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**Pollution Prevention Opportunity
Assessment for the K-25 Site
Steam Plant—Level III**

**MANAGED BY
MARTIN MARIETTA ENERGY SYSTEMS, INC.
FOR THE UNITED STATES
DEPARTMENT OF ENERGY**

UCN-18916 (1235 6-92)

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K-25 Waste Management Division

**Pollution Prevention Opportunity Assessment
for the K-25 Site Steam Plant—Level III**

Date Issued—September 1995

Prepared by
PAI Corporation
116 Milan Way
Oak Ridge, Tennessee 37830
under Support Services contract
to the U.S. Department of Energy
Contract number DE-AC05-88OR21794

Prepared for
U.S. Department of Energy
Office of Environmental Restoration and Waste Management
under budget and reporting code EW 31

Environmental Management and Enrichment Facilities
Oak Ridge K-25 Site
Oak Ridge, Tennessee 37831-7101
managed by
LOCKHEED MARTIN ENERGY SYSTEMS, INC.
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-84OR21400

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ABBREVIATIONS AND ACRONYMS

APC	air pollution control
CAACP	Clean Air Act Criteria Pollutant
CDR	conceptual design report
CNF	Central Neutralization Facility
CO	carbon monoxide
CY	calendar year
DOE	U.S. Department of Energy
DPLH	direct productive labor hours
EMD	K-25 Environmental Management Division
EPA	U.S. Environmental Protection Agency
FGR	flue gas return
FY	fiscal year
HiROI	high return on investment
IH	industrial hygiene
IHEM	In-house Energy Management
KWTARS	K-25 Waste Tracking and Reporting System
LMES	Lockheed Martin Energy Systems, Inc.
$\mu\text{mhos/cm}$	micromhos per centimeter
MK-F	MK-Ferguson
NA	not applicable
NG	natural gas
NO_x	nitrogen oxide
ORR	Oak Ridge Reservation
ORO	Oak Ridge Operations Office
P2	pollution prevention
ppm	parts per million
PPOA	pollution prevention opportunity assessment
RCRA	Resource Conservation and Recovery Act of 1976
ROI	return on investment
SO_2	sulfur dioxide
TBD	to be determined
TDS	total dissolved solids

EXECUTIVE SUMMARY

A Level III pollution prevention opportunity assessment (PPOA) was performed for the K-1501 Steam Plant at the K-25 Site. The primary objective was to identify and evaluate pollution prevention (P2) options to reduce the quantities of each waste stream generated by the Steam Plant, thus realizing significant benefits to the local environment and stakeholders.

For each of the waste streams, P2 options were evaluated to first reduce the quantity of waste generated and second to recycle the waste. This report provides a process description of the facility; identification, evaluation, and recommendations of P2 options; an implementation schedule with funding sources; and conclusions.

Largely for economic reasons, only 3 of the 14 P2 options are being recommended for implementation. These three are summarized in the table below; all are source reduction options. When implemented, these three options are estimated to reduce the annual generation of waste by 658,412 kg and will result in a cost savings of approximately \$29,232/year for the K-25 Site.

Steam Plant P2 options recommended for implementation

Option Description	Waste Stream Affected	Reduction in waste generation		ROI ^a (%) ^b
		kg/year	%	
Install FGR ^a System in Boiler 7	NO _x	2,358	17.2	NA
Reduce steam loss from traps	Nonhazardous wastewater	6,807	0.12	NA
	RCRA ^a wastewater	3,180	0.12	
	CAACPs ^{a,c}	47.1	0.12	
Increase lapse time between rinses	Nonhazardous wastewater	439,830	7.6	391
	RCRA wastewater	206,190	7.8	

^a ROI = Return on investment; FGR = flue gas return; NO_x = nitrogen oxide; RCRA = Resource Conservation and Recovery Act; CAACPs = Clean Air Act criteria pollutants.

^b NA means there are no cost savings or implementation cost for the project.

^c All CAACPs associated with Steam Plant operation—SO₂, NO_x, CO, particulate and organics.

1. INTRODUCTION

The Steam Plant pollution prevention opportunity assessment (PPOA) was prepared for the Oak Ridge K-25 Site Pollution Prevention (P2) Program and funded by DOE Headquarters EM-334 block funding.

A Level I PPOA was prepared for the Steam Plant in 1994, using CY 1993 data (LMES 1995a), in accordance with DOE's Model PPOA Guidance (DOE 1993). Waste stream ranking for the entire K-25 Site revealed that Steam Plant waste streams were relatively large. The high annual volumes at which the hydrogen softener wastewater is generated and its consideration as a Resource Conservation and Recovery Act (RCRA) wastewater (because of its low pH) dictate that a Level III PPOA be conducted. This Level III PPOA covers the hydrogen softener wastewater and all other waste streams generated by the Steam Plant.

From June through August 1995, the existing process was reviewed and P2 options were identified and evaluated in accordance with the Model DOE PPOA Guidance. The main objectives of this PPOA were to evaluate options to reduce the amounts of all Steam Plant waste streams or to recycle them. In the absence of source reduction and recycling opportunities, possible treatment or disposal options were considered to achieve P2 goals. The cost estimates for these options are detailed in Appendix A, Part 1, and the PPOA worksheets for the options are included in Appendix B.

Projected CY 1995 waste generation data were used in the preparation of this document. During the last quarter of CY 1994, a significant P2 project was implemented: the reuse of returned condensate at the Steam Plant as feedwater. Because the project was begun late in the year, the annual quantity of recovered condensate reported (~6,000,000 kg) was significantly less than the anticipated annual quantity for subsequent years (~58,000,000 kg). Consequently, to gain a more accurate picture of the waste stream quantities generated in future years, estimated CY 1995 data were used for analysis instead of CY 1994 data. The mass balance calculations for both the actual CY 1994 data and the revised CY 1995 data are presented in Appendix C.

The economic evaluation of P2 options (see Appendix B, Worksheet 8) includes a cost for the disposal of Steam Plant wastewaters at the Central Neutralization Facility (CNF) and a cost for the use of potable water from the Potable Water Treatment Facility. These cost factors were included at the request of Energy Systems Waste Management Organization and in accordance with DOE guidance (DOE 1995). The unit cost for waste disposal at the CNF was assumed to be \$0.02992/kg, which reflects input from CNF personnel. The unit cost for potable water was assumed to be \$0.01/kg, which reflects input from the Potable Water Treatment Facility personnel.

2. PROCESS DESCRIPTION

The K-1501 Steam Plant has been in operation since the mid 1940s. Because of decontaminating and decommissioning activities that began in the 1980s, the quantities of steam generated and the uses of the facility have changed. Of the nine boilers located in the Steam Plant, only Boilers 4, 7, 8, and 9 are currently in operation. In 1994, 139.3 million kg of steam were produced for use in site-wide space heating and garage, laundry, cafeteria, and Toxic Substances Control Act (TSCA) Incinerator activities¹. A comparable level is also predicted for 1995. Because of the space heating demands, steam production is seasonal, more than doubling during the coldest months of November through April. Excluding space heating, laundry operations and the TSCA Incinerator are the two largest consumers of steam. The peak processing capacity for the Steam Plant is 240,000 lb/hr, with average maximum production around 100,000–120,000 lb/hr.

The primary function of the K-1501 Steam Plant is to convert water into steam, which must be in a relatively pure state for both end user purposes and for boiler longevity. In 1994, 13,268,475 kg of wastewater were generated through removal of these impurities in the boiler feedwater, either before entering the boiler through an ion exchange process or while in the boiler through continuous and mud-drum blowdowns. Air emissions (39,209 kg/year) from combustion of either natural gas (NG) or No. 2 fuel oil is the other significant Steam Plant waste stream. Laboratory analysis wastewater and oily rags and solids used in facility maintenance account for the remainder of the waste (see Appendix B, Worksheets 3 and 4 for details). The Steam Plant flow diagram (Fig. 2.1) illustrates the steam generation process at K-25, identifying both the input of raw materials and the resultant waste and product streams.

2.1 WATER PROCESSES

As illustrated in Fig. 2.1, the steam generation process begins by softening potable water to remove the calcium and magnesium, which cause scaling and reduce boiler efficiency. A more detailed breakdown of the softening/demineralizing and associated regeneration process is illustrated in Fig. 2.2. To soften and demineralize its feedwater, the Steam Plant employs a split-bed ion exchange system, which consists of two hydrogen and two sodium beds—one bed of each type operating as a standby while the other regenerates and awaits use. Fifty-six percent of the total feedwater is treated by the hydrogen system, and 44% is treated by the sodium system. Each system contains a zeolitic substance which exchanges the Ca^{+2} and Mg^{+2} for those of either Na^{+} or H^{+} . Upon reaching its water treatment capacity—542,182 kg for each of the hydrogen beds and 236,727 kg for each of the sodium beds—the beds must be regenerated (the captured calcium and magnesium are removed so that the bed can be reused). The hydrogen beds are regenerated by first backwashing them with potable water, then treating them with a series of sulfuric acid (H_2SO_4) solutions (2%, 4%, and 6% by volume), followed by slow and then fast rinses of potable water. A sodium chloride (brine) treatment, also preceded by a backwash, regenerates the sodium zeolite—again followed by slow and fast rinses with potable water. The wastewaters

¹The quantity of steam used in this analysis was calculated using a computer-generated mass balance model. This CY 1994 quantity differs from the Steam Plant's reported steam production level for 1994 by five percent. Steam Plant personnel agree that the computer model's calculated steam quantity, based on the reported number of regenerations, is correct.

Fig. 2.1. Process flow diagram for the K-1501 Steam Plant. The number or letter following selected stream titles represents the stream quantities as identified in Table C.1.

Fig. 2.2. Process flow diagram for the K-1501 feedwater softening process. The number or letter following selected stream titles represents the stream quantities as identified in Table C.1.

from this renewal process are sent to the CNF for pH adjustment and particulate removal and are then released to a Clinch River tributary via a National Pollutant Discharge Elimination System (NPDES)-permitted outfall.

The softened water, with hardness between 0–1 ppm, flows through the degasifier and is pumped first through a heat exchanger and then through a de-aerator. In the degasifier, room temperature air is injected into the water, releasing carbon dioxide that is vented to the atmosphere. The process water then gathers heat as it is pumped through a heat exchanger (bringing the temperature to about 100°F), capturing heat transferred from the continuous blowdown. From the heat exchanger, water is heated and de-aerated as it flows over a series of trays, and sodium sulfite—an oxygen scavenger—is added to further decrease the corrosiveness of the water. The process water, now at approximately 215°F, is then pumped into one of the four water-tube boilers.

Once in the boilers, heat from NG combustion (or No. 2 fuel oil during periods of curtailment) volatilizes the water for distribution. As water vapor is removed from the system, dissolved solids become concentrated. Suspended solids are removed through an automatic/continuous blowdown, maintaining a constant total dissolved solids (TDS) level of 3750 μ mos/cm. Coagulated particulates settle to the boiler basin, or mud-drum, and are manually removed once a day using the boiler's mud-drum blowdown system.

A relatively small amount of wastewater is also generated by the on-site laboratory, which periodically tests the process water prior to its entrance into the softening systems. This wastewater is also sent to CNF for pH adjustment.

2.2 AIR PROCESSES

Combustion of the NG or fuel oil results in air emissions that are vented out the stack into the atmosphere. Boilers 8 and 9 are equipped with a flue gas return (FGR) system (see Fig. 2.3) that returns about 10% of the exhaust gases to mix with the boiler combustion air, which reduces nitrogen oxide (NO_x) emissions. Boilers 7, 8, and 9 are equipped with economizers to recover heat from the exhaust gases to heat the boiler feedwater. Boilers 4 and 7 are older and do not employ any emission reduction systems. Boiler 4 is a package boiler system that has nearly reached its useful service life. The Steam Plant plans to replace Boilers 4 and 7 with a new boiler in the year 2000. Alternatively, Boiler 7 may be refurbished if replacement funding is not made available.

