Evaluation of Wet FGD Technologies to Meet Requirements for Post CO_2 Removal of Flue Gas Streams

Paper # 49

Kevin Smith, William Booth, Stephane Crevecoeur - Dravo Technology, 3600 Neville Road, Pittsburgh, PA 15225

ABSTRACT

The possibility of CO_2 emission reductions from existing coal fired power plants being mandated is causing electric utilities to begin studying their options. One option to reduce CO_2 emission that is being considered is the use of regenerative sorbents (including amine) to scrub flue gas. One of several requirements to be met for power plant flue gas to be processed by amine scrubbing is for SO_2 concentration to be less than 10-ppmv (~20-mg/Nm3). This paper discusses the results of a comparative study of typical wet FGD methods used to achieve extremely low emissions of SO_2 and other acid gases in flue gas. This study reveals the critical assumptions and inputs that are required to draw meaningful conclusions.

INTRODUCTION

The US Congress has begun discussing climate change legislation seeks to reduce emissions of greenhouse gases (GHG), most notably CO_2, by as much as 80% by 2050. Regardless of whether or not CO_2 emissions will be limited to this degree in what eventually becomes law, industry and especially US power producers will have very difficult decisions to make. Among the most difficult decision is determining what to do about reducing CO_2 emissions from existing scrubbed and unscrubbed coal fired power plants. With utilities finding it more difficult to obtain permits to construct new more efficient coal based power plants such as supercritical boilers or IGCC, they are forced to consider extending the life of existing plants. Although not necessarily the motivation for their study, the US DOE investigated this scenario with a technical and economic study to capture CO_2 in a conventional PC fired power plant. The study recognized and proposed that a 42-ft (12.8-m) diameter secondary scrubber would be required to take flue gas SO_2 from 104 (~270-mg/Nm^3) to 6.5-ppmv (~17-mg/Nm^3).[1] The additional SO_2 scrubbing would be necessary for an advanced amine CO_2 scrubbing system to be installed. Whether extending the life of existing plants or building new ones; it is becoming more evident that reducing CO_2 emissions will have to be factored into how US utilities do business in the future.

CARBON CAPTURE AND SEQUESTRATION (CCS) AND FLUE GAS REQUIREMENTS

Based on the amount of discussion and research that is currently underway, carbon capture and sequestration techniques appear to be the near term solution for CO_2 emission reduction from coal fired power plants. Among many carbon capture technologies that are being developed; post combustion solvent scrubbing of flue gas using either chilled ammonia or Monoethanolamine (MEA) scrubbing, in spite of many drawbacks or development hurdles, are being discussed as likely near term possibilities[2]. A major consideration for either technique is the requirement for nearly all SO_2 (and NOx) to be removed from flue gas prior to being treated with MEA or chilled ammonia. Amine scrubbing requires an inlet flue gas SO_2 concentration to be less than 10-ppmv[3] (~20-mg/Nm3) or in a range from 3 (~8-mg/Nm3) to 15-ppmv[4] (~25-mg/Nm3). Several sources, while not specifically specifying a maximum SO_2 inlet concentration for chilled ammonia scrubbing of SO_2 recommend that for any post combustion chemical absorption process emissions controls either be designed to achieve ultra-low SOx emissions or be designed to allow equipment to be upgraded to accomplish this in the future.[5, 6] As described in Alstom Power Inc. U.S. Patent Application US 2008/0072762 A1, the chilled ammonia process removes remaining residual SO_2 by first chilling the flue gas that has already been through conventional treatment to below 20°C using water to condense any residual gaseous contaminants like SO_2 and SO_3 before entering the CO_2 scrubber. However not all CO_2 scrubber technologies operate at this low temperature, so other methods of removing SO_2 should be considered. The study presented in this article will assume that maximum possible SO_2 removal is required for any downstream CO_2 removal process. With this assumption comes the realization that post combustion CO_2 removal processes will dictate SO_2 emissions rather than governmental regulations.

SO_2 REMOVAL – FUNCTION OF COAL TYPE

Wet FGD is likely to be the most reliable means to achieve the high degree of SO_2 removal that will be required to accommodate CO_2 capture using a chemical absorption process. The specific design of any particular type of wet scrubber regardless of reagent is dependant upon the likely fuel to be consumed and the resultant flue gas conditions. Table 1 lists several coals found around the world that are used in coal fired power plants. The first three columns list sulfur content of each fuel type expressed in weight percent or mass SO_2 per unit energy common for the power industry. Untreated flue gas SO_2 concentration listed in the last two columns of Table 1 were estimated from coal analyses and combustion calculations and normalized to 6-volume % oxygen concentration.

