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High SO₂ Removal Efficiency Testing

DE-AC22-92PC91338

Technical Progress Report

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28 October 1993

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1.0

INTRODUCTION

This document provides a discussion of the technical progress on DOE/PETC project number DE-AC22-92PC91338, "High Efficiency SO₂ Removal Testing", for the time period 1 July through 30 September, 1993. The project involves testing at six full-scale utility flue gas desulfurization (FGD) systems, to evaluate low capital cost upgrades that may allow these systems to achieve up to 98% SO₂ removal efficiency. The upgrades to be evaluated primarily involve the addition of organic acid buffers to the FGD systems. The "base" project involved testing at the Tampa Electric Company Big Bend station. As of September 1993, all five potential options to the base program had been exercised by DOE, involving testing at the Hoosier Energy Merom Station (Option I), the Southwestern Electric Power Company Pirkey Station (Option II), the PSI Energy Gibson Station (Option III), the Duquesne Light Elrama Station (Option IV), and the New York State Electric and Gas Company Kintigh Station (Option V). As of September 1993, testing has been completed for the base project and for Options 1 and 2, has begun but not been completed for Options III and IV, and has not yet begun for Option V.

The remainder of this document is divided into four sections. Section 2, Project Summary, provides a brief overview of the status of technical efforts on this project. Section 3, Results, summarizes the outcome from these technical efforts during the quarter. Results for each site for which there were significant technical efforts or for which there are updated technical results are discussed in separate subsections. In Section 4, Plans for the Next Reporting Period, an overview is provided of the technical progress that is anticipated for the fourth quarter of calendar year 1993. Section 5 includes a brief acknowledgment.

2.0

PROJECT SUMMARY

On the base program, testing was completed at the Tampa Electric Big Bend Station in November, 1992. The upgrade option tested was DBA additive. Project efforts during the third quarter of calendar year 1993 primarily consisted of project management activities and reporting. A paper which summarized results from this site was presented by John Smolenski of Tampa Electric at the 1993 SO₂ Control Symposium in August.

For Option I, at the Hoosier Energy Merom Station, results from another program co-funded by the Electric Power Research Institute (EPRI) and the National Rural Electric Cooperative Association are being combined with results from DOE-funded testing. Three upgrade options have been tested: DBA additive, sodium formate additive, and high pH set point operation. All testing was completed by November, 1992. Project efforts during the current quarter were primarily in data reduction and reporting. A paper presented at the 1993 SO₂ Control Symposium by Paul Reynolds of Hoosier Energy included results from this program and from the EPRI co-funded testing at this site.

Option II has involved testing at the Southwestern Electric Power Company Pirkey Station. For this option, baseline testing was conducted in February of 1993. Both sodium formate and DBA additives were tested as potential upgrade options at Pirkey. Parametric testing with DBA additive was conducted in March 1993, and parametric testing with sodium formate was conducted in April. Based on results from the parametric test series, DBA appeared to be the more attractive upgrade option for this site. Consequently, a DBA additive consumption test was conducted in May of 1993. No sodium formate additive consumption test is to be conducted. As for the previous two sites, a paper which summarized results for this site was presented at the 1993 SO₂ Control Symposium, in this case, by a member of this project team.

On Option III, for testing at the PSI Energy Gibson Station, baseline testing was conducted in early May of 1993. Results from this baseline testing were discussed in the previous quarterly Technical Progress Report. Parametric testing with sodium formate was to have begun in July 1993. However, a coal-miners' strike forced the station to fire a low-sulfur coal that would have been inappropriate for this testing. The station stockpiled high-sulfur coal on site, and by mid-September had enough high-sulfur coal in their coal pile to support the parametric testing for this project. Consequently, parametric testing was begun on September 13th, and was completed with the conclusion of a sodium formate consumption test on October 2nd. Because this testing was completed so late in the quarter (actually early in the subsequent quarter), these results will be included in the next quarterly Technical Progress Report.

Option IV is for testing at the Duquesne Light Elrama Station. Baseline testing began on June 28th, and was completed on July 2nd. These baseline test results are discussed in the next section. Parametric testing at this site has not yet been scheduled, pending an EPRI-funded model evaluation of potential upgrade options for this FGD system, which employs magnesium-enhanced lime reagent and venturi absorber modules.

Option V, for testing at the New York State Electric and Gas Company Kintigh Station, was exercised in September 1993. There were no efforts related to this testing during the current quarter.

3.0 RESULTS

Results from the base program (at the Tampa Electric Big Bend Station) and the first optional site (Hoosier Energy Merom Station) were presented in detail in the April 1993 quarterly Technical Progress Report, and an update for the Tampa site was included in the July 1993 report. For the second optional site (the Southwestern Electric Power Company (SWEPCo) Pirkey Station), results were presented in the July 1993 quarterly Technical Progress Report. These sites will be discussed only briefly in this report, to update additive consumption data and SO₂ removal upgrade economics results. There is a brief subsection for each of these three sites.

For the third optional site (the PSI Energy Gibson Station), baseline results were presented in the previous (July) quarterly report. Parametric testing at this site was just completed in early October, and these results are not yet available. They will be included in the next quarterly report. For the fifth optional site (the New York State Electric and Gas Company), there have been no technical efforts yet, as the option was just exercised by DOE in September of 1993. Consequently, only results for the baseline testing at the fourth optional site (Duquesne Light's Elrama Station) are discussed in detail in this quarterly report. These results are discussed in the fourth subsection below.

3.1 Tampa Electric Big Bend Station Results Update

Details of the results for this site were presented in previous quarterly reports, as was discussed above. The FGD system at the Big Bend Station employs double-loop absorbers that operate in a forced-oxidation mode, and produces a wall-board-grade gypsum byproduct. DBA additive was the upgrade option tested at this site, and it was found to be effective at promoting very high SO₂ removal efficiencies (greater than 98%) in a cost-effective manner. During the past quarter, the additive consumption

rate calculations have been refined, and correspondingly, system upgrade economics have been revised slightly.

3.1.1 DBA Consumption Rate

When the results of the DBA additive consumption test were previously reported, the average non-solution loss rate was calculated to have been 5.8 ± 1.1 lb DBA/ton of SO₂ removed. Since then, a small error in the consumption rate calculation has been identified and corrected. The calculated DBA non-solution loss rate dropped slightly when this error was corrected, to 5.4 ± 1.0 lb/ton of SO₂ removed. Correspondingly, the total loss rate is now calculated to have been 6.5 lb/ton, down slightly from the value of 6.8 lb/ton that was previously reported.