The annual estimated Steam Plant air emissions are shown in Table 2.2. These emission rates are within the expected rates for steam plants below 100 million Btu/hr and are below the threshold that requires any air pollution control (APC) systems to reduce emissions. (An APC system was required when coal was the primary fuel.) A comparison of Steam Plant air emissions to the permitted allowable emissions is shown in Fig. 2.4. Currently, NG is the primary fuel used in all of the boilers. The primary air pollutant from the combustion of NG is NO_x . Approximately 20 days during the winter of each year, NG is curtailed because of a contractual agreement with the supplier that allows NG cut-off during high usage periods. During these periods, No. 2 fuel oil is used. The Steam Plant air emissions of sulfur dioxide (SO_2), organics, and particulates (as shown in Table 2.2) primarily result from use of the No. 2 fuel oil.

Fig. 2.3. Process flow diagram for the K-1501 boiler.

* Air emissions of nitrogen oxides and carbon monoxide increased in the four quarter of 1994 because of the increase in steam production at the K-1501 Steam Plant. Particulate matter and sulfur dioxide do not show a similar increase because No. 2 fuel oil was not used during second or third quarters. Other air emissions include carbon monoxide and organics. (Source: *Annual Site Environmental Report*, Water, Air, and Environmental Monitoring Department, K-25 Site Environmental Management Division, draft 1994.)

Fig. 2.4. Criteria pollutant emissions—CY 1994.

Table 2.2. Steam Plant output stream summary—1995

Output stream	Mass balance stream number	KWTARS stream number	CY 1995 quantity (kg) ^a	Output type
<i>Water waste streams</i>				
Hydrogen Softener Wastewater	8	12	2,650,256	RCRA wastewater
Sodium Softener Wastewater	11	217	2,263,489	Nonhazardous wastewater
Condensate Polisher Wastewater	19	217	102,355	Nonhazardous wastewater
Continuous & Mud-drum Blowdown	25	217	3,408,864	Nonhazardous wastewater
Lab Analysis Wastewater	12	217	9,305	Nonhazardous wastewater
Steam	17	NA	139,353,800	Product - Nonhazardous wastewater
<i>Air waste streams</i>				
Particulates	33	NA	1,409 ^b	Clean Air Act Criteria Pollutant
Other Air Emissions ^c	35	NA	19,491 ^b	Clean Air Act Criteria Pollutant
Sulfur Dioxide	34	NA	4,600 ^b	Clean Air Act Criteria Pollutant
Nitrogen Oxide	36	NA	13,709 ^b	Clean Air Act Criteria Pollutant
<i>Solid waste streams</i>				
Oily Rags and Solids	NA	145	109	RCRA wastewater

^a Based on CY 1995 mass balance, as shown in Figs. 2.1 and 2.2 and in Appendix C.

^b Based on CY 1994 data from the draft *Annual Site Environmental Report* (LMES 1994f).

^c Other air emissions include CO and organics.

2.3 STEAM DISTRIBUTION

Steam produced in the plant is distributed through insulated pipes throughout the K-25 Site. Approximately 40% of the distributed steam is returned as condensate to the Steam Plant. This condensate is treated in the condensate polisher units to remove any hardness and is reused as boiler feedwater in the plant. This condensate reduces the amounts of both potable water requiring softening and wastewater generated from regeneration of the softening beds. Distributed steam that is not returned to the Steam Plant as condensate is vented through steam traps to the atmosphere or as condensate that is discharged into local storm drains in each area.

3. DESCRIPTION OF OPTIONS

The P2 options identified for the Steam Plant are described in the following three sections. Section 3.1 discusses seven P2 options for reducing the wastewater generation rates. Section 3.2 discusses four P2 options for reducing air emissions. Section 3.3 discusses three P2 options for improving the steam distribution and return systems. Because the quantity of oily rags and solids generated from Steam Plant operation was minimal, no options for reducing this waste stream were identified.

A complete set of DOE's proposed worksheets was generated for the K-25 Steam Plant and can be found in Appendix B of this document. Worksheet 6 identifies all of the P2 options generated for this process, and Worksheet 7 documents the screening of these options, indicating which received economic consideration. Those options given economic consideration and for which cost estimates and weighted scoring were completed are listed in Worksheets 8 and 9. The calculations of waste quantities and costs for each of the technically feasible options are presented in Appendix A. Table 3.1 summarizes all options investigated.

3.1 WASTEWATER REDUCTION OPTIONS

Seven of the fourteen options concentrate on reducing the wastewater generated from this process. Six of the options—3, 9, 10, 11, 13, and 14—focus on altering the regeneration process. Option 12 looks at removing extraneous sources of wastewater attributed to Steam Plant generation. A more detailed description of each follows. For those options that were technically feasible, Sect. 4 discusses the option, providing the annual waste reduction, cost/savings, and the return on investment (ROI).

3.1.1 Reuse Hydrogen Regenerant (Option 3)

There are two hydrogen cation beds in use at the Steam Plant. However, only one is in operation at any given time. The two beds alternate, one treating feedwater until it reaches its capacity, while the other regenerates and awaits use. As discussed in the process description, one stage of the regeneration process for a hydrogen bed is a series of H_2SO_4 treatments (2, 4, and 6%). The 6% solution is necessary to remove any remaining Ca^{+2} and Mg^{+2} not removed by the weaker 2% and 4% solutions. Generally, the first half of the 6% solution is consumed in the exchange, but the second half, although continuing to remove small amounts of Ca^{+2} and Mg^{+2} as it flows over the ion resin, still retains the majority of its regeneration capabilities. This half of the rinse can be reclaimed, blended with the specified amount of slow rinse wastewater that follows, and reused in the coming regeneration as a 2% solution. Consequently, approximately half of the 6% sulfuric acid (H_2SO_4) used in a regeneration can be recycled. Currently, the wastewater from this regeneration process, titled Hydrogen Softener Blowdown in the K-25 Waste Tracking and Reporting System (KWTRS; Waste Stream No. 12), is a RCRA waste because of its pH level and is gravity drained to the CNF for treatment. This option is technically feasible and is analyzed further in Sect. 4.1.1.

Table 3.1 Summary of Steam Plant P2 options

Option number and description	Waste stream affected	Percentage waste reduction	Technically feasible? (yes/no)
1. Preheat Combustion Air	CAACPs ^a	NA	No
2. Install Low NO _x Burners	NO _x	40	Yes
3. Reuse Hydrogen Regenerant	RCRA wastewater	5.4	Yes
4. Install FGR System in Boiler 7 ^b	NO _x	17.2	Yes
5. Replace Underground Piping	Nonhazardous wastewater	TBD	Yes
6. Reduce Steam Loss from Traps ^b	Nonhazardous wastewater	0.12	Yes
	RCRA wastewater	0.12	
	CAACPs	0.12	
7. Increase Condensate Recovery	Nonhazardous wastewater, RCRA wastewater, CAACPs	TBD	Yes
8. Install Backup Propane System	Particulate SO ₂	100	Yes
9. Install Anion Demineralizer Bed	Nonhazardous wastewater	29.7	Yes
	RCRA wastewater	100	
10. Install Anion/Mixed Bed Polisher	Nonhazardous wastewater	41.5	Yes
	RCRA wastewater	100	
11. Reuse Brine Regenerant	Nonhazardous wastewater	2.3	Yes
12. Repair Piping	Nonhazardous wastewater	NA	Yes
13. Increase Lapse Time between Rinses ^b	Nonhazardous wastewater	7.6	Yes
	RCRA wastewater	7.8	
14. Contract Out Softening and Regeneration Services	Nonhazardous wastewater	98	Yes
	RCRA wastewater	100	

^a Recommended for option implementation.

^b All Clean Air Act Criteria Pollutants (CAACPs) associated with Steam Plant operation—SO₂, NO_x, CO, particulates, and organics.

3.1.2 Install Anion Demineralizer (Option 9)

This option considers the use of an anion bed to neutralize the RCRA waste stream resulting from the regeneration of the hydrogen softener bed and significantly reduces the continuous blowdown waste stream. Boiler feedwater is currently demineralized through a simultaneous split-bed cation system— 56% of the flow through the hydrogen bed and 44% through the sodium bed (see Figure 2.2). While removing the necessary Ca^{+2} and Mg^{+2} , this cation-only softening process does not remove any of the dissolved solids that become concentrated in the boilers and are eventually purged in the continuous blowdown stream. In addition, the sodium and hydrogen beds have differing capacities (the hydrogen having over twice the capacity of the sodium) and are therefore regenerated at different times, with the hydrogen bed's regeneration waste being considered a RCRA waste because of its pH. By decommissioning the sodium cation beds, installing anion beds, and rerouting the feedwater so that it flows first through the hydrogen cation bed, then through the degasifier, and then through the anion bed, the TDS concentration will be reduced by approximately 80% (i.e., to 15–20 ppm) reducing the continuous blowdown by 80%. Moreover, the anion and cation beds with matching capacities can be regenerated simultaneously, with the wastewater from one bed neutralizing the other as they mix together. This option is considered technically feasible and is analyzed further in Sect. 4.1.2.

3.1.3 Install Anion Bed and Mixed-Bed Polisher (Option 10)

This option is the same as Option 9 with the addition of a mixed-bed polisher (cation and anion resin blended together in one vessel) to be installed downstream from the proposed anion bed. The mixed-bed polisher provides additional feedwater demineralization, achieving a TDS of 0.5 ppm versus the estimated 15–20 ppm that will be achieved with the anion bed alone. The mixed-bed polisher does require regeneration, which creates nonhazardous wastewater that will require treatment at the CNF. The additional quantity of this waste, however, is offset by the additional decrease in the continuous blowdown. This option is considered technically feasible and is analyzed further in Sect. 4.1.3.

3.1.4 Reuse Brine Regenerant (Option 11)

As with the hydrogen regeneration previously discussed in Sect. 3.1.1 (storing and reusing part of the regenerant solution), the second phase of regenerating the sodium bed also consists of a regenerant treatment; however, on this bed, a single injection of 10% brine is used. As the brine flows through the resin it removes the collected Ca^{+2} and Mg^{+2} ions, replacing them with Na^{+} ions. In exiting the bed, the first two-thirds of the brine are spent, containing the great majority of the collected Ca^{+2} and Mg^{+2} ions. However, the remaining one-third of the brine, while continuing to remove additional Ca^{+2} and Mg^{+2} ions, still maintains a level of close to 10% brine. Reclaiming this remaining third of the brine and storing it for reuse in the following regeneration will reduce the waste generated from this process without any negative effect on the process. This option is considered technically feasible and is analyzed further in Sect. 4.1.4.

3.1.5 Repair Piping (Option 12)

This option considers capping an abandoned pipe that allows groundwater to flow into the G Sump at the CNF. Before 1992, wastewater from the Steam Plant sources merged into a single pipeline being pumped to the CNF. In 1992, three individual gravity drained pipelines were installed to separate the wastewater by source: the hydrogen regeneration waste; the sodium regeneration waste; and the remaining line combining the continuous blowdown, the mud-drum

blowdown, and the laboratory analysis wastewater. The original pipeline that was decommissioned in 1992 was never capped off. Currently, groundwater seeps into this pipeline and mixes with the Steam Plant wastewater in the G Sump, the total of which is attributed to the Steam Plant. Although the amount of groundwater entering the G Sump from this source is not monitored, it is thought to be minimal. For this reason and because the oversight will be corrected during FY 1995, this option is not analyzed further.

3.1.6 Increase Lapse Time Between Rinses (Option 13)

In regenerating both the hydrogen and the sodium beds, the rinse with the regenerant solution is followed by a slow rinse and an immediate fast rinse, both using potable water. The vendor of the ion exchange beds has indicated that incorporating a lapse time of 20 to 30 minutes between the slow and fast rinse would allow the salts to further diffuse on their own, reducing the relatively larger amount of fast rinse water required for regeneration. To achieve full diffusion, however, the regenerant solution exiting the bed during the slow rinse must be a minimum of 1% concentration (either H_2SO_4 or NaCl). For the sodium beds, this change will increase the volume of the slow rinse but significantly reduce the volume of the fast rinse, resulting in an overall waste reduction. For the hydrogen beds, no increase is needed in the slow rinse to achieve the 1% concentration. The fast rinse can automatically be minimized to achieve an overall reduction in the RCRA wastewater waste stream. The increase in regeneration time will not reduce the effectiveness of the softening process. This option is therefore considered technically feasible and is analyzed further in Sect. 4.1.5.

