

# An Economic Scoping Study for CO<sub>2</sub> Capture Using Aqueous Ammonia



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## Final Report

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### ***Executive Summary***

Aqueous ammonia (AA), which is used in commercial applications to capture SO<sub>2</sub> and NO<sub>x</sub> from power plant flue gas, can also be used to capture CO<sub>2</sub>. This study assesses the benefits of aqueous ammonia for CO<sub>2</sub> capture compared to state-of-the-art amine systems. The potential increase in the cost of electricity from aqueous ammonia based CO<sub>2</sub> capture applied to a grass-roots pulverized-coal power plant is also calculated. Researchers at NETL's Carbon Sequestration Science Focus Area have demonstrated laboratory-scale CO<sub>2</sub> capture via cycling between carbonate and bicarbonate, with a heat of regeneration of 262 Btu/lb CO<sub>2</sub> captured versus 825 for mono-ethanol amine. We estimate that an aqueous ammonia system would require a net of 500 Btu of steam per lb CO<sub>2</sub> captured compared to 1,621 Btu for amines. Aqueous ammonia is also less expensive than amines at \$0.44/kg CO<sub>2</sub> carrying capacity versus \$8.3/kg for amines. Finally, aqueous ammonia can be used as a part of a multi-pollutant control system for the reduction of NO<sub>x</sub>, SO<sub>x</sub>, CO<sub>2</sub>, and Hg emissions.

The incremental cost of capturing mercury from a power plant with aqueous ammonia control for NO<sub>x</sub> is negligible. The cost of carbon absorbents system for this application is estimated to be \$60,000/lb mercury (4 mills/kWh). We estimate that aqueous ammonia technology can reduce the heat rate of a PC power plant equipped for CO<sub>2</sub> capture from 11,800 Btu/kWh (amine capture) to 11,300 Btu/kWh. The corresponding capital cost is reduced from \$1,880/kW to \$1,560/kW; and, in a fully-integrated multi-pollutant control system, aqueous ammonia has the potential to provide a net cost of CO<sub>2</sub> capture of \$21/metric ton of CO<sub>2</sub> emissions avoided (a 21% increase in COE compared to a pulverized coal power plant without CO<sub>2</sub> capture). Whereas, the current cost of CO<sub>2</sub> capture using amines is \$63/metric ton of CO<sub>2</sub> emissions avoided (an 83% increase in COE relative to a PC power plant without CO<sub>2</sub> capture). Research challenges include accommodating the flue gas temperature of 130°F, which is hotter than optimal for aqueous ammonia capture, and minimizing ammonia loss in the adsorption tower and from ammonia slip out the stack.

### ***Background: Analysis Goals and Methodology***

The Carbon Sequestration Program at NETL has set the following goals for its CO<sub>2</sub> capture research portfolio [1]:

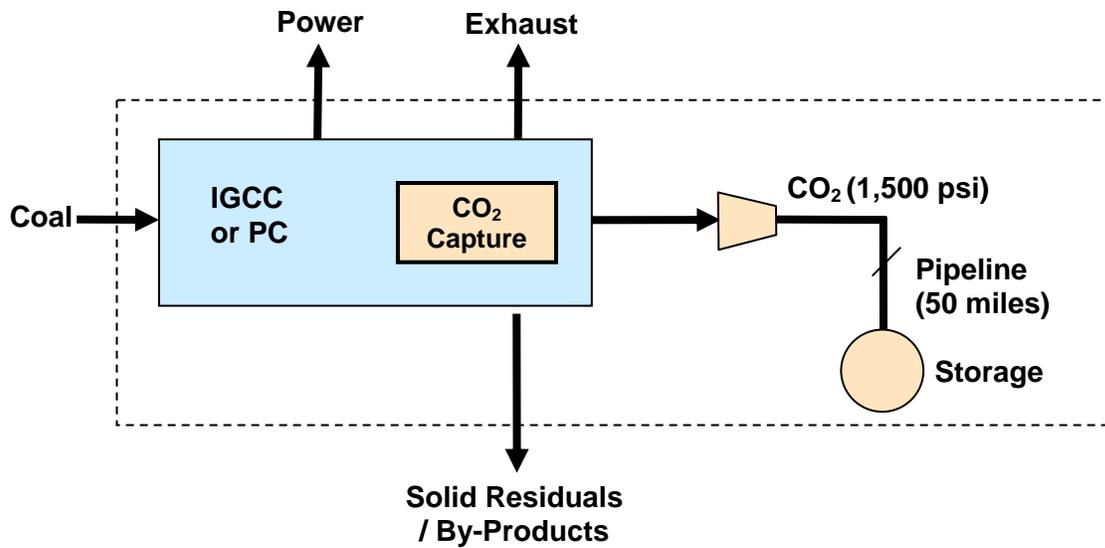
- Technologies for CO<sub>2</sub> capture from combustion-based steam power plants should capture at least 90% of CO<sub>2</sub> emissions and increase the cost of electricity by no more than 20%
- Technologies for CO<sub>2</sub> capture from gasification-based systems should capture at least 90% of CO<sub>2</sub> emissions and increase the cost of electricity by no more than 10%.