3.1.2 Upgrade Economics

In the April 1993 Technical Progress Report, the results presented for this site indicated that the most economical method of achieving 98% overall SO₂ removal for this FGD system was to operate in their current mode of operation, with two feet of packing installed in the upper absorber loop and with two of three upper-loop pumps in service, but adding 250 ppm of DBA to the upper-loop liquor. This increase in SO₂ removal from their baseline levels of between 93% and 94% resulted in the removal of an additional 3600 tons of SO₂ per year, at an incremental cost of about \$54 per additional ton removed.

By using an updated version of EPRI's FGDPRISM to model the results from this site, and with the revised additive consumption rates discussed above, these values have changed slightly. However, the conclusions as to the most cost-effective upgrade approach have not changed.

The overall SO₂ removal estimated for a 250 ppm DBA concentration in the upper loop is now 97.5%, resulting in the removal of an additional 3200 tons/yr rather than 3600 tons/yr. The incremental cost per ton is up slightly from \$54 per additional ton removed to \$60 per additional ton. However, this incremental cost is still very attractive compared to the expected market price of SO₂ allowances (e.g., \$150/ton to \$250/ton or greater).

For a 500 ppm DBA concentration in the upper loop, there are similar changes in the results. Originally, overall removal at this DBA concentration was predicted to be 99.5%, resulting in the removal of over 4600 additional tons per year of SO₂ compared to baseline performance. The incremental cost of this additional removal was originally estimated at \$63 per additional ton (again compared to baseline performance). With the more recent model calibration and additive consumption data, at 500 ppm DBA in the upper loop the overall removal is predicted at 99.2%. This results in an additional 4400 tons of SO₂ removed per year (relative to baseline performance), which is down slightly from the original estimate of 4600 tons/yr. The incremental cost is estimated at \$65 per additional ton removed, which is up slightly from the original value.

3.2 Hoosier Energy Merom Station Results

Hoosier Energy operates two 535-MW coal-fired units at the Merom Station. The units fire a high-sulfur coal, with the sulfur content ranging from about 3.5% to 4%. Both units have FGD systems installed, each including four packed, co-current absorber modules. Three upgrade options were tested at the Merom site: DBA additive, sodium formate additive, and high-pH set point operation. Most of this testing was co-funded by EPRI and the National Rural Electric Cooperative Association. Only the sodium formate additive consumption tests were funded as part of this DOE project.

Results for this site were discussed in the April 1993 Technical Progress Report. During the third quarter of calendar year 1993, the sodium formate consumption rate results, and the SO₂ removal upgrade economics were revised as analytical results and calculation algorithms have been refined. These results are updated below.

3.2.1 Sodium Formate Consumption Rate

The results of the two formate additive consumption tests were previously reported in the April 1993 Technical Progress Report. The first of these tests was conducted at a normal pH set point of 5.55, and with an average formate ion concentration of 2300 ppm to 2800 ppm in the absorber slurry liquor. The average SO₂ removal for this test was 93.4%. The average total formate ion loss rate for this first test was calculated to have been 28 lb formate/ton of SO₂ removed (42 lbs of sodium formate/ton). Since then, an error in the consumption rate calculation has been identified and corrected. The calculated total loss rate dropped significantly when this error was corrected, to 14.9 lb/ton of SO₂ removed. The non-solution loss rate is now calculated at 11.3 lb/ton. Both of these numbers are reported on a formate ion basis; they would increase by 50% if they were reported as sodium formate.

In the second sodium formate consumption test, the pH set point was increased to 5.8, and the formate ion concentrations were increased to an average between 2800 ppm and 3000 ppm in the absorber slurry liquor. The total formate ion loss rate was originally reported to be 29 lb formate per ton of SO₂ removed, as measured between the first and second formate inventories during this test. The results from the third and final inventory during this test were not used because of an unplanned increase in formate concentration just prior to taking that last inventory. With the error correction mentioned above, this total formate ion loss rate between the first and second inventory is now calculated to have been 23.5 lb/ton. The formate ion non-solution loss rate for this second test is now calculated to have been 19.6 lb/ton.

3.2.2 Upgrade Economics

In the April 1993 Technical Progress Report, the results presented for this site indicated that DBA, rather than sodium formate, would be the more economical additive for achieving 95% or greater overall SO₂ removal for this FGD system. By adding DBA in their current mode of operation (inhibited oxidation, pH set point of 5.55), SO₂ removal could be increased from their baseline levels of between 86 and 87% across each absorber, to 95% at an incremental cost of about \$30 to \$40 per additional ton of SO₂ removed.

By using an updated version of EPRI's FGDPRISM to model the results from this site, and with the revised additive consumption rates discussed above, these values have changed slightly. However, the conclusions as to the most cost-effective upgrade approach have not changed.

A 95% overall SO₂ removal level is now estimated to be achievable with their flue gas bypass closed, and with a 1030 ppm DBA concentration in the absorber loops. This results in the removal of an additional 8,800 tons of SO₂/yr, compared to the amount which they could currently remove by operating at their normal operating conditions, but closing their flue gas bypass to treat all of the flue gas at 86% to 87% SO₂ removal. The incremental cost per ton is now calculated at \$50 to \$60 per additional ton removed, rather than \$30 to \$40 per additional ton. However, this incremental cost is still very attractive compared to the expected market price of SO₂ allowances (e.g., \$150/ton to \$250/ton or greater).

For sodium formate additive, there are similar changes in the results. Originally, 95% overall removal was predicted to be achievable with sodium formate at an incremental cost of approximately \$60 to \$70 per additional ton (again compared to baseline, closed bypass performance). With the more recent model calibration and additive consumption data, 2500 ppm formate would be required in the absorber loops to

achieve a 95% overall SO₂ removal level. The incremental cost is now estimated at \$80 to \$110 per additional ton removed, depending on whether or not the FGD system is operated in a closed-loop or partially open-loop manner with respect to water balance.

The practical limit for achieving high SO₂ removal levels with additive alone still appears to be about 97% removal. Above 97% removal, DBA cost increases dramatically such that the incremental costs for achieving additional SO₂ removal rises above \$150/ton.

The combination of one to two additional feet of packing in each absorber plus DBA still appears to be very attractive. For example, by adding two additional feet of packing, the model predicts that 95% SO₂ removal can be achieved with a DBA concentration of only 505 ppm, rather than 1030 ppm as in the base case with DBA additive. However, this modeled result has not been supported with any full-scale performance data for this FGD system.

