

Attachments:

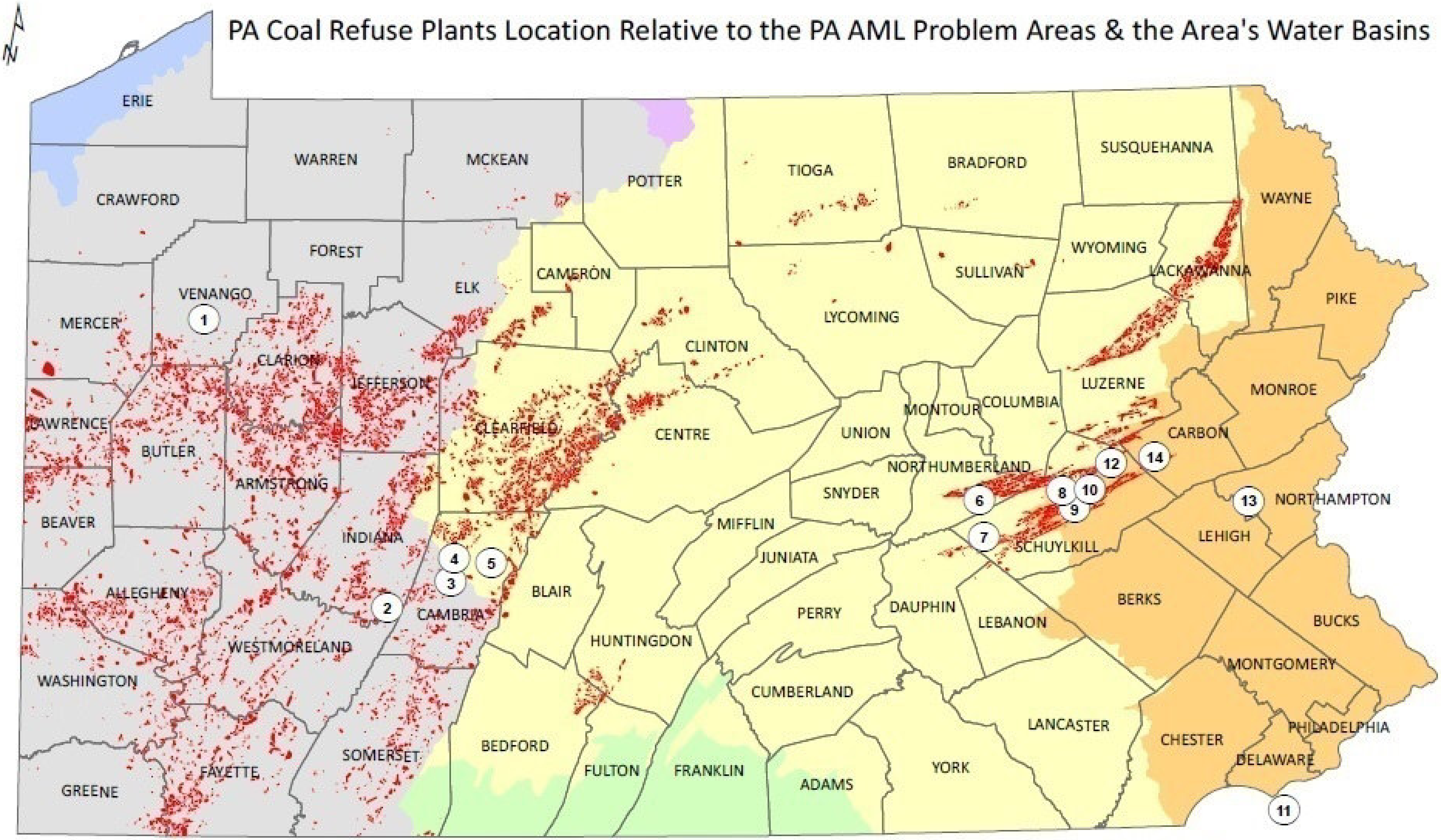
ARIPPA Map with PA Plants, MGW & Tons Per Year

Annex A. ARIPPA Coal Refuse Whitepaper with Photos 10_05_15

Annex B. ARIPPA CSAPR Whitepaper 9_24_15 (with logo)

Annex C. ARIPPA MATS Whitepaper 9_24_15 (With Logo)

PA Coal Refuse Plants Location Relative to the PA AML Problem Areas & the Area's Water Basins



PA Coal Refuse Plants (1,419 MW & 10,922,000 Tons/Year)

1. Scrubgrass Generating - 83 MW; 644,000 TPY
2. NRG Seward - 525 MW; 2,925,000 TPY
3. Ebensburg Power - 50 MW; 536,000 TPY
4. Colver Power Project - 102 MW; 701,000 TPY
5. Cambria Cogen Company - 85 MW; 664,000 TPY
6. Mt. Carmel Cogen - 40 MW; 529,000 TPY
7. Westwood Generation - 30 MW; 384,000 TPY
8. Schuylkill Energy Resources, Inc. - 80 MW; 1,300,000 TPY
9. Gilberton Power Company - 80 MW; 575,000 TPY
10. Wheelabrator Frackville Energy Company - 42 MW; 535,000 TPY
11. Kimberly Clark Chester Plant - 60 MW; 223,000 TPY
12. Northeastern Power Company - 52 MW; 559,000 TPY
13. Northampton Generating Co. - 107 MW; 651,000 TPY
14. Panther Creek Energy - 83 MW; 696,000 TPY

Water Basins

Ohio
Genesee
Delaware
Potomac
Erie
Susquehanna

Abandoned Mine Land Problem Areas

*MW = Installed Capacity; TPY = Average Tons per Year from 2009-2013

COAL REFUSE

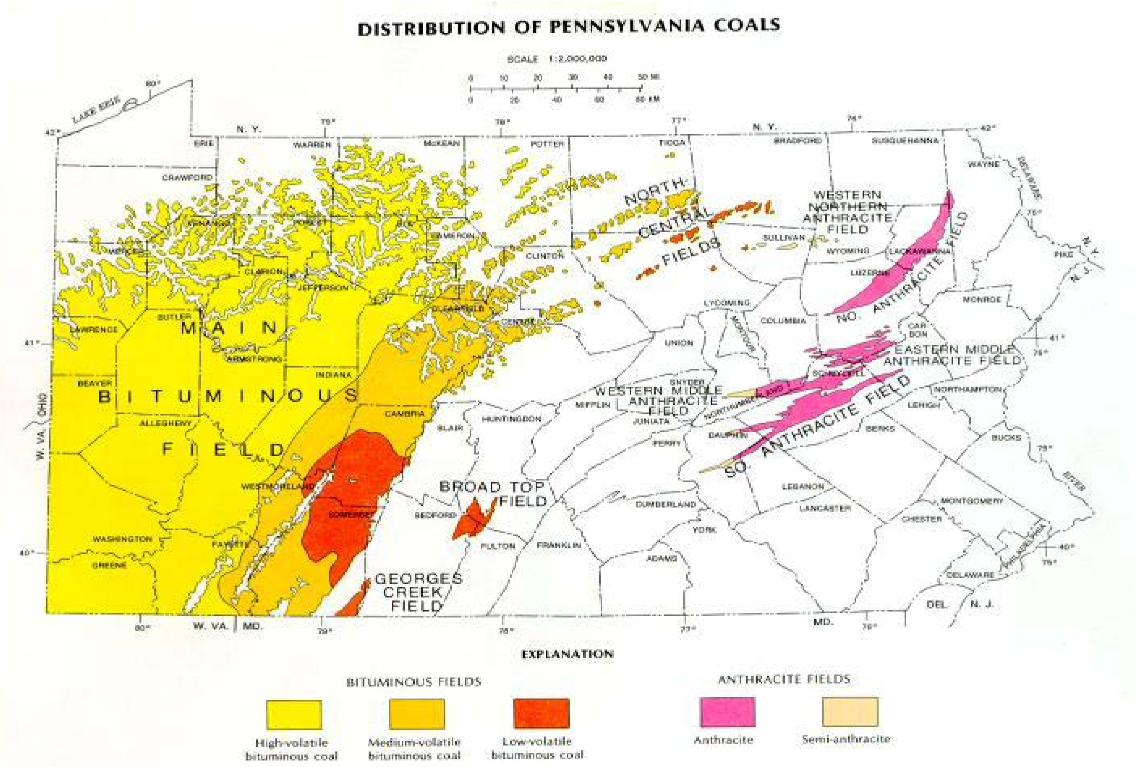
What is coal refuse?