This analysis is one of several being conducted to determine the degree to which selected CO<sub>2</sub> capture technologies have the potential to achieve the program goals and to establish a framework for evaluating progress toward the goals. The aqueous ammonia concept is being pursued within NETL's Carbon Sequestration Science Focus Area [2, 3].

Research on aqueous ammonia use for CO<sub>2</sub> capture is at a very early stage, and a detailed system analysis at this time is not possible. Instead, an economic scoping study has been conducted to quantify the potential benefits of this technology. Our methodology is to develop a heat and material balance for a base case pulverized coal (PC) fired plant with amine-based CO<sub>2</sub> capture, using data

from published studies [4, 5]. Then, the performance of the new technology is compared to that of the amine system, a heat and material balance is developed, and an estimate of the differences in capital and operating cost relative to the base case amine is developed. Where possible, design heuristics (i.e. rules of thumb or guidelines from published papers) were used to estimate flows and sizes of equipment. However, some sizing and costing algorithms are employed for specific equipment such as CO<sub>2</sub> compressors and gas/liquid contact towers. For this initial assessment, we do not engage in rigorous modeling of unit operations. This is an area for later work as development of the technology progresses.

Figure 1 shows the system boundary used for this analysis. In estimating the impact of CO<sub>2</sub> sequestration on the cost of electricity, we consider the cost and energy consumption of pipeline transport for 50 miles and injection into a saline formation. We also consider revenues from by-products, which is an important consideration in the aqueous ammonia analysis.



**Figure 1. Analysis Boundary**

***Base Case PC Plant with Amine-based CO<sub>2</sub> Capture***

Aqueous ammonia capture of CO<sub>2</sub> is compared to a base case PC plant using conventional amines. A spreadsheet model was developed that is consistent with case 7A from reference [4] extrapolated to 400 MW net generation. Figure 2 and Table 1 show outputs from the model's amine capture case.

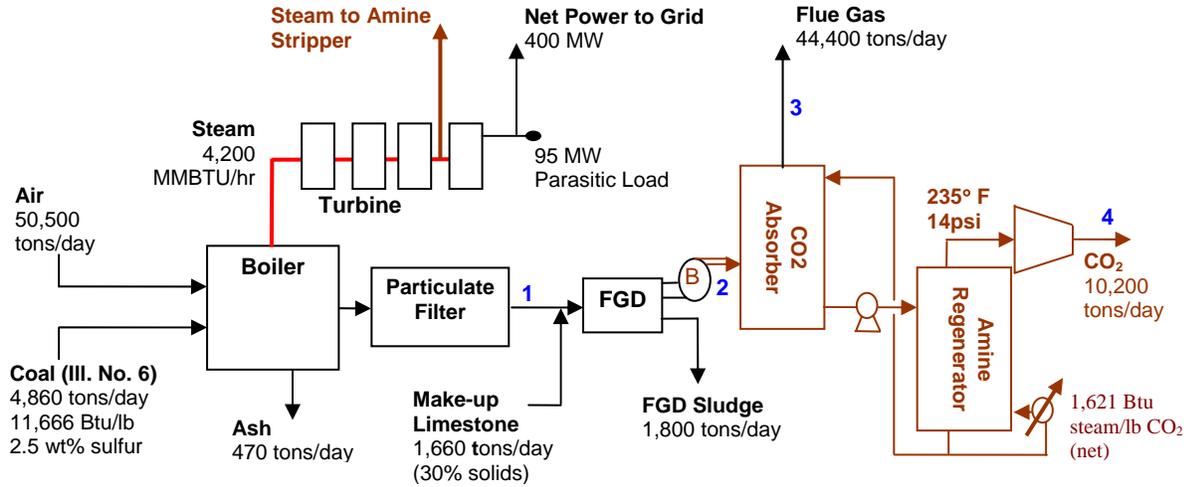
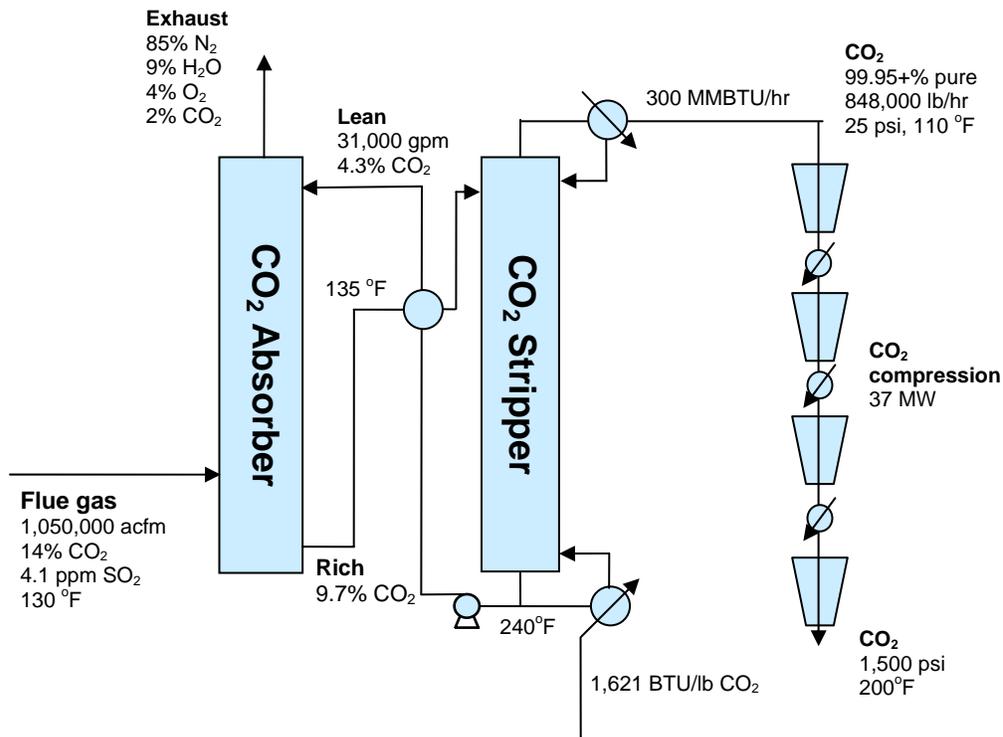