3.3 SWEPCo Pirkey Station Results

The Henry W. Pirkey Station is a 720-MW mine-mount lignite unit located near Marshall, Texas. The lignite sulfur content ranges from approximately 2 to 10 lbs of SO₂ per 10⁶ Btu. The FGD system typically achieves an outlet emission rate of approximately 1.05 lbs SO₂ per 10⁶ Btu. To achieve this outlet level, the four modules in the FGD system normally treat about 80% of the flue gas. The remainder of the flue gas is bypassed directly to the stack, with the amount bypassed being varied to control the outlet emission rate. Both DBA and sodium formate additives, combined with operating with a closed bypass damper, were considered as upgrade options.

Results of the baseline and parametric testing at this site were discussed in detail in the previous (July 1993) quarterly report. Preliminary DBA additive consump-

tion rate data and upgrade economics were presented. Updated results for DBA consumption and upgrade economics are discussed below.

3.3.1 Additive Consumption Results

The overall non-solution DBA loss rate was originally estimated at 11.5 lb DBA per ton of SO₂ removed, and the corresponding overall consumption rate was estimated at 12.4 lb/ton. These values were refined as the results of off-site analyses became available, and dropped slightly. The current value for the non-solution loss rate is 9 lb/ton, while the overall consumption rate value is 11 lb/ton of SO₂ removed. An uncertainty analysis for the total consumption rate value indicates that this value is accurate to about $\pm 35\%$ at the 95% confidence level. Of the three components in DBA (adipic, glutaric, and succinic acids), the observed consumption rates for each indicated that glutaric acid was consumed at the highest rate, while adipic acid was consumed at the lowest rate.

3.3.2 Upgrade Economic Evaluation

Because the field testing at this site was just completed in mid-May, a detailed evaluation of SO₂ removal upgrade economics was not included in the previous quarterly report. This evaluation has now been completed, and the results are summarized below.

The baseline and parametric test results for this site indicate that a system-wide SO₂ removal level of 98% could be achieved without additives, strictly by operating at the current upper- and lower-loop pH set points and closing the system bypass damper. A repair to the stack drain would be required. By closing the bypass damper, approximately 20,500 tons/yr of additional SO₂ could be removed by the Pirkey FGD system. The primary costs for this upgrade would be the limestone required to remove

this additional SO_2 , and the additional fan power required to force the additional flue gas flow through the absorbers.

The economics of this upgrade, or other upgrades involving DBA additive, are somewhat dependent on the limestone utilization value for the Pirkey Station FGD system which is used in the evaluation. There is a range of possibilities, based on the information source used to evaluate utilization. During baseline testing, the observed lower-loop limestone utilization measured at their normal pH set point of 5.5 was about 87%. Pirkey on-site laboratory utilization determinations for 1992 indicate a higher average of 92.6%. However, 1992 data for lignite consumption, SO_2 removal, and limestone consumption indicate an annual average utilization of only 75%.

The upgrade economic calculations were conducted for utilization values of 75% and 87%. The former value was selected because it is based on the actual annual limestone consumption data for the plant, rather than on chemical analyses. The latter value was selected as an alternate point for evaluation because it represents the results of measurements made at controlled and well-documented FGD system operating conditions. The Pirkey lab measurements, which averaged higher than 87% utilization, may have included data at lower unit load and lower lignite sulfur content than were evaluated in these tests.

For the case where the baseline limestone utilization is assumed to be 75%, the marginal costs associated with increasing the overall SO_2 removal to 98% by closing the bypass damper amounted to \$53 per additional ton of SO_2 removed. If the limestone utilization is instead assumed to be 87%, this marginal cost drops to \$47 per additional ton. Either of these values are attractive relative to the expected cost of SO_2 allowances.

An alternate approach would be to employ DBA additive, also with the bypass damper closed, and operate the system at lower pH set points in both the upper

and lower loops. This would allow 98% or greater SO₂ removal to be achieved at a limestone utilization of 95%, rather than at the current utilization of 75% (or 87%). If the upper-loop DBA concentration is maintained at 1000 ppm, and the upper- and lower-loop pH set points are dropped to 6.0 and 5.2, respectively (a drop of 0.3 pH units for each), parametric test results indicate that 99% overall SO₂ removal could be achieved. This would result in 20,970 additional tons of SO₂ removal per year (compared to baseline operation). For the case where the current limestone utilization is assumed to be 75%, this is a very attractive option. The incremental costs are estimated to be only \$37 per additional ton of SO₂ removed. For the case where the baseline limestone utilization is assumed to be 87%, the savings in limestone consumption resulting from the lower pH set point is less significant; the incremental cost for the additional 20,970 tons of SO₂ removed was estimated at \$47 per additional ton.

Besides improved limestone utilization, there would be other benefits resulting from the expected lower sulfite oxidation percentage with DBA additive. One expected benefit, reduced fan power requirements due to less scale formation in the absorbers and thus lower flue gas pressure drop, was accounted for in these cost estimates. There are other potential benefits, which might include reduced manpower for absorber scale removal during outages, that were not considered in these economics.

Finally, it should be noted that the selection of DBA rather than sodium formate as the additive of choice for this site was initially based on a review of field data and a limited amount of analytical results from the parametric tests. As more analytical results became available during the current quarter, this selection has been confirmed. It appears that the consumption rates for DBA and for formate ion would be nearly equal at similar additive concentrations in this FGD system. Since delivered formate costs for this site (delivered as a sodium formate solution) would be about 50% greater than delivered DBA additive costs, formate is clearly a less attractive upgrade option for this site.

3.4 Duquesne Light Elrama Station Results

3.4.1 System Description

Figure 3-1 illustrates the physical arrangement of a single scrubber module at the Elrama Station. Flue gas and slurry sampling points are indicated in the figure. The FGD system consists of five individual modules; four are in service during normal full-load operation. Each module has its own ID fan present between the scrubber module and the external mist eliminator. Module 401 was selected as the test module because it had recently been cleaned and there was easy access to the sampling locations on the module.

3.4.2 Baseline Test Description

The planned conditions for Baseline Tests 1 through 6 are summarized in Table 3-1. In Tests 1 through 4, the gas flow was held constant by putting the fan control damper for Module 401 in manual and setting the damper position at 100%. Since the inlet duct suction is held constant (by automatic control of the other fan control dampers), the gas flow through the module remained steady throughout these tests. In Test 5, the venturi pressure drop was decreased from its normal set point of 10 in. WC to 8 in. WC; the gas flow was maintained at a constant level by adjusting the control damper to compensate for the reduced pressure drop across the module. In Test 6, problems in some of the other scrubber modules were causing the plant trouble with staying in compliance with SO₂ limits. Plant operators found that it was necessary to operate Module 401 at a venturi pressure drop of 18 in. WC to keep the plant in compliance. Test 6 was therefore performed at a venturi pressure drop of 18 in. WC. At this pressure drop, it was not possible to maintain the gas flow at the same level as in previous tests. The module was thus tested at a slightly lower gas flow.