The Environmental Protection Agency (EPA) describes coal refuse as waste products of coal mining, physical coal cleaning, and coal preparation operations containing coal, matrix material, clay, and other organic and inorganic material. Others have described coal refuse as a by-product of coal mining activities, not including overburden, which has been spread on the land. Coal refuse piles vary from a few to hundreds of acres of unreclaimed mine lands.

Pennsylvania regulations define coal refuse as ”…any waste coal, rock, shale, slurry, culm, gob, boney, slate, clay and related materials, associated with or near a coal seam, which are either brought aboveground or otherwise removed from a coal mine in the process of mining coal or which are separated from coal during the cleaning or preparation operations. The term includes underground development wastes, coal processing wastes, excess spoil, but does not mean overburden from surface mining activities.”

Where was and is coal refuse placed?

Because it is a by-product of coal mining operations, coal refuse is located throughout the coal regions of Pennsylvania and other coal producing states. The coal regions in Pennsylvania are shown in the map below.



Pennsylvania's coal miners have extracted approximately 16.3 billion short tons of anthracite and bituminous coal from the state's mines since commercial mining began in 1800. While mines permitted under the 1997 Surface Mining Control and Reclamation Act (SMCRA) are required to be reclaimed after the coal is extracted and processed, many pre-SMCRA mines were abandoned without any reclamation. These sites are referred to as Abandoned Mine Lands (AML).

Typical coal refuse pile on abandoned mine lands. This site is Mine 37 located near Windber, PA along the Paint Creek.

In Pennsylvania, there are more than 5,000 abandoned, unreclaimed mining areas covering approximately 184,000 acres. The coal refuse piles at these abandoned mine lands cover an aggregated area of 8,500 acres and contain a total volume of more than 200 million cubic yards.

The total amount of coal refuse in Pennsylvania is unknown. Based on the known amount on abandoned mine lands and estimates of the amount of coal refuse associated with historical mining operations, the amount is between 200 million and 8 billion cubic yards. It has been speculated that the amount of coal refuse is approximately 2 billion cubic yards split almost equally between the anthracite and bituminous coal regions.

<u>What problems do unreclaimed coal refuse sites cause?</u>

<u>Land</u>

The coal refuse piles are scattered across the landscape next to communities, rivers and streams and sometimes fill entire valleys. These piles are unsightly and scar the landscape and some areas look like moonscapes. The piles also tend to attract dumping and other activities increasing the potential for nuisances such as starting the coal refuse piles on fire. Abandoned coal mines and coal refuse piles result in many adverse impacts to surrounding land. Unstable coal refuse piles may collapse and threaten the safety of nearby communities and the scenic and recreational quality of the landscape is ruined. Properly reclaimed coal refuse sites can and have returned the land to productive uses including wildlife habitat, recreational opportunities and commercial development.

Large coal refuse pile on an abandoned mine land located directly in the community of Nanty Glo, PA. These piles often attract use of recreational vehicles and other dangerous activities, which causes a safety concern.

Water

More than 3,300 miles of streams in Pennsylvania are impacted by Acid Mine Drainage (AMD), according to the United States Geological Survey (USGS). This is the result of AMD from both mine discharges as well acid runoff from coal refuse piles, as shown in this photograph. The acid mine drainage discharges, resulting from the oxidation of pyrites and maracites (iron-sulfide minerals), significantly impact water quality in the streams into which these contaminated waters flow. The acidic discharges contain iron, manganese, aluminum along with other metals and materials which become more readily soluble due to the increased acidity. The run-off from precipitation in addition to being acidic and contaminated by metals, contains silt which is a pollutant as well. This acidic contaminated discharge creates water pollution and negatively affects the ability of a stream to support and aquatic life. The chemistry of oxidation of pyrites in a coal refuse pile is very complex. Although a host of chemical processes contribute to acid mine drainage, pyrite oxidation is by far the greatest contributor. The net effect of these reactions is to release hydrogen ions (H^+), which lowers the pH and maintains the solubility of the ferric ion in the water. These reactions can occur spontaneously or can be catalyzed by microorganisms that derive energy from the oxidation reaction.

AMD entering a stream from a nearby coal refuse pile causes the stream to turn orange in color due to the iron precipitating out of solution as the solid iron hydroxide ($Fe(OH)2$). In many streams affected by AMD, the iron hydroxide covers the entire stream bed and rocks.

During 200 years of coal mining, Pennsylvania produced more than 25 percent of the nation's total coal output and presently ranks fourth in the nation in annual coal production by state. Pennsylvania’s coal regions are located within, or extend into, the four major river basins in Pennsylvania--the Ohio, Susquehanna, Potomac, and Delaware River Basins. Bituminous coal deposits underlie western and north-central Pennsylvania, and anthracite deposits underlie east-central and northeastern Pennsylvania.

As noted in the DEP Citizens Advisory Council’s Transition Report to the incoming State administration, Pennsylvania faces a documented abandoned mine land inventory cost of $16.1 billion. Of this amount, reclaiming coal refuse piles represents approximately $2 billion or more.

By comparison, federal abandoned mine land (AML) funding grants fell by 15% last year, and in 2014 only provided around $50 million toward abatement of such hazards. Under the current federal AML program, coal refuse piles receive relatively low priority and very limited funding; and the finding from the federal AML program is expected to continue to fall as reclamation fees from ongoing mining diminish.

Air

Depiction of uncontrolled combustion byproducts commonly referred to as "red-dog".

Coal refuse sites have historically and currently catch fire. Coal refuse fires typically start as a smoldering, oxygen starved fire producing the necessary oxygen from the generation of steam from the moisture in the coal refuse. Slowly, as the fire continues to develop, avenues for oxygen migration through the refuse expand resulting in flames. Combustion of the coal refuse allows uncontrolled toxic air pollutants and greenhouse gases to be emitted into the atmosphere. The toxic air pollutants are a particular health and safety problem in the proximity of the coal refuse fires.

The oxidation of pyrites produces an exothermic reaction which produces the heat that causes the carbonaceous material in the coal refuse pile to ignite and burn. The temperature within a coal refuse pile (or portions of a pile) will increase when more oxygen is available to cause oxidation but the amount of air circulating in the pile is insufficient to provide for the dissipation of heat. The temperature of the refuse increases until the ignition temperature of the carbonaceous material in the refuse is reached. At this point the coal refuse pile spontaneously combusts releasing the various uncontrolled air pollutants into the air of the near-by community.

Pennsylvania has identified more than 40 coal refuse piles that are currently burning and at some point will need to be addressed. This does not include underground mine fires. In 2014, the PADEP's Abandoned Mine Land Program spent $2,213,477.80 in emergency funds to extinguish and reclaim the Anthracite Region's Simpson Northeast coal refuse fire located in Fell Township, Lackawanna County.

Pennsylvania was the first state to pass a law to address the air pollution associated with coal refuse disposal entitled "The Coal Refuse Disposal Control Act, Act of September 24, 1968, P.L. 1040, No. 318." This has allowed the Commonwealth to address active coal refuse pile fires and to attempt to prevent additional coal refuse piles from catching fire. While the efforts have met with success, new coal refuse fires continue to occur.

The EPA (1978 Study) identified the uncontrolled emissions from burning coal refuse piles. The following pollutants were listed: (1) criteria pollutants (total particulates, respirable particulates, nitrogen oxides, sulfur dioxide, sulfur trioxide, hydrocarbons, carbon monoxide, and mercury); (2) non-criteria pollutants (ammonia, hydrogen sulfide, polycyclic organic materials); and (3) trace elements (arsenic, boron, silicon, iron, manganese, magnesium, aluminum, calcium, copper, sodium, titanium, lead, tin, chromium and vanadium)

The USGS Report entitled "Emissions from Coal Fires and Their Impact on the Environment" identified the following:

"…Self-ignited, naturally occurring coal fires and fires resulting from human activities persist for decades in underground coal mines, coal waste piles, and unmined coal beds. These uncontrolled coal fires occur in all coal-bearing parts of the world (Stracher, 2007) and pose multiple threats to the global environment because they emit greenhouse gases—carbon dioxide (CO2), and methane (CH4)—as well as mercury (Hg), carbon monoxide (CO), and other toxic substances…"

"…In the United States, the combined coast of coal fire remediation projects, completed, budgeted, or projected by the Office of Surface Mining Reclamation and Enforcement, exceeds $1 billion, with about 90% of that in two States—Pennsylvania and West Virginia… Altogether, 15 States have combines cumulative OSM coal-fire project costs exceeding $1 million…."