Figure 2. PC Power Plant with Amine CO<sub>2</sub> Capture (consistent with EPRI case 7A [4])

		1	2	3	4
		Boiler effluent	Absorber inlet	Flue gas exhaust	CO <sub>2</sub> product
Temperature, °F		281	131	136	100
Pressure, psia		14	17	14	1,500
Volume %	CO <sub>2</sub>	14%	14%	2%	100%
	O <sub>2</sub>	3%	3%	4%	0%
	N <sub>2</sub>	74%	74%	85%	0%
	H <sub>2</sub> O	8%	8%	9%	0%
	SO <sub>2</sub>	0.2%	4.1 ppm	0%	0%
	Argon	1%	1%	1%	0%
Molar flow (lbmoles/hr)		153,383	153,066	133,790	19,276
Vol. flow (10 <sup>6</sup> ACFM)		1.57	1.05	1.12	0.0010
Mass flow (tons/day)		55,346	54,602	44,424	10,178

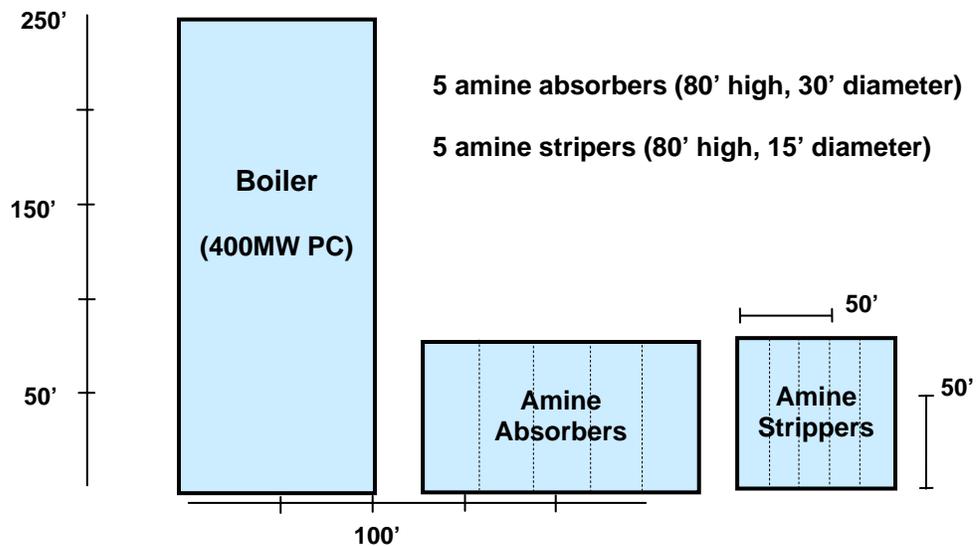
Table 1. Selected Process Flow Rates and Compositions

Figure 3 presents a more detailed look at the amine capture system. The size and cost of the absorber tower are functions of the actual volumetric flow rate of flue gas (1.05 million scfm) and percent CO<sub>2</sub> removal required (90%). CO<sub>2</sub> in the flue gas is reduced from 14 vol% to 2 vol%. The size and cost of the CO<sub>2</sub> stripper are primarily functions of the amine solution volumetric flow rate, which is calculated from the concentration difference between the rich amine solution (9.7 wt% CO<sub>2</sub>) and the lean amine solution (4.3 wt% CO<sub>2</sub>) [6, 7, 8]. The steam load for the amine stripper reboiler is large and pulls steam from the low-pressure turbine. The reboiler provides the net sensible heat required, the heat of reaction, and the heat for stripping steam. The reported 1,621 Btu/lb CO<sub>2</sub> is the enthalpy change in the steam across the reboiler.



**Figure 3. Amine Capture System used in the PC Base Case**

Figure 4 shows the size of the CO<sub>2</sub> capture equipment relative to the boiler. This gives a sense of the magnitude of impact that CO<sub>2</sub> capture will have on a PC power plant.



