COLUMBIA WATER & LIGHT
COLUMBIA, MISSOURI

Volume 1 – Revised Draft Submittal

Municipal Power Plant
Comprehensive Condition Assessment Report of Solid Fuel Fired Steam Electric Generating Units
(Turbines 5 & 7, Boiler 6 & 7 and Balance of Plant Systems)

January 21, 2013

LUTZ, DAILY & BRAIN, LLC
Consulting Engineers

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January 21, 2013

Mr. Christian Johanningmeier, P.E.
Power Production Superintendent
Columbia Water & Light Department
1501 Business Loop 70E
Columbia, MO 65205-6015

RE: Comprehensive Power Plant Condition Assessment (PPCA) Report
Volume 1, Revised Draft Submittal

Dear Christian:

We are pleased to submit our Revised Draft Submittal for Volume 1. Since the previously issued Revised Draft Submittals for Volumes 2 and 3 have not changed, we have not included these two Volumes in this resubmittal.

Also enclosed is a flash drive which includes pdf files for all three volumes.

We look forward to reviewing this Revised Draft Volume 1 Submittal as well as the previously issued Revised Draft Volumes 2 and 3 Submittals with you and other involved CWL staff.

Very truly yours,

LUTZ, DAILY & BRAIN, LLC

Thomas L Shepard

Thomas L. Shepard, P.E.

tmr
w/enc
cc: Fred Lutz, Tom Lutz, Bruce Smith, Randy Snell, Wyatt Howell, Michal Rice w/enc via email

TABLE OF CONTENTS

TABLE OF CONTENTS, continued

1.0 EXECUTIVE SUMMARY

1.1 Overview: This Comprehensive Power Plant Condition Assessment (PPCA) Report has been prepared over the last year. This report is a comprehensive condition assessment of the 16.5 MW and 22.0 MW solid fuel fired plant additions at the City of Columbia, Missouri Municipal Power Plant which Lutz, Daily & Brain (LD&B) initially designed in the 1950's and 1960's. Improvements have been made over the years to maintain the reliability of these two unit additions and to maintain their compliance with all applicable environmental rules and regulations.

The last Comprehensive PPCA Report for these two solid fuel unit power plant additions was conducted in the early 1980's.

In light of the recently passed environmental rules and regulations which have included the Industrial/Commercial/Institutional (ICI) Boiler Maximum Achievable Control Technology (MACT) Rule; Mercury & Air Toxics Standards (MATS); Cross-State Air Pollution Rule (CSAPR), Coal Combustion Residuals (CCR) proposed rule and others, the City of Columbia and their Columbia Water & Light (CWL) Department authorized the preparation of this Comprehensive PPCA Report to assist them in determining how to best utilize these power supply resources in the future.

1.2 Findings: In general, these two solid fuel fired steam electric generating units are in good condition with the exception of some components which will need upgrading and/or replacement over the next 20 years. These components which have been identified as being in need of either upgrading or replacing over the next 20 years have been categorized and listed below.

1.2.1 *Routine Maintenance Related Projects*: These routine maintenance related projects include the following:

1.2.1.1 Replacement of Boiler 6 Economizer Tube Bends

1.2.1.2 Boiler 6 Mechanical Collector Collection Tubes Replacement

1.2.1.3 Boiler 7 Attemperator Repair & Replacement

1.2.1.4 Boilers 6 & 7 Chemical Cleaning

1.2.1.5 Boilers 6 & 7 Common Flue Gas Ductwork Replacement at Stack

1.2.1.6 Replacement of Baghouse Controls & Installation of Additional Monitoring

1.2.1.7 Direct Buried 48-inch Diameter Circulating Water Piping Repairs/Replacement

1.2.1.8 Routine Maintenance Electrical Related Items

1.2.2 *Potential Future Environmental Related Upgrades*: These potential future environmental related upgrades include the following:

1.2.2.1 Potential Retrofit of Impervious Ash Storage Area Liner (Approx. 5 Acre Area)

1.2.2.2 Potential Installation of Dry Type Ash Handling System

1.2.2.3 Potential Future Addition of Two Baghouse Compartments

It should be noted that the above list of potential future environmental related upgrades are not a complete list. Other potential future environmental related upgrade projects are to be separately addressed by the CWL.

1.2.3 *Capital Related Projects*: Capital related projects are those projects which will include substantial capital dollar outlays to accomplish. These capital related project include the following:

1.2.3.1 Steam Turbine Generators 5 & 7 Upgrades

1.2.3.2 Cooling Tower Replacements for STG-5 and STG-7

1.2.3.3 Replacement of Stokers on Boilers 6 and 7

1.2.3.4 Distributed Control System (DCS) Upgrade

1.2.3.5 Miscellaneous Electrical Systems Improvements

1.3 Construction Cost Estimates: The construction cost estimates for the various life extension projects are tabulated in Table 1.3-2.

1.4 Conclusions: Current limitations on electrical output can in all likelihood be overcome and reliability maintained with relatively low capital outlays to extend the remaining useful life of these two steam electric generating units an additional 20 years.

The construction cost estimates which have been identified in this report does not include all air quality control system (AQCS) upgrades that will likely be needed to extend the useful life an additional 20 years if the current solid fuel firing blend of coal and wood chips are to continue.

Table 1.3-1
Colubmia Water & Light Department
Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Construction Cost Estimates
(Dec 2012 Cost Level)

Item No.	Item Description	Estimated Construction Cost (December 2012 Cost Level)		
--	***Routine Maintenance Related Projects***	**16.5 MW Power Plant Addition**	**22.0 MW Power Plant Addition**	**Common**
RM-1	Replacement of Boiler 6 Economic Tube Bends	$ 274,000	$ -	$ -
RM-2	Boiler 6 Mechanical Collector Collection Tubes Replacement	20,000	-	-
RM-3	Boiler 7 Attemperator Repair & Replacement	-	274,000	-
RM-4	Boilers 6 & 7 Chemical Cleaning	190,000	190,000	-
RM-5	Boilers 6 & 7 Common Flue Gas Ductwork Replacement at	-	-	367,000
RM-6	Replacement of Baghouse Controls & Installation of Additional Monitoring Instrumentation			250,000
RM-7	Direct Buried 48-inch Diameter Circulating Water Piping Repairs/Replacement (An Allowance)			500,000
RM-8	Routine Maintenance Electrical Related Items			90,000
	Total Routine Maintenance Related Projects	$ 484,000	$ 464,000	$ 1,207,000
--	***Potential Future Environmental Upgrade Related Projects Other Than Air Quality Control Systems (AQCS)***			
PE-1	Installation of Impervious Ash Storage Area Liner (Approx. 5 acre area)	$ -	$ -	$ 436,000
				*See note below.
PE-2	Installation of Dry Type Ash Handling System	-	-	6,100,000
PE-3	Potential Future Addition of Two Baghouse Compartments	-	-	750,000
	Total Potential Future Environmental Upgrade Related Projects	$ -	$ -	$ 6,850,000
	*Note: PE-1 & PE-2 projects would likely not be additive. PE-1, PE-2 & PE-3 Estimated Project Costs are not included in the grand totals below. PE-1, PE-2 & PE-3 do not include other air quality control system (AQCS) improvements which may be needed to comply with recently issued environmental rules and regulations. CWL is to separately address these additional AQCS related improvements.			
--	***Capital Related Projects***			
C-1	Steam Turbine Generators 5 & 7 Upgrades	$ 3,000,000	$ 3,000,000	$ -
C-2	Cooling Tower Replacements for STG-5 and STG-7	1,080,000	1,600,000	-
C-3	Replacement of Stokers on Boilers 6 and 7	1,650,000	1,920,000	-
C-4	Distributed Control System (DCS) Upgrade			1,000,000
C-5	Miscellaneous Electrical Systems Improvements			596,000
	Total Capital Related Projects	$ 5,730,000	$ 6,520,000	$ 1,596,000
	Grand Total Routine Maintenance & Capital Related Projects	$ 6,214,000	$ 6,984,000	$ 2,803,000
	Note: The above grand total excludes potential environmental related projects PE-1, PE-2 and PE-3. These three potential environmental projects will be further evaluated by CWL and possibly combined with other environmental related projects.			
	Combined Grand Total			**$ 16,001,000**

As part of the Comprehensive PPCA authorization, an option may be exercised by the City to have an independent review of the recently implemented and forecasted future environmental rules and regulations, and to develop how these two units may remain in compliance. LD&B and their environmental consultant are ready to proceed with and promptly complete these optional services using already approved City of Columbia funding.