Figure 3-1. Schematic Flow Diagram of a Single Scrubber Train at the Elrama Station

Table 3-1

Original Baseline Test Schedule for Elrama Station

Test No.	Objective	Performance Indicators	Duration (days)	pH	Thiosulfate Level	Mg Level	Venturi Pressure Drop
1	Characterize baseline performance under normal operating conditions	SO ₂ Removal Utilization Oxidation Solids Dewatering Relative Saturation	2	Normal	Normal	Normal	Normal
2	Characterize performance versus pH	SO ₂ Removal	0.5	High	Normal	Normal	Normal
3		Utilization Relative Saturation	0.5	Low	Normal	Normal	Normal
4	Characterize performance at higher sulfite concentrations	SO ₂ Removal	0.5	Normal	High	Normal	Normal
5		Utilization Relative Saturation	0.5	Normal	High	Normal	High
6	Characterize performance at lower magnesium concentrations	SO ₂ Removal Utilization Relative Saturation	1	Normal	Normal	Low	Normal
	Total Baseline Duration		5				

Independent variables tested included reaction tank pH, thiosulfate level, magnesium level, and venturi pressure drop. For each test, the reaction tank pH and venturi pressure drop were set by Elrama operation personnel. Controlling the reaction tank pH was often difficult. Lime slurry is supplied to the reaction tank through a constant speed pump. The pH is controlled by adding dilution water to the pump suction and thereby varying the weight percent solids of the lime slurry sent to the scrubber module. The degree to which the weight percent solids could be controlled was limited; it was not possible to send only dilution water to the scrubber. Also, the weight percent solids of the lime slurry in the lime storage tank varied with the station load and the number of lime slakers in service; this further complicated control of the scrubber pH. The venturi pressure drop was controlled automatically; no problems with venturi pressure drop control were encountered.

The higher thiosulfate concentrations of Tests 4 and 5 were achieved by adding sodium thiosulfate to the test module. The system typically operates at thiosulfate concentrations of 90 to 120 ppm $\text{Na}_2\text{S}_2\text{O}_3$; the target value of 400 ppm for the thiosulfate concentration represented the highest concentration that the plant felt comfortable operating with. (There was some concern that operating at higher concentrations could loosen the scale in the ductwork upstream of the ID fan and possibly cause damage to the fan). For these tests, the thiosulfate level was raised by adding sodium thiosulfate directly to Module 401. Based on material balance calculations, it was estimated that the thiosulfate concentration could be maintained at the target concentration by adding 100 lb $\text{Na}_2\text{S}_2\text{O}_3$ at the start of the test and 50 lb/hr during the test. During the testing, it was found that this addition rate did not achieve the desired concentration, and additional sodium thiosulfate was added. A summary of the thiosulfate addition rate and the thiosulfate concentrations measured on site during the testing is provided below.

Time	Sodium Thiosulfate Added Pounds	Thiosulfate Concentration ppm as $\text{Na}_2\text{S}_2\text{O}_3$
0845	100	
0920		255
0945	50	
1000	100	
1040		417
1100	50	
1200	50	
1300	100	
1330		305

Test 6 was initially slated to be a test a lower magnesium concentration. The magnesium level was lowered by operating Module 401 at very low load over night. Operation at low load (low gas flow to the module) tended to dilute the scrubber slurry and thus reduce the magnesium concentration. Also, operators washed the lower side of the mist eliminators in Module 401 with service water for three hours overnight to help further dilute the chemistry. As it turned out, the module had to be operated at a higher venturi pressure drop, as well as at a reduced magnesium concentration.

The weight percent solids of the scrubber slurry is not controlled at Elrama. Waste slurry is blown down continuously from each module through a blow-down line off the scrubber recycle slurry pump. There are no provisions to control the flow through this line.

Performance measurements included simultaneous inlet and outlet SO_2 concentrations; inlet and outlet flue gas oxygen, carbon dioxide, and nitrogen concentrations; and inlet and outlet flue gas moistures. During a typical test, the outlet gas velocity was measured at the beginning of the day using a 48-point traverse to verify that the flue gas flow was at desired test conditions. Once it was verified that the flue gas flow was at the desired test level, simultaneous inlet and outlet Method 6 SO_2 samples were collected. Flue gas samples for Orsat analysis were collected as the Method 6 tests were conducted. Slurry samples were collected during each test, and solids settling rate

tests were conducted during for each unique set of chemistry conditions. Slurry flow measurements were also collected using a portable ultrasonic flow meter.

3.4.3 Test Results

SO₂ Removal Efficiency. Table 3-2 summarizes the actual test conditions and SO₂ removal results. Test 1 began on the afternoon of June 28 and continued through June 29. Operators attempted to maintain the pH at a set point of 7.2 during the testing. A summary of the pH measured by the portable pH meter, as well as an indication of the range over which the pH varied (as indicated by the control room strip chart) during each SO₂ removal measurement, is included in Table 3-2. Where "steady" is indicated, the pH varied by no more than ± 0.1 pH units from the measured value. Because of the difficulty in controlling pH, the pH was measured by the portable meter frequently throughout the testing.

The flue gas velocity was measured at the outlet duct for each of the sampling runs. After reviewing the velocity traverse data from the runs performed on June 28, it was discovered that the flue gas flow in the outlet duct showed a significant amount of stratification with respect to velocity. Subsequently, a 48-point velocity traverse was performed each day to confirm that the gas flow measurements obtained during the Method 6 traverses (which entailed sampling at 24 points for the outlet duct) were accurate. A comparison of the results from the 48-point traverses and the traverses performed during the Method 6 indicates that the velocity data obtained during the Method 6 traverses are accurate. On the last day of testing, the velocity measured during the 48-point traverse was significantly higher than the velocities measured during the Method 6 traverses. This occurred because the 48-point traverse was performed prior to when operators increased the venturi pressure drop. The Method 6 samples were collected after the venturi pressure drop was increased.