**Figure 4. Amine CO<sub>2</sub> Capture Footprint**

A discounted cash flow model was developed that inputs the capital expenditures for a 400 MW PC power plant, variable operating costs including coal use and chemical makeup, fixed operating costs, and by-product revenues. Using a plant economic life of 20 years and a capital charge factor of 14.5%, an iterative cost of electricity solution that balances expenditures and revenues was calculated. Table 2 shows the results from the cash flow analysis, which closely replicates the results from the EPRI study [4]. The cost of electricity goes from 4.9 cents/kWh in the no-capture case to 9.0 cents/kWh in the amine capture case, an 84% increase.

	No CO <sub>2</sub> Capture	Amine Capture
<b>Gross Power (MW)</b>	425	503
<b>Heat Rate (Btu/kWh)</b>	8,500	9,900
<b>\$/kW (equipment)</b>	1,100	1,900
<b>\$/kW (contingency)</b>	400	700
<b>COE (cents/kWh)</b>	4.9	9.0
<b>CO<sub>2</sub> emissions (kg/kWh)</b>	0.76	0.112
<b>Increase in COE (%)</b>	N/A	84
<b>CO<sub>2</sub> Avoided Costs (\$/tonne CO<sub>2</sub>)</b>	N/A	63

**Table 2. Economic Results**

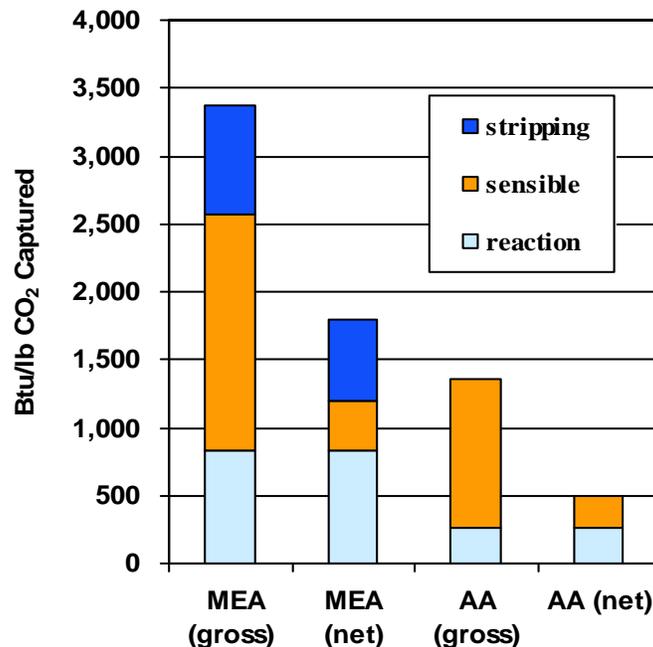
***PC with Aqueous Ammonia CO<sub>2</sub> Capture***

The following four advantages of the aqueous ammonia process compared to conventional amines have been identified: (1) reduced steam load, (2) more concentrated CO<sub>2</sub> carrier, (3) lower chemical cost, and (4) multi-pollutant control with salable by-products. The impact of each is discussed below.

1) *Reduced steam load.* In a system that captures and releases CO<sub>2</sub> by cycling between carbonate and bicarbonate, the heat of reaction is reduced to 262 Btu/lb CO<sub>2</sub>, which is much less than the 825 Btu/lb CO<sub>2</sub> needed with MEA [8, 9]. Also, it is possible that the carbonate/bicarbonate will exhibit a higher CO<sub>2</sub> carrying density than MEA (carrying density is the delta in CO<sub>2</sub> weight percent between rich and lean solutions), reducing sensible heat requirements. Finally, it is possible the carbonate/bicarbonate may require little or no stripping steam for regeneration, compared to one mole steam per mole of CO<sub>2</sub> captured typical of amine systems.

Figure 5 compares the heat requirements for an MEA CO<sub>2</sub> capture

**Figure 5. Heat Requirements for CO<sub>2</sub> Capture**



system versus one using aqueous ammonia. The total heat requirement is divided up into heat of reaction, sensible heat, and stripping steam. Figure 5 shows that heat integration enables significant reduction in the net heat requirement for the amine system. The gross heat requirement for an aqueous ammonia system was calculated and heat integration savings similar in magnitude to those achieved by amine was assumed.

2) *More concentrated CO<sub>2</sub> carrier.* In addition to affecting sensible heat, the CO<sub>2</sub> carrying capacity also affects the size of the CO<sub>2</sub> absorber and the circulation pump size and load. Laboratory data from NETL indicate the carbonate/bicarbonate system could exhibit a carrying capacity of 0.068 lb CO<sub>2</sub> per lb solution versus 0.054 for amines. Based on cost and sizing heuristics, the reduced liquid flow lowers the stripper cost from \$36.4 to \$25.2 million (three strippers in parallel vs. four) and reduces the circulation pump power requirement from 1.8 to 1.2 MW.