3.1.7 Contract Out the Softening and Regeneration Services (Option 14)

It is possible to contract out the water softening services using portable mixed-bed units regenerated off-site, completely removing all LMES responsibility for regeneration waste.² Additionally, the portable system, through the use of both cation and anion beds as described in Sect. 4.1.2 completely demineralizes the process water, reducing by 95.5% the continuous blowdown waste stream. Approximately once a week, or as needed, the vendor would replace the spent unit with a fresh one that has been regenerated off-site. The inside of the unit contains the softening/demineralizing system, which is connected to the influent process water source with a hose similar to a fire hose. The potable water is run through the system to remove the Ca^{+2} and Mg^{+2} and approximately 99.5% of the TDS. Another hose carries the now-softened/demineralized effluent water to the degasifier where it then continues on its regular path to the boiler. The returned condensate could also be rerouted to the portable unit for demineralization, eliminating the need for the polishers and therefore eliminating the waste originated from their regeneration. As mentioned in Sect. 3.1.2, removing the TDS from the feedwater will largely eliminate the need for the continuous blowdown. With this system then, all regeneration waste—hydrogen, sodium, and condensate polisher—continuous blowdown waste, and laboratory analysis waste will be eliminated. The initial concerns that privatizing would elicit objections from the Union and that the need to alter the waste permits would lengthen the implementation process do not seem to be serious enough to prohibit implementation. This option is therefore considered technically feasible and is analyzed further in Sect. 4.1.6.

²LMES will retain legal responsibility in the event of vendor default or bankruptcy.

3.2 AIR EMISSION REDUCTION OPTIONS

Four options were identified for reducing air emissions from the Steam Plant: (1) preheat the combustion air, (2) install low NO_x burners, (3) install an FGR system in Boiler 7, and (4) replace backup No. 2 fuel oil with propane. Each of these options is described below. For those options that were technically feasible, Sect. 4 further discusses the option, providing the annual waste reduction, cost/savings, and the ROI.

3.2.1 Preheat Combustion Air (Option 1)

An option was considered to preheat the combustion air used in all four of the boilers by recovering heat from the exhaust gases. Implementing this option would improve the fuel efficiency and thereby reduce fuel use and the associated air emissions. Boilers 7, 8, and 9 currently use economizers to recover heat from the exhaust gases to heat the boiler feedwater before it enters the boiler. The boiler off-gas temperature, prior to the economizer, is between 500 and 600°F. Afterward, it is reduced to approximately 325°F. This stack temperature is too low to economically recover heat because of (1) the potential to cause the formation of H₂SO₄ from the exhaust gases below its dew point (near 225°F), resulting in severe stack corrosion problems, and (2) the limited heat recovery potential (from 325°F to 225°F). To prevent severe corrosion, the carbon steel exhaust stacks would have to be replaced with those constructed of an alternate material such as Hastelloy (a high chromium molybdenum alloy), which is economically unfavorable. The limited heat recovery potential and possible H₂SO₄ formation cause this option to be technically infeasible; therefore, the option is not analyzed further.

3.2.2 Install Low NO_x Burners (Option 2)

Boilers 8 and 9 currently have low NO_x emissions as a result of the FGR systems. One option for further reducing NO_x emissions is to install low NO_x burners in Boilers 7, 8, and 9. Initially, this option also included consideration of installing a low NO_x burner in Boiler 4. However, because of the expected short operation period remaining for Boiler 4, this option was limited to Boilers 7, 8, and 9.

The NO_x concentration in the combustion off-gas from typical NG-fired boilers is approximately 100 ppm. FGR systems in Boilers 8 and 9 reduce the NO_x emission concentration to about 50 ppm. A low NO_x burner would further reduce this concentration to about 30 ppm, reducing the NO_x air emissions correspondingly. The reduced NO_x emissions are estimated based on the latest draft *Annual Site Environmental Report* (LMES 1994f). The Steam Plant's total estimated NO_x emissions for CY 1994 are 13,709 kg. Boiler 7 is estimated to provide 43% of the annual NO_x emissions, and Boilers 8 and 9 are estimated to generate 38% of the NO_x emissions. The burner vendor estimated that the installation of NO_x burners would reduce NO_x emissions by about 40%.

This option would require removal of the existing burners in Boilers 7, 8, and 9 and installation of new low NO_x burner systems. Air permit modifications could be filed as an amendment to the current permit with minimal administrative work. The option is considered technically feasible and is analyzed further in Sect. 4.2.1.

3.2.3 Install an FGR System in Boiler 7 (Option 4)

Installing an FGR system in Boiler 7 would reduce NO_x emissions from that boiler by about 40%. This option requires the installation of a carbon steel duct and manual damper control valve that will return about 10% of the exhaust gas to be mixed with the influent boiler combustion air. Discussions with the burner vendor indicated that the recirculated flue gas would not reduce the burner flame stability. This option is therefore considered technically feasible and is analyzed further in Sect. 4.2.2.

3.2.4 Install Backup Propane System (Option 8)

Using propane instead of No. 2 fuel oil as the Steam Plant's backup fuel would remove the Steam Plant's air emissions of particulates and SO_2 . No. 2 fuel oil is the primary source of these emissions at the K-25 Site, and propane combustion does not emit particulates or SO_2 as a byproduct.

Although the backup No. 2 fuel oil is used only 15 to 20 days a year, the Site is required to file air emission permits as though it were using the fuel oil daily, increasing the permitting fees and labor required in permit preparation. The use of propane as the backup fuel would remove these concerns. Installation of a propane shaving plant and replacement of the boiler's burner guns would be required. The option is considered technically feasible and is analyzed further in Sect. 4.2.3.

3.3 STEAM DISTRIBUTION OPTIONS

Three other waste reduction options—Options 5, 6, and 7—were identified based on the LMES In-house Energy Management (IHEM) Study currently under way. Option 5 looks at the Steam Plant's distribution system, Option 6 explores the possibility of improving debris detection in the header traps, and Option 7 considers installation of additional condensate return systems. These options are discussed below.

3.3.1 Replace Underground Piping (Option 5)

This option looks at replacing the underground steam distribution system between the K-25 Administration area and Building K-1007. The underground piping is currently covered with a silica type insulation. This insulation deteriorates rapidly and has, since initial installation, lost its heat retention capabilities. As a result, steam loss is compounded in this section of the Site. The IHEM Study is looking at replacing this below-ground piping with above-ground piping, and will address the associated costs and benefits. In addition to decreasing the heat loss, moving the distribution system above-ground would improve maintenance and inspection capabilities. Preliminary results from the study indicate that this option is technically feasible and should be considered further. However, to minimize duplication of effort, this option will not be analyzed further until final issue of the IHEM Study.

3.3.2 Reduce Steam Loss from Steam Traps (Option 6)

Currently, steam traps that vent to the atmosphere are visually inspected weekly. Steam traps requiring repair are reported to Maintenance for correction. The IHEM Study is considering the implementation of a system to track steam trap failures.

In addition, the proper operation of some improperly plumbed traps for condensate return headers cannot be determined from visual inspection. This PPOA recommends quarterly inspections of the condensate header traps that include temperature measurement upstream and downstream of the traps and the use of a stethoscope to listen for steam leaks. The implementation of this option will reduce steam leaks and decrease fuel and other material usages, thereby reducing emissions and wastewater generation rates. The option is considered technically feasible and is analyzed further in Sect. 4.3.

3.3.3 Increase Condensate Recovery (Option 7)

This option considers the installation of additional condensate return piping at the K-25 Site. Currently, about 40% of all condensate is returned to the Steam Plant for reuse as boiler feed-water. The remaining 60% is released through collection header traps to the ground. Increasing the condensate return by installing additional recovery systems would decrease the amount of potable water needed for softening, thereby reducing related regeneration waste.

The IHEM Study is considering the costs and benefits associated with this option. To minimize duplication of effort, this option will not be analyzed further until final issue of the IHEM Study.

4. ANALYSIS OF OPTIONS

Section 4 discusses the cost analysis and waste reduction of the ten options selected for further analysis. Section 4.1 discusses the wastewater P2 options identified, Sect. 4.2 discusses air emission P2 options, and Sect. 4.3 discusses the steam distribution P2 option. The cost estimates for these options are included in Appendix A.1. The waste reduction calculations for these options are included in Appendix A.2. The worksheets for cost evaluations (worksheet 8) are included in Appendix B. All cost estimates were based on MK-Ferguson (MK-F) direct-hire pricing. Wastewater disposal cost of \$0.02992/kg is based on a discussion with CNF personnel, and potable water costs of \$0.01/kg were obtained from the Potable Water Treatment Facility Manager. The implementation costs for these options are presented in Table 4.1.

Table 4.1. Steam Plant P2 options—implementation cost estimate summary^a

Option	Vendor price or. direct costs (\$)	MK-F direct- hire cost (\$)	Total project cost ^b (\$)
Install Low NO _x Burners (Option 2)	1,134,000	1,617,000	2,350,000
Reuse Hydrogen Regenerant (Option 3)	40,000	62,000	136,000
Install FGR System in Boiler 7 (Option 4)	30,000	43,000	90,000
Reduce Steam Loss from Steam Traps (Option 6)	0	0	0
Install Backup Propane System (Option 8)	1,998,000	2,850,000	3,975,000
Install Anion Demineralizer Bed (Option 9)	245,000	350,000	580,000
Install Anion/Mixed Bed Polisher (Option 10)	340,000	485,000	785,000
Reuse Brine Regenerant (Option 11)	5,000	8,000	20,000
Increase Lapse Time between Rinses (Option 13)	0	0	0
Contract Out Softening and Regeneration Services (Option 14)	4,500	NA	4,500

^aImplementation costs only.

^bTotal includes escalation and contingency costs which are not individually identified in the table.

4.1 WASTEWATER REDUCTION OPTIONS

Six options—3, 9, 10, 11, 13, and 14—were considered technically feasible and were analyzed further for waste reduction and implementation costs. A detailed discussion follows.

4.1.1 Reuse Hydrogen Regenerant (Option 3)

Implementing the option would reduce the RCRA wastewater waste stream by 144,360 kg/year or 5.4%. The reduction in potable water use and disposal costs for treatment at the CNF will produce an annual savings of \$5763. In addition, K-25 Waste Management personnel have indicated that option implementation would not present any permitting or regulatory roadblocks, and Steam Plant personnel are receptive to the idea. The cost to implement the option, however, is excessive, estimated to be \$136,000. The implementation cost estimate was structured on MK-F labor rates and overhead costs and is detailed in Appendix A, Part 1. Consequently, the ROI is only 4.24%. Because an ROI of less than 25% is considered unfundable, this option is not recommended for implementation.

4.1.2 Install Anion Demineralizer (Option 9)

The main concern in implementing this option was the permitting requirements that might be associated with mixing the regeneration wastewater from the two ion exchange beds with one another to neutralize their pHs. However, K-25 Environmental Management Division personnel have indicated that permitting requirements will not be an issue for implementation, and Steam Plant personnel are receptive to the option.

As indicated in Sect. 3.1.2, 100% treatment of the feedwater by both the cation and anion beds would increase total regeneration waste by 927,675 kg annually. (Note that each of the currently installed cation beds now treats only about half of the total process water.) Because the waste from each bed will now be mixed with ether, regeneration will no longer create a RCRA waste stream. One hundred percent of the RCRA waste stream (2,650,256 kg/year) is therefore eliminated, and all of the regeneration waste is now nonhazardous wastewater.

With the 80% reduction in the continuous blowdown that results from the lowered TDS concentration (2,645,278 kg) and the increase in regeneration waste (927,675 kg), the total annual reduction of the nonhazardous wastewater stream is 1,717,603 kg or 29.7%.

Annual savings in potable water use and wastewater treatment are \$68,567, and the cost for option implementation is \$580,000, which results in an ROI of approximately 11.82%. The implementation cost estimate was based on MK-F labor rates and overhead costs and is detailed in Appendix A, Part 1. An ROI of less than 25% is considered unfundable; consequently, this option is not recommended for implementation.

4.1.3 Install Anion Bed and Mixed-Bed Polisher (Option 10)

With the additional mixed-bed polishers, total annual nonhazardous wastewater is further reduced by 2,399,835 kg or 41.5%. In this scenario, annual regeneration waste increases by 889,230 kg, with savings in continuous blowdown rising to 3,290,065 kg/year.