Six Method 6 sampling runs were completed during Test 1. The SO₂ removal efficiencies measured for Test 1 ranged from 84.5% to 87.0% with an average of

Table 3-2

Summary of Elrama Baseline Test Results

Test No.	Run No.	Date	Time	Measured pH	Est. pH Range	Outlet Gas Flow (acfm)	Inlet SO ₂ (ppm dry)	Outlet SO ₂ (ppm dry)	SO ₂ Removal (%)	Inlet				Outlet			
										O ₂ % dry	CO ₂ % dry	N ₂ % dry	H ₂ O %	O ₂ % dry	CO ₂ % dry	N ₂ % dry	H ₂ O %
1	1	6/28/93	1630-1749	7.18	Steady	523,600	945	132	86.1	7.4	11.2	81.4	6.5	7.4	11.2	81.4	13.9
1	2	6/28/93	1855-2004	7.30	Steady	524,400	890	116	87.0	7.4	11.2	81.4	7.1	7.4	11.2	81.4	14.8
		6/29/93	0950-1005			538,300											
1	3	6/29/93	1040-1117	7.31	Steady	531,400	1013	136	86.5	8.6	11.2	80.2	7.6	8.8	10.8	80.4	15.1
1	4	6/29/93	1151-1228	6.89	6.5 - 7.2	529,600	1043	162	84.5	8.6	11.2	80.2	7.6	8.8	10.8	80.4	16.1
1	5	6/29/93	1328-1410	7.27	Steady	518,400	1064	156	85.3	8.6	11.2	80.2	7.4	8.8	10.8	80.4	14.8
1	6	6/29/93	1449-1523	7.38	Steady ^a	522,700	NA ^b	144	86.2	8.6	11.2	80.2	NA ^b	8.8	10.8	80.4	15.9
		6/30/93	0950-1005			531,400											
2	1	6/30/93	0959-1033	8.08	Steady	505,400	1072	105	90.3	8.7	11.0	80.3	6.7	8.2	11.3	80.5	15.5
2	2	6/30/93	1100-1131	8.14	Steady	519,300	1108	121	89.1	8.7	11.0	80.3	7.3	8.2	11.3	80.5	15.1
3	1	6/30/93	1315-1346	6.53	6.5 - 7.0	514,900	1130	198	82.5	9.0	10.4	80.6	8.0	8.8	11.0	80.2	15.7
3	2	6/30/93	1410-1452	6.81	6.4 - 6.8	507,200	1138	221	80.6	9.0	10.4	80.6	7.3	8.8	11.0	80.2	14.7
		7/1/93	0855-0910			554,700											
4	1	7/1/93	0925-0959	7.20	7.0 - 7.5	519,300	1152	155	86.6	8.8	10.0	81.2	7.4	8.8	10.4	80.8	15.1
4	2	7/1/93	1030-1101	7.25	Steady	504,600	1197	139	88.4	8.8	10.0	81.2	7.1	8.8	10.4	80.8	14.9
		7/1/93	1225-1240			514,900											
5	1	7/1/93	1248-1323	7.29	7.2 - 7.4	488,200	1279	180	86.0	9.4	10.4	80.2	7.7	9.5	10.2	80.3	15.8
5	2	7/1/93	1402-1439	7.31	Steady	513,200	1265	182	85.6	9.4	10.4	80.2	7.4	9.5	10.2	80.3	15.1
		7/2/93	0912-0919			524,400											
6	1	7/2/93	0942-1014	7.71	7.2 - 7.7	457,900	1238	107	91.4	9.8	10.2	80.0	8.4	9.6	10.0	80.4	15.6
6	2	7/2/93	1034-1123	7.42	7.2 - 7.7	460,500	1247	84	93.3	9.8	10.2	80.0	7.9	9.6	10.0	80.4	15.1

^a The pH probe was pulled for cleaning during the test. When put back in service, the reading was the same as when taken out of service. Since the pH control was in manual and was not changed during this period, it is believed that the pH remained steady.

^b No inlet SO₂ or moisture data were obtained for this run. An inlet SO₂ concentration of 1040 ppm dry (average for the day) is used for the SO₂ removal calculation.

85.9%. During Run 4, operators were experiencing significant difficulties in controlling the pH at a constant level. It is estimated that the average pH during this testing was approximately 6.85, which is significantly lower than the pH during the other tests. The low SO₂ removal measured in Run 4 is believed to have been caused by the pH control problems.

Test 2 was completed on June 30. This was a short-term test designed to measure the SO₂ removal efficiency at a higher pH. The test was performed at a nominal pH of 8.0, which represented as high a pH as was felt could reasonably be obtained. Tower gas flow and venturi pressure drop remained at the same levels as for Test 1. Two Method 6 runs were performed during this test; SO₂ removal efficiencies of 90.3% and 89.1% were measured for an average removal of 89.7%.

Test 3 was also completed on June 30. Because of the very short residence time in the reactions tanks and the fact that, in magnesium-enhanced lime systems, alkalinity is present predominantly in the liquid phase, it was possible to change conditions rapidly in the test module. Test 3 was designed to determine the removal efficiency at a low pH. The test was accordingly performed at a nominal pH of 6.5; this represented the lowest level that plant personnel felt could be operated at while still maintaining compliance with SO₂ emissions regulations. Two Method 6 traverses were performed during this test; SO₂ removal efficiencies of 82.5 and 80.6 were measured for an average removal of 81.6%.

Tests 4 and 5 were completed on July 1. The objective of these tests was to measure the SO₂ removal efficiency at a normal pH (7.2) and at high thiosulfate concentrations. The intent of adding the thiosulfate was to inhibit the oxidation of sulfite to sulfate and thereby cause an increase in the dissolved sulfite concentration. Since dissolved sulfite provides a significant portion of the alkalinity required for SO₂ removal in magnesium-enhanced lime systems, it was anticipated that it might be possible to raise the SO₂ removal by increasing the thiosulfate concentration.

The SO₂ removal was measured twice during Test 4 using inlet and outlet Method 6 traverses. Removals of 86.6% and 88.4% were measured for an average removal of 87.5%. It is evident that the addition of thiosulfate did not have the effect of increasing the SO₂ removal efficiency of the FGD system. It will be interesting to see the how much (if any) the dissolved sulfite level changed for this test.

Test 5 was performed at the same chemistry conditions as Test 4 but with a reduced venturi pressure drop. The reduced venturi pressure drop was tested to determine how a change in pressure drop would effect removal. In the venturi scrubber, a substantial amount of the mass transfer surface is present in the droplets created as slurry is stripped off the center cone and perimeter walls just upstream of the venturi section. Reducing the pressure drop was expected to reduce the amount of area available for mass transfer, and the removal was therefore expected to drop. Two Method 6 runs were performed during Test 5. Removal efficiencies of 86.0% and 85.6% were measured for an average removal of 85.8% for the test.