It is also noted that there are several other options for continuing to use these two steam electric generating units as part of the power supply resources for the City of Columbia. Evaluation of these options, which are not a part of this Comprehensive PPCA Report include their conversion to fire other fuels including renewable fuels such as agricultural based renewable fuels, chipped wood and other renewable fuels. These renewable fuels could be co-fired with natural gas or solely fired with natural gas. CWL has already commissioned several studies to evaluate firing of renewable fuels.

Also, steam turbine generators could be repowered with the installation of a combustion turbine generator and heat recovery steam generator (HRSG) at the existing CWL Municipal Power Plant which could result in an overall net plant heat rate (NPHR) that is in the 8500 (without supplemental natural gas firing) to 9400 (with supplemental natural firing) Btus/kwh range based on higher heating value (HHV) which is well below the current full load NPHR of 12,000 to 13,000 Btus/kwh.

2.0 BACKGROUND & INTRODUCTION

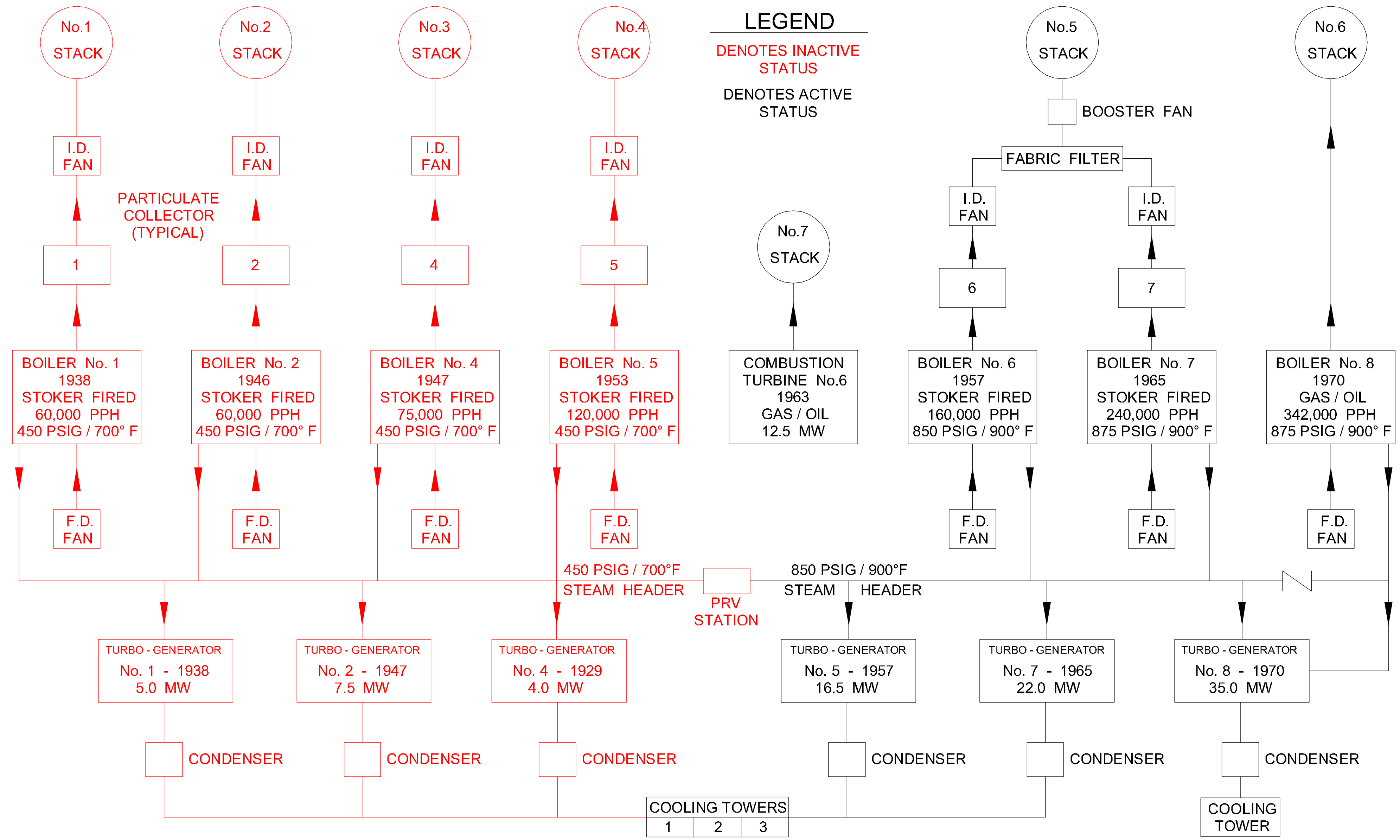
2.1 Background: The City of Columbia, Water & Light Department (CWL) owns and operates their Municipal Power Plant (MPP). The MPP consists of two solid fuel fired steam electric generating units that are capable of producing 16.5 MW and 22.0 MW of electrical power as well as a 35 MW natural gas fired steam electric generating unit and a 12.5 MW simple cycle combustion turbine generator as tabulated below and as schematically shown on Figure No. 2.0-1.

Steam Turbine Generators				
Turbine No.	Manufacturer	Maximum Rated Gross Generator Output, MW	Year Installed	Age
5	Westinghouse (now Siemens)	16.5	1957	56
7	Westinghouse (now Siemens)	22.0	1965	48
8	General Electric	35.0	1970	43

Boilers							
		Superheater Outlet Conditions					
Boiler No.	Manufacturer	Flow, pph	Pressure, psig	Temperature, F	Fuels Fired	Year Installed	Age
6	Springfield	160,000	875	900	Coal, Wood Chips	1957	56
7	Erie City Iron Works	240,000	875	900	Coal, Wood Chips	1965	48
8	Babcock & Wilcox	342,000	875	900	Natural Gas & #2 Fuel Oil	1970	43

The existing air quality control system for the two stoker fired Boilers 6 and 7 consist of a common fabric filter reverse air type 10 compartment baghouse which was installed in 1979 for the control of particulate matter (PM) emissions. The particulate matter or fuel ash is transported to the onsite water impounded ash storage area where the ash is periodically removed and properly disposed.

An aerial view of the CWL Municipal Power Plant site is shown on Figure No. 2.0-2.



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			DRAWING NUMBER 541211-1 FIGURE NUMBER 2.0 - 1 PAGE NUMBER 2.0 - 2

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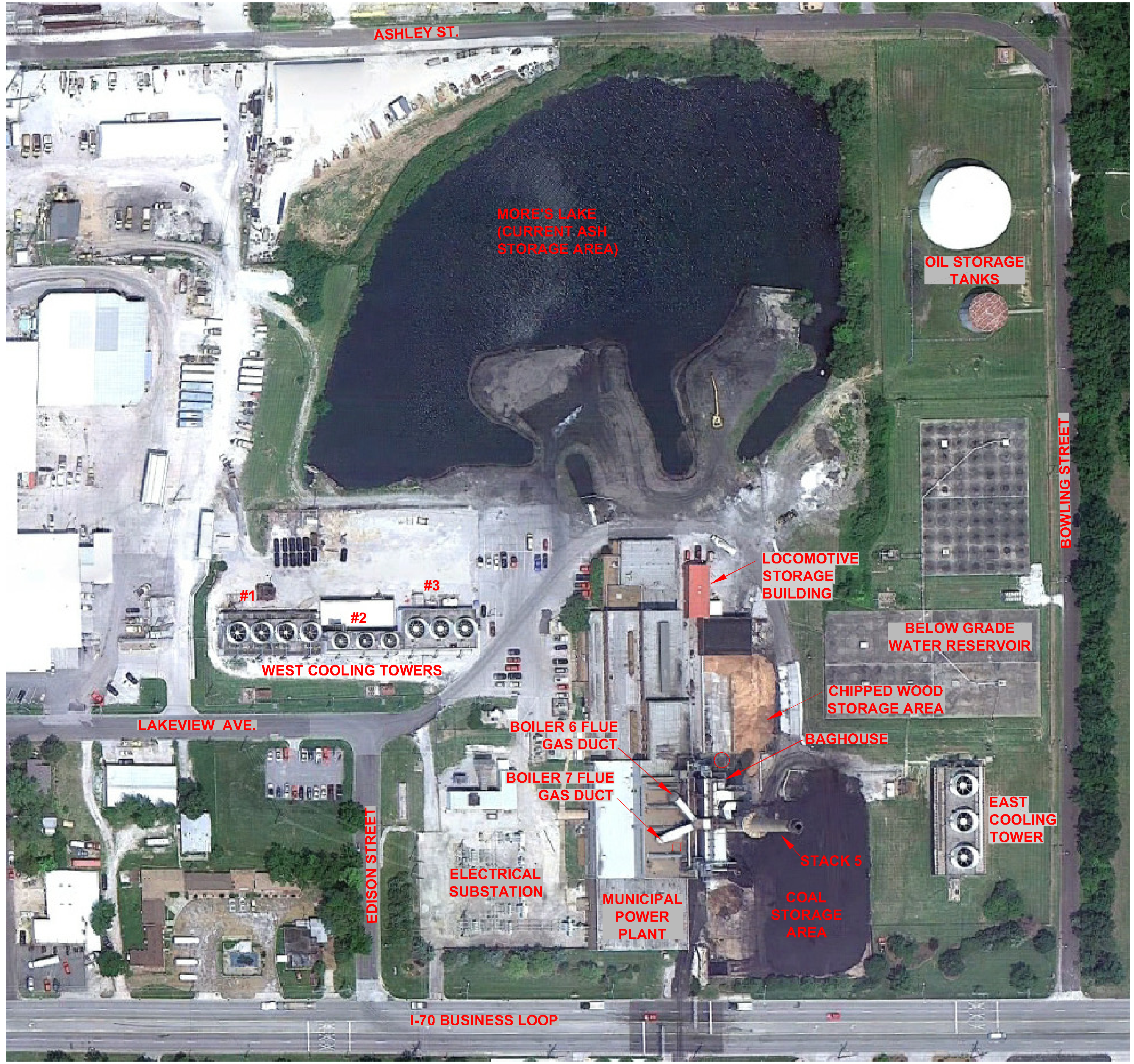