"…Direct hazards to humans and the environment posed by coal fires include emission of pollutants, such as CO, CO2, nitrogen oxides, particular matter, sulfur dioxide, toxic organic compounds, and potentially toxic trace elements, such as arsenic, Hg, and selenium (Finkleman, 2004). Mineral condensates formed from gaseous emissions around vents pose a potential indirect hazard by leaching metals from mineral-encrusted surfaces into nearby water bodies…"

<u>What is Pennsylvania's experience with reclaiming coal refuse sites?</u>

Over the last 50 years, Pennsylvania's experience has evolved. The commonwealth established and implemented "Operation Scarlift" in the 1960s and 1970s to address environmental damage from mining operations and today participates in the U.S. Department of the Interior's Abandoned Mine Land Reclamation Program, which utilizes money from industry to reclaim abandoned mine lands.

Reclamation costs, based on PADEP AML Program experience, varies between $40,000 per acre to $100,000 per acre. These costs are tied to the physical reclamation (grading, covering with soil, and planting vegetation) of a site. **These costs do not address the treatment of AMD or the elimination of the threat of future fires.** Using these cost-per-acre projections to reclaim sites, the physical reclamation of coal refuse sites of different acreage would be:

a. 20 acres $800,000 to $2,000,000
b. 50 acres $2,000,000 to $5,000,000
c. 100 acres $4,000,000 to $40,000,000

To reclaim these sites properly requires more than just planting vegetation such as beach grass. The sites need to be examined and plans developed to address water pollution problems, proper grading and controls and the proper use of vegetative sustaining cover using indigenous vegetation.

Frequently the PADEP's Abandoned Mine Land Program must utilize emergency funds to remediate coal refuse piles that have become a health or safety hazard. Examples include unstable or literally collapsed coal refuse piles as well smoldering or open flame fires. One experience occurred in 2014 with the Simpson Northeast Refuse Fire, Fell Township in Lackawanna County when the coal refuse pile that had been smoldering ignited in flames. The department had to expend $2,213,477.80 in emergency funds to extinguish the fire and reclaim the pile by grading, covering with soil and planting vegetation.

To extinguish a coal refuse fire, the burning coal refuse must be removed, spread out, and water or other chemicals used to quench the flames. After the fire is extinguished, the coal refuse is re-deposited by spreading and compacting, with the addition of alkaline materials as necessary to neutralize the residual acidic materials. The site is then covered with soil and re-vegetated. Hydrologic controls are also constructed, however, there is no money allocated to provide long-term discharge treatment for pollutants that have not been remediated.

<u>What must be considered in the reclamation of coal refuse piles?</u>

To properly reclaim coal refuse piles, the following, at a minimum, need to be addressed:

- water pollution from run-off and acid mine drainage discharges
- site stabilization including re-grading to insure the stability of the site as well as properly managed water run-off
- covering with vegetative supporting material
- planting with vegetation to support the final land use

The reclamation engineering design must include:

- Installation of hydrologic controls
- Installation of wet land treatment systems for small volume discharges
- Grading and compacting
- Covering of the site with 1 to 4 feet of soil
- Adjusting the soil acidity with alkaline materials
- Addition of fertilizers
- Vegetate consistent with the local flora

As the photograph shows, even after several years the site is still void of vegetation. Reclamation of a coal refuse site requires far more effort and expenditures than simply planting a species such as beach grass that may survive in that hostile environment. In that situation, the surface water, ground water and air pollution issues still would exist. The only problem that may be addressed by that solution is purely a cosmetic one in that the view of the coal refuse pile is not as stark.

The photograph also shows water pollution in the form of run-off and mine drainage (orange tinted water to the right and bottom of the pile) that is being caused by this abandoned coal refuse site. It is a site that previously experienced a fire, as evidenced by the red-dog (red color material on the top and right side of the pile). The site also has steep slopes that are eroding and will cause future stability concerns. Further, water accumulates on the pile and causes concentrated mine drainage to flow in the nearby stream.

Alternative Solution for reclaiming coal refuse impacted areas

Another approach to reclamation of coal refuse piles and the areas affected by them is through the utilization of coal refuse as a fuel. This solution addresses water pollution, potential coal refuse fires, and reclamation of coal refuse affected sites. Coal refuse can be an effective fuel in facilities designed to burn coal refuse in a controlled manner minimizing environmental impacts. If coal refuse from these sites is used as fuel, the coal refuse is removed, processed, burned and the resultant ash beneficially used to remediate the residual acidity at the site. When reclaimed in this fashion, all of the problems associated with coal refuse piles are permanently addressed. The EPA has described the benefits of coal refuse-fired electric generating units:

> "Coal refuse (also called waste coal) is a combustible material containing a significant amount of coal that is reclaimed from refuse piles remaining at the sites of past or abandoned coal mining operations. Coal refuse piles are an environmental concern because of acid seepage and leachate production, spontaneous combustion, and low soil fertility. Units that burn coal refuse provide multimedia environmental benefits by combining the production of energy with the removal of coal refuse piles and by reclaiming land for productive use. Consequently, because of the unique environmental benefits that coal refuse-fired EGUs provide, these units warrant special consideration so as to prevent the amended NSPS from discouraging the construction of future coal refuse-fired EGUs in the U.S."

Following are examples of before and after pictures of coal refuse pile reclamation projects performed by coal refuse fired plants:

GALLITZIN SITE -- Allegheny Township, Blair County

BEFORE RECLAMATION

AFTER RECLAMATION

ERNEST SITE -- Rayne Township, Indiana County

BEFORE RECLAMATION

AFTER RECLAMATION

ACOSTA SITE -- Jenner Township, Somerset County Permit

BEFORE RECLAMATION

AFTER RECLAMATION

Northampton's Huber Site -- Hanover Township, Luzerne County

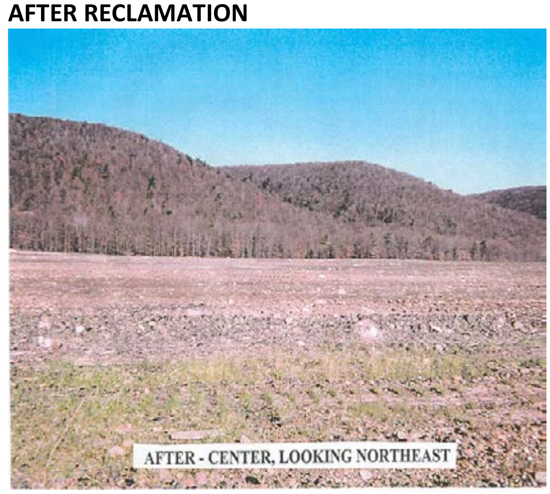
BEFORE RECLAMATION

AFTER RECLAMATION

Panther Creek – Nesquehoning Borough, Carbon County

BEFORE RECLAMATION

AFTER RECLAMATION

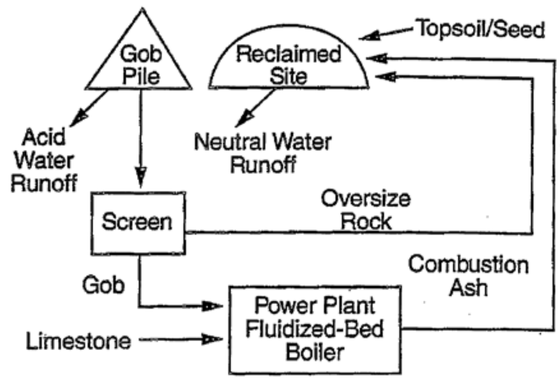


What processes do coal refuse-fired units use to solve the problems associated with abandoned coal refuse sites?