3) *Lower chemical cost.* Amine costs are estimated to be \$1.5/kg, which is high compared to anhydrous ammonia at \$0.29/kg. The calculations below show that ammonia is also significantly less expensive per unit of CO<sub>2</sub> absorption capacity:

Mono-ethanolamine Carrying Capacity:

$$\left( \frac{\$1.50}{\text{kgMEA}} \right) \times \left( \frac{0.3\text{kgMEA}}{\text{kgSolution}} \right) \times \left( \frac{18.5\text{kgSolution}}{\text{kgCO}_2} \right) = \frac{\$8.33}{\text{kgCO}_2}$$

Aqueous Ammonia Carrying Capacity:

$$\left( \frac{\$0.29}{\text{kgNH}_3} \right) \times \left( \frac{0.15\text{kgNH}_3}{\text{kgSolution}} \right) \times \left( \frac{14.7\text{kgSolution}}{\text{kgCO}_2} \right) = \frac{\$0.64}{\text{kgCO}_2}$$

The cost of the absorbent chemical is particularly important for coal-fired power plant applications, where residual SO<sub>2</sub>, SO<sub>3</sub>, and other species cause solvent degradation. For amines, the attrition was estimated from the following heuristics: general loss of 1.6 kg MEA/tonne CO<sub>2</sub>, and SO<sub>x</sub> loss of 2 mole MEA/mole SO<sub>x</sub> in absorber inlet [7]. Based on normal limestone scrubber operation removal (98%), amine make-up costs could be \$60 per ton CO<sub>2</sub> captured. A \$7.5 per ton CO<sub>2</sub> was assumed for aggressive limestone scrubbing (4.1 ppm SO<sub>2</sub> in the effluent) and recognizing that flue gas treatment options to reduce SO<sub>x</sub> upstream from the CO<sub>2</sub> absorber may be cost effective. A detailed analysis to accurately estimate ammonia attrition has not yet been performed. Instead, it was assumed that it will be similar on a molar basis to amine, based on reaction with contaminants in the flue gas and that the total cost will be less because of the lower purchase price of ammonia.

4) *Value-added by-products.* The use of ammonia-based systems to react NO<sub>x</sub> and SO<sub>x</sub> in flue gas to form fertilizer (ammonia sulfate and ammonia nitrate) has been demonstrated at commercial scale. A comparison of an amine system plus an SCR (Selective Catalytic Reduction) unit and limestone scrubber to an aqueous ammonia system in which ammonia is used for NO<sub>x</sub>, SO<sub>x</sub>, and CO<sub>2</sub> control was made.

Table 3 compares the aqueous ammonia process to a limestone scrubber. It has advantages if there is a market for the fertilizer. The domestic market for ammonium sulfate is roughly 2 million tons/yr [9]. One 400 MW coal-fired power plant with Aqueous Ammonia SO<sub>2</sub> control will produce about 100,000 tons per year. Therefore, twenty power plants would swamp the domestic market. The international market for nitrogen fertilizers is 83 million tons per year [10], so the world wide

potential for the aqueous ammonia technology is significant. Also, at the right price, ammonium sulfate could displace urea.

	Limestone Scrubber	Aqueous Ammonia
<b>Parasitic Load (MW, for a 400 MW net power plant)</b>	4-7	0.2
<b>Reactant Consumption and Cost (\$/ton SO<sub>2</sub>)</b>	22	154
<b>By-Product Revenue (\$/ton SO<sub>2</sub>)</b>	0	276
<b>Net Material Revenue (\$/ton SO<sub>2</sub>)</b>	-22	122
Limestone \$13/ton [4, 11], anhydrous ammonia \$290/ton [4], no market for FGD sludge, ammonia sulfate \$134/ton [12]		

**Table 3. Comparison of Aqueous Ammonia and Limestone Scrubbers for SO<sub>x</sub> Control**

Capturing NO<sub>x</sub> is not as attractive as capturing SO<sub>2</sub>. First, ammonium nitrate has the disadvantage that it can be used as an explosive. Its use will require detailed accounting and will pose a moderate security risk [13]. Second, in order for aqueous ammonia to react with NO<sub>x</sub>, NO, which is 95% of the NO<sub>x</sub>, must be oxidized to NO<sub>2</sub>. This requires another unit operation and an oxidant, such as ozone or peroxide. The oxidant represents a significant cost. However, if NO is oxidized, any Hg in the flue gas will also be oxidized, enabling it to be reacted with aqueous ammonia and removed from the flue gas. Mercury oxide reacts with ammonia to form a non-gaseous species that is in solution with the ammonia sulfate and ammonia nitrate. The aqueous solution containing all three species would be run through a carbon adsorbent bed to remove the mercury so that it does not contaminate the fertilizer. The current cost estimate for carbon-based mercury capture is \$60,000/pound [14]. We assume that mercury control will be required and that the avoided cost of a carbon system represents a revenue for the aqueous ammonia process.