Test 6 was performed at reduced dissolved salts concentrations and at a higher venturi pressure drop. The dissolved salts concentrations were reduced by operating the test module at reduced load overnight, and the extent to which the dissolved salts concentrations were actually reduced will not be known until chemical analyses of the samples are complete. Though not originally part of the test plan, operation at a high venturi pressure (18 in. WC) was necessary to keep the plant in compliance. The SO₂ removal of the scrubber was measured twice during Test 6. Removals of 91.4% and 93.3% were measured for an average removal of 92.4%. It is evident from these results that the increase in venturi pressure drop (which would be expected to increase SO₂ removal efficiency) overshadowed any effect of operating at a more dilute scrubber chemistry (which would be expected to reduce the SO₂ removal efficiency).

Slurry Flow Measurements. Slurry flow measurements were obtained from three locations on the slurry supply line using an ultrasonic Doppler flow meter. The three locations sampled represented the total slurry flow to Module 401, the slurry flow to the center (bull) nozzle, and the slurry flow to the tangential nozzles. The sum of the flows to the center nozzle and tangential nozzles should be equal to the total flow to the scrubber. Each of the sample locations was reasonably distant from any flow disturbance, and stable readings were obtained at each location.

The average of the measured flow to the center nozzle was 9697 gpm and the average measured flow to the tangential nozzle was 9378 gpm. Adding these two flows gives a total flow of 19,075 gpm. This value agrees reasonably well (within 9%) with the total measured flow of 17,598 gpm. Some of the difference in the measured flow rates may be due to an uncertainty in the pipe inside diameter. The pipe inside diameter for the smaller pipe was based on actual measurements made on pipe from an out-of-service module. The estimate of pipe ID for the larger pipe was based on the assumption that the lining thickness was the same in both pipes. However, according to plant personnel, it is possible that the lining may have deteriorated significantly, so the actual ID of the pipe at the measurement locations was uncertain.

For Tests 1-5, the measured slurry flow rates correspond to a liquid-to-gas ratio (L/G) of approximately 33.9 to 36.8 gallons/kacf, depending on whether the total measured flow or the sum of the flows to the center and tangential nozzles is used as a basis. For Test 6, the slurry flow rates correspond to an L/G of approximately 38.4 - 41.7 gallons/kacf.

Slurry Sample Chemical Analyses. Results of solid-phase analyses for the baseline test slurry samples are summarized in Table 3-3. The sample description tells which test each sample was collected from. Each slurry sample indicated in the table was filtered, and the filter cake was dried and weighed to determine the slurry solids content in weight percent. A portion of the dried solids was then digested in HCl. The

Table 3-3

Solid-Phase Analyses

Description	Test 1	Test 1	Test 2	Test 2	Test 2	Test 3	Test 5	Test 6	Lime	Test 1
Date	6/28/93	6/29/93	6/30/93	6/30/93	6/30/93	6/30/93	7/1/93	7/2/93	6/29/93	6/29/93
Time	17:27	15:30	10:25	11:38	12:05	14:50	14:55	11:36	11:25	14:30
Ca, mm/g	5.29	5.36	-	5.78	5.85	5.51	5.58	5.71	11.97	5.35
Mg, mm/g	0.09	0.11	-	0.21	0.22	0.19	0.23	0.21	1.10	0.13
SO ₃ , mm/g	4.03	4.05	-	3.25	-	3.89	4.26	4.07	-	4.07
SO ₄ , mm/g	0.39	0.40	-	0.28	-	0.39	0.34	0.39	-	0.44
CO ₃ , mm/g	0.64	0.67	2.02	2.04	2.07	0.88	0.64	0.89	0.37	0.57
Inerts, wt%	29.18	28.88	-	25.74	24.91	28.24	26.69	25.87	0.00	28.31
Solids, wt%	8.30	8.50	11.10	11.10	11.00	8.70	8.80	8.70	15.60	8.50
pH	7.19	7.39	-	8.13	-	6.64	7.25	7.25	12	-
T _{comp} , °C	49.9	50.6	-	50.6	0	50.3	50.4	50.2	50	-
Reagent Utilization, %	87.3	87.0	63.6*	6.4	63.0*	83.0	87.8	83.3	-	88.7
Reagent Ratio	1.15	1.15	-	1.58	-	1.20	1.14	1.20	-	1.13
Oxidation, %	8.8	9.0	-	8.0	-	9.2	7.4	8.8	-	9.7
Solid Solution, wt. %	57.6	58.1	-	46.0	0	55.9	59.9	58.2	-	58.9
Gypsum, wt. %	0.0	0.0	-	0.0	0	0.0	0.0	0.0	-	0.0
CaCO ₃ , wt. %	6.4	6.7	20.2	20.4	20.7	8.8	6.4	8.9	3.7	5.7
Inerts, wt. %	29.2	28.9	0.0	25.7	24.9	28.2	26.7	25.9	0.0	28.3
Ca, mg/g	211	215	0	231	234	221	223	228	479	214
Mg, mg/g	2	3	0	5	5	5	5	5	27	3
SO ₃ , mg/g	322	324	0	260	0	311	341	326	-	326
SO ₄ , mg/g	37	39	0	27	0	38	32	38	-	42
CO ₃ , mg/g	39	40	121	122	124	53	38	54	22	34
Closures										
Molar, %	3.0	3.4	3.6	5.0	5.1	5.0	-	3.7		
Acceptable, %	6.4	6.4	6.0	6.3	6.4	6.3	-	6.4		

* Utilization calculated by assuming the total solid-phase sulfur content was constant during the test.

portion of solids that remained undissolved is reported as "inerts" in weight percent of the solids.

The digested solids solution was analyzed for Ca^{++} and Mg^{++} by atomic absorption and for SO_4^- by ion chromatography (IC). A separate portion of the dried solids was analyzed for SO_3^- (sulfite) by thiosulfate/iodine titration. A third portion of the dried solids was analyzed for CO_3^- (carbonate) by coulometric measurement of CO_2 gas evolved from an acidified sample. These analytical methods are described in detail in EPRI's FGD Chemistry and Analytical Methods Handbook.