Annual savings from reduced potable water use and wastewater treatment total \$95,801. The cost to implement the option is \$785,000, resulting in an ROI of 12.21%. The implementation cost estimate was based on MK-F labor rates and overhead costs and is detailed in Appendix A, Part 1. An ROI of less than 25% is considered unfundable; therefore, this option is not recommended for implementation.

4.1.4 Reuse Brine Regenerant (Option 11)

Option implementation will reduce the sodium softener waste by 52,650 kg annually, a 2.3% reduction from the current level of 2,383,244 kg. Implementation cost for the option is approximately \$20,000, with annual cost savings totalling \$2102. The implementation cost estimate was based on MK-F labor rates and overhead costs and is detailed in Appendix A, Part 1. The calculated ROI for the option is approximately 10.52%, which is unacceptable for funding. Given the initial capital investment required, the minimal waste reduction, and the low ROI, this option is not recommended for implementation.

4.1.5 Increase Lapse Time Between Rinses (Option 13)

Based on vendor information and current regeneration procedures, the implementation of a 20-minute lapse time will decrease the overall amount of rinse water needed in the regeneration process. The Steam Plant is currently conducting tests to determine the exact process changes that will be needed and the resulting decrease in wastewater. This analysis uses estimated waste reductions provided by the vendor and Steam Plant personnel.

Given the current rinse times for the hydrogen beds, an increase in the slow rinse time is not needed. The fast rinse, however, can be decreased by 5 minutes to reduce the waste stream by 2291 kg/regeneration. This change will reduce the RCRA waste stream by 206,190 kg annually.

For the sodium beds, the slow rinse will need to be increased by 3 minutes, generating an additional 149 kg of waste per regeneration. The fast rinse can then be reduced by 10 minutes, decreasing the waste stream by 2864 kg/regeneration. The combination of these changes will decrease the regeneration waste by 2715 kg/regeneration. The nonhazardous wastewater waste stream from the sodium beds would decrease by 439,830 kg annually.

The total annual waste reduction for implementing this option is expected to be 665,025 kg/year. Annual savings from decreased potable water use and wastewater treatment at the CNF is \$25,789. The implementation cost is \$1000, which includes administrative costs for rewriting operations procedures, testing, and employee training. The ROI for the option is 391%. Because of the high return on investment (HiROI), the minimal implementation cost, and reduction of both the RCRA wastewater and nonhazardous wastewater waste streams, this option is recommended for implementation. The HiROI Proposal has been prepared.

4.1.6 Contract Out the Softening and Regeneration Services (Option 14)

Operational and administrative effects on the Steam Plant from implementing the option will be insignificant. Hook-ups for the portable units can be constructed so that there is no operational down-time during exchanges.

Annual waste reduction totals 8,315,470 kg/year. This includes a 99.5% reduction in blowdown, complete elimination of the RCRA wastewater stream, and elimination of all the nonhazardous wastewater waste except the mud-drum blowdown. As mentioned in Sect. 3.1.7, the portable units need regeneration just as the stationary units. Technically, no waste has been generated until the regeneration occurs. The portable units, therefore, will be regenerated off-site, with the resulting waste being the responsibility of the vendor. In a global sense, the regeneration waste is not being reduced, it is only being relocated. The P2 opportunity for this option is that

the use of the portable system prevents 99.5% of the continuous blowdown (3,290,065kg/year) from being generated (i.e., source reduction).

Total annual savings, based on (1) the reduction in potable water use, wastewater treatment at the CNF, and purchase of raw materials (\$340,372) and (2) an increase in annual operations cost, based on vendor estimates (\$320,000), is \$19,772. Structural alteration is minimal, and implementation can be performed by the vendor for approximately \$4,500. Based on this data, an ROI of 43,478% can be calculated.

The HiROI and annual savings for this option would indicate that a recommendation for implementation should be made. However, in considering the option's funding and the absence of a chargeback system at K-25, which if employed could provide an accurate variable CNF treatment cost, this option's benefits are falsely inflated.

Because payment for the portable beds is an annual operating expense, funding for this option would traditionally come from the Steam Plant's operating budget. Because of the current accounting methods at K-25, the Steam Plant's operating budget does not include a cost for wastewater treatment at the CNF. Contracting out the softening services would require an increase in the Steam Plant's operating budget that could not be justified. For these reasons and because of the concern over relocation rather than removal of the regeneration wastewaters, this option is not recommended for implementation.

4.2 AIR EMISSION REDUCTION OPTIONS

4.2.1 Install a Low NO_x Burners (Option 2)

A 40% reduction of NO_x from Boilers 7, 8, and 9 would reduce the NO_x emission by 5,483 kg/year. The NO_x burner selected for estimating purposes was a North American Manufacturing Company low-emission (LE) model burner of a capacity similar to that of the burner currently installed in Boiler 7.

No tangible or intangible savings from implementing the option can be estimated. The implementation cost to purchase and install low NO_x burners in Boilers 7, 8, and 9 is \$2,350,000. The estimate includes the associated burner system valves and controls compatible with an Allen Bradley control system (which the Steam Plant currently uses). The estimate was structured based on MK-F labor rates and overhead costs and is detailed in Appendix A, Part 1. Because no savings are realized from this option, an ROI was not estimated.

Because of the high initial capital expense, the current low NO_x emissions (which are below the permitted levels), and the planned replacement of both Boilers 4 and 7 with one new, large-capacity boiler, this option is not recommended for implementation. However, this option should be evaluated further if the boilers are refurbished rather than replaced.

4.2.2 Install an FGR System in Boiler 7 (Option 4)

Implementation of this option would reduce total NO_x emissions by 2358 kg/year, or 17.2%. Discussions with the burner vendor indicate that the returned flue gas would not reduce burner flame stability. The option would therefore have no negative impact on the operation of Boiler 7.

The use of an FGR system is the lowest-cost option for reducing NO_x emissions. No tangible or intangible savings from implementing the option can be estimated. Total implementation cost is approximately \$90,000, which is detailed in Appendix A.1. Because no savings could be estimated from this option, an ROI was not calculated. Although Boiler 7 is in compliance with current NO_x emission rates, this option is recommended because it is the lowest cost option to reduce NO_x.

4.2.3 Install Backup Propane System (Option 8)

This option would reduce the permitted level of air emissions by 1,064,000 kg/year and save \$10,000 annually in permitting fees. Additional annual savings earned by reducing the time required for preparation of the permit application and record keeping are estimated to be \$2000, for a total \$12,000 annual savings. Implementation costs are estimated to be \$3,975,000 and are detailed in Appendix A.1. The estimate includes the purchase and installation of a propane tank large enough to operate the plant for 20 days. The ROI for the option is 0.30%. Because the implementation cost for this option is prohibitive, this option is not recommended for implementation.

4.3 STEAM DISTRIBUTION OPTION

4.3.1 Reduce Steam Loss from Steam Traps (Option 6)

For cost estimating purposes, it was assumed that one malfunctioning steam trap was identified each quarter that would not otherwise have been identified through visual inspection. The steam leakage rate per failed trap was assumed to be 1000 kg/day³ and to last 6 weeks before detection. The total annual savings with option implementation is estimated to be \$3,443, which includes \$299 for reductions in wastewater treatment and \$5,544 for savings in reduced steam loss and an increase in the annual operating costs of \$2,400. The labor cost to implement this option was estimated to be 16 hours per month at \$50/hour. For cost estimating purposes, it was assumed that one additional malfunctioning steam trap is found each quarter (i.e., that otherwise would not have been found from visual inspection). At an estimated steam production cost of \$0.033/kg⁴, the value of the lost steam is \$1,386/trap. The replacement cost per trap was estimated to be \$50 and the installation cost \$50/trap. The labor and materials to inspect and replace one trap were estimated to cost \$600 per quarter.

Implementation of this option would result in the annual reduction of nonhazardous wastewater by 6807 kg, RCRA hazardous wastewater by 3180 kg, and air emissions by 47.1 kg. Annual total waste reduction with option implementation is 10,034 kg. Because no implementation costs are associated with this option, an ROI could not be calculated. However, with the positive reduction in waste generation and annual cost savings, this option is recommended for implementation.

³Steam loss is based on header pressure of 100 psi and an orifice of 3/16 in.

⁴Steam cost based on \$15/1000 lb. steam.

5. IMPLEMENTATION PLAN AND FUNDING

Of the ten options evaluated further, three options are recommended:

- Option 4, to install an FGR system on Boiler 7;
- Option 6, to reduce steam loss from traps; and
- Option 13, to increase the lapse time between regeneration rinses for both the sodium and hydrogen beds.

Options 5, 6, and 7 are being further evaluated in the IHEM Study and may be recommended in the future depending upon the Study's findings. The funding for the recommended options will be pursued from the K-25 Site Landlord, the IHEM Program, and the DOE High ROI and High Investment Value Programs. At present, all recommended options are unfunded. The implementation schedule is based on evaluation by Steam Plant personnel, contingent upon funding. The implementation plan and funding for the three recommended options are shown in Table 5.1. Implementation schedules for Options 4, 6, and 13 are detailed in Figs. 5.1, 5.2, and 5.3 respectively.

A HiROI proposal has been written for Option 13. This HiROI received a total score of 595 following the *Criteria for Selecting High Investment Value Pollution Prevention Projects* (LMES 1995c).

Table 5.1. Steam Plant recommended P2 option implementation plan and funding

Option	Cost (\$)	Annual savings	Schedule (years)	Implementation status	Funding status
Install FGR System in Boiler 7 (Option 4)	90,000	\$0	5	Planning	Unfunded
Reduce Steam Loss from Traps (Option 6)	NA	\$3443	0.5	Planning	Facility Operating Budget
Increase Lapse Time between Rinses (Option 13)	1000	\$26,548	0.5	Pilot Test	Unfunded

Table 5.2 HiROI proposal ranking

Option number		13	
Option description		Increase lapse time between rinses	
HiROI Factor	Weight (W)	Scale (S)	W*S
Return on Investment	25	7	175
Waste Quantity	25	5	125
Waste Hazard	25	5	125
Technical Risk	10	10	100
Environmental compliance/liability	5	5	25
Waste treatment/disposal liability	5	1	5
Position on EPA heirarchy	5	8	40
TOTAL			595
RANK			1

Fig. 5.1. Implementation schedule for Option 4.

Fig. 5.2. Implementation schedule for Option 6.

Fig. 5.3. Implementation schedule for Option 13.

6. CONCLUSIONS

This pollution prevention opportunity assessment identified 14 options, 10 of which were technically feasible and analyzed further for waste reduction and costs/benefits. However, because of generally low ROIs, only three options could be recommended:

- Install an FGR system in Boiler 7 (Option 4)
- Reduce steam loss from steam traps (Option 6)
- Increase lapse time between rinses (Option 13)

Many of the options had ROIs of less than 25%, which is the minimum baseline for recommendation. Three of the options are being further evaluated in the IHEM Study, and future recommendations in this PPOA depend on that Study's findings. Based on preliminary information from the IHEM Study, it is expected that the payback period will also be high for these options. A summary of the options evaluated and their costs is presented in Table 6.1.

Table 6.1. Steam Plant P2 options analyzed for implementation

Option number and description	Waste reduction (kg/year)	Cost (\$)	Annual savings (\$)	ROI % ^a	Recommended (yes/no)
Install Low NO _x Burners (Option 2)	5,484	2,350,000	0	NA	No
Reuse Hydrogen Regenerant (Option 3)	144,360	136,000	5,763	4.24	No
Install FGR System in Boiler 7 (Option 4)	2,358	90,000	0	NA	Yes
Reduce Steam Loss from Steam Traps (Option 6)	10,034.1	0	3,443	NA	Yes
Backup Propane System (Option 8)	6,009	3,975,000	12,000	0.30	No
Install Anion Demineralizer Bed (Option 9)	4,367,859	580,000	68,567	11.82	No
Install Anion/Mixed Bed Polisher (Option 10)	5,050,091	785,000	95,801	12.21	No
Reuse Brine Regenerant (Option 11)	52,650	20,000	2,102	10.52	No
Increase Lapse Time between Rinses (Option 13)	646,020	1,000	25,789	391	Yes
Contract Out Softening/Regeneration Services (Option 14)	8,315,470	4,500	19,772	NA	No

^a NA means there are no cost savings or implementation cost for the project.