Table 4 shows the relative operating cost impact of the by-products. The first thing to note is that the flow rate of CO<sub>2</sub> is very large compared to the other species. Even if revenues from one of the by-products is high on a per pound basis, it is much less when normalized on a per ton of CO<sub>2</sub> basis. Ammonium nitrate revenues do not cover the cost of the oxidation step, but the overall process works well when including the cost of mercury control. The value of the avoided cost of mercury control is highly uncertain. Appendix A contains the calculations behind the values presented in Table 4.

	Production Rate (lb/kWh)	Value (\$/ton)	Operating Cost (\$/ton)	Operating Revenue (\$/ton)	Operating Revenue (cents/kWh)	Revenue (\$/ton CO <sub>2</sub> avoid.)
<b>Mercury</b>	1.26E-07	1.2E+08	0	1.2E+08	0.75	10.3
<b>Ammonium Nitrate</b>	0.007	155	335.25	-180.25	-0.07	-0.9
<b>Ammonium Sulfate</b>	0.10	133.8	74.54	59.26	0.35	4.7
<b>CO<sub>2</sub></b>	2.26	--	--	--	--	--
*Includes value of avoided parasitic load from the limestone scrubber of 0.21 kWh/lb SO <sub>2</sub> captured						

**Table 4. By-product flows and Revenues in the Aqueous Ammonia Case**

### Aqueous Ammonia Multi-pollutant Capture System

Figure 6 and Table 5 show outputs from the spreadsheet model's aqueous ammonia multi-pollutant capture case. NO<sub>x</sub> and mercury are oxidized by ozone in a LoTOx™ system after exiting the particulate filter. The flue gas is contacted with aqueous ammonia to form ammonia nitrate, ammonia sulfate, and a non-gaseous mercury oxide specie. The solution is then passed through an activated carbon bed for mercury removal before passing through a centrifuge for fertilizer separation. CO<sub>2</sub> is removed from the flue gas in an ammonia scrubber, then compressed to 1,500 psi for injection.

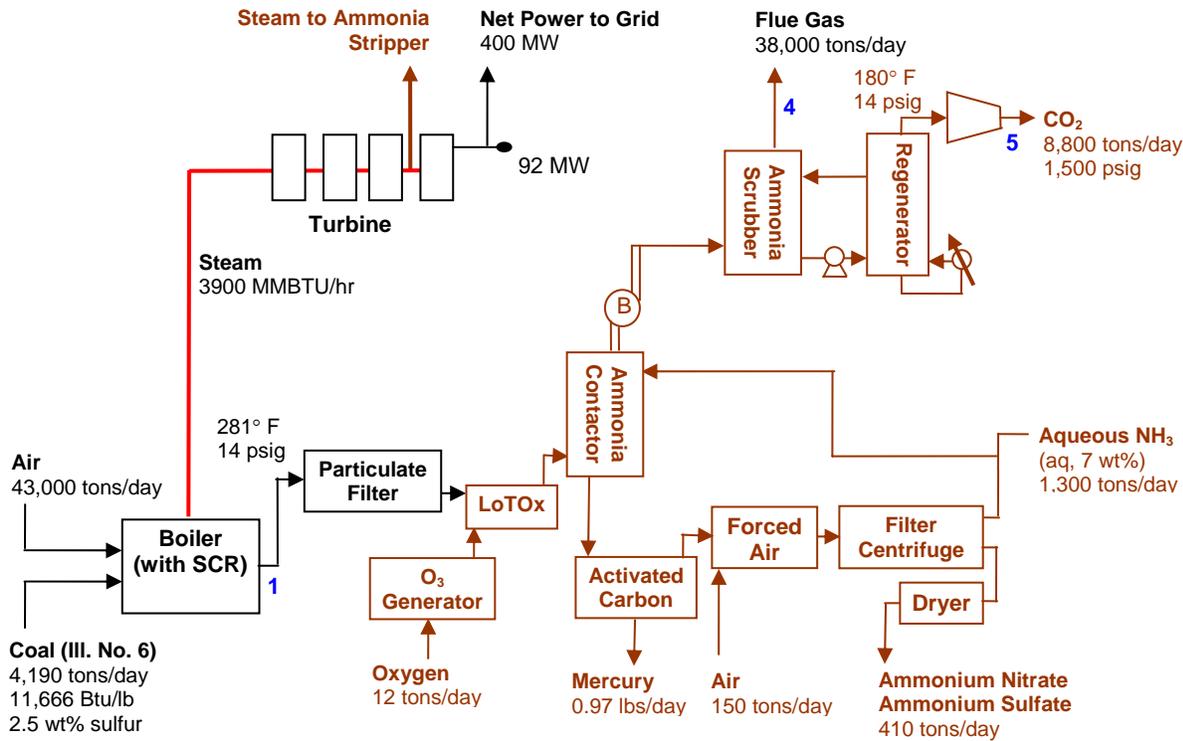


Figure 6. PC Power Plant with Aqueous Ammonia Multi-pollutant Control System

	1	2	3	4
	Boiler effluent	Absorber inlet	Flue gas exhaust	CO <sub>2</sub> product
Temperature, °F	281	131	120	136
Pressure, psia	14	14	17	14
Volume %	14%	14%	2%	100%
	3%	3%	4%	0%
	74%	74%	85%	0%
	8%	8%	9%	0%
	0.2%	0.2%	0%	0%
	1%	1%	1%	0%
Molar flow (lbmoles/hr)	132,033	132,065	131,760	115,167
Vol. flow (10 <sup>6</sup> ACFM)	1.35	1.1	0.91	0.97
Mass flow (tons/day)	47,642	47,223	47,001	38,240