Table 1 - Common fuel sulfur content and resulting flue gas conditions

				FGD Inlet @ 6-vol% O_2	
Fuel Type	**Sulfur wt.%**	**lb-SO_2/mmBTU**	**kg-SO_2/10^6 kJ**	**ppmv**	**mg/Nm3**
PRB	0.34	0.77	0.33	371	973
N. Dakota Lignite	0.70	2.26	0.97	1077	2824
Brown Coal	0.73	2.03	0.87	971	2546
SW USA Lignite	0.76	1.67	0.72	783	2052
S. Africa Coal	1.35	2.09	0.90	1034	2709
Illinois basin	2.54	4.22	1.81	2086	5466
Eastern USA Bit.	4.17	6.59	2.83	3240	8492

Clearly varying sulfur and heating value of each coal type results in different amounts of SO_2 that has to be removed from flue gas to achieve less than 10-ppmv SO_2. (Conversion from ppmv to mg/Nm^3 is not straight forward but for this exercise it will be assumed that 10-ppmv equals 20-mg/Nm^3 although this is not strictly accurate.) Figure 1 illustrates this clearly by indicating required SO_2 removal efficiency in terms of percentage and Number of Transfer Units (NTU). NTU is a particularly useful means of expressing SO_2 removal efficiency as it conveys the amount of mass transfer "work" that is required for a scrubber to achieve a desired level of SO_2 emission. NTU is calculated from percent removal using the following equation:

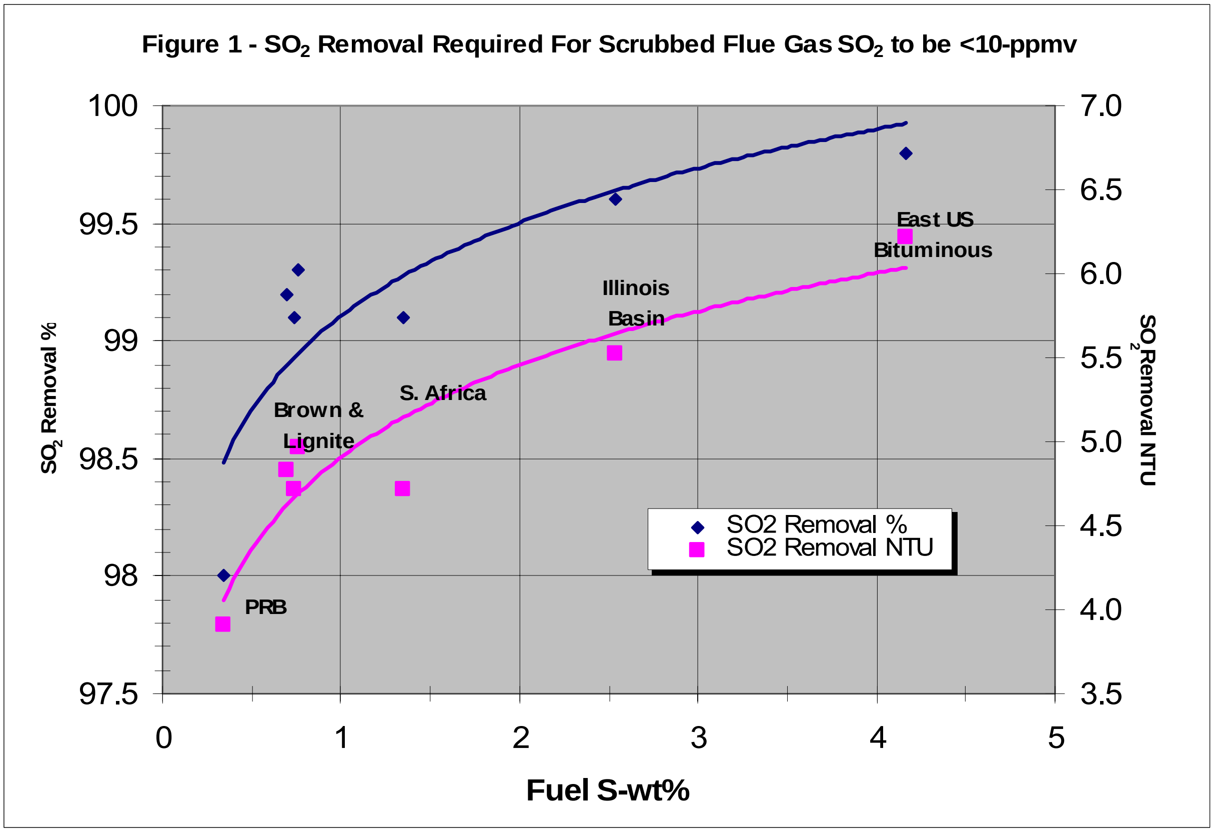
$$NTU = -\ln(1 - SO_2\% / 100).$$

An incremental increase of 1 NTU represents an equal amount of work to provide the necessary mass transfer to achieve a diminishing increase in SO_2 removal efficiency as shown in Table 2. Therefore increasing SO_2 removal efficiency from 95% to 99.3% (a 4.3 percentage point increase) requires double the effort of raising SO_2 removal from 86.5% to 95% (an increase of 8.5 percentage points). For wet scrubbers, the mechanical work required to push flue gas through a medium where sufficient mass transfer exists to achieve a desired SO_2 removal efficiency is the energy to operate recycle pumps and induced draft fans. The mass transfer medium is usually a combination of liquid droplets from spray headers, sieve trays or other flue gas flow straightening devices. Mass transfer can also be aided by using alkalinity enhancing chemicals such as $Mg(OH)_2$ or DBA.