The calculated values for lime utilization are reported in Table 3-3 following the analytical results. Utilization is defined as $[1 - \text{moles of carbonate}/(\text{moles of sulfur solids} + \text{moles of carbonate})]$. By this definition, calcium from the lime that reacts with absorbed SO_2 is utilized; calcium that reacts with absorbed CO_2 is not considered to be utilized. The calculated utilization values are also expressed as reagent ratio, which is the inverse of utilization.

Some slurry samples included in Table 3-3 were analyzed for carbonate content to improve the accuracy of the lime utilization data and to examine pH-lime utilization relationship. For samples with only carbonate analyses, approximate utilizations were calculated by using the sulfur analyses for the sample from the same test that was completely analyzed.

The calculated utilization values from Table 3-3 have been plotted as a function of slurry pH in Figure 3-2. The decrease in lime utilization at increased pH is expected. However, the measured utilization for the low-pH test appears somewhat low; the utilization for the low-pH test would normally be expected to be higher than the utilization for the mid-pH tests.

Figure 3-2. Effect of Operating pH on Lime Utilization

Oxidation percentages reported in Table 3-3 are calculated as $100 \times [1 - \text{moles of sulfite} / \text{moles of total sulfite plus sulfate}]$. The calculated oxidation percentages for the baseline tests average about 9%, and there does not appear to be any trend among the different tests.

The remaining entries in Table 3-3 include solids analyses calculated on a weight basis, followed by calculated "closures" for the analytical results. Closures are calculated as a quality assurance indicator. The molar closure in percent is calculated for a given set of solids analyses as the difference between the sums of positively and negatively charged ionic species in moles/gram divided by the total of the positively and negatively charged species in moles/gram. The calculated "acceptable" closure in percent is the expected error in the calculated molar closure at the 95% confidence level, based on the assumption that each of the individual analyses has an expected error of $\pm 5\%$ at the 95% confidence level. The calculated closures in Table 3-3 indicate good data quality for the baseline solids analyses. All of the molar closures are well below the acceptable limits.

Results of liquid-phase analyses for the baseline filtered slurry samples are shown in Table 3-4. Calcium, magnesium, and sodium were determined by atomic absorption spectrophotometry. Chloride, sulfite, sulfate, and thiosulfate were determined by ion chromatography. The reported result for "total hydrolyzable sulfate" is the total sulfate measured in the liquor sample after digestion under acidic oxidizing conditions, which converts all sulfur species to sulfate. On Tests 3 and 5, only those species expected to change with the change in test conditions were analyzed. Also, for Test 4 (high thiosulfate test), two additional samples were analyzed for thiosulfate and sulfite concentration.

Calculated molar closures (charge imbalances) have again been used as a data quality check. All of the baseline liquid samples are well within the acceptable level.

Table 3-4

Liquid-Phase Analyses

Description	Test 1	Test 1	Test 1	Test 2	Test 3	Test 4	Test 5	Test 6	Test 4	Test 4
Date	6/28/93	6/29/93	6/29/93	6/30/93	6/30/93	7/1/93	7/1/93	7/2/93	7/1/93	7/1/93
Time	17:05	12:28	15:18	11:33	14:47	11:20	14:45	11:48	10:00	13:30
Ca, mm/L	6.4	5.3	4.8	4.1	7.0	2.7	2.7	4.3	-	-
Mg, mm/L	115.4	107.4	110.0	114.8	-	113.9	-	109.4	-	-
Na, mm/L	4.9	4.6	4.7	4.8	-	10.0	-	4.8	-	-
Cl, mm/L	48.4	46.5	47.6	46.0	-	48.3	-	47.2	-	-
CO ₃ , mm/L	7.8	5.7	11.3	17.3	5.4	12.0	9.8	7.1	-	-
SO ₃ , mm/L	10.6	11.7	12.6	15.2	13.3	19.9	19.6	13.5	15.7	18.6
SO ₄ , mm/L	91.4	77.2	75.9	75.6	92.9	69.8	71.9	78.6	-	-
S ₂ O ₃ , mm/L	0.87	0.71	0.69	0.90	-	4.02	3.48	0.90	2.78	2.93
Tot Hyd SO ₄ , mm/L	99.5	88.7	88.0	86.0	105.0	97.3	99.7	94.3	-	-
pH	7.18	7.12	7.39	8.13	6.64	7.26	7.25	7.25	-	-
Temp, °C	49.6	50.5	50.6	50.6	50.3	50.6	50.4	50.2	-	-
Ca, mg/L	256	213	190	164	282	108	108	174	-	-
Mg, mg/L	2804	2612	2674	2792	-	2768	-	2658	-	-
Na, mg/L	112	106	108	110	-	230	-	110	-	-
Cl, mg/L	1716	1648	1689	1631	-	1714	-	1672	-	-
CO ₃ , mg/L	466	345	680	1040	324	720	586	423	-	-
SO ₃ , mg/L	847	937	1007	1217	1063	1592	1569	1083	1260	1491
SO ₄ , mg/L	8775	7415	7289	7258	8921	6701	6908	7547	-	-
S ₂ O ₃ , mg/L	98	80	78	101	-	450	390	100	312	328
Charge Imbalance										
Calculated, %	-0.6	1.6	1.0	0.9	-	1.3	-	-0.3	-	-
Acceptable, %	6.0	5.9	5.9	5.8	-	5.8	-	5.9	-	-
Relative Saturation										
Gypsum	0.37	0.28	0.24	0.19	0.41*	0.12	0.12*	0.23	-	-
CaSO ₃ •30.5H ₂ O	3.98	3.87	3.80	3.94	4.55*	3.17	3.13*	3.67	-	-
CaCO ₃	1.68	0.93	3.00	16.28	0.32*	1.24	0.98*	1.22	-	-

* Calculated using assumed Mg, Na, and Cl concentrations.

Calculated relative saturations are also shown in the liquid-phase analytical results table. Relative saturation for a specific compound is defined as the activity product for the ionic components in solution divided by the solubility product. These values were obtained using FGDPRISM equilibrium module, which calculates the equilibrium distribution of chemical species using the analytical results as inputs. For the purpose of these calculations, magnesium, sodium, and chloride concentrations were estimated for samples where all species were not analyzed.

One important result in Table 3-4 is the gypsum relative saturation. One objective of inhibiting oxidation with sulfur (which reacts to produce thiosulfate in solution) is to prevent scaling by maintaining the gypsum relative saturation below 1.0. Previous research has shown that all of the sulfate produced by oxidation of absorbed SO_2 will precipitate as a solid solution with calcium sulfite, up to the point where the system oxidation percentage reaches about 15%. Above 15% oxidation, the balance of the sulfate (beyond 15% of the SO_2 absorbed) will precipitate as gypsum. The results in Table 3-4 show that the baseline liquor samples all had gypsum relative saturations well below 1.0. These results are consistent with the solids analyses, which showed that the baseline test oxidation percentage was well below 15% (generally around 9%).