Of the seven options evaluated to reduce wastewater, only one option was recommended—to increase the lapse time between regeneration rinses for the sodium and hydrogen beds (Option 13). Only one of the other six options—contracting out the water softening treatment

(Option 14)—significantly reduces both the RCRA hazardous and nonhazardous wastewater generation rate. Options 9 and 10, installing an anion bed, eliminate the RCRA wastewater from the hydrogen bed regeneration and reduce the continuous blowdown rate; however, the regeneration waste would increase and would still require (precipitation) treatment at CNF to remove salts prior to discharge. The remaining two options to reuse regenerant, Options 3 and 11, only slightly reduce the amount of wastewater generated.

The current Steam Plant air emissions are well within allowable rates. Four options were identified and three were evaluated to reduce air emissions. None of the options provided any economic incentive for implementation. If the K-25 Site wishes to further reduce NO_x emission rates, Option 4—to install an FGR system in Boiler 7—is recommended. When Boilers 4 and 7 are replaced, it is recommended to evaluate the use of a low NO_x burner.

The three options currently being evaluated in the IHEM Study to improve the Steam Plant operating efficiency would reduce both the wastewater and air emission rates. Currently, no information from the Study regarding the cost, waste reduction rates, or payback periods is available to evaluate whether these options should be recommended. Of the three options, Option 6—to reduce steam loss from steam traps—is recommended. This option has little P2 benefit as reflected by its ranking on Worksheet 9 in Appendix B, but it is economically justified.

7. REFERENCES

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Appendix A

Part 1. Cost Estimate Summaries

Part 2. Calculations

Appendix A
Part 1

Cost Estimate Summaries

A-5

OPTION 2

LOW NO_x BURNERS

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Direct Hire		\$1,617,000
A/E - Title I and II Engineering (600 hrs × \$65.00/hr)		39,000
LMES - Title III Engineering (400 hrs × \$70.00/hr)		28,000
LMES - Construction Support/Project Management (500 hrs × \$70.00/hr)		<u>\$ 35,000</u>
	SUBTOTAL	\$1,719,000
Contingency at 30%		<u>\$ 515,000</u>
	SUBTOTAL	\$2,234,000
Escalation at 5%		<u>\$ 161,000</u>
	PROJECT TOTAL	\$2,350,000

JOB NAME K-25 Steam Plant PPOA - Option 2
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 8/07/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	DPLH	CRAFT RATE	LABOR TOTAL
1	Install new low NO _x Burners	3	Each	378,000.00	1,134,000.00				
	Administration at 25%	1	Lot		284,000.00				
	Subtotal				1,418,000.00				
	Indirects at 14%	1	Lot		199,000.00				
	MK-F Direct Hire Total				\$1,617,000.00				

OPTION 3

HYDROGEN REAGENT REUSE

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Construction - Direct Hire		\$ 62,000
A/E - Title I & II Engineering (240 hrs × \$65.00/hr)		16,000
LMES - Title III Engineering		8,000
LMES - Construction Support/Project Management (200 hrs × \$70.00/hr)		<u>14,000</u>
	SUBTOTAL	\$100,000
Contingency at 30%		<u>\$ 30,000</u>
	SUBTOTAL	\$130,000
Escalation at 5%		<u>\$ 6,000</u>
	PROJECT TOTAL	\$136,000

JOB NAME K-25 Steam Plant PPOA - Option 3
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 7/28/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	DPLH	CRAFT RATE	LABOR TOTAL
1	Excavation	1	Lot				64		
2	Stone under slabs	20	Ton	10.00	200.00		32		
3	Concrete foundation	8	CY	400.00	3,200.00		64		
4	Rework existing piping	1	Lot	500.00	500.00		32		
5	Polyethylene tank	1	Each	2,000.00	2,000.00		32		
6	2" Piping with fittings	100	LF	20.00	2,000.00		72		
7	Valves	6	Each	300.00	1,800.00		24		
8	Pump	1	Each	800.00	800.00		8		
9	Electrical	1	Lot	2,000.00	2,000.00		24		
10	Instrumentation	1	Lot	3,000.00	3,000.00		24		
11	Test Piping Systems	1	Lot	200.00	200.00		16		
12	Equipment for grading	4	Days	800.00	3,200.00				
13	Pipe insulation	100	LF	2.50	250.00		8		
	Subtotal				19,150.00		400	31.00	12,400.00
14	Support craft to above (20%)	1	Lot						2,480.00
18	Temporary services	1	Lot		300.00		40	31.00	1,240.00

JOB NAME K-25 Steam Plant PPOA - Option 3
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 7/28/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	DPLH	CRAFT RATE	LABOR TOTAL
19	Tags, identification	1	Lot		300.00		20	31.00	620.00
20	PPE	1	Lot	200.00	200.00		8	31.00	248.00
21	Shop support/Misc. 3.2%/6.3% Labor				638.00				1,070.00
22	Clean up at 6%								1,020.00
23	Vehicle charge				600.00				
	Subtotal				21,188.00				19,078.00
	Material				21,000.00				
	Labor				19,000.00				
	Subtotal				40,000.00				
	Administrative Support				10,000.00				
	Subtotal				50,000.00				
	Indirects at 24%				12,000.00				
	Total MK-F - Direct Hire				\$62,000.00				

A-10

OPTION 4

FLUE GAS RETURN TO BOILER 7

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Direct Hire		\$43,000
A/E - Title I & II Engineering (150 hrs x \$65.00/hr)		10,000
LMES - Title III Engineering		5,000
LMES - Construction Support/Project Management (100 hrs x \$70.00/hr)		<u>7,000</u>
	SUBTOTAL	\$65,000
Contingency at 30%		<u>\$20,000</u>
	SUBTOTAL	\$85,000
Escalation at 5%		<u>\$ 5,000</u>
	PROJECT TOTAL	\$90,000

DATE 8/07/95

[illegible]

A-12

OPTION 8

BACKUP PROPANE SYSTEM

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Direct Hire		\$2,850,000
A/E - Title I & II Engineering (2,000 hrs x \$65.00/hr)		130,000
LMES - Title III Engineering (1,000 hrs x \$70.00/hr)		70,000
LMES - Construction Support/Project Management (1,500 hrs x 70.00/hr)		<u>105,000</u>
	SUBTOTAL	\$3,155,000
Contingency at 20%		<u>\$ 630,000</u>
	SUBTOTAL	\$3,785,000
Escalation at 5%		<u>\$ 190,000</u>
	PROJECT TOTAL	\$3,975,000

JOB NAME K-25 Steam Plant PPOA - Option 8
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 8/07/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	DPLH	CRAFT RATE	LABOR TOTAL
1	Propane tanks, 60,000 gallon	12	Each	50,000.00	600,000.00				
2	Tank trim	12	Each	20,000.00	240,000.00				
3	Tank piers	12	Each	20,000.00	240,000.00				
4	New piping	1	Lot		120,000.00				
5	Rail car loading station	1	Lot		240,000.00				
6	Compressor station	12	Each	20,000.00	240,000.00				
7	Mixing station	1	Each		93,000.00				
8	Indian compressor	1	Each		225,000.00				
	Subtotal Vendor Quote				1,998,000.00				
	Administrative at 25%				449,000.00				
	Subtotal				2,497,000.00				
	Indirects at 14%				353,000.00				
	MK-F Direct Hire - Total				2,850,000.00				

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OPTION 9

ANION BEDS

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Direct Hire		\$ 350,000
A/E - Title I & II Engineering (500 hrs x \$65.00/hr)		33,000
LMES - Title III Engineering		16,000
LMES - Construction Support/Project Management (400 hrs x \$70.00/hr)		<u>28,000</u>
	SUBTOTAL	\$ 427,000
Contingency at 30%		<u>\$ 128,000</u>
	SUBTOTAL	\$ 555,000
Escalation at 5%		<u>\$ 25,000</u>
	PROJECT TOTAL	\$ 580,000

DATE 8/07/95

[illegible]

A-16

OPTION 10

ANION AND CATION/ANION MIXED BEDS

**K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY**

MK-F - Direct Hire		\$ 485,000
A/E - Title I & II Engineering (600 hrs x \$65.00/hr)		39,000
LMES - Title III Engineering		18,000
LMES - Construction Support/Project Management (500 hrs × \$70.00/hr)		<u>35,000</u>
	SUBTOTAL	\$ 577,000
Contingency at 30%		<u>\$ 173,000</u>
	SUBTOTAL	\$ 750,000
Escalation at 5%		<u>\$ 35,000</u>
	PROJECT TOTAL	\$ 785,000

JOB NAME K-25 Steam Plant PPOA - Option 10
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 8/07/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	MHRS	CRAFT RATE	LABOR TOTAL
1	Vendor Quote - Equipment	1	Lot		225,000.00				
2	Vendor Quote - Installation	1	Lot		80,000.00				
3	Mixing tank complete	1	Each		35,000.00				
	Subtotal				340,000.00				
	Administrative support				85,000.00				
	Subtotal				425,000.00				
	Indirects at 14%				60,000.00				
	MK-F Direct Hire - Total				485,000.00				

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OPTION 11

STORE AND REUSE BRINE REAGENT

K-25 Steam Plant PPOA
COST ESTIMATE SUMMARY

MK-F - Direct Hire		\$ 8,000
A/E - Title I & II Engineering (40 hrs x \$65.00/hr)		2,600
LMES - Title III Engineering		1,400
LMES - Construction Support/Project Management		<u>1,000</u>
	SUBTOTAL	\$ 13,000
Contingency at 50%		<u>\$ 6,000</u>
	SUBTOTAL	\$ 19,000
Escalation at 5%		<u>\$ 1,000</u>
	PROJECT TOTAL	\$ 20,000

JOB NAME K-25 Steam Plant PPOA - Option 11
 JOB NO. 1001-516
 BUILDING _____
 CONST. BY MK-F - Direct Hire

DATE 8/07/95

ITEM NO.	DESCRIPTION	QUAN	UNIT	MATERIAL PRICE	MATERIAL TOTAL	UNIT DPLH	MHRS	CRAFT RATE	LABOR TOTAL
1	Tank - small	1	Each	500.00	500.00		8		
2	Piping, including fittings	50	LF	10.00	500.00		24		
3	Pump	1	Each	500.00	500.00		8		
4	Controls	1	Lot	500.00	500.00		12		
	Subtotal				2,000.00		52	31.00	1,612.00
	Support Craft to above (20%)								322.00
	Temporary Services				100.00		8	31.00	248.00
	Tags, identification				100.00		4	31.00	124.00
	Shop support/Misc. 3.2%/6.3% Labor				70.00				145.00
	Clean up 6%								138.00
	Subtotal				2,270.00				2,589.00
	Material				2,300.00				
	Labor				2,600.00				
	Subtotal				4,900.00				
	Administrative support				1,300.00				
	Subtotal				6,200.00				
	Indirects at 24%				1,500.00				
					7,700.00				
	Use				8,000.00				

Appendix A
Part 2

Calculations

REGENERATION OF HYDROGEN SOFTENER

1. Backwash	= 150 gpm × 15 min.	= 2,250 gal
2. Acid regeneration	(2% H ₂ SO ₄) = 106 gpm × 11.5 min.	= 1,219
	(4% H ₂ SO ₄) = 52 gpm × 9 min.	= 468
	(6% H ₂ SO ₄) = 31 gpm × 9 min.	= 278
3. Slow rinse	= 31 gpm × 15 min.	= 465
4. Fast rinse	= 120 gpm × 25 min.	= 3,000
TOTAL HYDROGEN BED WASTEWATER/CYCLE		= 7,681 gal

$$7,681 \text{ gal} \times 8.34 \frac{\text{lb}}{\text{gal}} \times \frac{1 \text{ kg}}{2.2 \text{ lb}} = 29,118 \frac{\text{kg}}{\text{cycle}}$$

REGENERATION OF SODIUM SOFTENER

1. Backwash	= 75 gpm × 14 min.	= 1,050 gal
2. Brine regeneration	= 60.7 gal saturated brine + 13 gpm dilution water × 15 min.	= 255
3. Slow rinse	= 13 gpm × 10 min.	= 130
4. Fast rinse	= 75 gpm × 30 min.	= 2,250
TOTAL SODIUM BED WASTEWATER/CYCLE		= 3,685 gal

$$3,685 \text{ gal} \times 8.34 \frac{\text{lb}}{\text{gal}} \times \frac{1 \text{ kg}}{2.2 \text{ lb}} = 13,969 \frac{\text{kg}}{\text{cycle}}$$

REGENERATION OF CONDENSATE POLISHER

1. Backwash	= 30 gpm × 10 min.	= 300 gal
2. Brine regeneration	= 48 gal saturated brine + 2.8 gpm dilution water × 30 min.	= 132
3. rinse	= 13 gpm × 36 min.	= 468
TOTAL CONDENSATE POLISHER WASTEWATER/CYCLE		= 900 gal

$$900 \text{ gal} \times 8.34 \frac{\text{lb}}{\text{gal}} \times \frac{1 \text{ kg}}{2.2 \text{ lb}} = 3,412 \frac{\text{kg}}{\text{cycle}}$$

HARDNESS/TDS CALCULATIONSGiven:

- Incoming potable water analysis

80 ppm Ca^{+2}
 40 ppm Mg^{+2}
 140 ppm TDS
- Annual potable water flow to softeners
(Hydrogen softener receives 56%; sodium softener receives 44%.) = 87,062,020 kg
- Maximum TDS in boiler feedwater = 3,750 $\mu\text{mhos/cm}$ or 2,475 ppm*

Required:

Annual rate of continuous blowdown needed to maintain desired TDS level.