Table 2 - Relationship of % SO_2 Removal to NTU

% SO_2 Removal Efficiency	**NTU**
63.2	1.0
86.5	2.0
95.0	3.0
98.16	4.0
99.33	5.0
99.75	6.0
99.91	7.0

Once the concept of NTU is understood, Figure 1 shows that regardless of the type of fuel and its sulfur content, in order to achieve SO_2 concentration of less than 10-ppmv (~20-mg/Nm^3) scrubbers will require a greater number of transfer units than is typically used to scrub SO_2 today.



WET FGD TECHNOLOGY DEVELOPMENTS TO ACHIEVE ULTRA-SO_2 REMOVAL

Limestone Forced Oxidation (LSFO) FGD

Wet limestone FGD scrubber vendors are aware of the need to achieve ever greater SO_2 removal efficiency and have both modified a number of existing LSFO scrubbers and designed new scrubbers to achieve up to 98% removal efficiency. This performance has been achieved using combinations of inlet flue gas straightening, dual trays, wall rings on the inside of the scrubber shell or baffles to force flue gas and liquid slurry toward the center of the scrubber, dual flow nozzles, and of course additional spray levels.

Table 3 lists several wet LSFO FGD retrofit and new installation projects that include next generation or ultra high SO_2 removal scrubbers.

Table 3 - LSFO FGD High SO_2 Removal Systems **(multiply L/G by 0.1334 for l/m^3)**

	Michigan South Central Power Agency - Endicott[7]						Vectren – Culley Station[8]		Trimble County[9]	Meliti Echlada[10]	K. C. Coleman[11]
SO_2 Removal %	97	98	95	93	90	89	99	98	99.2	99.2	99.3
NTU	3.5	3.9	3.0	2.7	2.3	2.2	4.6	3.9	4.8	4.8	5.0
Trays	2	2	2	2	1	2	-	-	-	-	3
Spray Headers	2	2	2	2	2	2	5	5	5	6	5
Liquid distribution Rings	N	N	N	N	N	N	N	N	N	Y	N
Baffles	N	N	N	N	N	N	Y	Y	Y	N	N
Dual direction nozzles	N	N	N	N	N	N	N	N	Y	N	N
L/G (gallon/ACF)	107	87	95	80	85	87	170	136	140	218	150
SO_2 lb/h	4,204	3,944	4,204	3,996	3,310	4,204	29,160	27,574	35,748	32,550	21,732
Recycle Rate (GPM)	19,400	15,600	14,400	14,600	15,500	17,100	180,000	144,000	220,000	237,200	208,000
SO_2-lb/k-gallon	3.50	4.13	4.62	4.24	3.20	3.65	2.67	3.13	2.69	2.27	1.73
Equivalent L/G (gallon/ACF)	157	137	145	130	110	137	195	161	190	243	225

Endicott, Culley and Trimble County power stations are existing LSFO FGD units that were modified by their original designers to improve SO_2 removal efficiency. Coleman Station and Meliti Echlada, a power plant located in Greece, represent new state-of-the-art FGD installations designed for higher than typical SO_2 loading of the flue gas. The SO_2 removal efficiencies mentioned in Table 3 were reported as the highest achieved during testing but do not represent the design condition or a performance guarantee.

SO_2 removal performance enhancements that are mentioned in the references include increased number of spray headers, multiple perforated trays, liquid distribution rings, baffles and dual direction nozzles. These enhancements either increase mass transfer area of recycled liquid, insure an even distribution of flue gas across the scrubber module or both. L/G for each column is as reported in each reference.