The re-mining of coal refuse piles in accordance with surface mining regulations provides for the reclamation of the energy remaining in this material. Because these sites had discharges to surface and ground waters, the companies are required to develop abatement plans. These abatement plans rely upon the use of acid-forming coal refuse being used as fuel in a fluidized bed combustion boiler or circulating fluidized bed boiler (CFB). The removal of the coal refuse results in the elimination of the AMD. The CFB Units are designed to fire coal refuse with limestone to control acid gas emissions, primarily sulfur dioxide (SO2), while producing an alkaline byproduct (coal ash) that can be beneficially used for mine land reclamation.

The figure below depicts the typical processes used to reclaim a coal refuse site using a coal refuse-fired CFB boiler. The coal refuse material is processed at the mine site by screening to remove rock and other inert materials. The finer material is used as fuel for the alternative energy power plant where limestone is added to the furnace to control acid gas emissions. The resulting ash material, which meets the beneficial use criteria, is returned to the mine site and mixed with any unusable coal refuse material as a means to neutralize any remaining acidic materials. The materials are then compacted in place to contours as described in the surface mining permit.

Typical Reclamation Process with a coal fired CFB boiler



The reclamation of the piles remediates the acidic drainage that comes from the coal refuse pile in two ways. Typically 75 percent or more of the coal refuse is moved off site as fuel for the alternative energy plant meaning the majority of the acidic materials and the resultant water pollution is removed from the nearby waterways. The remaining acidic material is neutralized by the beneficial use ash and compacted in place according to the contours defined in the surface mining permit. In addition, most of the water runoff in the area is diverted to flow around the reclaimed area rather than through the site. Consequently, the previous pollution released from an unreclaimed coal refuse pile is addressed both by reducing the quantity of water flow from the now reclaimed pile as well as by the improved quality of the runoff. The quality of the runoff is improved by removing the acidic materials that would normally dissolve the metals that exist in the coal refuse piles as well as through the change in the solubility of these materials due to the change in acidity at the site. As such the concentration of the acidity as well as the metals such as iron, aluminum, and manganese in surface and groundwater releases are significantly reduced.

<u>What is the air emission profile of a coal refuse-fired CFB boiler?</u>

Coal refuse-fired units convert coal refuse into steam and electricity by burning the fuel in a highly controlled and regulated fashion, using a specialized type of technology, circulating fluidized bed boiler (CFB) with limestone injection for acid gas control. These units are also equipped with fabric filter systems to control filterable particulate matter (FPM) emissions. The coal refuse-fired units control emissions of SO2, nitrogen oxides (NOx), air toxics, FPM and total particulate matter (TPM).

These units are some of the lowest emitters of mercury and FPM. That is evidenced in their use in the development of the MATS rule. Multiple coal refuse-fired units were included in Maximum Achievable Control Technology (MACT) Floor calculations (top 12% performing units) used to establish the emission standards for mercury and non-mercury metals. The result of the inclusion of these coal refuse-fired units resulted in lower MATS emission standards for mercury and non-mercury metals (including the FPM surrogate) than would have otherwise been established. While the coal refuse may be higher in mercury content, coal refuse fired units are very low emitters of mercury and are a primary reason why the MATS mercury emission rates are low for all coal-fired units.

In addition, the emissions of greenhouse gases from these units can be considered as offset due to the eventual in-place burning of the coal refuse piles. Coal refuse fires also result in the uncontrolled release of the same pollutants that these plants control with high removal rates. Because these units provide electricity to the grid they also reduce emissions from other fossil fuel-fired EGUs which otherwise would be operating. The reclamation and re-vegetation of coal refuse sites also results in the expansion of green spaces which aids in the sequestration of GHGs.

What are coal ash or Coal Combustion Residuals (CCR) and how can they be beneficially used for reclamation of coal refuse sites?

EPA has classified coal combustion residuals (CCRs), also called coal ash, as non-hazardous. Further, EPA has stated that due to the unique characteristics of surface mine reclamation the regulations are not applicable to the utilization of coal ash in coal mine land reclamation but EPA will be working with the Federal Office of Surface Mining Reclamation and Enforcement in the development of their rules. This office has been reviewing and analyzing various state programs including Pennsylvania as part of their process to develop rules that reflect best practices. Under the Pennsylvania Regulatory Program, the beneficial use of coal ash in coal mine land reclamation is a two-fold program.

The first component of Pennsylvania regulatory program is the certification and ongoing recertification of the coal ash for having a beneficial use in coal mine land reclamation. The coal ash certification process involves a comprehensive review of the source of the coal ash and an ongoing evaluation of the physical, chemical and leaching properties of the ash both at the point of generation and the where the coal ash is placed. Coal ash and coal ash leachate are analyzed for 37 different chemical constituents and properties. The ash leachate must consistently contain concentration levels lower than the certification requirements set forth in the regulations in order to be approved for statewide beneficial use at coal mine sites.

The second component of this regulatory program is integrating the beneficial use of the coal ash in coal mine land reclamation through Pennsylvania's Coal Mine Primacy Regulatory Program or through contract when the utilization is tied to the reclamation of abandoned mined lands. The programs are designed to insure that the management of the coal ash at the coal mine site will result in the reclamation of the land and improve water quality.

Over the past fifty years, the Pennsylvania's program have demonstrated its effectiveness. This is especially true for the coal refuse sites that have been re-mined and reclaimed.

Are there examples of the benefits provided by this reclamation?

There are numerous case studies regarding the reclamation of coal refuse sites and the benefits achieved. The Revloc Site and Maple Coal Site are two such examples:

REVLOC, PENNSYLVANIA

Revloc, PA is located in Cambria County approximately 90 miles east of Pittsburgh in the heart of the western Pennsylvania coalfields. The mining town centered the Revloc mine built in 1916-17. The Revloc mine later became Bethlehem Steel's Mine 32 and Beth Energy operated the mine until it was closed in the 1980s.

REVLOC Site – Pre-1989

In 1989, Ebensburg Power Company obtained a surface mining permit from the PA DEP for the re-mining and reclamation of the western side of the Revloc coal refuse pile. The reclamation project required the processing of the coal refuse to produce usable fuel by separating out some reject material that could not be burned in the CFB. The larger sized reject material consisted of the rock, clays, and "red dog", or the material left from the in-place burning of the coal refuse over the last century.

The fuel was trucked to Ebensburg Power Company's coal refuse-fired power plant and used for the production of alternative electric energy. The fuel was combusted with limestone, which controls acid gases in a circulating fluidized bed boiler. The ash that that is produced meets all criteria for beneficial use for coal mine land reclamation. This beneficial use ash was returned to the Revloc site and mixed with the reject material, compacted and contoured as defined in the surface mining permit.

In 1997, at the request of the local townspeople and the PADEP, Ebensburg submitted and received a surface mining permit for the re-mining and reclamation of the eastern side of the Revloc coal refuse pile. This part of the coal refuse pile was burning and on days when the wind was blowing from the east, the fumes would inundate the Revloc community. As part of the re-mining and reclamation work, Ebensburg Power Company extinguished the fires and ended the air pollution from the coal refuse pile that had occurred over the last century.

That coal refuse pile contained approximately 4,120,000 tons of material and covered approximately 56 acres of land. The eastern and western parts of the pile were separated by the South Branch of the Blacklick Creek. The runoff from the coal refuse pile would all flow into this creek resulting in the stream being devoid of aquatic life. The runoff from the coal refuse pile before reclamation discharged 226 tons per year of acidity, 0.5 tons per year of iron, 1 ton per year of manganese and 33 tons per year of aluminum.

The reclamation project was completed in 2011. During the project life, approximately 3,200,000 tons of usable coal refuse was removed from the site, and approximately the same number of tons of beneficial use ash was returned to neutralize the remaining acidic compounds contained in the reject material. The cost of the project was approximately $24 million.

The process reclaimed about 56 acres, of which 20 acres are available for industrial development. The coal refuse piles and fires are gone forever and approximately six miles of the South Branch of the Blacklick Creek has returned to a quality which supports aquatic life, including trout. The reclamation process reduced the acidity from the baseline by 93 percent, reduced iron by 92 percent, reduced manganese by 71 percent and reduced aluminum by 95 percent.