Assumptions:

- Softeners remove all Ca^{+2} and Mg^{+2} .
- The rate at which TDS enters the boilers is equal to the rate at which it is purged via continuous blowdown.

Calculations:

- Increase in $[\text{Na}^+]$ out of sodium softener:

$$80 \text{ ppm Ca} \times \frac{2 \times \text{MWNa}}{\text{MWCa}} + 40 \text{ ppm Mg} \times \frac{2 \times \text{MWNa}}{\text{MWMg}} \times \frac{2 \times \text{MWNa}}{\text{MWMg}}$$

$$= 80 \times \left[\frac{2 \times 23}{40} \right] + 40 \times \left[\frac{2 \times 23}{24.3} \right] = 167.7 \text{ ppm Na}$$

- Increase in TDS out of sodium softener:

Non-hardness TDS = 140 ppm - 120 ppm = 20 ppm TDS

Effluent TDS = 20 ppm + 167.7 ppm = 187.7 ppm TDS

- Decrease in TDS out of hydrogen softener:

140 ppm TDS in - 120 ppm hardness removed = 20 ppm TDS out

- Combined TDS from both softeners:

$0.56 \times 20 \text{ ppm TDS} + 0.44 \times 187.7 \text{ ppm TDS} = 94 \text{ ppm TDS}$

$$87,062,020 \frac{\text{kg H}_2\text{O}}{\text{year}} \times \frac{94 \text{ kg TDS}}{10^6 \text{ kg H}_2\text{O}} = 8,184 \text{ kg TDS}$$

- Continuous blowdown required:

$$\frac{8,184 \text{ kg TDS}}{\text{year}} \times \frac{10^6 \text{ kg}}{2,475 \text{ kg TDS}} = 3,306,598 \frac{\text{kg blowdown}}{\text{year}}$$

*Conversion factor of .66 $\mu\text{hos/ppm}$ provided by Mike Parkison, Steam Plant Systems Engineer

**WASTE REDUCTION CALCULATIONS FOR LOW NO_x BURNERS
OPTION 2 AND OPTION 4—FLUE GAS RETURN**

Estimated NO_x emissions of 15.08 tons/year as cited from the *Annual Site Environmental Report* draft, 1994.

Boiler	NO _x Tons/Year	Percent NO _x Emissions
4	39	19%
7	78	38%
8/9	88	43%
Total	205	100%

Estimated NO_x Emission per Boiler

Using the NO_x emission percent based on Allowable Emissions to calculate the estimated NO_x per boiler:

Boiler	Percent NO _x Emission	Estimated NO _x Emissions (kg/year)	40% NO _x Reduction (kg/year)
4	19%	2604	N/A
7	43%	5895	2358
8/9	38%	5209	2084
Total	100%	13,709	4442

**OPTION 3
HYDROGEN REGENERANT REUSE**

Reclaim 50% of the 6% sulfuric acid rinse	535 kg
Add slow rinse wastewater to achieve 2% solution	+ 1,069 kg
	<hr/>
Wastewater saved per regeneration	1,604 kg
	× 90 regenerations
	<hr/>
Total annual waste reduction	144,360 kg
	<hr/>
Cost per kilogram to treat at CNF	× 0.02992
	<hr/>
Annual savings in waste treatment	\$ 4,319
Annual saving in potable water use (144,360 kg)(\$0.01/kg)	+ \$ 1,444
	<hr/>
Total annual savings with option implementation¹	\$ 5,763
	<hr/>

¹Savings from reduction in sulfuric acid use is negligible and therefore not added into Total Cost Savings.

**OPTION 6
REDUCE STEAM LOSS FROM STEAM TRAPS**

- Assumptions:
- 1) 1000 kg/day is the steam leak rate
 - 2) 4 leaks/year
 - 3) each leak lasts 6 weeks
 - 4) steam cost is \$0.033/kg
 - 5) waste reduction is estimated as a percentage of steam produced

Annual steam loss	168,000 kg
Annual steam produced	÷ 139,353,800 kg
Annual associated waste reduction	<u>.0012 or .12 percent</u>

Annual RCRA wastewater reduction (0.0012) (2,650,356 kg)	3,180 kg
---	----------

Annual Nonhazardous wastewater reduction

(sodium + condensate + continuous
wastewater + wastewater + blowdown)

+ 6,807 kg

(0.0012)(2,263,489 kg + 102,355 kg + 3,306,598 kg)

Total Annual Wastewater Reduction

9,987 kg

Air emission reductions:

NO _x (0.0012)(13,709 kg) =	16.5 kg
---------------------------------------	---------

Particulate (0.0012)1,409 kg) =	1.7 kg
---------------------------------	--------

Sulphur Dioxide (0.0012)(4,600 kg)	5.5 kg
------------------------------------	--------

Other (0.0012)(19,491 kg)	+ 23.4 kg
---------------------------	-----------

Total Annual Air Emission Reductions

47.1 kg

Annual Cost Savings from Air Emission Reductions

\$0

Annual Cost Savings from wastewater reductions
(9,987 kg) (\$0.02992)

\$299

Annual Cost Savings from reduction in steam loss
(168,000 kg)(\$0.033)

+ \$5,544

Annual Operating Costs

(\$1,600 labor + \$400 materials + \$400 maintenance)

- 2,400

Total Annual Cost Savings with Option Implementation

\$ 3,443

**OPTION 8
INSTALL BACKUP PROPANE SYSTEM**

Reduction in permitted air emissions	1,064,000 kg
Permit cost per kg	<u>× \$0.0094</u>
Annual savings in permitting fees	\$10,000
 Annual savings in work hours (40 hours)(\$50.00/hour)	 <u>\$ 2,000</u>
Total Annual savings with option implementation	<u><u>\$ 12,000</u></u>

OPTION 9 ANION BEDS

Reduction in Continuous Blowdown of 80% (0.80)(3,306,598 kg)	2,645,278 kg
Increase in regeneration waste (see 1 below)	- 927,675 kg
Total annual waste reduction	1,717,603 kg
Cost per kg to treat at CNF	× 0.02992
Annual savings from waste treatment	\$ 51,391
Annual savings from decreased potable water use (1,717,603 kg)(0.01 \$/kg)	+ \$ 17,176
Total annual savings with option implementation	\$ 68,567

1. Regeneration waste

Anion regeneration waste (see 2 below) (8011 kg/regen.)(156 regens.)	1,249,716 kg
Cation regeneration waste (29,434 kg/regen.)(156 regens.)	+ 4,591,704 kg
	5,841,420 kg
Current regeneration waste	- 4,913,745 kg
Increase in regeneration waste	927,675 kg

2. Regeneration Cycles

Current treated water	87,062,020 kg
Less potable water saved from blowdown	- 2,645,278 kg
Total water treated	84,416,742 kg
Anion/Cation treatment capacity each	÷ 542,181 kg
Number of regenerations	156

OPTION 10
ANION AND CATION/ANION MIXED BEDS

Reduction in Continuous Blowdown of 99.5% (0.995)(3,306,598 kg)	3,290,065 kg
Increase in regeneration waste (see 1 below)	- 890,230 kg
Total annual waste reduction	2,399,835 kg
Cost per kg to treat at CNF	× 0.02992
Annual savings from waste treatment	\$ 71,803
Annual savings from decreased potable water use (2,399,835 kg)(0.01 \$/kg)	+ \$ 23,998
Total annual savings with option implementation	\$ 95,801

1.

Anion regeneration waste (see 2 below) (8011 kg/regen.)(155 regens.)	1,241,705 kg
Cation regeneration waste (29,434 kg/regen.)(155 regens.)	+ 4,562,270 kg
	5,803,975 kg
Current regeneration waste	- 4,913,745 kg
Increase in regeneration waste	890,230 kg

2. **Regeneration Cycles**

Current treated water	87,062,020 kg
Less potable water saved from blowdown	- 3,290,065 kg
Total water treated	83,771,955 kg
Anion/Cation treatment capacity each	÷ 542,181 kg
Number of regenerations	155

**OPTION 11
STORE AND REUSE BRINE REAGENT**

1/3 of brine injection saved for reuse from sodium
softener

325 kg

Number of regenerations (see Appendix C)

× 162

*Total annual reduction

52,650 kg

Cost per kg for CNF treatment

× 0.02992

*Annual savings in waste treatment

\$ 1,575

Annual savings in potable water
(52,650 kg)(0.01 \$/kg)

+ \$ 527.00

Total annual savings with Option implementation

\$ 2,102

OPTION 13
INCREASE LAPSE TIME BETWEEN RINSES

Total amount waste reduction [A + B (see below)]	646,020 kg
Cost per kg to treat at CNF	× \$ 0.02922
Annual savings in waste treatment	\$9,329
Annual savings in potable water use (646,020 kg) (\$0.01/kg)	+ \$6,460
Total annual savings with option implementation	<u>\$5,789</u>

A: Hydrogen bed savings:

No increase in slow rinse

0 kg

Decrease in fast rinse by 5 minutes

2291 kg

Regenerations

× 90

Total annual waste reduction206,190 kg**B: Sodium bed savings:**

Increase in slow rinse by 3 minutes

149 kg

Decrease in fast rinse by 10 minutes

+ 2864 kg

2,715 kg

Regenerations (see Appendix C)

× 162

Total annual waste reduction439,830 kg

OPTION 14
CONTRACT OUT SOFTENING AND REGENERATION SERVICES

Reduction in Continuous Blowdown of 99.5% = (0.995)(3,306,598 kg)	3,290,065 kg
Reduction in condensate polishing waste	102,355 kg
Reduction in Lab analysis wastewater	9,305 kg
Reduction in Na ⁺ regeneration waste	2,263,489 kg
Reduction in H ⁺ regeneration waste	<u>+ 2,650,256 kg</u>
Total annual waste reduction	<u><u>8,315,470 kg</u></u>
Cost per kg for CNF treatment	<u>× 0.02992</u>
Savings in wastewater treatment	\$ 248,799
Savings in Potable Water (8,315,470 kg wastewater)(\$0.01/kg)	\$ 83,155
Savings in sulfuric acid cost	\$ 240
Savings in rock salt cost	\$ 128
Savings in work hours (161 hrs. × \$50/hr)	<u>\$ 8,050</u>
Annual savings w/ option implementation	\$ 340,372
Annual operating expenses	<u>- \$ 320,600</u>
Total annual savings with option implementation	<u><u>\$ 19,772</u></u>

Appendix B
PPOA Worksheets

Worksheet 1
Level III

Revision No.: 1

Revision Date: 8/22/95

Pollution Prevention Opportunity Assessment
PPOA Team**PPOA Title or PPOA ID Code:** Steam Plant

Name	Job Classification	Phone
Sherry L. Odom	Environmental Scientist	615/483-0666
James T. Nelson	Sr. Environmental Engineer	615/483-0666
Steven J. Kirsliis	Environmental Engineer	615/483-0666
Iqbal Ahmed	Analytical Engineer	615/483-0666
Mike Parkison	Steam Plant Systems Engineer	615/574-9900
Tim Kelly	Utilities Engineer	615/576-8802

Worksheet 2**Level III****Revision No:** 1**Revision Date:** 8/11/95

Pollution Prevention Opportunity Assessment

Process Description

PPOA Title: Steam Plant

PPOA ID Code: Steam Plant

Process Location: K-1501

Process Description: See Section 2

Description of Major Product(s) of Process:

Production of steam for use in site-wide space heating during October through April as well as for use in other processes such as the cafeteria, laundry, garage, and TSCA Incinerator.