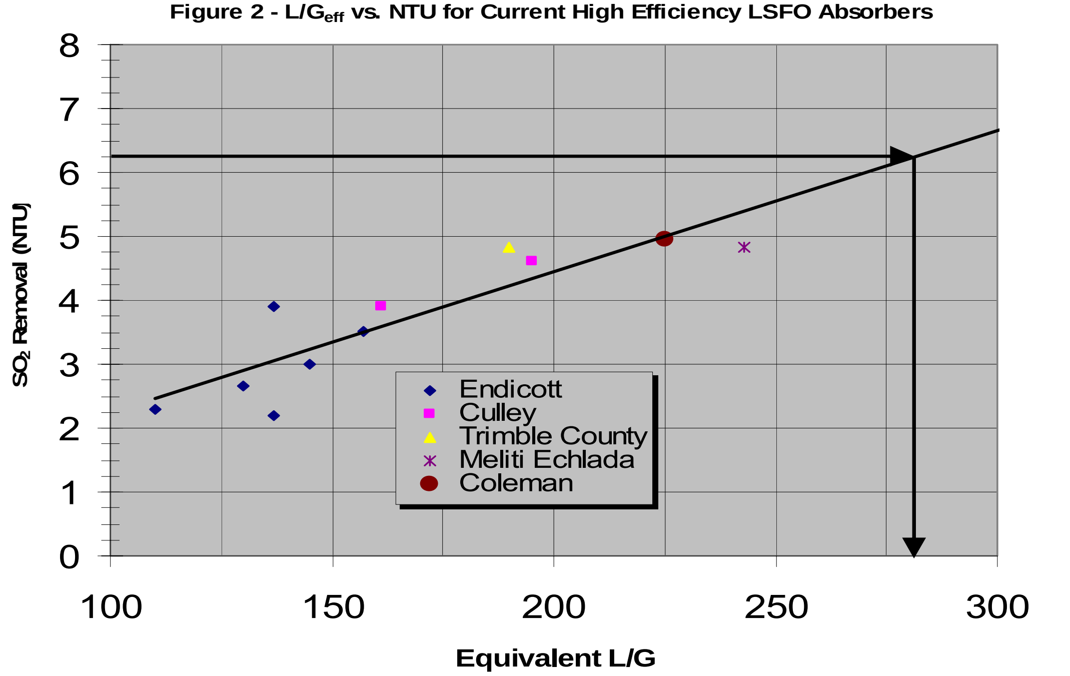
Using what flue gas information was provided in the respective references and making some assumptions about boiler operation, the values for SO_2 flowrate, scrubber recycle rate, SO_2 scrubbed per 1000 gallons of recycle slurry, and equivalent L/G were calculated by the writer. Babcock & Wilcox provides a useful parameter – SO_2 scrubbed per 1000 gallons of recycle slurry - that helps give a sense of the minimum volume of recycle slurry necessary to capture the desired amount of SO_2. Babcock & Wilcox mentions that a value of 5 is typical for the modified Endicott LSFO scrubber. This parameter decreases in value (regardless of sulfur loading in the flue gas) as actual L/G increases to improve SO_2 removal efficiency and increases if enhancements like those listed in Table 3 are employed[6].

While impressive improvement in SO_2 removal efficiency is reported for all the cases in Table 3, calculations using the information on hand indicate that SO_2 concentration in the flue gas exiting these absorber systems remain significantly above 10-ppmv. To achieve flue gas with less than 10-ppmv SO_2 a removal efficiency of 99.8% or 6.2 NTU is required. With an understanding of the relationship between NTU and SO_2 removal efficiency and the data presented in Table 3, one should be able to estimate how much further absorbers need to be improved to exceed the SO_2 concentration threshold of 10-ppmv.

One way to do this is to plot SO_2 removal as NTU vs. L/G, but a means of accounting for the enhancements listed in Table 3 is required. B&W states in reference 6 that the use of a single perforated tray is worth an L/G of 25 to 30 gal/1000-ft^3 (3.34 to 4-l/m^3). This analogy was also assigned to each of the other absorber enhancements (liquid distribution rings, baffles and dual direction nozzles) and added to the reported L/G to arrive at the Equivalent L/G values in the last row of Table 3. Figure 3 is a plot of Effective L/G vs. reported SO2 removal efficiency as NTU.

With the exception of Meliti Echlada, all stations in Table 3 burn high sulfur bituminous coal so

Figure 2 - L/G$_{eff}$ vs. NTU for Current High Efficiency LSFO Absorbers



a least squares trend line can be drawn through the plotted data and extended. At where the trend line intersects 6.2 NTU (99.8% SO_2 removal efficiency) an equivalent L/G of approximately 280 gal/1000-ft^3 (37.5 l/m^3) is determined. It is important to remember again that equivalent L/G here equals any combination of recycled slurry and absorber enhancement; i.e. tray, baffle, dual direction nozzle or liquid distribution rings, each assumed to be equivalent to L/G of 25 gal/1000-ft^3 (3.344-l/m^3).

Magnesium Enhanced Lime (MEL) FGD

While MEL FGD has always been thought to have the capability to achieve ultra-high SO_2 removal efficiency, there is little published data indicating a removal efficiency of 99.8%. Using published articles about various MEL FGD facilities an approach similar to that used for LSFO can be taken to determine what improvement in absorber design may be required for MEL absorbers to achieve SO_2 concentration below 10-ppmv (~20-mg/Nm^3).