Table 5. Selected Process Flow Rates and Compositions

## Results

Table 6 presents the results of a cash flow analysis of the no-CO<sub>2</sub>-capture, amine, and aqueous ammonia cases. The capturing only CO<sub>2</sub> aqueous ammonia case has potential advantages over the amine case, but the multi-pollutant system is needed for aqueous ammonia to approach the NETL program goal for CO<sub>2</sub> capture from power plants.

	1	2	3	4	5
	No Capture	Amine	Ammonia	Ammonia	Ammonia
<b>Component Captured</b>	N/A	CO <sub>2</sub>	CO <sub>2</sub>	CO <sub>2</sub> , SO <sub>2</sub>	CO <sub>2</sub> , SO <sub>2</sub> , NO <sub>x</sub> , Hg
<b>Boiler/Turbine capital cost, (\$/kW)</b>	830	830	830	830	830
<b>Gross Power, MW</b>	425	503	494	492	492
<b>CO<sub>2</sub> capture capital cost (\$/kg CO<sub>2</sub>/hr)</b>	N/A	350	320	320	320
<b>Steam to CO<sub>2</sub> recovered (Btu/kg CO<sub>2</sub>)</b>	N/A	6,000	1,700	1,700	1,700
<b>CO<sub>2</sub> comp. load (kWh/kg CO<sub>2</sub>)</b>	N/A	0.15	0.14	0.14	0.14
<b>By-product revenue (cents/kWh)</b>	N/A	0	0	0.32	1.01
<b>Capture cost (\$/tonne CO<sub>2</sub> avoided)</b>	N/A	63	37	28	21
<b>Cost of Electricity (c/kWh)</b>	4.9	9	7.4	6.4	5.9
<b>Increase in COE (%)</b>	N/A	84	51	31	20

**Table 6. Performance Metrics and Economic Summary of Results**

## 4. Recommendations for Future Work

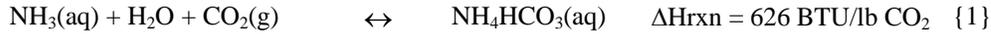
This initial analysis shows that aqueous ammonia technology has the potential to achieve the goals of NETL's Carbon Sequestration Program, but challenges for technology performance remain. The temperature of the flue gas is hotter than is optimal for carbonate/bicarbonate absorption. Researchers are investigating options to accommodate this higher temperature. Also, ammonia may vaporize in the absorption tower, due both to high temperatures and operational transients. Ammonia loss would hurt the economics directly and may require costly tail gas control. Laboratory-scale testing and more rigorous process analyses and modeling to address both these issues is recommended. Also, a more rigorous assessment of the oxidant cost would lower the uncertainty of the results. A study of domestic and international fertilizer markets would be useful to quantify the size of the potential market for aqueous ammonia capture technology.

## References

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## Appendix A.

### Heats of Reaction



### Calculations for by-product revenues from a supercritical PC power plant with Aqueous Ammonia-based multi-pollutant control

#### Global Data

- 2.5 wt% sulfur in coal
- NO<sub>x</sub> emissions
- heat content 11,666 Btu/lb
- 11,279 Btu/kWh net heat rate with AA capture
- 8,421 Btu/kWh net heat rate base case without CO<sub>2</sub> capture

#### Global calculations:

- CO<sub>2</sub> emissions avoided
- $[(8,421 - 11,279 \cdot (1 - 0.9)) \text{ Btu/kWh}] / 11,666 \text{ Btu/lb} \cdot 0.6375 \text{ lb C/lb coal} \cdot 3.67 \text{ lb CO}_2/\text{lb C} = 1.46 \text{ lb CO}_2/\text{kWh}$

#### Ammonia Sulfate

##### Data

- Ammonia cost, \$290/ton (Anhydrous, Chemical Marketing Reporter)
- Market value of ammonium sulfate, \$134/ton (Chemical Marketing Reporter)
- Reaction stoichiometry:  $\text{SO}_2 + 2\text{NH}_3 + \frac{1}{2} \text{O}_2 + \text{H}_2\text{O} \rightarrow (\text{NH}_4)_2\text{SO}_4$
- SO<sub>2</sub> removal 99.8%
- Load associated with a limestone scrubber: 0.21 kWh/lb SO<sub>2</sub> captured
- Value of electricity 5 cents/kWh

##### Calculations

- Ammonia use:  $2 \text{ NH}_3/\text{SO}_2 \rightarrow 34/64$ , 0.53 tons Ammonia/tons SO<sub>2</sub>
- Fertilizer generation rate:  $\text{SO}_2/(\text{NH}_4)_2\text{SO}_4 \rightarrow 64/132 = 0.485 \text{ ton SO}_2/\text{ton fertilizer}$