Pollution Prevention Opportunity Assessment

Process Flow Diagram

PPOA Title or PPOA ID Code(s): Steam Plant

Inputs:

Potable Water
Sulfuric Acid (97%)
Rock Salt
Phosphate Reagent
Sodium Sulfite
Natural Gas
Recovered Condensate
Air
No. 2 Fuel Oil
Antifoam Agent

PR3	gas	139,353,000.00
Steam

Criteria Pollutant-CAAA
Hazardous- RCRA
Nonhazardous
Product

CA3	Gas	39,209.00
Particulate		
Other Air Emissions		
Sulfur Dioxide		
Nitrogen Oxides		

HZ1	Solid	109.00
Oily Rags and Solids		
HZ2	Liquid	2,650,256.00
Sulfuric Acid Wastewater		

NH2	Liquid	5,784,013.00
Mud-Drum Blowdown		
Lab Analysis Wastewater		
Brine Condensate Wastewater		
Brine Softener Wastewater		
Continuous Blowdown		

Pollution Prevention Opportunity Assessment

Material Balance Summary

PPOA Title or PPOA ID Code(s): Steam Plant

Output Quantity Units: kg

Material Description	Total Output	Stream ID Code	Stream ID Code	Stream ID Code	Stream ID Code	Stream ID Code
		CA3	HZ1	HZ2	NH2	PR3
Sulfuric Acid Wastewater	2,650,256	0	0	2,650,256	0	0
Sulfur Dioxide	4,600	4,600	0	0	0	0
Steam	139,353,000	0	0	0	0	139,353,000
Particulate	1,409	1,409	0	0	0	0
Other Air Emissions	19,491	19,491	0	0	0	0
Oily Rags and Solids	109	0	109	0	0	0
Nitrogen Oxides	13,709	13,709	0	0	0	0
Mud-Drum Blowdown	102,266	0	0	0	102,266	0
Lab Analysis Wastewater	9,305	0	0	0	9,305	0
Continuous Blowdown	3,306,598	0	0	0	3,306,598	0
Brine Softener Wastewater	2,263,489	0	0	0	2,263,489	0
Brine Condensate Wastewater	102,355	0	0	0	102,355	0
Totals/Subtotals	147,826,587	39,209	109	2,650,256	5,784,013	139,353,000

Pollution Prevention Opportunity Assessment

Input Material and Output Disposal Cost

PPOA Title or PPOA ID Code: Steam Plant

Input Material Cost:

Material	Quantity (kg)	Cost Per Unit	Annual Cost
Air		0	
Recovered Condensate	56,407,060.00	0	\$0.00
Rock Salt	11,183.00	0.01	\$111.83
Potable Water	92,133,680.00	0.01	\$921,336.80
Sulfuric Acid (97%)	12,114.00	0.02	\$242.28
Natural Gas	11,476,150.00	0.104	\$1,193,519.60
No. 2 Fuel Oil	539,253.00	0.255	\$137,509.52
Sodium Sulfite	527.00	0.88	\$463.76
Phosphate Reagent	31.00	2.38	\$73.78
Antifoam Agent	443.00	3.315	\$1,468.55
Total/Subtotal	160,580,441.00		\$2,254,726.11

Waste Disposal Cost:

Material/Waste Stream	Stream Code	Qty (kg)	Cost Per Unit	Annual Cost
Particulate	CA3	1,409	0	\$0.00
Other Air Emissions	CA3	19,491	0	\$0.00
Oily Rags and Solids	HZ1	109	0	\$0.00
Sulfur Dioxide	CA3	4,600	0	\$0.00
Nitrogen Oxides	CA3	13,709	0	\$0.00
Lab Analysis Wastewater	NH2	9,305	0.02992	\$278.41
Mud-Drum Blowdown	NH2	102,266	0.02992	\$3,059.80
Brine Condensate Wastewater	NH2	102,355	0.02992	\$3,062.46
Brine Softener Wastewater	NH2	2,263,489	0.02992	\$67,723.59
Sulfuric Acid Wastewater	HZ2	2,650,256	0.02992	\$79,295.66
Continuous Blowdown	NH2	3,306,598	0.02992	\$98,933.41
Total/Subtotal		8,473,587		\$252,353.33

Pollution Prevention Opportunity Assessment Option Generation

PPOA Title or PPOA ID Code: Steam Plant

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 1 : Reroute current air injection on all boilers through the flue gas exhaust system to preheat the influent air to approximately 250 degrees Fahrenheit. Option implementation would require the replacement of present stack materials, which are inadequate to accommodate the acidic condensate that would result from a decrease in stack emission temperature levels. Full replacement of the stack would be necessary. The option is not considered further at this time because of the prohibitive cost of implementation.

Consider Option Further ☐ Yes ☒ No

Practices & Procedure ☐	Waste Segregation/Hazardous Reduction ☐
Material Substitution ☐	Equipment Modification ☒
New Product &/or Process ☒	Recycle, Reuse, Reclamation ☒

Option No. 2 : Install Low NOx burners in all boilers. Option implementation will reduce NOx emissions approximately 40%.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☐	Waste Segregation/Hazardous Reduction ☐
Material Substitution ☐	Equipment Modification ☒
New Product &/or Process ☒	Recycle, Reuse, Reclamation ☐

Option No. 3 : Reclaim and blend approximately 50% of the 6% sulfuric acid with the necessary slow rinse wastewater to achieve a 2% sulfuric acid concentration. The retained 2% solution can then be used in the following regeneration. Option implementation will reduce potable water use, sulfuric acid use, and wastewater generation.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒	Waste Segregation/Hazardous Reduction ☐
Material Substitution ☐	Equipment Modification ☒
New Product &/or Process ☒	Recycle, Reuse, Reclamation ☒

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 4 : Install 10% Flue Gas Return system in Boiler 7 to reclaim and return the uncombusted organics and BTUs to the boiler furnace. Option implementation will result in reduced air emissions (40% for NO_x) and fuel use.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☐

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☒

Recycle, Reuse, Reclamation ☒

Option No. 5 : Replace the below ground steam distribution lines between the Administration Area and Building K-1007 with above ground piping to reduce heat loss. Option implementation will result in decreased steam production and reductions in raw material use, fuel use, and waste generation. The LMES Energy Management Section has conducted a study, currently in draft, which evaluated the costs and benefits of this option. Preliminary results indicate that the option may be cost effective. To minimize duplication, further consideration of this option is postponed until final issue of the study.

Consider Option Further ☐ Yes ☒ No

Practices & Procedure ☒

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☐

New Product &/or Process ☐

Recycle, Reuse, Reclamation ☐

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 6 : Reduce loss of steam through steam header traps by improving diagnosis of trap failure. Option implementation will result in decreased steam production and reductions in raw material use, fuel use, and waste generation. Currently, the LMES Energy Management Section is conducting a study on the Steam Plant distribution line traps which evaluates the costs and benefits of a database system to track steam trap failure. To minimize duplication, further consideration of implementing a database tracking system is postponed until final issue of the study. In addition to the tracking system, Steam Plant personnel agree that conducting quarterly inspections of improperly plumbed traps by taking temperature measurement up and downstream of the traps and using a stethoscope to listen for steam leaks would improve leak identification and reduce overall steam loss.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒	Waste Segregation/Hazardous Reduction ☐
Material Substitution ☐	Equipment Modification ☐
New Product &/or Process ☐	Recycle, Reuse, Reclamation ☐

Option No. 7 : Install additional condensate recovery piping systems. Option implementation will result in a decrease in softener/demineralizer wastewater. The LMES Energy Management Section has conducted a study, currently in draft, which evaluated the costs and benefits of this option. Preliminary results indicate that the implementation cost may be prohibitive. To minimize duplication, further consideration of this option is postponed until final issue of the study.

Consider Option Further ☐ Yes ☒ No

Practices & Procedure ☐	Waste Segregation/Hazardous Reduction ☐
Material Substitution ☐	Equipment Modification ☒
New Product &/or Process ☐	Recycle, Reuse, Reclamation ☒

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 8 : Replace No. 2 fuel oil with propane as the backup fuel source. Option implementation will result in a decrease of permitted air emissions by 532 tons/year, saving \$10,000 annually in permitting fees with additional savings in permit preparation and record keeping costs.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☒

Equipment Modification ☒

New Product &/or Process ☒

Recycle, Reuse, Reclamation ☐

Option No. 9 : Install an anion demineralizer bed downstream of the existing hydrogen cation bed and degasifier. Option implementation has two benefits: 1-- this new system demineralizes the feedwater to reduce the TDS (total dissolved solids) from 94 ppm to 15-20 ppm, thereby reducing the continuous blowdown by the same ratio (80%), from 2,182,355 to 436,471 kg/year; 2-- in addition, regeneration of the two beds will now occur simultaneously, allowing the hydrogen and anion regeneration waste to be blended, resulting in an effluent with a pH near 8 that will be classified as nonhazardous.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☐

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☒

Recycle, Reuse, Reclamation ☐

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 10 : In conjunction with the anion bed installed in option 9, install a cation/anion mixed bed polisher downstream of the proposed anion bed. Option implementation will further reduce TDS to achieve a level of 0.5 ppm (versus 15-20 with only the anion bed) and again allow blending of the waste streams to achieve a nonhazardous waste.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☐

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☒

Recycle, Reuse, Reclamation ☐

Option No. 11 : Store and reuse one-third of the brine regenerant. Implementation will result in significant decreases in potable water use and wastewater generation.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☐

Recycle, Reuse, Reclamation ☒

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 12 : Repair leaky valves and cap off the open pipelines from the Steam Plant to the CNF that were not completed during a repiping project in 1992. As a result of the infiltrating ground/rain water, the amount of wastewater sent to the CNF from the Steam Plant is artificially inflated. Option implementation reduces the amount of wastewater attributed to generation by the Steam Plant needing CNF treatment. Activities effectively implementing this option are currently scheduled for the late part of the summer by the Maintenance Division, so no further consideration of the option is needed.

Consider Option Further ☐ Yes ☒ No

Practices & Procedure ☐

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☐

Recycle, Reuse, Reclamation ☐

Option No. 13 : Increase lapse time between slow and fast rinse during resin regeneration to approximately 20-30 minutes, which increases the salt diffusion. Option implementation will result in decreased potable water use and wastewater generation.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☐

New Product &/or Process ☐

Recycle, Reuse, Reclamation ☐

Pollution Prevention Opportunity Assessment

Option Description

PPOA Title or PPOA ID Code: Steam Plant

Option Name and Description

(Include input materials, products affected, and anticipated reduction quantity.)

Option No. 14 : Contract out the softening and related regeneration services. The contractor will provide a portable mixed-bed system (cation and anion) that will be regenerated off-site. Option implementation will result in a zero discharge rate for all regeneration waste and will decrease the continuous and mud-drum blowdowns by 99.5% each.