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CAD DATA FILENAME: 541211-0 PLOT SCALE: 1:1 (11x17) REVISION: REV 4 12-19-2012 © 2012 LUTZ, DAILY & BRAIN, LLC	LUTZ, DAILY & BRAIN, LLC CONSULTING ENGINEERS 6400 GLENWOOD CLOVERLEAF 4 BUILDING OVERLAND PARK, KANSAS 66202 DESIGN BY ____ CHECKED BY RBS 12/12 DRAWN BY DKL 12/12 APPROVED BY TLS 12/12	COLUMBIA WATER & LIGHT DEPARTMENT COLUMBIA, MISSOURI POWER PLANT CONDITION ASSESSMENT STUDY	MUNICIPAL POWER PLANT AERIAL PLAN VIEW

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2.2 Changing Environmental Regulations: In response to rapidly changing environmental regulations, CWL commissioned the preparation of a study in 2010 for the potential retrofit of various air quality control system (AQCS) technologies to comply with these recently issued final and proposed environmental regulations. Because environmental regulations are continuing to change, this CWL Power Plant Condition Assessment (PPCA) will need to be integrated with these recently enacted and proposed environmental regulations such as the Cross State Air Pollution Rule (CSAPR) that was issued on July 7, 2011, the Institutional, Commercial & Industrial (ICI) Boiler Maximum Achievable Control Technology (MACT) Rule [also referred to as ICI Boiler MACT Rule] which USEPA issued , reconsidered and reproposed on December 23, 2011; the currently proposed Electric Generating Utility (EGU) MACT Rule which has been issued and Coal Combustion Residues (CCR) regulations to optimize improvements to the MPP solid fuel fired units.

Based on current operation of the MPP over the past few years, CWL is currently about three times over the maximum annual allowable emissions limits for sulfur dioxide (SO_2) and nitrogen oxides (NOx) limits on solid fuel fired Boilers 6 and 7 as stated in the CSAPR which was to have gone into effect January 1, 2012 before a stay was issued in an Appellate Court on December 31, 2011.

Thus, either immediate solutions to reducing SO2 and NOx emissions on Boilers 6 & 7 or means to remove these two boilers from being subject to the CSAPR and EGU MACT are important considerations to this PPCA.

To determine the condition of these two coal and biomass fired steam electric generating unit additions at the CWL Municipal Power Plant, the City of Columbia, Missouri through CWL authorized the preparation of this Comprehensive PPCA. The results of this Comprehensive PPCA Report will be used by CWL as part of their decision-making process to determine whether or not it is feasible to extend the useful life of the 16.5 MW and 22.0 MW power plant additions an additional 15 to 20 years. CWL will need to add to the costs which have been identified in this Comprehensive PPCA Report the estimated cost to retrofit new air quality control systems (AQCS) to meet these expected environmental regulations in their analysis.

2.3 Introduction: This Comprehensive PPCA Report has been prepared in three separate volumes. Volumes 2 and 3 provide supporting information which is summarized in Volume 1. All three volumes are summarized in the Executive Summary.

This Comprehensive PPCA Report is limited to the 16.5 MW and 22.0 MW power plant additions which Lutz, Daily & Brain Consulting Engineers and their predecessor companies designed in the 1950's and 1960's. These two plant additions have been modified over the years with the retrofit of a high efficiency fabric filter baghouse, continuous emission monitoring system (CEMS), the co-firing of wood chips with coal and numerous other improvements to enable these two power plant additions to continue to provide electrical power in an economical and environmentally compliant manner.

3.0 SCOPE OF WORK

The scope of work for this Comprehensive Power Plant Condition Assessment (PPCA) Report includes a condition assessment of the following items:

3.1 Boilers 6 & 7

3.1.1 Boiler pressure parts (furnace, steam drum, lower drum, steam generating bank, superheater, economizer and associated headers, safety relief valves, etc.)

3.1.2 Boiler non pressure parts (casing, refractory/brick work, insulation & lagging)

3.1.3 Hoffman stokers, fuel feeders, non-segregating chutework

3.1.4 Fly ash reinjection system, overfire air (OFA) system, ductwork and insulation and lagging

3.1.5 Forced draft fans (FDF's) and induced draft fans (IDF's)

3.2 Steam Turbine Generators (STG's) 5 & 7 Including Controls, Hydrogen Cooling Systems and Other Related Equipment

3.3 Mechanical Auxiliaries

3.8.1 Condensate pumps

3.8.2 Boiler feed pumps

3.8.3 Closed heat exchangers

3.8.4 Deaerators

3.8.5 Evaporators

3.8.6 Softener & Reverse Osmosis System

3.8.7 Steam surface condensers

3.8.8 Cooling towers

3.8.9 Circulating water pumps

3.8.10 Fabric filter baghouse

3.8.11 Induced draft booster fan (IDBF)

3.8.12 Chimney

3.8.13 Ash handling

3.8.14 Fuel handling (hoppers, conveyors, bunkers, scales, bucket elevators, controls, motors & related equipment)

3.4 Electrical Auxiliaries

3.4.1 Motor control centers

3.4.2 2.4 KV switchgear

3.4.3 Transformers

3.5 Instruments & Controls

3.5.1 Boiler combustion controls

3.5.2 Plant controls

3.5.3 Plant instrumentation

3.6 Piping & Wiring

3.6.1 High energy piping (main steam & boiler feedwater)

3.6.2 Service water (scale buildup, etc)

3.6.3 Wiring

3.7 General Site

3.7.1 Fuel delivery & storage

3.7.2 Ash storage impoundment

3.7.3 Plant discharge

3.7.4 Fire protection

3.8 Correlation of Comprehensive Power Plant Condition Assessment with Expected Environmental Relations & Development of a Compliance Strategy (Optional Services to be Separately Submitted When Later Approved by the CWL.): Listed below are optional services that may later be authorized by the CWL. A separate submittal of optional services is planned.

3.8.1 Review of existing environmental permits

3.8.2 Review of expected environmental regulations

3.8.2.1 CSAPR

3.8.2.2 ICI Boiler MACT

3.8.2.3 EGU MACT

3.8.2.4 CCR

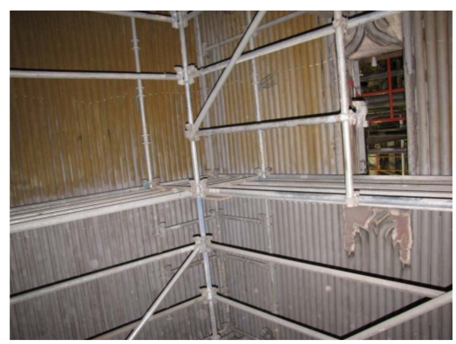
3.8.3 Development of an Environmental Control Strategy for compliance with expected regulations

4.0 INSPECTION, NON DESTRUCTIVE TESTING (NDT) AND DESTRUCTIVE TESTING (DT)

4.1 General: This Volume 1 section of the Comprehensive Power Plant Condition Assessment (PPCA) Report summarizes the inspection, non destructive testing (NDT) and destructive testing (DT) work which has been performed and included in Volumes 2 and 3 on the 16.5 MW and 22.0 MW power plant additions, namely Steam Turbine Generators 5 and 7, Boilers 6 and 7, common baghouse, chimney, coal and ash handling and other associated balance of plant (BOP) items.