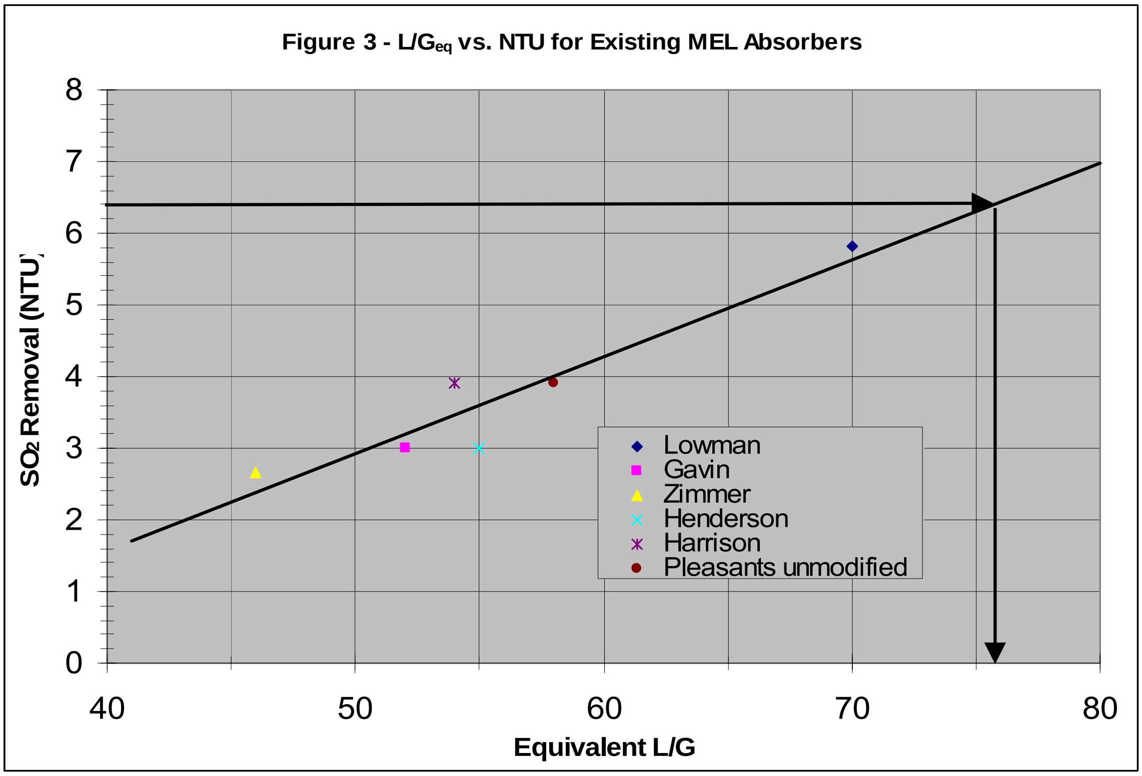
Table 4 lists several retrofit and new MEL FGD projects that were installed in the mid 1990's and typically burn mid to high sulfur fuels ranging from 3 to 4.5-wt% sulfur. There is no documentation of any SO_2 removal enhancement other than perforated trays being used in any MEL absorber. For any absorber designs having a perforated tray, 25 L/G was added to actual L/G to arrive at equivalent L/G listed in the last row of Table 3. As with the LSFO cases using what flue gas information was provided in the respective references and making some assumptions about boiler operation, the values for SO_2 flowrate, scrubber recycle rate, SO_2 scrubbed per 1000 gallons of recycle slurry, and equivalent L/G were calculated by the writer.

Table 4 - MEL FGD Systems **(multiply L/G by 0.1334 for l/m^3)**

	Lowman[12]			Gavin[13]	Zimmer[14]	Henderson[15]	Harrison[16]	Pleasants Unmodified[17]
SO_2 Removal %	96.7	99.2	99.7	95	93	95	98	98†
NTU	3.4	4.8	5.8	3.0	2.7	3.0	3.9	3.9
Trays	-	-	-	1	1	1	0	1
L/G (gallon/ACF)	23	44.7	70	27	21	30	54	33
SO_2 lb/h	9,922	9,922	9,922	82,520	64,584	12,653	103,675	36,107
Recycle Rate (GPM)	16,200	31,000	48,400	15,000	23,000	22,065	221,000	48,000
SO_2-lb/k-gallon	9.87	5.29	3.41	11.36	8.14	9.08	7.66	12.29
Equivalent L/G (gallon/ACF)	23	44.7	70	52	46	55	54	58

† SO_2 removal efficiency is only for flue gas that is not bypassed around the scrubbing system.

As with the LSFO data, equivalent L/G is plotted vs. SO_2 removal efficiency as NTU in Figure 3. A least squares trend line is extended beyond 6.2 NTU to estimate the required effective L/G of 76-g/1000-ft^3 (9.9-l/m^3).