Consider Option Further ☒ Yes ☐ No

Practices & Procedure ☒

Waste Segregation/Hazardous Reduction ☐

Material Substitution ☐

Equipment Modification ☒

New Product &/or Process ☒

Recycle, Reuse, Reclamation ☐

Pollution Prevention Opportunity Assessment **Options Cost Evaluation**

PPOA Title or PPOA ID Code(s): Steam Plant

	Option No.	Option No.	Option No.	Option No.	Option No.
	2-Low NOx	3-Reuse H. Regen.	4-FGR	6-Steam Traps	8-Propane
Implementation Costs					
Purchased Equipment	\$1,134,000.	\$19,150.	\$30,000.		\$1,998,000.
Installation	\$35,000.	\$19,000.	\$7,000.		\$105,000.
Materials		\$21,000.			
Utility Connections					
Engineering	\$67,000.	\$24,000.	\$15,000.		\$200,000.
Development					
Start Up/Training					
Administrative	\$284,000.	\$10,000.	\$8,000.		\$449,000.
Other	\$875,000.	\$42,850.	\$30,000.		\$1,223,000.
Total Implementation Cost	\$2,395,000.	\$136,000.	\$90,000.		\$3,975,000.
Incremental Operating Costs					
Change in Raw Materials		\$1,444.		(\$400.)	
Change in Maintenance				(\$400.)	
Change in Labor				(\$1,600.)	\$2,000.
Change in Disposal		\$4,319.		\$299.	
Change in Utilities					
Other			\$600.	\$5,544.	\$10,000.
Annual Operating Savings/(Costs)		\$5,763.	\$600.	\$3,443.	\$12,000.
Incremental Intangible Costs					
Penalties and Fines					
Future Liabilities					
Other					
Annual Intangible Savings/(Cost)					
Pay-back Period	NA	23.60	150.00	0.00	331.25

Pollution Prevention Opportunity Assessment

Weighted Sums Options Evaluation

PPOA Title or PPOA ID Code(s): Steam Plant

Criteria	Weight (W)	Option 2		Option 3		Option 4		Option 6		Option 8	
		Low NOx		Reuse H. Regen.		FGR		Steam Traps		Propane	
		Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S
Public Health, Safety, & Environment	10	8	80	8	80	8	80	4	40	8	80
Employee Health & Safety	10	4	40	8	80	4	40	6	60	6	60
Regulatory Compliance	8	6	48	4	32	6	48	6	48	6	48
Economic	6	0	0	6	36	0	0	8	48	0	0
Implementation Period	4	0	0	0	0	4	16	10	40	0	0
Improved Operation / Product	2	4	8	4	8	4	8	10	20	4	8
Other	0	0	0	0	0	0	0	0	0	0	0
Subtotal			176		236		192		256		196
Likelihood of Technical Success (Multiplier)		X	1	X	1	X	1	X	1	X	1
Likelihood of Useful Results (Multiplier)		X	1	X	1	X	1	X	0	X	.1
Total			176		236		192		0		196
Rank			8		5		7		10		6

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Pollution Prevention Opportunity Assessment

Weighted Sums Options Evaluation

PPOA Title or PPOA ID Code(s): Steam Plant

Criteria	Weight (W)	Option 9		Option 10		Option 11		Option 13		Option 14	
		Add OH- Bed		Anion/Mixed Bed		Reuse Brine		Lapse Time		Use Contractors	
		Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S	Scale (S)	W * S
Public Health, Safety, & Environment	10	8	80	8	80	4	40	8	80	8	80
Employee Health & Safety	10	6	60	6	60	4	40	6	60	6	60
Regulatory Compliance	8	6	48	6	48	4	32	8	64	8	64
Economic	6	6	36	6	36	6	36	10	60	0	0
Implementation Period	4	4	16	4	16	4	16	10	40	10	40
Improved Operation / Product	2	6	12	6	12	4	8	4	8	10	20
Other	0	0	0	0	0	0	0	0	0	0	0
Subtotal			252		252		172		312		264
Likelihood of Technical Success (Multiplier)		X	1	X	1	X	1	X	1	X	1
Likelihood of Useful Results (Multiplier)		X	1	X	1	X	1	X	1	X	1
Total			252		252		172		312		264
Rank			3		4		9		1		2

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Worksheet 10**Level III**

Revision No.: 1

Revision Date: 8/22/95

Pollution Prevention Opportunity Assessment

Final Report Check Sheet

PPOA Title or PPOA ID Code: Steam Plant

<u>Requirement</u>	<u>Completed</u>
Title Page	<u>X</u>
PPOA Title	
PPOA Id Code	
Team Members	
Issue date/revision date/revision no.	
Executive Summary	<u>X</u>
Process Description	
Process Assessment	
Option Summary and analysis	
Conclusions	
Recommendations	
Introduction	<u>X</u>
Background of evaluation	
Process Description	<u>X</u>
Associated Equipment	
Process Flow Diagram	
Process Assessment	<u>X</u>
Methodology	
Material Balance	
Unusual Occurrences	
Option Summary and Analysis	<u>X</u>
Option Description and rank	
Upstream/Downstream impacts	
Material usage	
Anticipated reduction	
Estimated costs	
Estimated benefits	
Feasibility	
Waste streams affected	
Conclusion	<u>X</u>
Concluding evaluation	
Option analysis decisions	
Concerns	
Options already implemented	
Lessons learned	
Recommendations	<u>X</u>
Future work	
New Equipment	
Implementation strategies	
Worksheets	<u>X</u>
1-10	

Appendix C
Mass Balance Stream Quantities

Table C.1 Mass Balance Stream Quantities

Stream number	Mass balance stream name	Annual quantity (kg/year)	
		CY 1994	CY 1995
A	Potable water influent (total)	146,428,400	91,917,030
1	Dilution water to sulfuric acid	1,047,320	657,283
2	Potable water fed to softeners	138,694,200	87,062,020
3	Dilution water to brine (main sodium softener)	190,721	119,755
4	Potable water fed to hydrogen softener	78,054,820	48,986,130
5	Potable water fed to main sodium softener	60,639,380	38,075,890
6	Sulfuric acid regenerant (after dilution)	1,081,504	678,737
7	Dilute brine regenerant to main sodium softener	250,089	157,032
8	Wastewater from Hydrogen softener (total) to G Sump via 6-in. pipeline	4,222,936	2,650,256
9	Effluent from hydrogen softener	(see #4)	(see #4)
10	Effluent from main sodium softener	(see #5)	(see #5)
11	Wastewater from main sodium softener (total) to G sump via 6-in. pipeline	3,604,816	2,263,489
12	Softened water to laboratory	9,305	9,305
13	Softened water to degasifier	138,684,900	87,052,710
14	Continuous blowdown	5,267,578	3,306,598
15	Softened water from condensate polisher	6,099,401	55,709,920
16	Softened water to boilers	144,784,300	142,762,600
17	Steam from boilers	139,353,800	139,353,800
18	Recovered condensate	6,109,090	55,806,820
19	Wastewater from condensate polisher (total)	10,235	102,355
20	Combined wastewater to G Sump via 6-in. pipelines	3,615,051	2,365,843
21	Combined wastewater to G Sump via 12-in. pipeline	5,439,798	3,418,169
22	Mud-drum blowdown	162,915	102,266
23	Rinse water to condensate polisher	8,734	87,343
24	Total wastewater from Steam Plant to CNF	13,277,780	8,434,268
25	Continuous + Mud-drum blowdown	5,430,493	3,408,864
26	Concentrated sulfuric acid to hydrogen bed	19,303	12,114
27	Concentrated brine to main sodium softener	59,368	37,278
28	Rinse water to main hydrogen softener	3,141,432	1,971,519
29	Rinse water to sodium softener	3,354,727	2,106,457
30	Brine dilution water to condensate polisher	955	9,553

Table C.1. Mass Balance Stream Quantities (continued)

Stream number	Mass balance stream name	Annual quantity (kg/year)	
		CY 1994	CY 1995
31	Dilute brine to condensate polisher	1,501	15,012
32	Concentrated brine to condensate polisher	546	5,459
33	Particulate	1,409	Not available
34	Other air emissions	19,491	Not available
35	Sulfur dioxide	4,600	Not available
36	Nitrogen oxide	13,709	Not available

C-5

Fig. C.1. Process flow diagram for the K-1501 Steam Plant (in support of Table C.1).

* The number or letter following selected stream titles represents the stream quantities as identified in Table C.1

C-6

Fig. C.2. Process flow diagram for the K-1501 water softening process (in support of Table C.1).

PAI REV. 08-25-93
SteamPa.Drw
Disk 1. Misc.

* The number or letter following selected stream titles represents the stream quantities as identified in Table C.1

Steam Power Plant PPOA
Wastewater Mass Balance for the Year of 1994

WMB1-1

Date: 8-24-1995

***** Input Data *****

Calculation Number: WMB-1

Input Data For Dilution & Rinse Water

Cap,H2 (gal)	Nreg,H2 (#)	Cap,Na (gal)	Nreg,Na (#)	Cap,Pol (gal)	Nreg,Pol (#)
-----	-----	-----	-----	-----	-----
142000.0	145	62000.0	258	500000.0	3

Vw,28 (gal)	Nreg,28 (#)	Vw,29 (gal)	Nreg,29 (#)	Vw,3 (gal)	Nreg,3 (#)
-----	-----	-----	-----	-----	-----
5715.0	145	3430.0	258	195.0	258

Vw,23 (gal)	Nreg,23 (#)	Vw,30 (gal)	Nreg,30 (#)
-----	-----	-----	-----
768.0	3	84.0	3

Input Data For H2SO4 and Brine

Vs,26 (gal)	H2SO4 (%) Concn,26	Nreg,26 (#)
-----	-----	-----
28.0	97.0	145

Vs6a (gal)	H2SO4 (%) Concn,6a	Vs6b (gal)	H2SO4 (%) Concn,6b	Vs6c (gal)	H2SO4 (%) Concn,6c	Nreg,6 (#)
-----	-----	-----	-----	-----	-----	-----
1219.0	2.0	468.0	4.0	279.0	6.0	145

Vb,27 (gal)	Brine (%) Concn,27	Nreg,27 (#)	Vb,32 (gal)	Brine (%) Concn,32	Nreg,32 (#)
-----	-----	-----	-----	-----	-----
60.7	30.0	258	48.0	30.0	3

Other Input Data

Mw,12 (kg)	Mw,18 (kg)	Mw,14 (kg)
-----	-----	-----
9305.	6109090.	5267578.

WMB1-2

Blowdown Flow Percent
 At 14, Y3 At 22, Y4

 97.0 3.0

 ***** Output Data *****

Mw,28	Mw,29	Mw,3
(kg)	(kg)	(kg)
-----	-----	-----
3141432.	3354727.	190721.

Mw,23	Mw,30
(kg)	(kg)
-----	-----
8734.	955.

Mw,26	Ms,26	Mw,6	Ms,6
(kg)	(kg)	(kg)	(kg)
-----	-----	-----	-----
462.	18841.	1047782.	33722.

Mw,6a	Mw,6b	Mw,6c
(kg)	(kg)	(kg)
-----	-----	-----
656661.	246961.	144160.

Mbr,27	Mbr,32
(kg)	(kg)
-----	-----
59368.	546.

Mw,1	Mbr,7	Mbr,31
(kg)	(kg)	(kg)
-----	-----	-----
1047320.	250089.	1501.

Mw,8	Mw,11	Mw,19
(kg)	(kg)	(kg)
-----	-----	-----
4222936.	3604816.	10235.

Mw,14	Mw,22	Mw,25
(kg)	(kg)	(kg)
-----	-----	-----
5267578.	162915.	5430493.

Mw,4	Mw,5
(kg)	(kg)
-----	-----
78054820.	60639380.

WMB1-3

Mw, a (kg) -----	Mw, 2 (kg) -----		
146428400.	138694200.		
Mw, 13 (kg) -----	Mw, 15 (kg) -----	Mw, 16 (kg) -----	Mw, 17 (kg) -----
138684900.	6099401.	144784300.	139353800.
Mw, 20 (kg) -----	Mw, 21 (kg) -----	Mw, 24 (kg) -----	
3615051.	5439798.	13277780.	

Distribution

1. K. E. Amburn
- 2-5. B. D. Barkenbus
6. J. F. Betschart
7. H. T. Conner, Jr.
8. C. E. Frye
9. T. D. Kelly
10. M. L. Parkison
11. C. H. Peterson
12. J. S. Suffern
13. E. F. Thomas
14. A. E. Walzer
15. H. D. Whitehead, Jr.
16. WMD Document Center—RC