4.2 Boilers & High Energy Piping Systems: Volume 2 includes five (5) reports which have been prepared by Thielsch Engineering Inc. (TEI) of the boiler pressure parts and high energy (main steam and feedwater) piping systems. Also, the stokers, overfire air (OFA) systems, fuel feeders and nonsegregating chutes on Boilers 6 and 7 have been inspected by Detroit Stoker Company (DSC). In addition visual inspections along with a review of plant records and discussions with CWL power plant staff have been performed by LD&B as part of this Comprehensive PPCA Project. Condition assessment of these items are further described below.

4.2.1 *Boiler Pressure Part Evaluation & Remaining Useful Life Studies*: A condensed summary of the evaluation and remaining useful life of Boilers 6 and 7 pressure parts is given below.



4.2.1.1 A portion of Boiler 6 front waterwall tubes are to be replaced by the Spring of 2013. These tubes have likely been damaged by the buildup of hot fuel/ash clinkers and excessive heat at the front of the boiler. Replacement of the existing stoker, fuel feeders at the stoker front and OFA system along with firing coal that is better suited for stoker firing should alleviate these front waterwall tube failures.

4.2.1.2 A portion of Boiler 6 economizer tube bends need replacement likely due to exterior tube thinning from fly ash ladened flue gas impinging on the tube bends.

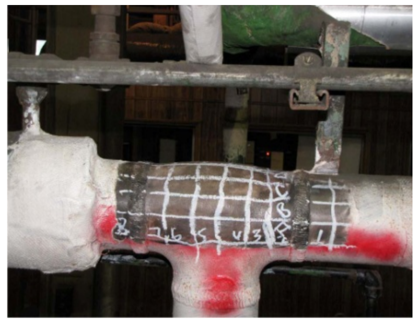
4.2.1.3 Boiler 7 lower drum attemperator header is damaged and in need of replacement in the near future.

4.2.1.4 Boilers 6 and 7 have excessive scale buildup on the interior (water side) tube surface and are considered dirty. These two boilers are in need of a chemical cleaning in the near future. Chemically cleaning these two boilers should improve their performance and reduce future tube failures.

4.2.1.5 While the pressure parts on Boilers 6 and 7 are in need of minor repairs, their overall condition appears to be good based on the results of the TEI inspections and testing work which are described in Volume 2 of this Comprehensive PPCA Report. While periodic routine repairs and replacements will likely continue to be needed, the pressure parts on Boilers 6 and 7 are projected to have a remaining useful life of over 20 years with proper operation and maintenance.

4.2.2 *Non Pressure Part Evaluation (Casing, Brickwork, Refractory, Insulation & Lagging)*: These components have been visibly inspected and appear to have at least 20 years of remaining useful life with proper operation and maintenance.

4.2.3 *High Energy Piping System Evaluation*: There have been some electric utility industry problems with flow accelerated corrosion (FAC) thinning the walls of boiler feedwater piping to the point of rupture and loss of life. Also, temperature excursions can occur in the steam being produced by the boilers which can shorten and permanently damage the main steam piping. Last summer TEI performed both on site non destructive testing (NDT) and destructive testing (DT) and found no evidence of these problems. Based on this NDT and DT by TEI, it is reasonable to believe that these high energy piping systems are in good condition and have at least 20 additional years of remaining useful life if CWL continues to operate and maintain these systems as they have done in the past.



4.2.4 *Hoffman Stokers, Fuel Feeders, Non-Segregating Chutework & Overfire Air (OFA) Systems*

4.2.4.1 *Traveling Grate Spreader Stokers*: The Hoffman Type 6D continuous ash discharge travelling grate spreader stokers for both Boiler 6 and Boiler 7 have been inspected by one of the leading stoker manufacturers of traveling grate spreader stokers, Detroit Stoker Company (DSC). The original stoker manufacturer for both Boilers 6 and 7, Hoffman Combustion Engineering Company, is no longer in business. Spare parts must be custom fabricated. The DSC Inspection Report for both boilers is contained in Volume 3 Section 2.0 of this Comprehensive Power Plant Condition Assessment (PPCA) Report.

In Section 2.0, DSC reports that many parts of the Hoffman traveling grate spreader stoker of Boilers 6 and Boiler 7 are worn, and in need of either repair or replacement in the near future. The grate bars are in poor condition depicting deterioration and deformation from heat, heat related fractures, orifices are enlarged and/or plugged off. Also, sealing around grates is ineffective due to heat erosion and wear. The grate bars, center rail, side rails and other stoker components need to be replaced within the next few years.

These stoker deficiencies noted in Volume 3, Section 2.0 of this Comprehensive PPCA Report hinders the CWL from achieving optimum performance from the combustion of coal and wood chips in the furnaces of Boilers 6 and 7 by not properly conveying the coal and wood chips through the furnace, by misdirecting the combustion air and permitting unwanted ambient air (called tramp air) to either leak into the furnace through cracks caused by wear or bypass the fuel/ash bed on the grate due to misalignment of the many traveling grate seal plates. Some seals are immobile and continuously permit the entry of significant volumes of tramp air.

Uneven distribution of coal/wood chips results in the non-uniform bed thickness of fuel lying and burning on the traveling grate. Combustion air cannot flow uniformly through the varying fuel/ash bed thicknesses resulting in incomplete combustion creating both cold areas within the bed and overheating other areas in the bed. Overheating a portion of the bed can damage nearby pressure parts (headers and waterwall tubing) and refractory within the furnace.

Misdirecting combustion air through the grate can also create both hot and cold areas reflecting poor, non-uniform combustion. Unwanted additional air that leaks into the furnace reduces the efficiency of the combustion process. Unburned coal may be discharged with the coal/ash at the end of the traveling grate.

The incomplete combustion and overheating in the traveling grate coal bed may raise flue gas emissions.

The existing structural beams supporting the entire traveling grate appeared damaged and may need replacement.

4.2.4.2 *Fuel Feeders* – In Volume 3 Section 2.0 of this Comprehensive PPCA Report, DSC reports that the six fuel feeders on each boiler have many openings that are disrupting proper distribution of the coal on the traveling grate. Coal fines are "underthrown" due to accumulations of the fines at the feeders resulting from insufficient and/or mis-oriented combustion air streams. In addition to positioners and fasteners being worn and misaligned; DSC suggests in their report that the openings are not properly sealing off in-leakage of tramp air into the furnace making optimum combustion more difficult to achieve.

4.2.4.3 *Overfire Air (OFA) Systems*: The existing OFA system needs to be upgraded. The number of OFA parts will likely need to be increased and additional instrumentation added to better track the OFA air flow.

4.2.5 *Fly Ash Reinjection Systems, Mechanical Collectors & Ductwork*: The fly ash reinjection systems have been visibly inspected. In addition, a review of plant records and interviews with CWL power plant staff have been made. The fly ash reinjection system on Boilers 6 and 7 appear to be in good condition and have a remaining useful life of at least 20 years with proper operation and maintenance. Boiler 6 mechanical collector has two collecting tubes that need to be replaced. The section of flue gas ductwork or breeching that connects to the stack is reported by Enerfab to be in need of replacement within the next few years.

4.2.6 *FD Fans & ID Fans*: These boiler fans have been inspected and appear to be in satisfactory condition with at least 20 years of additional life with continued proper operation and replacement.

4.3 Baghouse, ID Booster Fan & Continuous Emissions Monitoring System (CEMS)

4.3.1 *General*: Onsite inspections and/or performance tests have been conducted for the baghouse, ID booster fan and CEMS.

4.3.2 *Baghouse*: The Carborundum 10 compartment reverse air baghouse which was installed in 1979 has had its bags replaced several times. This common baghouse receives fly ash ladened flue gas from both Boilers 6 and 7. The time in service for the current woven fiberglass and mostly with TPFE membrane acid resistant substrates finish bags are listed below.

Compartment No.	Date of Bag Replacement	Age, Years As of Dec 2012
1 & 9	May 2012	2.6
6	Jun 2012	2.5
4, 7, 8 & 10	Oct 2010	2.2
2, 3 & 5	Apr 2012	0.7

The current bag specifications are shown in Table 4.3-1. The baghouse design conditions which are shown in Table 4.3-2 have been taken from the Carborundum Baghouse Operations & Maintenance (O&M) Manual. As shown in Volume 3, Section 7.0, the design flue gas flow into the common baghouse is well above the predicted flue gas flow from Boilers 6 and 7 at their maximum continuous rated steam output indicating that the baghouse has not been undersized from a design standpoint.

The reverse air fan and its associated ductwork have been periodically repaired over the past 33 years.

There is an excessive flue gas path pressure drop through the baghouse. During the August 2012 performance tests, at approximately 70% of the combined Boilers 6 and 7 maximum rated steam flow (278,400 pph), the flue gas pressure drop through the baghouse was measured to be approximately 9 inches water gauge (wg) and should not be over 6 inches wg.