REVLOC Reclaimed

On December 12, 2008, the local paper the Johnstown Tribune-Democrat described and proclaimed the Revloc Reclamation Project as a **"**huge success**"**.

MAPLE COAL Site

Maple Coal Company – Colver Refuse Site, Barr and Blacklick Townships, Cambria County, PA.
Elk Creek (North Branch of Blacklick Creek; Blacklick Creek; Conemaugh River; Kiskiminetas River; Allegheny River; Ohio River)

Maple Coal Company (Maple), a wholly owned subsidiary of Inter-Power/AhlCon Partners, LP, provides coal refuse fuel to the Colver Power Plant (located in Cambria County, Pennsylvania).

The Maple Coal Company currently has three surface mining permits to mine coal refuse for use in their circulating fluidized bed boiler at the Colver Power Plant, the resulting alkaline ash is beneficially utilized to reclaim the area previously occupied by the acidic coal refuse. During the mining and reclamation activities, “red dog” was encountered providing evidence that the coal refuse had previously burned in-place.

Site reclamation of the Colver refuse site began in 1995 and has continued to this date. The majority of the coal refuse has been removed and the vast majority of the alkaline coal ash placement has been completed in the areas that were producing the AMD related to the first two Surface Mining Permits (SMP). Maple is now developing the area related to third SMP which will address the last remaining source of AMD in this portion of the drainage basin.

Pre-1965 Coal Refuse Mining and Reclamation

The Subchapter “F” monitoring stations (SW-2B, SW-4A and SW-23) on the Colver Refuse Site SMP #11900201 and the Rail Yard Refuse Site SMP #11970201 provide evidence that the water quality was severely impacted by AMD prior to the commencement of Maple’s reclamation operations. At the time of the original permit application, it was assumed that the removal of the acidic coal refuse and the beneficial use of the alkaline coal ash during their reclamation activities would improve the quality of the receiving stream (Elk Creek) by improving the water quality of the Subchapter “F” water monitoring stations (SW-2B, SW-4A and SW-23).

The pre-mining water quality from abandoned mine discharges to Elk Creek and its tributaries from the above referenced surface mining permits (abandoned coal refuse sites) accounted for 843.5 total tons of acidity, iron, manganese, and aluminum for the water samples collected and analyzed April 13, 1995, through April 8, 1996. The loadings in pounds per day is the average for the entire year based on twenty five samples/bi-monthly monitoring at each monitoring point.

Pre-Mining Loading on Elk Creek

April 13, 1995 through April 8, 1996

Acidity	689,149 lb/yr	344.6 tons/year
Iron (Fe)	23,932.9 lb/yr	11.97 tons/year
Manganese (Mn)	3,952.95 lb/yr	1.98 tons/year
Aluminum (Al)	47,779 lb/yr	23.89 tons/year
	TOTAL	382.44 tons/year

The most current data (December 18, 2013 through December 8, 2014) collected at these same monitoring stations indicate that the total tonnage of acidity, Fe, Mn, and Al is 1.0 tons or a reduction of 381.44 tons (99.73%). The loadings pounds per day is the average for the entire year based on thirteen samples, one sample per month per sampling point.

Post Refuse Removal – Site Utilization of Beneficial CFB Ash Placement

December 18, 2013 through December 8, 2014

	% Improvement Over Baseline
Acidity	99.9%
Iron (Fe)	97.6%
Manganese (Mn)	99.2%
Aluminum (Al)	99.9%
TOTAL	99.73%

Present Coal Mining and Reclamation Activities

Cross-State Air Pollution Rule (CSAPR)

Coal Refuse-Fired Electric Generating Units (EGUs)

What is CSAPR?

CSAPR is a rulemaking developed by EPA to address the transport of precursors of fine particulate matter (PM2.5) and ozone from EGUs. It is a market-based rule that establishes annual emissions budgets for SO2 and NOx and ozone season NOx including specific limitations on allowance trading. CSAPR was specifically developed to meet the "good neighbor" state implementation plan (SIP) requirements of the Clean Air Act (Section 110). The rule variously requires a total of 28 states to meet annual emissions budgets of NOx and SO2 and ozone season NOx, dependent upon the contributions to ambient air quality in "downwind" states. These emissions budgets were established for the 1997 ozone and PM2.5 and 2006 PM2.5 national ambient air quality standards (NAAQS).

What is ARIPPA recommending?

ARIPPA, the trade association representing coal refuse-fired EGUs in Pennsylvania and West Virginia, is proposing a technical correction to the CSAPR unit specific Phase 2 SO2 allowance allocations for bituminous coal refuse-fired EGUs. Specifically, ARIPPA is recommending:

- *Continuation of Phase 1 SO2 allocations to existing bituminous coal-refuse fired EGUs in Phase 2 and future CSAPR budgets;*
- *preservation of EPA's SO2 emissions budget by re-allocating SO2 allowances from EGUs that have retired or converted to natural gas and are no longer affected under CSAPR for SO2;*
- *that there be no economic windfall to bituminous coal refuse-fired EGUs;*
- *that bituminous coal refuse-fired EGUs can't sell or transfer SO2 allowances during Phase 2 or future CSAPR budgets to any other facility; and*
- *that any banked SO2 allowances held by a unit receiving this allocation must be surrendered upon retirement of that unit*

What is coal refuse, what are coal refuse-fired EGUs and why are they important?

Coal refuse is the material that has been left behind by historic coal mining activities. This includes the mining process and the processes which separated the coal from rock and carbonaceous material. Historically this process was far less efficient and a considerable amount of coal and carbonaceous material remains in this refuse.

Coal refuse causes a number of very damaging environmental effects. Coal refuse-fired EGUs provide a solution to those serious land, water and air pollution problems, as well as health and safety issues, by removing, remediating and reclaiming coal refuse piles. Coal refuse-fired EGUs convert coal refuse into steam and electricity by burning it in a highly controlled and regulated fashion, using a specialized type of technology. Most of the electricity generated by these facilities is sold in the PJM wholesale electric market.

Coal refuse-fired EGUs in Pennsylvania remove, and convert into electricity, approximately 11 million tons of coal refuse per year. To date, over 214 million tons of Pennsylvania coal refuse have been removed and burned as fuel and thousands of acres remediated and reclaimed, thus providing a solution for which Pennsylvania and West Virginia otherwise has very limited resources to address.

How does CSAPR work?

This program is being implemented under a Federal Implementation Plan (FIP) that allocates SO2 and NOx allowances to EGUs in two Phases. Phase 1 became effective January 1, 2015 and Phase 2 becomes effective on January 1, 2017. Under each Phase of the program, EGUs must surrender allowances to account for the SO2 and NOx emissions from the affected units.

How many of the 28 states are included in the CSAPR SO2 program?

Twenty-two of the 28 states included in CSAPR are affected by the CSAPR SO2 program. These are separated into two groups:

- Group 1 state are Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Mississippi, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Wisconsin
- Group 2 states are Alabama. Georgia, Kansas, Minnesota, Nebraska, and South Carolina

How did EPA determine SO2 allowance allocations for EGUs in the 22 states?

Using air quality modelling and their estimated costs of emissions controls, EPA established unit specific Phase 1 and Phase 2 emissions budgets for SO2 and NOx.

Pollution control-related cost estimates focused on assumptions for traditional coal-fired EGUs and the emission control technologies associated with those facilities, flue gas desulfurization (scrubbers) for SO2; selective catalytic reduction (SCR) for NOx; and dry sorbent injection (DSI) for SO2.

Using air quality dispersion and photochemical modeling to estimate total state contributions and the integrated planning model (IPM) modeling tools to estimate costs, EPA determined that Phase 2 unit specific SO2 allowance allocations would be made using 2005 unit specific heat input and an SO2 emission rate of 0.20 lb SO2/MMBtu.

Did EPA properly consider the SO2 emission rate for coal refuse-fired EGUs in their analysis?

No. EPA did not fully evaluate each unit with respect to the types of combustion technology used at specific facilities; the fuel being burned by specific facilities; emission control technologies already in place at specific facilities; or the availability and appropriateness of technologies to control SO2 from units less than 150 MW. While EPA included fuel switching as an option for emissions control, they did not recognize or consider that option is a limited opportunity for facilities like coal refuse-fired EGUs. Additionally, EPA did not recognize and consider the variation in the quality of coal refuse being burned in coal refuse-fired EGUs. Coal refuse is considerably lower in calorific value (Btu/lb), much higher in ash content and in the case of bituminous coal refuse, much higher in sulfur content. EPA did recognize high sulfur content in coal refuse when developing the NSPS standards for SO2 for coal refuse-fired EGUs.