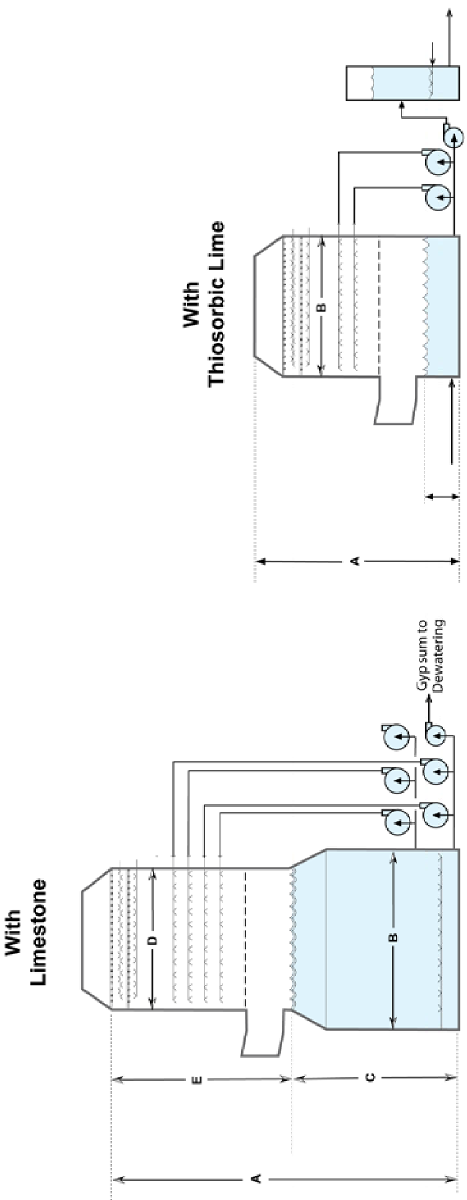
IMPLICATIONS FOR EXISTING AND NEW FGD INSTALLATIONS

Both LSFO and MEL FGD results indicate significant changes in absorber design and operation will be required to achieve less than 10-ppmv (~20-mg/Nm^3) SO_2 in flue gas that is to be processed for CO_2 removal. Scrubbing "harder" will mean higher L/G combined with use of multiple scrubbing enhancements that have been discussed and in turn will mean taller absorbers and more energy expended. Although Dravo Technology is familiar with the basic concepts of FGD design and engineering, Dravo Technology is not in the business of designing and engineering FGD absorber systems and users are advised to consult qualified engineering companies to address specific design and engineering issues. Our interest in this subject lies in the need to discuss intelligently with utilities what to expect future absorber design to be as emission limits become even more stringent. It is possible using published information and application of basic engineering skills to approximate the trend in absorber design. Therefore in order to appreciate the magnitude of changes to absorber design, an assessment of MEL and LSFO absorber designs a study was conducted where three different coal sulfur cases are presented. The fuels considered for this study include Powder River Basin (PRB) at 0.6-wt% S, Appalachian coal at 1.3-wt% Sulfur and Appalachian coal having 3-wt% Sulfur. These fuels are identical to those used by Sargent & Lundy in their economic evaluation of MEL and LSFO FGD processes[18].

Design assumptions for all cases are a nominal 500-MW single unit supplying flue gas to a single absorber module. Scrubber flue gas velocity was nominally set to 12-fps (3.7-m/s) and a single sieve tray is the only flue gas contacting enhancement device employed for all cases. The mass rate of SO_2 entering the absorber was taken into account when deciding on the liquid to gas ratio for each case. Whenever possible the references cited in this paper were used for guidance. Materials of construction were not considered germane in this study.

The LSFO PRB cases used individual pumps of 36,000 GPM (8176-m^3/h) while the Appalachian coal cases used individual pumps of 50,000 GPM (11,360-m^3/h), reaction tanks were assumed to have a residence time of between 18 and 24 hours. All MEL FGD cases with the exception of PRB at 98% SO2 removal use two recycle spray headers which resulted in varying individual pumps capacities ranging from 20,000 to 40,000 GPM (4543 to 10,000 m3/h) and ex-situ oxidation is used to produce gypsum

Using standard coal combustion calculations and knowledge of FGD chemical reactions, a material balance was created to determine resulting flue gas conditions from the three coals previously mentioned for a hypothetical 500-MW boiler. Using available information about LSFO and MEL absorber design and the results of Figures 2 and 3, MEL and LSFO scrubber designs were developed for both 98% removal efficiency and the SO_2 removal efficiency was required to achieve a scrubbed flue gas that had less than 10-ppmv (~20-mg/Nm^3) SO_2. For PRB, low sulfur Appalachian and high sulfur Appalachian coals those SO_2 removal efficiencies were respectively, 99% (3.9 NTU), 99.6% (5.5 NTU) and 99.8% (6.2 NTU). Also estimated is electric power consumption to move flue gas and air through the absorber and recirculate absorber slurry. The results are found in Figure 4.