The excessive baghouse flue gas pressure drop could be due to a number of factors such as insufficient bag cleaning, inadvertent compartment isolation, flue gas inlet ductwork being partially obstructed, excessive air in-leakage, malfunctioning of the compartment inlet poppet valves and isolation dampers and an undersized baghouse.

Table 4.3-1
CWL Power Plant Condition Assessment Report
Boilers 6 & 7 Common Reverse Air Baghouse

CURRENT BAGHOUSE BAG FABRIC SPECIFICATIONS

WOVEN fiberglass

Style Number:	107 TIX
Fiber:	N/A
Construction:	3 x 1 Twill
Finish:	PTFE Membrane on acid resistant substrates
Yarns:	Warp: 75 1/0 Fill: 50 1/0 TEX 150 1/0 FIL
Stability:	N/A

Recommended Maximum Continuous Operating Temperature: 500°F

	English	Metric
Fabric Weight	10-11.5 oz/sq yd	340-390 gm/sq m
Thickness	N/A	N/A
Mullen Burst	Min 500 PSI	35.2 kg/cm^2
Permeability*	5-10 ft^3/ft^2 min	N/A
Thread Count	54 ± 2 x 30 ± 2/in	21 ± 1 x 12 ± 1/cm
Tensile Strength - Warp/Fill	N/A	N/A
Scrim Count	N/A	N/A
Scrim Weight	N/A	N/A

*Frazier Method - the volume of air, in CFM, that can flow through 1 $ft.^2$ of media at 0.5 W.G. pressure drop (or $1/sec/m^2$ at 20mm H_2O).

NOTE: All data established using ASTM test methods where appropriate.

Date: 07/25/08

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Table 4.3-2
CWL Power Plant Condition Assessment Report
Baghouse Operation & Maintenance Manual Excerpt Showing
Design Conditions & General Design Parameters

1. INTRODUCTION

These instructions are for one Carborundum ten compartment, suction type fabric filter system and associated breeching and auxiliaries. This baghouse is for Boilers No. 6 and 7 at the Municipal Power Plant, City of Columbia, Missouri.

2. DESIGN CONDITIONS

Gas volume, maximum expected ACFM	264,360 @ 500° F
Gas temperature, normal (F°)	370
Plant altitude, above sea level (feet)	750
Outdoor temperature, maximum (F°)	110
minimum (F°)	-22
Pressure, design (in. water gage)	20
Flyash density, (lb/ft^3)	
Volume design	70

3. COLLECTOR DESCRIPTION

A. Basic Design

Number of compartments	10
Number of bags per compartment	248
Total number of bags	2480
Bag Diameter (inches)	8
Bag Length (feet)	22'-4"
Bag Effective Area (sq. ft.)	46.1
Total Effective Area (sq. ft.)	114,290
Reverse Air Volume, ACFM	18,500
System Gas Volume, ACFM	264,360
System Gas Volume, ACFM including Reverse Air	282,860

Air to cloth ratios
All compartments operating
not including reverse air — 2.31:1

Table 4.3-2, Continued
CWL Power Plant Condition Assessment Report
Baghouse Operation & Maintenance Manual Excerpt Showing
Design Conditions & General Design Parameters

3. COLLECTOR DESCRIPTION CONT'D

A. Basic Design Cont'd

One Compartment cleaning including reverse air	2.75:1

B. Filter Fabric and Bag Construction

Manufacturer	Filter Media Division The Carborundum Company
Style	0034
Fiber	Glass ECDE
Weight	14.6 oz./sq. yd.
Weave	Twill
Permeability	50-65 CFM
Finish	Teflon "B"
Size	8" dia. x 22'-4" long
Top Suspension Method	Chain, spring, and cap. Filter tube has sewn in compression band for retainment over cap.
Bottom Attachment	Filter tube slips over the thimble and is secured with a stainless steel clamp.
Filter Tube Rings	Mild steel rings are sewn into the tube so that its shape is maintained when clamped. 5 rings per tube.
Length and Tension Adjustment	Length is varied via chain and clip. Tension is shown by deflection of spring.

There have been comments from CWL plant staff that the baghouse capacity has been deficient for many years indicating that one of two additional modules may be needed to reduce the current excessive flue gas pressure drop through the baghouse. However, review of a 1979 Baghouse Compliance Test Report data sheet indicates an overall flue gas pressure drop through the baghouse of 6.72 inches wg at a combined steam flow of 315,000 pounds per hour (pph).

During the August 2012 performance test, the pressure drop through the baghouse was 9.02 inches wg at a combined Boilers 6 and 7 steam flow of 278,400 pph which was about 70% of the maximum rated steam flow for Boilers 6 and 7. During the August 2012 performance test, the flue gas pressure drop through the baghouse increased approximately 2.3 inches of water with approximately 12% less (1-[278,400/315,000]) flue gas flow from the 1979 Baghouse Compliance Test Report, indicating that there has been a significant change in pressure drop over the past 30+ years.

Further investigation of baghouse flue gas pressure drop performance is needed to determine the root cause(s) of these excessive flue gas side pressure drops and corresponding opacity spikes. Then, corrective action can be implemented. This additional investigation is beyond the scope of this power plant condition assessment.

The baghouse control system is nearing the end of its useful life and will be in need of replacement within the next few years. The proposed replacement baghouse control system will include a new PLC and a new remote input/output (I/O) cabinet as well as additional field devices to provide additional monitoring and control capabilities. Most existing baghouse field devices would be reused.

4.3.3 *ID Booster Fan*: The ID booster fan and motor are reported to be in good condition and are performing in a satisfactory manner. With continued proper operation and maintenance, this fan should have an additional 20 years of life.

4.3.4 *Continuous Emissions Monitoring System (CEMS)*

4.3.4.1 *General*: The CEMS which has been in service since the 2007/2008 time frame is being operated and maintained by CWL power plant staff. CWL power plant staff reports that the CEMS is in good working order. There will be periodic routine maintenance type of upgrades in the analyzers, data acquisition system (DAS), etc. which will be needed over the next 20 years.

4.3.4.2 *CEMS Description:* Stack 5 which receives flue gas from solid fuel fired Boilers 6 and 7 is equipped with a dilution extractive type CEMS that monitors carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_X) emissions. The dilution extractive system draws a flue gas sample through the sample probe located in the stack. The sample is routed to low-level gas analyzers for measurement. Additionally, a volumetric flow monitor and an opacity monitor are located on common Stack 5.

The operation of the flue gas sample probe is controlled by an Allen-Bradley PLC, which enables monitoring and adjustment of the critical flow and pressure parameters and indicates operational modes such as sampling, calibration, backpurge, and bypass. A diagnostic control center performs complete system diagnostics and provides access to all diagnostic data. The standard diagnostics package performs real time failure warnings, such as calibration drift, and provides a fail-safe startup of the CEMS. The electronic signals processed by the analyzer controller are sent by serial communications to the DAS.

The DAS is the electronic component of the CEMS which is designed to interpret and convert individual output signals from the pollutant concentration monitors, flow monitors, and other components of the CEMS to produce a continuous readout of the measured parameters in units required by the USEPA.

The NO_X, SO_2, CO_2, and Flowrate instruments have been installed to comply with the specific requirements of 40CFR75 and 40CFR60. A Quality Assurance Plan has been developed from guidelines developed by the Missouri Department of Natural Resources (MDNR) and the U.S. Environmental Protection Agency (EPA).

4.4 Chimney

4.4.1 *General*: The existing reinforced concrete shell with an acid resistant brick liner chimney has an overall height of 300 feet. The outside diameter of the concrete shell is 21'-8". The brick liner has an inside diameter of 8 feet at the top and 12 feet at the base. The chimney has been in service for over 50 years.

4.4.2 *Chimney*: The chimney has been periodically inspected and maintained since its initial installation. The last chimney inspection was performed by the International Chimney Corporation (ICC) during 2009. There are some minor repairs which are considered routine maintenance to perform. These recommended repairs include the removal and replacement of the partial platform at 80' elevation; the clean and recoat of the external ladder and the installation of a new safety climb system, repair of the top 10 feet of brick liner, and the replacement of the test ports.