- Fertilizer feedstock cost:  $\$290/\text{ton Amm} * 0.53 \text{ Amm}/\text{SO}_2 * 0.485 \text{ SO}_2/\text{fertilizer} = 74.5 \text{ \$/ton}$
- Fertilizer operating revenue:  $134 - 74.5 = \$59/\text{ton fertilizer}$
- $(11,279 \text{ Btu}/\text{kWh}/11,666 \text{ Btu}/\text{lb}) * 0.025 \text{ lb S}/\text{lb coal} * 2 \text{ lb SO}_2/\text{lb S} * 99.8\% = 0.0482 \text{ lb SO}_2/\text{kWh}$
- $0.0482 \text{ lb SO}_2/\text{kWh}/0.485 \text{ lbs SO}_2/\text{lb fertilizer} = 0.10 \text{ lbs fertilizer generated per kWh}$
- $\$74.5 / \text{ton fertilizer} * 0.10 \text{ lbs fert}/\text{kWh} * .0005 \text{ tons}/\text{lb} * 100 \text{ cents}/\$ = 0.30 \text{ cents}/\text{kWh}$
- $0.211 \text{ kWh}/\text{lb SO}_2 * 5 \text{ cents}/\text{kWh} * 0.0482 \text{ lbs SO}_2/\text{kWh} = 0.051 \text{ cents}/\text{kWh}$
- $(0.35 \text{ cents}/\text{kWh}/1.46 \text{ lbs CO}_2/\text{kWh}) * (2000 \text{ lbs}/\text{ton}/100 \text{ cents}/\$) = \$4.75/\text{ton CO}_2$

## Ammonia Nitrate

### Data

- Ammonia cost,  $\$290/\text{ton}$  (Anhydrous, Chemical marketing Reporter)
- Market value of ammonium nitrate,  $\$155/\text{ton}$  (Chemical Marketing Reporter)
- Ozone cost:  $\$450/\text{ton}$
- $\text{NO}_x \rightarrow \text{N}_2\text{O}_5; \text{N}_2\text{O}_5 + 2\text{NH}_3 + \text{H}_2\text{O} \rightarrow 2\text{NH}_4\text{NO}_3$

### Calculations

- Ammonia use:  $\text{NH}_3/\text{NO}_x \text{ --- } 17/30, 0.6 \text{ tons Ammonia}/\text{tons NO}_x$
- Fertilizer generation rate:  $\text{NO}_x/\text{NH}_4\text{NO}_3 \text{ -- } 30/80 = 0.375 \text{ ton NO}_x/\text{ton fertilizer}$
- Fertilizer feedstock cost:  $\$290/\text{ton Amm} * 0.6 \text{ Amm}/\text{NO}_x * 0.375 \text{ NO}_x/\text{fertilizer} = \$65/\text{ton}$
- $1 \text{ moles O}_3/\text{mole NO}_x * (48 \text{ gO}_3/\text{mole}/30 \text{ g NO}_x/\text{mole}) = 1.6 \text{ lb O}_3/\text{lb NO}_x$
- $\$450/\text{ton NO}_x * 1.6 \text{ lb O}_3/\text{lb NO}_x * 0.375 \text{ ton NO}_x/\text{fert} = \$270/\text{ton fertilizer}$
- $155 - (65 + 270) = -\$180/\text{ton fertilizer operating revenue}$
- $0.00275 \text{ lb NO}_x/\text{kWh}/0.375 \text{ lbs NO}_x/\text{lb fertilizer} = 0.0073 \text{ lbs fertilizer generated per kWh}$
- $0.0073 \text{ lbs fert}/\text{kWh} * (-\$180)/\text{ton} * (100 \text{ cents}/\$/2000 \text{ lb}/\text{ton}) = -0.066 \text{ cents}/\text{kWh}$
- $-0.066 \text{ cents}/\text{kWh}/1.46 \text{ lb CO}_2/\text{kWh} * 2000 \text{ lb}/\text{ton}/100 \text{ cents}/\text{kWh} = -\$0.90 \text{ ton CO}_2 \text{ avoided}$

## Mercury

### Data:

- Mercury in coal,  $* 0.13 \times 10^{-6} \text{ lbs Hg}/\text{lb coal}$  [USGS]
- Estimated value of mercury emissions reduction:  $\$60,000/\text{lb Hg}$  [FE website]

### Calculations:

- $11,279 \text{ Btu}/\text{kWh} / 11,666 \text{ Btu}/\text{lb coal}) * 0.13 \times 10^{-6} \text{ lbs Hg}/\text{lb coal} = 1.26 \times 10^{-7} \text{ lb Hg}/\text{kWh}$
- $\$60,000/\text{lb} * 1.26 \times 10^{-7} \text{ lb Hg}/\text{kWh} = 0.75 \text{ cents}/\text{kWh}$
- $(0.75 \text{ cents}/\text{kWh}/1.46 \text{ lbs CO}_2 \text{ avoided}/\text{kWh}) * (2,000 \text{ lb}/\text{ton}/100 \text{ cents}/\$) = \$10.3/\text{ton CO}_2$