	PRB Coal				Appalachian Coal - 1.3% sulfur				Appalachian Coal 3% sulfur			
	98% SO_2 Removal		99% SO_2 Removal		98% SO_2 Removal		99.6% SO_2 Removal		98% SO_2 Removal		99.8% SO_2 Removal	
Dimensions	MEL	LSFO	MEL	LSFO	MEL	LSFO	MEL	LSFO	MEL	LSFO	MEL	LSFO
A - ft. (m)	57 (17.4)	95 (29)	60 (18.3)	95 (29)	58 (17.7)	105 (32)	65 (19.9)	125 (38.1)	62 (18.9)	145 (44.2)	72 (22)	170 (51.8)
B - ft. (m)	50 (15.3)	50 (15.2)	50 (15.3)	50 (15.2)	50 (15.3)	55 (16.8)	50 (15.3)	55 (16.8)	50 (15.3)	65 (19.8)	50 (15.3)	65 (19.8)
C - ft. (m)	n/a	20 (6.1)	n/a	20 (6.1)	n/a	30 (9.1)	n/a	30 (9.1)	n/a	50 (15.2)	n/a	45 (13.7)
D - ft. (m)	n/a	50 (15.2)	n/a	50 (15.2)	n/a	50 (15.2)	n/a	50 (15.2)	n/a	50 (15.2)	n/a	50 (15.2)
E - ft. (m)	n/a	75 (22.9)	n/a	75 (22.9)	n/a	75 (22.9)	n/a	95 (29)	n/a	95 (29)	n/a	125 (38.1)
No. of Spray Headers	2	3	3	3	3	3	3	5	3	5	3	8
No. of Trays	1	1	1	1	1	1	1	1	1	1	1	1
L/G gal/kacf (l/Nm3)	20 (3.06)	50 (483)	30 (4.6)	60 (579)	30 (4.52)	80 (759)	50 (7.53)	150 (1423)	40 (6.02)	130 (1234)	70 (10.54)	240 (2277)
SO_2 lb/h (kg/h)	7100 (3230)	7122 (3231)	7100 (3230)	7122 (3231)	9600 (4360)	9625 (4366)	9600 (4360)	9625 (4366)	23050 (10460)	23122 (10488)	23050 (10460)	23122 (10488)
SO_2-lb/k-gallon (kg/kl)	4 (0.48)	2 (0.19)	3 (0.32)	2 (0.16)	4 (0.46)	2 (0.18)	3 (0.28)	1 (0.1)	7 (0.83)	3 (0.26)	5 (0.49)	2 (0.14)
Operating Spray Headers	1	2	2	2	2	2	2	4	2	4	2	7
Recycle Rate - GPM (m3/h)	29230 (6640)	71976 (16346)	43850 (9960)	86378 (19617)	40400 (9180)	106677 (24227)	67330 (15290)	200044 (45430)	54060 (12280)	176766 (40144)	94600 (21490)	326485 (74145)
Approx. Tower ΔP - inWC (torr)	10 (19)	11 (20.5)	11 (19)	11 (20.5)	11 (19)	12 (22.4)	11 (20)	15 (28)	11 (20)	14 (26.1)	12 (22)	19 (35.5)
SO_2 Removal Efficiency NTU	3.91		4.61		3.91		4.83		3.91		6.21	
Equivalent L/G Gal/kacf (l/Nm3)	45 (6.89)	75 (724)	55 (8.43)	85 (869)	55 (8.28)	105 (1139)	75 (10.67)	175 (2135)	65 (9.79)	155 (1850)	95 (14.94)	265 (3416)
Absorber/Oxidation Energy Consumption (kW-h)	3,524	5,156	3,872	5,455	3,835	6,145	4,629	10,114	5,117	10,562	6,308	18,371
Reagent Preparation Energy Consumption (kW-h)	749	1,120	749	1,131	783	1,100	783	1,113	854	1,100	854	1,119

Figure 4 - Absorber dimensions and Operating Conditions for High SO_2 Removal Efficiency

All top SO_2 absorber vendors undoubtedly have more sophisticated techniques to design absorbers for ultra SO_2 removal efficiency. The projected absorber size, L/G, energy consumed etc for each fuel type and FGD process in Figure 4 should be considered high estimates. With this in mind, as SO_2 removal moves from high to ultra high efficiency, the trends rather than absolute numbers indicated in Figure 4 should be the focus. Projecting the design of an ultra high SO_2 removal absorber system, whether MEL or LSFO, from published information reveals that absorbers must be required to be even taller, have more spray levels, recirculate more slurry, employ multiple numbers of trays, baffles or periphery rings and consume more power than ever before.

For PRB coals wet scrubbing is likely necessary in order to reliably achieve less than 10-ppmv SO_2 where previously dry scrubbing would be sufficient to achieve up to 98% SO_2 removal. For bituminous coals, absorber size increases in overall height by as much as 25% to accommodate as many as 9 spray headers for LSFO and 3 spray headers for MEL along with use of at least one tray or set of baffles can be expected. For medium sulfur bituminous coals, FGD parasitic load for LSFO exceeds 4% while for MEL parasitic load approaches 2%.

CONCLUSION

All post combustion CO_2 removal processes, with the possible exception of the chilled ammonia process, require SO_2 to be less than 10-ppmv (~20-mg/Nm^3) in order to slow the degeneration of the CO_2 reagent. Power plants with existing FGD systems will have to modify their processes to achieve ultra high SO_2 removal by either adding secondary absorbers or upgrading existing absorbers. Power plants that do not already have FGD will have to consider installing systems that achieve up to 99.8% SO_2 removal efficiency. In order to achieve this level of performance the absorbers, whether MEL or LSFO, will have to be the largest and most expensive ever built with parasitic electric consumption ranging from 2% for MEL to over 4% for LSFO of the plants output.