EPA suggested that dry sorbent injection (DSI) would be effective in controlling SO2 from units less than 150 MW. However, the sorbent used in the DSI system considered in the analysis reacts with hydrochloric acid (HCl) and sulfur trioxide (SO3) prior to reacting with SO2, resulting in greatly reduced effectiveness for the control of SO2. Further, the analysis did not consider the effect of the sorbent on the ash from the combustion of coal refuse in a circulating fluidized bed boiler with limestone injection. The sorbent used in the DSI system resulted in the inability to beneficially use the ash in the remediation and reclamation of mine affected lands. To alter the composition of the ash in this fashion not only eliminates the opportunity to remediate and reclaim mine affected lands through the beneficial use of the coal refuse ash, it also adds an exorbitant cost (based on using EPA's DSI Cost Development Methodology) to the use of coal refuse to make electricity because it would have to be disposed in a landfill.

Another confounding issue related to the use of DSI is that the amount of sorbent that can be injected is limited due to the sizing of the existing fabric filters and other systems that are part of the particulate control equipment. When material is added to a system that was not initially designed for this purpose you have the risk of an emissions increase. With an emissions increase, it is possible that sorbent injection to the level necessary to achieve the required emission reduction would result in triggering the extreme costs of New Source Review (NSR) for particulate matter. Triggering NSR would require the installation of Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) dependent upon the classification of the area in which the facility is located.

Based on the technology used to burn coal refuse to generate electricity, circulating fluidized bed with limestone injection; the unique characteristics of bituminous coal refuse, high ash and sulfur content; the relatively small size of coal refuse-fired EGU's; and the limited ability to install additional post-combustion controls, it appears that EPA ***did not*** conduct a comprehensive and technically proper evaluation of the SO2 allowance allocations for bituminous coal refuse-fired EGUs. Utilizing the same methodologies and models used by EPA, ARIPPA performed a cost analysis for retrofitting existing units with the same post combustion emission control technologies that were used by EPA in their analysis. This analysis demonstrated levelized costs of SO2 control to be $3,300 to $6,483 per ton. This is considerably higher than the EPA cost threshold of $2,300 used for their technical feasibility analysis. Importantly, the levelized costs of control calculated by ARIPPA do not include the exorbitant cost of ash disposal in an approved landfill which, if included, could increase the costs to control SO2 by an order of magnitude.

Can coal refuse-fired EGUs achieve an emission rate of 0.20 lb SO2/MMBtu?

The ability of coal refuse-fired EGUs to operate and emit SO2 within the current Phase 2 allowance allocation, which is based upon 0.20 lb SO2/MMBtu, is dependent upon the sulfur content of the coal refuse. Coal refuse-fired units with limestone injection typically operate with a SO2 capture rate of 88% to 90% in the boiler. Consequently, those units burning coal refuse containing less than 1.5% sulfur by weight can achieve SO2 emissions at or below the current SO2 allowance allocation. However, when the coal refuse contains a sulfur content greater than 2% by weight, the ability to operate and emit SO2 at the current Phase 2 SO2 allowance allocation levels would require a unit specific SO2 emission capture rate in the boiler of 98%. That emission capture rate is considerably higher than the SO2 capture rate that has been demonstrated as achievable by these units.

The most recent design of a coal refuse-fired EGU in the US, which includes an integrated post combustion SO2 emission control system, cannot meet a 98% capture rate. Even with the post-combustion emission control systems those units only achieve an overall 95% SO2 capture rate.

What did EPA define as the New Source Performance Standards (NSPS) SO2 emission rate for coal refuse-fired EGUs?

As specified by 40 CFR Part 60 Subpart Da §60.43, the standards for sulfur dioxide (SO_2) for EGUs that burn 75 percent or more (by heat input) coal refuse on a 12-month rolling average shall control SO2 to limits including an output emission rate; an emission rate based on heat input; ***or*** 94% capture for new and reconstructed units and 90% capture for modified existing units. By providing these options for compliance demonstration, EPA established regulatory limits in the NSPS that recognize the inherent differences in the ability to control SO2 emissions from various vintage coal refuse-fired units and the variability of coal refuse as a fuel.

Why did EPA establish different SO2 control standards for Coal Refuse-Fired EGUs under the NSPS?

Coal refuse piles are an environmental concern because of acid mine discharge, acid seepage and leachate; spontaneous combustion and the resulting air pollution; and low soil fertility. Advancements in fluidized bed combustion technology allows coal refuse to be reclaimed and converted into steam and electricity using circulating fluidized bed technology. Many of these facilities began initial operations as combined heat and power co-generation qualifying facilities. Unfortunately, many of these facilities have lost their steam customers.

In the NSPS, EPA recognized facilities that burn coal refuse provide unique multimedia environmental benefits by combining the production of energy with removal, remediation and reclamation efforts that returns previously unavailable resources to public and commercial uses. Thus providing a unique solution to a serious environmental problem. Because of the unique environmental benefits that coal refuse-fired EGUs and cogeneration facilities provide, these units warranted special consideration. Consequently, the amended NSPS was written to avoid discouraging the construction and operation of coal refuse-fired power plants in the United States.

EPA stated, "…there is a possibility that coal refuse from some piles will have sulfur contents at such high levels that they present potential economic and technical difficulties in achieving the same SO2 standard that we are proposing for higher quality coals. Therefore, so as not to preclude the development of these projects, we are proposing a separate SO2 emission limit that we concluded is achievable for the full range of coal refuse piles remaining in the United States".

The critical points are that (1) EPA recognized the multi-media environmental benefits provided by coal refuse-fired electric generation units; (2) EPA recognized that the quality of coal refuse varies widely especially in terms of calorific value and sulfur content; and (3) EPA recognized that different vintage coal refuse-fired EGUs have different capabilities relative to the ability to control SO2. Rather than discourage and lose these benefits, EPA provided a mechanism to encourage and promote the environmental benefits. The key aspect relating to SO2 was recognizing that the units either achieve a reduction expressed as a percentage removal ***or*** an SO2 emission rate based upon either unit heat input or unit output which were established considering the capability of existing coal refuse-fired EGUs to achieve SO2 emissions control.

What are the problems associated with allowance allocations which cannot be achieved by all of the affected EGUs?

The trading of allowances under CSAPR is limited both by which group of states in which the affected unit is located and also by the number of allowances which can be emitted within a state in any given year. If emissions in a state are over the state's assurance level then any unit that is emitting over their annual allowance allocation must surrender additional allowances at a ratio of 2:1 for a total of 3:1 for the number of tons emitted in that year over the unit specific allocation. For a unit that can't economically control emissions below their allocation level, the only option to control that risk is to restrict the operations of the unit.

Also, the issues associated with an allowance allocation below the level that can be achieved by an affected unit is more complicated for a unit that operates in a competitive electric market such as the PJM Interconnection. This is because the need to use allowances to account for emissions ***favors those that can*** emit below their allowance allocation. When ***all*** of the units can operate below their allocation, the decision to purchase an allowance versus implementing additional control measures is an economic decision which results in lower total costs to the affected sources and the customers. That is exactly the situation that was in place when the acid rain program was implemented by EPA. Additionally, all units affected under the acid rain program were rate-based electric utilities. Now, most of the units in the PJM Interconnection are competitive electric generators that must use all of their competitive opportunities to ensure their economic success. Consequently, if a generator must go into the market to purchase allowances at an inflated price because they cannot economically implement additional emissions controls measures or switch fuel, except at an inflated cost that they are not certain that they can recover in the market, it is unlikely they will make these investments. In this "seller's market," they are more likely to operate at a reduced level for as long as they can remain profitable which is likely only a very short period. This becomes more likely if EPA is unable to cost justify the Mercury and Air Toxics Standards (MATS) Rule. That is because the affected traditional coal-fired EGUs will not be required to meet a "command and control" limit at the same emission rate as was used to allocate CSAPR SO2 allowances. The result of that situation is that the multi-media environmental benefits provided by coal refuse-fired EGUs will be lost, most likely forever.