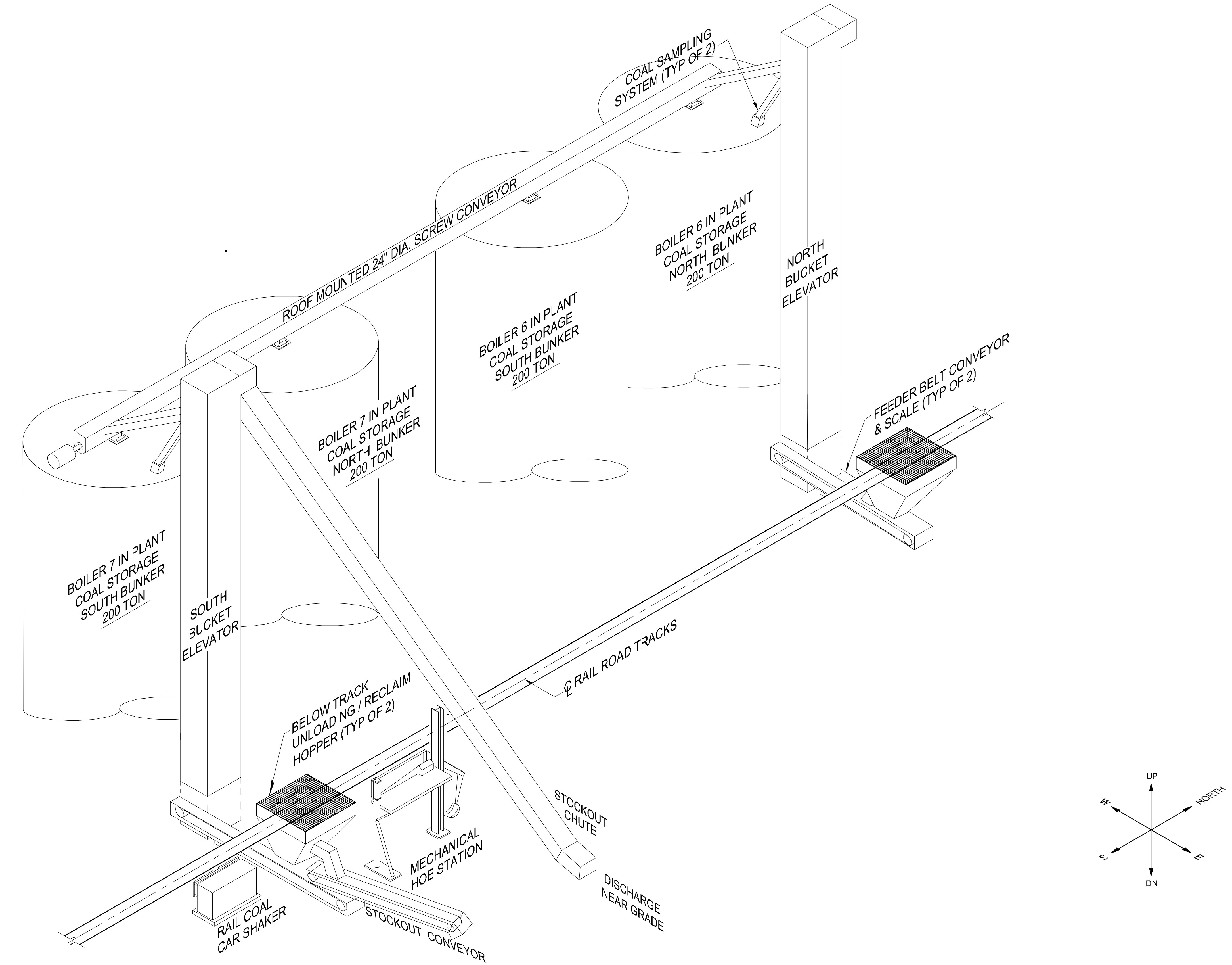
4.5 Fuel Handling System

4.5.1 *General*: A description of the coal and chipped wood unloading, handling and storage system at the CWL Municipal Power Plant is given below and schematically shown on Figure No. 4.5-1. Also, an aerial view has been shown on Figure No. 4.5-2.

The current coal/chipped wood blend which is being fired in Boilers 6 and 7 consists of 8 units of coal per 5 units of wood chips. The 8 coal units consist of 4 units of Oklahoma coal and 4 units of Illinois coal.

4.5.2 *Unloading/Reclaim System*: There is a single stainless steel lined unloading hopper which is located beneath railroad tracks at two locations. The south unloading/reclaim track hopper is part of the primary unloading/reclaim system.

The north unloading/reclaim track hopper is part of the secondary unloading/reclaim system. The main purpose of the north unloading/reclaim system is to serve as a backup to the south unloading/reclaim system. The north unloading/reclaim primarily serves in this backup role due to its age and condition. The north unloading/reclaim system and bucket elevator is operated approximately once every month to verify its ability to transport coal/chipped wood.



CAD DATA FILENAME: 541211-CH4 PLOT SCALE: 1:1 (11x17) REVISION: REV E 12-28-2012 Ⓒ 2012 LUTZ, DAILY & BRAIN, LLC	LUTZ, DAILY & BRAIN, LLC CONSULTING ENGINEERS 6400 GLENWOOD CLOVERLEAF 4 BUILDING OVERLAND PARK, KANSAS 66202 DESIGN BY - CHECKED BY RBS DRAWN BY DKL APPROVED BY TLS	CITY OF COLUMBIA WATER & LIGHT	COLUMBIA WATER & LIGHT DEPARTMENT COLUMBIA, MISSOURI COMPREHENSIVE POWER PLANT CONDITION ASSESSMENT REPORT	MUNICIPAL POWER PLANT ISO VIEW SHOWING COAL HANDLING SYSTEM SERVING BOILERS #6 & 7

DRAWING NUMBER 541211-CH4
FIGURE NUMBER 4.5 - 1
PAGE NUMBER 4.0 - 12

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CAD DATA FILENAME: 541211-A4 PLOT SCALE: 1:1 (11x17) REVISION: REV C (01-21-13) © 2013 LUTZ, DAILY & BRAIN, LLC	LUTZ, DAILY & BRAIN, LLC CONSULTING ENGINEERS 6400 GLENWOOD CLOVERLEAF 4 BUILDING OVERLAND PARK, KANSAS 66202 DESIGN BY - CHECKED BY WMH DRAWN BY DKL APPROVED BY TLS	WATER & LIGHT COLUMBIA WATER & LIGHT DEPARTMENT COLUMBIA, MISSOURI COMPREHENSIVE POWER PLANT CONDITION ASSESSMENT REPORT	MUNICIPAL POWER PLANT AERIAL PLAN VIEW COAL AND WOOD CHIP HANDLING

DRAWING NUMBER	541211-A4
FIGURE NUMBER	4.5 - 2
PAGE NUMBER	4.5 - 13

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4.5.3 *Receiving Coal/Chipped Wood*: Coal may be received either via railroad car or by truck. All coal that is received via railroad cars must be emptied into one of the two unloading/reclaim track hoppers which are approximately 14'-6" wide by 14'-6" long. Twenty-four (24) rail cars are typically received per shipment.

Coal that is unloaded from railroad cars which carry approximately 95 tons of coal per car into the south unloading reclaim hopper is transported via a short belt conveyor which has a Belt-Way conveyor belt type weigh scale mounted unit to weigh the coal and coal/chipped wood blend as it is conveyed from the track hopper to the bucket elevator and to the stockout conveyor which stocks out a portion of the coal to the outdoor coal storage area.

Coal that is unloaded from railroad cars or trucks into the north unloading/reclaim track hopper is also transported in a similar manner as the south unloading/reclaim station via a 30-inch wide belt conveyor with weigh belt scale onto the north bucket elevator. However, unlike the south unloading/reclaim system, there is no stockout conveyor at grade.

Both track hoppers are covered with heavy duty grillage to allow coal lumps and chipped wood below 3" x 6" (approximate opening size) to pass through while keeping larger lumps and chips from entering.

4.5.4 *Railroad Car Shaker & Hoe*: On the east side of the south coal/chipped wood unloading track hopper is a new Kinergy Corporation side attached railroad car shaker to assist in the emptying out of coal from the rail cars. In addition, there is a large mechanically operated hoe that can be used to break up frozen coal or large lumps that will not empty from the railroad cars with the car shaker. The mechanical hoe is reportedly rarely used. The north unloading/reclaim system does not have the railroad car shaker and hoe like the south unloading/reclaim station.

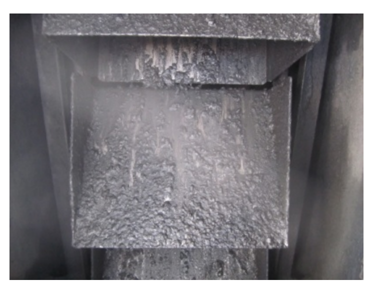
4.5.5 *__Coal/Chipped Wood Storage Areas at Grade__*: There are two adjoining fuel storage areas at grade on the east side of the power plant. Coal is stored on top of a concrete surface area with a containment around the perimeter that directs water run-off to a sump at the southwest end of the storage area. Chipped wood is received via enclosed moving floor trailers that are delivered by truck. Chipped wood is stored at the northwest end of the fuel storage area on the east side of the power plant.