Settling Test Data. The settling test data are summarized in Table 3-5. Settling tests were performed only on those tests where there was at least 6 hours of operation at the specified test conditions. Since the solids residence time in the reaction tank is roughly 1-1/2 hours, this ensured that the solids present in the reaction tank were actually generated at the conditions of the test.

Table 3-5 shows the settling time and unit area required to achieve a 15 wt.% solids. The table shows that the unit area required to achieve a 15 wt.% underflow varies from 23 to 30 square feet/ton per day solids, with the exception of the samples from Test 2. For Test 2, unit areas of 10 and 12 sq. ft/tpd were measured. The reason that the unit areas are so much lower for Test 2 is that the initial weight percent solids

Table 3-5

Summary of Elrama Baseline Settling Test Data

Test	Date	Time	Specific Gravity	Weight Percent Solids	15% Underflow Solids		Final Solids wt %
					Settling Time (min)	Unit Area (sq. ft/tpd)	
1	6/28/93	17:40	1.05	8.3	128.6	27.0	24.2
1	6/29/93	14:30	1.049	8.5	140.8	26.9	23.5
1	6/29/93	15:40	1.05	8.5	117.9	23.0	22.8
2	6/30/93	10:25	1.07	11.1	74	10.4	21.4 ^a
2	6/30/93	12:10	1.07	11.0	88	12.0	23.5
3	6/30/93	15:00	1.05	8.7	170.9	30.5	22.4
5	7/1/93	15:15	1.055	8.8	138.6	24.5	23.7
6	7/2/93	11:15	1.052	8.7	159.5	28.8	15.6 ^a

^a Samples were not allowed to sit overnight to achieve a 'final' weight percent solids. The first settling run for Test 2 was stopped after 275 minutes and the settling run for Test 6 was stopped after 166 minutes.

of the slurry were significantly higher; i.e., the slurry started out much closer to 15 wt.%. Comparing the amount of time it took each sample to settle from 11 wt.% to 15 wt.% indicates that there were no substantial differences in the actual settling rates of the various samples. The difference in unit areas is solely the effect of the initial weight percent solids of the slurry.

The final settled solids weight percent is also reported in the table. This number represents the weight percent solids of the settled solids after being allowed to sit overnight. As is evident in the table, there are no significant differences in the final weight percent solids of the various samples.

3.4.4 Performance Correlations

Absorber performance can be approximately described by the following expression:

$$\text{Number of Transfer Units (NTU)} = \ln (\text{SO}_{2\text{in}}/\text{SO}_{2\text{out}}) = K A/G \quad (3-1)$$

where: $\text{SO}_{2\text{in}}$ and $\text{SO}_{2\text{out}}$ = inlet and outlet SO_2 concentrations;
 K (lb/hr-ft²) = average overall gas-phase mass transfer coefficient;
 A (ft²) = total interfacial area for mass transfer; and
 G (lb/hr) = total gas flow rate.

It is assumed in the above expression that the equilibrium partial pressure of SO_2 above the FGD liquor is small compared to the inlet and outlet concentrations.

The overall coefficient K can be expressed as a function of two individual coefficients, k_g and k_l , that represent mass transfer rates across the gas- and liquid-films, respectively:

$$1/K = 1/k_g + H/k_l \phi \quad (3-2)$$

where H is a Henry's law constant, and ϕ is the liquid-film "enhancement factor." For a given absorber operating at constant gas and liquid flow rates, NTU will be a function of slurry pH because of the effect of pH on the liquid-film enhancement factor.

Figure 3-3 is a plot of NTU vs pH for Tests 1-3. For these three tests, the venturi pressure drop and scrubber chemistry was relatively constant; the only variable is the scrubber slurry pH. For those tests where the pH varied during the test, the average pH (over the range that the pH varied during the test) is plotted.

Equation 3-1 also shows that NTU is proportional to the mass transfer interfacial area A . At Elrama, the mass transfer area can be varied by adjustment of the venturi pressure drop. The effect of venturi pressure drop on SO_2 removal is shown in Figure 3-4. This figure includes data from Tests 1, 4, 5, and 6. Data from Tests 2 and 3 are not included because the operation at different pHs overshadows the effect of venturi pressure drop.

Figure 3-3. Effect of pH on SO₂ Removal

Figure 3-4. Effect of Venturi Pressure Drop on SO₂ Removal

4.0

PLANS FOR THE NEXT REPORTING PERIOD

The base program (Tampa Electric Big Bend) and Options I and II (Hoosier Energy Merom and SWEPCo Pirkey, respectively), are in the final reporting phases. For these sites, the final version of the Technical Notes and draft version of the Topical Reports will be prepared.

At the PSI Energy Gibson Station (Option III), efforts during the quarter will involve conducting chemical analyses on samples collected, and data reduction and evaluation of results from the parametric test series and additive consumption test with sodium formate additive. A Test Report is due in late October.

We have anticipated conducting an additional, week-long performance and additive consumption test with DBA additive at this site, as well. The need to conduct this additional test will be evaluated based on results from testing with sodium formate. The calibrated EPRI FGDPRIISM model will be used to conduct an initial comparison of the two additives for this site, to determine if DBA additive appears to be a cost-effective alternative to sodium formate.

The Technical Note for this site is currently scheduled to be submitted to DOE and to the host utility by the end of the fourth quarter of calendar year 1993. However, the timing of this Technical note will depend on whether or not a DBA additive performance and consumption test is performed at this site.

Parametric testing at the Duquesne Light Elrama site (Option IV) has not yet been scheduled, pending the results of EPRI-funded modeling of potential upgrade options for this site. It has not yet been decided what upgrade option(s) will be tested, nor whether this testing will be conducted during the fourth quarter of calendar year 1993 or delayed until warmer weather in the spring of 1994.

Option V, for testing at the New York State Electric and Gas Company Kintigh Station, was just exercised by DOE/PETC at the end of the third quarter of calendar year 1993. The schedule for the testing efforts at this site has not been set. However, it is anticipated that the baseline testing at this site will not begin until spring of 1994.

5.0 ACKNOWLEDGMENTS

Funding for the FGDPRISM modeling portion of this study is being provided by the Electric Power Research Institute.

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