Another question is whether a competitive electric generating company will sell their unused allowances to their competitors. A true supply and demand market would result in the allowances be available. However, if a competitor cannot operate without the purchase of allowances to cover their emissions, the seller may decide not to put their unused allowances on the market for competitive reasons.

Mercury and Air Toxics Standards (MATS) Rule

Coal Refuse-Fired Electric Generating Units (EGUs)

What is MATS?

The MATS rule was developed by EPA to meet the requirements of Section 112(d) of the Clean Air Act (CAA). MATS establishes maximum achievable control technology (MACT) standards for hazardous air pollutants (HAPs) for coal and oil fired electric utility steam generating units (EGUs). The rule establishes emission limits for a variety of HAPS including mercury, non-mercury hazardous metals and acid gases, (40 CFR Part 63, Subpart UUUUU, National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs)).

What is ARIPPA recommending?

ARIPPA is recommending an additional, alternative sulfur dioxide (SO2) limit for coal refuse-fired EGUs to use to demonstrate compliance with the MATS acid gas requirement. Coal refuse-fired EGUs meet the mercury emission limits and the filterable particulate matter alternative limit for demonstrating compliance with the non-mercury metals requirements. In some cases these units are part of the lowest emitters group that were used to develop the MACT "floor" to establish the MATS limits for mercury; filterable particulate matter (FPM); and non-mercury metals (NMM). However, these coal-refuse fired EGUs can't meet the hydrochloric acid (HCl) limits and many of the units that are burning coal refuse with a sulfur content greater than1.5% by weight, cannot meet the current SO2 limits for acid gases. Using the ARIPPA, recommendation, affected coal refuse-fired EGUs could demonstrate compliance with acid gas requirement using any one of the following: the current limits for HCl; the current SO2 limits; **or a demonstration of a 93% SO2 capture based on as-fired fuel sampling and continuous emissions monitoring.**

What is coal refuse, what are coal refuse-fired EGUs and why are they important?

Coal refuse is the material that has been left behind by historic coal mining activities. This includes the mining process and the processes which separated the coal from rock and carbonaceous material. Historically this process was far less efficient and a considerable amount of coal and carbonaceous material remains in this refuse.

Coal refuse causes a number of very damaging environmental effects. Coal refuse-fired EGUs provide a solution to those serious land, water and air pollution problems, as well as health and safety issues, by removing the coal refuse piles and remediating and reclaiming mine affected lands. Coal refuse-fired plants convert this material into steam and electricity by burning this coal refuse in a highly controlled and regulated fashion, using a specialized type of technology. Most of the electricity generated by these facilities is sold in the PJM wholesale electric market.

Coal refuse-fired plants in Pennsylvania remove, and convert into electricity, almost 11 million tons of coal refuse per year. To date, over 214 million tons of Pennsylvania coal refuse has been removed and burned as fuel and thousands of acres remediated and reclaimed, thus providing a solution for which Pennsylvania and West Virginia otherwise have very limited resources to address.

What is MACT?

MACT is defined under Section 112 of the CAA for control requirements or standards for compounds which have been listed as hazardous air pollutants (HAPs) and are often called "air toxics."

Historically, to develop a MACT standard for a particular source category, EPA evaluates the level of emission that is currently being achieved by the best-performing similar sources using HAP-compliant materials, clean processes, control devices, work practices, or other methods. These emissions are used to set a baseline for establishing the new standard. That baseline is commonly called the "MACT floor."

For existing sources, the MACT floor must equal the average emissions limitations currently achieved by the best-performing 12% of sources in that source category, if there are 30 or more existing sources. If there are fewer than 30 existing sources, then the MACT floor must equal the average emissions limitation achieved by the best-performing five sources in the category.

A MACT standard must, at a minimum, achieve throughout the industry, a level of emissions control that is at least equivalent to the MACT floor.

A "major source" of HAPs is defined as any stationary source (or group of stationary sources) that annually emits, in the aggregate, at least 10 tons of any single HAP or an aggregate of 25 tons of multiple HAPs.

How did EPA establish the standards for the MATS rule?

EPA's MACT floor for HCL was separated into only two subcategories with coal refuse-fired EGUs being included in the floor calculations for "Units designed for coal > 8,300 Btu/lb. While EPA attempted to capture all the coal fired units that were not "unit designed for low rank virgin coal", the low rank run of mine coal was tied to a calorific value (moisture, mineral material-free basis) of less than 8,300 Btu/lb. However, the "unit designed for coal >8,300 Btu/lb" is defined as being on an "as-received" basis rather than on a moisture, mineral free basis.

EPA definitions under the MATS rule:

Coal means all solid fuels classifiable as anthracite, bituminous, subbituminous, or lignite by ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (not meeting the definition of natural gas), solvent refined coal, coal-oil mixtures, and coal water mixtures, are considered ''coal'' for the purposes of this subpart.

Anthracite coal means solid fossil fuel classified as anthracite coal by American Society of Testing and Materials (ASTM) Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14)

Bituminous coal means coal that is classified as bituminous according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14)

Subbituminous coal means coal that is classified as subbituminous A, B, or C according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14)

Lignite coal means coal that is classified as lignite A or B according to ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14)

Coal refuse means any by-product of coal mining, physical coal cleaning, and coal preparation operations (*e.g.,* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

EPA development of MACT floors for "coal":

Rather than developing "subcategories" in the rule that would have established individual standards for different coals and different boiler types, i.e. anthracite coal, bituminous coal, subbituminous coal, lignite coal, coal refuse, pulverized coal-fired boiler, stoker coal feeder boiler or fluidized bed combustion boiler, EPA chose to define "coal" so as to include all the different types of coals into a single category only differentiating between lignite and all other coal types.

"***Fuel type*** means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, subbituminous coal, lignite, anthracite, biomass, and residual oil. Individual fuel types received from different suppliers are not considered new fuel types."

And, rather than establishing subcategories based on boiler technologies, EPA establish two subcategories for establishing the MACT floors:

Unit designed for coal > 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

Unit designed for low rank virgin coal subcategory means any coal-fired EGU that is designed to burn and that is burning non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

How many coal refuse-fired units are there?

There are 18 coal refuse-fired units:

Bituminous coal refuse-fired:

Utah – Sunnyside
Montana – Rosebud
Illinois – Marion
West Virginia – Grant Town and Morgantown
Pennsylvania – Cambria, Ebensburg, Colver, Scrubgrass, and Seward

<u>Anthracite coal refuse-fired:</u>

Pennsylvania – Westwood, Frackville, Mt. Carmel, Gilberton, Schuylkill Energy, Panther Creek, NEPCO and Northampton

<u>Were coal refuse-fired EGUs used to set the MACT floor for mercury and non-mercury metals emissions from all EGUs?</u>

Yes. Multiple coal refuse-fired units were included in MACT floor calculations to establish the emission standards for mercury and non-mercury metals. Inclusion of these units that use circulating fluidized bed combustion with limestone injection that are equipped with fabric filter systems for particulate matter (PM) control resulted in lower MATS standards for mercury and non-mercury metals, including the filterable PM alternative limit, than would have otherwise been established for pulverized coal-fired EGUs which are typically equipped with electrostatic precipitators for PM control.

<u>Were the coal refuse-fired EGUs used to set the MACT floor for acid gases?</u>

Only one coal refuse-fired electric generating facility was included in development of the HCl MACT floor. Seward, the newest coal-refuse fired electric generating facility, was included in the HCl data base and in the HCl MACT floor calculations. Seward includes two circulating fluidized bed boilers and has a total net capacity of 520 megawatts (MW). Included in Seward's initial design is an integrated flyash hydration system which was designed as a post combustion system to maximize the control of SO2. This system optimizes the use of limestone to provide SO2 control in addition to the SO2 capture in the fluidized bed. The integrated system was designed to control SO2 and the control of HCl is an "unexpected co-benefit." While Seward does achieve an HCl MATS limit, it does not achieved the SO2 acid gas emission limits, including 0.2 lb SO2/MMBtu.