4.5.6 *__Handling of Coal/Chipped Wood in the Outside Coal/Chipped Wood Storage Area__*: There is a Case Model 821E coal/chipped wood fuel handling tractor with a 5 cubic yard bucket that is used to maintain the chipped wood and coal in the outdoor fuel storage area at grade. This fuel handling tractor is also used to blend the chipped wood and coal before moving the coal/chipped wood to the unloading/reclaim track hopper.

4.5.7 *__Bucket Elevators (BE)__*: There are two redundant BE's that are used to convey coal or coal/chipped wood to the top of the plant. Nameplate data on the south BE is listed below.

Manufacturer: Continental Screw Conveyor
Height: 118'-2"
Capacity: 100 tons per hour (tph)
Speed: 100 rpm

The south BE has recently been refurbished with new chains, sprockets, bearings and shaft. Buckets are stainless steel construction with the following approximate dimensions:



20" wide x 17" tall x 13.5" deep

The south BE has a stockout chute which allows the coal and any other solid fuels to be returned to the outdoor fuel storage area at grade.

4.5.8 *<u>Screw Conveyor</u>*: There is a reversible screw conveyor with a 24-inch diameter helical screw which is located on the roof of the power plant that is approximately 150 feet long. The screw conveyor received coal/chipped wood and moves it to one of 4 outlets which discharges into four 200 ton capacity indoor coal/chipped wood storage bunkers.

4.5.9 *<u>In Plant Coal/Chipped Wood Storage Bunkers</u>*: There are four 200 ton bunkers in the power plant--two for Boiler 6 and two for Boiler 7 that stores the coal or coal/chipped wood blend.

There are strain gauges located at the bottom of the bunkers which are used as part of a weight measuring system that maintains readings showing the tons of fuel being stored in the in plant storage bunkers.

From these in plant storage bunkers, the coal/chipped wood blend is discharges via non-segregating chutes to the fuel feeders at the front of Boilers 6 and 7.

4.5.10 *<u>Overall Condition of Coal & Chipped Wood Unloading, Storage & Handling System</u>*: The overall condition of the coal and chipped wood unloading, storage and handling system is good. However, unlike most coal handling systems, there are no provisions for separating out tramp iron in the current system. If tramp iron should later become a problem, magnetic separators should be retrofitted. Also, a less labor intensive method to blend the chipped wood and coal should be considered.

Also, there is no thaw shed to thaw frozen coal at the CWL Municipal Power Plant. Instead, CWL schedules no coal deliveries during the winter season which spans from mid-December through mid-March each year to avoid handling frozen coal. During the winter season coal is taken from the outside coal storage pile.

Based on the observations made, no major capital improvements appear to be needed to extend the useful life of these fuel unloading, storage and handling systems another 20 years.

4.6 Ash Handling System

4.6.1 *General*: The originally installed Boiler 6 ash handling system which was constructed in the 1955-57 timeframe has a combined fly ash and bottom ash handling system.

This ash handling system uses water to transport the ash from collection hoppers to the ash storage pond. Overall, the existing ash handling system is in good condition and capable of performing an additional 20 years with continued proper operation and maintenance.

A description of the existing ash handling system is given below.

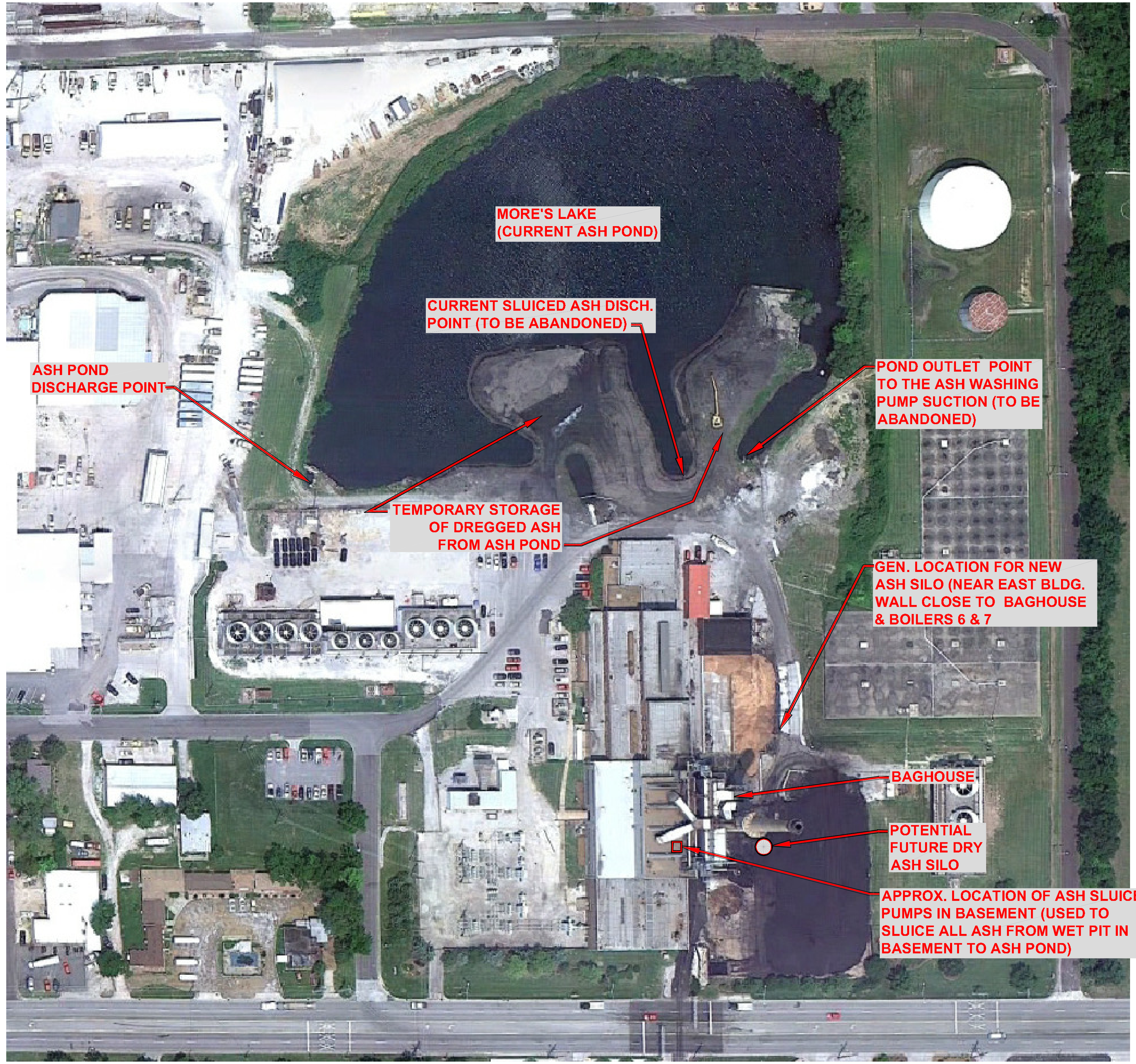
Fly ash is transported by vacuum which is produced by a water powered vacuum producing device that is referred to as a hydroveyor. The transported ash mixes with the water in the hydroveyor and discharged through a covered floor trench into the ash transfer sump which is located in the basement near the bottom ash storage hopper discharge end of the traveling grate of Boiler 6.

4.6.2 *Boiler 6 Ash Pickup Points*: The 160,000 pounds per hour (pph) stoker fired Boiler 6 ash pickup points are listed below.

1. (1) Stoker Ash Pit 10" Discharge Chute (Bottom Ash)
2. (4) Siftings or Ash Reinjection Hopper Outlets (Fly Ash Reinjection)
3. (5) Boiler Bank Hopper Outlet Connections (Fly Ash)
4. (3) Economizer Hopper Outlet Connections (Fly Ash)
5. (2) Boiler Dust Collector 6" Outlet Connections (Fly Ash)
6. (2) I D Fan Inlet Dust Collector Outlet Connections (Fly Ash)

Bottom ash drops off the front end of the traveling grate at the boiler operating floor level and falls into a bottom ash storage hopper that is located in the basement. The bottom of the bottom ash hopper slopes towards the discharge end where jets of water sluices the bottom ash into a covered basement floor trench. The bottom ash water slurry in this covered floor trench discharges into the ash transfer sump in the basement where the fly ash water slurry is also discharged.