REFERENCES

[1] "Carbon Capture At An Existing Power Plant"; J.P. Ciferno-US DOE/National Energy Technology Laboratory and T.J. Skone and M. Ramezan-Science Applications International Corp; Power Engineering Magazine; May 2008

[2] Advances in CO_2 capture technology-The U.S. Department of Energy's Carbon Sequestration Program; Jose D. Figueroa[a], Timothy Fout[a], Sean Plasynski[a], Howard McIlvried[b], Rameshwar D. Srivastava[b]
[a] National Energy Technology Laboratory, U.S. Department of Energy, 626 Cochran's Mill Road, Pittsburgh, PA 15236; [b]Science Applications International Corporation, National Energy Technology Laboratory, Pittsburgh, PA 15236; International Journal of Greenhouse Gas Control 2 (2008) 9-20; © 2007 Elsevier Ltd.

[3] "Separation and Capture of CO_2 from Large Stationary Sources and Sequestration in Geological Formations-Coalbeds and Deep Saline Aquifers; Curt M. White, Brian Strazisar, Evan J. Granite, James S. Hoffman, and Henry W. Pennline; National Energy Technology Laboratory; Pittsburgh, PA; Journal of the Air & Waste Management Association; Volume 53 June 2003; pp 645-715.

[4] Carbon Dioxide Capture Technology for the Coal-Powered Electricity Industry: A Systematic Prioritization of Research Needs; George Salem Esber III; Master of Science in Technology and Policy at the Massachusetts Institute of Technology; June 2006.

[5] "Potential Long Term Options for CCS"; Energy Technology Forum – NCEP, Washington DC; Stu Dalton; Director, Generation EPRI; January 24, 2008.

[6] Marsulex Presentation to the National Commission on Energy Policy Engineering Considerations for Retrofits; January 2008.

[7] "WFGD Case Study – Maximizing SO_2 Removal by Retrofit with Dual Tray Technology"; A. A. Silva and P.J. Williams- The Babcock & Wilcox Company, Barberton, Ohio; J. Balbo – Michigan South Central Power Agency, Litchfield, MI; EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, August 28-31, 2006; Baltimore MD.

[8] "SO_2 Removal Enhancement to the Vectren, Culley Generating Station Units 2 & 3 Wet Flue Gas Desulfurization System"; M. Quitadamo, C. Erickson - Babcock Power Inc. and J. Langone – Babcock Power Environmental Inc.; ICAC Forum 05'; March 7-10, 2005, Baltimore MD.

[9] "Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1"; C. Erickson, M. Jasinski – Babcock Power Environmental Inc., L. VanGansbeke – E.On US; Mega Symposium, August 28-31, 2006, Baltimore MD.

[10] "State of the Art Wet FGD System for High-Sulfur Fuels in Florina, Greece"; G. Catalano–Alstom Power Environmental Control Systems; R. LeRose-Public Power Corporation S.A.S.

[11] "Next Generation FGD Multiple Trays, Low Outlet Emissions"; M. Hoydick – Wheelabrator Air Pollution Control, Inc.-A Siemens Company; R. Gregory and D. Braunecker–Western Kentucky Energy

[12] "AEC Lowman Station FGD Conversion from Limestone to Magnesium-enhance Lime Scrubbing"; W. I. Inkenhaus-Dravo Lime Company, L. Loper-Alabama Electric Cooperative; PowerGen International 96, Orlando FL, December 4-6, 1996

[13] "Gavin FGDS Retrofit Project"; R.S. Gollenbeck-American Electric Power Service Corporation; Thiosorbic Users Meeting, Owensboro, KY; October, 1992

[14] "Wm. H. Zimmer Generating Station's Magnesium Enhanced Lime FGD System"; R.S. Gollenbeck-American Electric Power Service Corporation; F.C. Owens, II-The Babcock & Wilcox Company; 1990 SO2 Symposium, Proceedings Vol.2 Session 5-Wet Full Scale Operation, New Orleans LA, May 8-11, 1990

[15] "Henderson Station Two FGD System Retrofit Project"; F.W. Campbell & J.L. McIlroy-Burns & McDonnell Engineering Company, J.A. Garner-Henderson Municipal Power and Light, and R.L. Phillips-Big Rivers Electric Corporation; 1993 SO2 Symposium, Volume 1-Session 2 Phase 1 Designs; Boston MA; August 1993

[16] "Design and Startup of a High Efficiency, Dilute Phase Lime FGD System"; M. Walsh-General Electric Environmental Services, Inc, A.J. Cirillo-Raytheon Engineers & Constructors; 1995 SO2 Control Symposium, Book 2 Session 48-Phase 1 Startups, Miami FL, March 28-31, 1995

[17] "Full Scale Comparison of a Venturi/Dual Flow Tray Scrubber versus Multiple Dual Flow Trays at a Reference Power Plant"; M. Hoydick-Wheelabrator Air Pollution Control; Las Vegas, Nevada; December 9-11, 2003

[18] "Economics of Lime and Limestone for Control of Sulfur Dioxide"; W. DePriest, R. P. Gaikwad – Sargent & Lundy LLC, Mega Symposium, Washington DC, May 19-22, 2003

KEY WORDS

CO_2 capture, ultra SO_2 removal, magnesium-enhanced lime, LSFO, FGD