None of the existing coal refuse-fired EGUs, with the exception of the last facility built, were designed with integrated post-combustion emission controls. Consequently, the units that were put into operation prior to Seward are limited to the capability of the boiler to capture SO2. Specific design characteristics that effect the capability of a boiler to capture SO2 include flue gas residence time in the furnace; limestone characteristics; material handling capacity; and material recycling capabilities.

In examining the coal refuse fired units, the characteristics of the coal refuse appear to be the main factor in the emission of HCl from these EGUs.

<u>What did EPA define as the New Source Performance Standard (NSPS) SO2 emission limit for coal refuse-fired units?</u>

As specified in 40 CFR Part 60 Subpart Da §60.43, the standards for sulfur dioxide (SO_2) for units that burn 75 percent or more, by heat input, coal refuse on a 12-month rolling average shall control SO2 to limits including an output emission rate; an emission rate based on heat input; ***<u>or</u>*** 94% capture for new and reconstructed units and 90% capture for modified existing units. By providing these options for compliance demonstration, EPA established regulatory limits in the NSPS that recognize the inherent differences in the ability to control SO2 emissions from various vintage coal refuse-fired units and the variability of coal refuse as a fuel.

<u>Did EPA properly consider coal refuse-fired EGUs in their analysis for their MATS emissions standards for acid gases?</u>

No. In the NSPS EPA recognized facilities that burn coal refuse provide unique multimedia environmental benefits by combining the production of energy with removal, remediation and reclamation efforts that returns previously unavailable resources to public and commercial uses. Thus providing a unique solution to a serious environmental problem in a number of states. Because of the unique environmental benefits that coal refuse-fired EGUs and cogeneration facilities provide, these units warranted special consideration. Consequently, the amended NSPS was written to avoid discouraging the construction and operation of coal refuse-fired power plants in the United States.

EPA stated, "…there is a possibility that coal refuse from some piles will have sulfur contents at such high levels that they present potential economic and technical difficulties in achieving the same SO2 standard that we are proposing for higher quality coals. Therefore, so as not to preclude the development of these projects, we are proposing a separate SO2 emission limit that we concluded is achievable for the full range of coal refuse piles remaining in the United States".

The critical points are that (1) EPA recognized the multi-media environmental benefits provided by coal refuse-fired electric generation units; (2) EPA recognized that the quality of coal refuse varies widely especially in terms of calorific value and, in the case of bituminous coal refuse, sulfur content; and (3) EPA recognized that different vintage coal refuse-fired EGUs have different capabilities relative to the ability to control SO2. Rather than discourage and lose these benefits, EPA provided a mechanism to encourage and promote the environmental benefits. The key aspect relating to SO2 was recognizing that the units either achieve a reduction expressed as a percentage removal ***<u>or</u>*** an SO2 emission rate based upon either unit heat input or unit output which were established considering the capability of existing coal refuse-fired EGUs to achieve SO2 emissions control.

These same factors were not considered in the development of the MATS standards for acid gases, consequently the analysis performed by EPA is flawed and the standards established under MATS for coal-refuse fired EGUs are inappropriate and flawed.

<u>Did EPA properly consider the SO2 emission rate achievable by coal refuse-fired EGUs in their analysis?</u>

No. EPA did not fully evaluate each unit with respect to the types of combustion technology used at specific facilities; the fuel being burned by specific facilities; emission control technologies already in place at specific facilities; or the availability and appropriateness of technologies to control SO2 from units less than 150 MW. While EPA included fuel switching as an option for emissions control, they did not recognize or consider that option was not available for facilities like coal refuse-fired EGUs. Additionally, EPA did not recognize and consider the variation in the quality of coal refuse being burned in coal refuse-fired units. Coal refuse is considerably lower in calorific value (Btu/lb), much higher in ash content and, in the case of bituminous coal refuse, much higher in sulfur content. EPA did however, recognize high sulfur content in coal refuse when developing the NSPS standards for SO2 for coal refuse-fired EGUs.

During the development of the Cross State Air Pollution Rule (CSAPR), EPA suggested that dry sorbent injection (DSI) would be effective in controlling SO2 from units less than 150 MW. However, the sorbent used in the DSI considered in the analysis reacts initially with hydrochloric acid (HCl) and sulfur trioxide (SO_3) prior to reacting with SO_2, resulting in greatly reduced effectiveness for use in the control of SO_2. Further, the analysis did not consider the effect of the sorbent on the ash from the combustion of coal refuse in a circulating fluidized bed boiler and the inability to beneficially use that ash in the remediation and reclamation of mine affected lands. To alter the composition of the ash in this fashion not only eliminates the opportunity to most successfully remediate and reclaim these areas through the beneficial use of the coal refuse ash, it also adds an exorbitant cost (based on using EPA's DSI Cost Development Methodology) to the use of coal refuse to make electricity because the ash would have to be disposed in a landfill..

Another confounding issue related to the use of DSI is that the amount of sorbent that can be injected is limited due to the sizing of the existing fabric filters and the systems used to control particulate emissions. When material is added in this fashion to a system that was not initially designed for this purpose you have the risk of an emissions increase. In this case, it could be possible that sorbent injection to the level necessary to achieve the required emission reduction would result in triggering the extreme costs of New Source Review (NSR) for particulate matter. Triggering NSR would require the installation of Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) technology, dependent upon the classification of the area in which the facility is located.

Based on the technology used to burn coal refuse to generate electricity, circulating fluidized bed with limestone injection; the unique characteristics of coal refuse, high ash and sulfur content; the relatively small size of coal refuse-fired EGU's; and the limited opportunity to install additional post-combustion controls, it appears that EPA ***did not*** conduct a technically proper evaluation of the HCl and SO_2 emissions to establish appropriate and achievable acid gas standards for coal refuse-fired EGUs.

Why did EPA establish different SO2 control standards for coal refuse-fired units under NSPS?

Coal refuse piles are an environmental concern because of acid mine discharge, acid seepage and leachate production; spontaneous combustion and the resultant air pollution; and low soil fertility. Advancements in fluidized-bed combustion technology allows coal refuse to be reclaimed and converted into steam and electricity using circulating fluidized bed technology. Many of these facilities began initial operations as combined heat and power co-generation qualifying facilities. Unfortunately, many of these facilities have lost their steam customers.

Are the chemical characteristics a greater impact on HCl emissions than emission controls?

The HCl emissions are primarily a function of the fuel because, with the exception of one facility, the coal-refuse fired EGUs can only use limestone injection into the boiler to control acid-gases, primarily SO_2.

Did any coal refuse-fired units attempt to control HCl emissions using DSI?

Yes. The results of that testing were provided to EPA. The testing demonstrated that it might be possible to reduce the HCl emission to 0.002 lb/MMBtu, however, the testing demonstrated several other undesirable effects:

1. Mercury emissions were increased by a factor of 6 to 40 times, resulting is the facility becoming non-compliant with the MATS mercury emission Rate of 1.2 lb/TBtu.

2. If a DSI system were to be installed and operated to achieve the HCl limit, then an additional mercury control system would be required to achieve the 1.2 lb/TBtu mercury MATS emission limit which is otherwise achieved without any additional controls.
3. DSI impacts the quality of the ash making it unacceptable chemically for beneficial use in coal mine land reclamation.

Can the coal refuse-fired EGUs meet the acid gas standard of 0.2 lb SO2/MMBtu?

The ability of coal refuse-fired EGUs to operate and emit SO2 within the current acid gas limit of 0.20 lb SO2/MMBtu, is dependent upon the sulfur content of the coal refuse. Coal refuse-fired EGUs with limestone injection typically operate with a SO2 capture rate of 88% to 90% in the boiler. Consequently, those EGUs burning coal refuse containing less than 1.5% sulfur by weight can achieve SO2 emissions at or below a current acid gas SO2 limit. However, when the coal refuse contains a sulfur content greater than 2% by weight, the ability to operate and emit SO2 at a current acid gas SO2 limit would require a SO2 emission capture rate in the boiler of 98%. That emission capture rate is considerably higher than the SO2 capture rate that has been demonstrated as achievable by even the newest coal refuse-fired EGU.

The newest design of a coal refuse-fired EGU in the US, which includes an integrated post combustion SO2 emission control system, cannot meet a 98% capture rate. Even with post-combustion emission control systems those units only achieve an overall 95% SO2 capture rate.