Two belt driven horizontal ash sluice pumps take suction from the ash transfer sump and discharges the slurry of both bottom ash and fly ash into abrasion resistant lined piping that is used to transport the ash water slurry from the ash transfer sump in the basement of the power plant to the ash pond (More's Lake) which located north of the power plant as shown in the attached aerial view Figure No. 4.6-1. The ash in the water/ash slurry settles in the ash pond. The settled out ash is periodically dredged out of the ash pond and removed from the site.



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CAD DATA FILENAME: 541211-A5 PLOT SCALE: 1:1 (11x17) REVISION: REV B 12-28-2012 © 2012 LUTZ, DAILY & BRAIN, LLC	LUTZ, DAILY & BRAIN, LLC CONSULTING ENGINEERS 6400 GLENWOOD CLOVERLEAF 4 BUILDING OVERLAND PARK, KANSAS 66202 DESIGN BY ____ CHECKED BY RBS 12/12 DRAWN BY DKL 12/12 APPROVED BY TLS 12/12	CITY OF COLUMBIA WATER & LIGHT	COLUMBIA WATER & LIGHT DEPARTMENT COLUMBIA, MISSOURI COMPREHENSIVE POWER PLANT CONDITION ASSESSMENT REPORT	MUNICIPAL POWER PLANT AERIAL PLAN VIEW SHOWING CONCEPTUAL LAYOUT FOR PROPOSED BOILERS 6 & 7 ASH HANDLING UPGRADE	DRAWING NUMBER 541211-A5 FIGURE NUMBER 4.6 - 1 PAGE NUMBER 4.0 - 18

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A return pipeline transports clarified or recycled water from the ash pond back to the power plant for reuse in sluicing more ash to the pond. Two ash sluice water booster pumps takes suction from the ash pond through the pipeline and pressurizes the recycled water from the ash pond. The pressurized ash sluice water creates the vacuum in the incoming fly ash line using the jet pump or hydroveyor. The decanted and clarified water is recycled from the pond and pressurizes the jetting nozzles and sluicing nozzles that flushes the bottom ash from the bottom ash hopper and trough receiving bottom ash from the traveling grate.

Reservoir water is maintained as a backup ash sluice water supply for the jet pump to allow emergency functioning of the fly ash and bottom ash systems in Boiler 6.

4.6.3 *Boiler 7 Ash Pickup Points*: When Boiler 7 was constructed in 1965-66 timeframe, the existing ash handling system was extended to transport all Boiler 6 fly ash and bottom ash in the ash transfer sump located adjacent to Boiler 7. The basement covered floor trench conveying Boiler 6 bottom ash from the collection point (under Boiler 6 traveling grate discharge) was extended to the Boiler 7 trench. Ash sluicing nozzles were added to convey the bottom ash along the trench to the discharge point where the bottom ash from both boilers drops into the ash transfer sump located in the Boiler 7 basement.

The 240,000 pph stoker fired Boiler 7 ash pickup points are listed below.

1. (1) Stoker Ash Pit 12" Discharge Chute (Bottom Ash)
2. (6) Siftings or Ash Reinjection Hopper Outlets (Fly Ash Reinjection)
3. (5) Boiler Bank 6" Hopper Outlet Chute Connections (Fly Ash)
4. (4) Economizer 6" Outlet Connections (Fly Ash)
5. (3) Boiler Dust Collector 6" Outlet Connections (Fly Ash)

4.6.4 *Fly Ash Handling System*: All fly ash in Boiler 7 is transported through the hydroveyor jet pump into the ash transfer sump which is located in the basement of the power plant. All fly ash and bottom ash from Boiler 7 is deposited in the same ash transfer sump as the ash from Boiler 6.

There are three hydroveyor jet pumps which are located above the ash transfer sump adjacent to Boiler 7 to provide the vacuum to convey the fly ash collected in Boiler 6 ash hoppers, in Boiler 7 ash hoppers and in the baghouse hoppers which were added in 1979.

As previously noted, there are two replacement ash sluice pumps that draw suction from the ash transfer sump and sluice the ash to the ash pond.

4.6.5 Baghouse Ash: The baghouse receives ash laden flue gases from both Boilers 6 and 7. The existing common baghouse was added in 1979 to collect the entrained fly ash which generated by both Boilers 6 and 7. The baghouse ash is transported as part of the fly ash system as described above.

4.6.6 Future Potential Environmentally Driven Dry Type Ash System Modifications: While the existing water based ash handling system is working in a satisfactory manner and is projected to continue to do so for the next 20 years, the installation of a “dry” ash handling system would provide a means to comply with future environmental coal combustion residues (CCR) draft rules and regulations. The CCR rules and regulations have been discussed for a number of years and their implementation schedule is unknown at this time. A description is given below of how the existing ash handling system could be modified to go to a dry type ash handling system.

The existing fly ash transport piping for both the fly ash branches for each of the two boilers would be headered together. The fly ash transport piping from the baghouse would be separately routed to a new ash silo entrance point near the top of the ash silo as previously shown on the aerial view in Figure No. 4.6-1 on page 4.0-18.

One concept for handling the bottom ash from each of the boilers includes redirecting the bottom ash from the bottom ash collection hopper, which receives bottom ash as it falls off traveling stoker grate into a new carbon steel chute and fabric type expansion joint. The bottom ash would pass through the new steel chute and be discharged onto a new dry drag chain conveyor (DCC). This new DCC will be a horizontal water jacketed conveyor to cool the bottom ash to a maximum of 750 deg F. This DCC from each stoker fired boiler will be elevated with the discharge being approximately 4 ft above grade, and will include support legs and at expansion joint at the discharge.

A second new dry DCC (water jacket is not needed) will be set at about a 20 degree incline to convey the bottom ash up to a bottom ash collection tank in the basement for temporary storage of bottom ash of approximately 4 hours. A new single roll clinker grinder will be placed between the new secondary conveyor and the new bottom ash collection tank to crush the bottom ash to maximum ¾” particle size for pneumatic conveying. The bottom ash will be pneumatically conveyed from each of the two new collection tanks to a common bottom ash fly ash header that will convey the combined bottom ash fly ash to the top of the new ash storage silo where the ash will be discharged into the ash storage silo.

Another concept for handling the bottom ash is to either modify or replace each existing bottom ash hopper on Boilers 6 and 7 with a new triple V shaped bottom ash hopper to keep vertical height requirements to a minimum. The two new bottom ash hoppers would have three (3) outlets for discharging bottom ash into new clinker grinders. The bottom ash discharge from each of the three new clinker grinders would discharge into new bottom ash conveyor piping. The new bottom ash conveying line would convey the bottom ash to the new ash storage silo. The new ash silo would be of bolted construction and be located just south and to the east of the existing stack.

The above described ash handling modifications are schematically shown on Figure No. 4.6-2.

It is proposed that a new dry ash silo be located just south and to the east of Stack 5 on the east side of the power plant as shown on Figure No. 4.5-1 on page 4.0-12. This new ash silo would receive all ash generated by Boilers 6 and 7. The ash silo storage capacity would be designed to store approximately 96 hours (4 days) of the ash generated by Boilers 6 and 7 operating at their full output.

Both fly ash and bottom ash portions of the ash handling system would be designed to convey the maximum amount of ash produced per day by both Boilers 6 and 7 in approximately 6 hours to provide one shift operation. Two new 100% capacity vacuum blowers (sometimes also referred to as mechanical exhausters) would draw ambient air into the ash piping to be used as the transport medium to convey the ash into the top of the ash silo. Primary, secondary (both accomplished by use of cyclone type separators) and tertiary ash (accomplished by baghouse) filtration would retain the ash in the new ash silo, returning the transport air to the atmosphere.

The two 100% capacity mechanical exhausters could be located in a new pre-insulated metal building that is approximately 20 feet square with a 12 foot high eve height. The new mechanical exhauster building would be located adjacent to the new ash silo. There are alternate locations for this mechanical exhauster building that should be investigated during preliminary design.

The ash pipelines to and from More's Lake would be either abandoned in place or removed.

A new programming logic controller (PLC) would control the entire ash handling system either with a "start conveying" signal from either the plant control room or a local panel with a "start conveying' signal. In any event, the ash conveying from each fly ash branch or the bottom ash branch for each boiler would be sequenced (or bypassed) by local control. The baghouse sequencing would also be controlled from the PLC.

BOILER & YARD AREA PLAN
PROPOSED ASH HANDLING SYSTEM

CAD DATA
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PLOT SCALE: 1:1 (30 x 42)
LAST MODIFIED: 12/28/2012

REV	DESCRIPTION		REV	DESCRIPTION
B	ISSUED FOR DRAFT SUBMITTAL	12-28-2012		
A	ISSUED FOR REVIEW	12-10-2012		

LUTZ, DAILY & BRAIN, LLC
CONSULTING ENGINEERS
6400 GLENWOOD
CLOVERLEAF 4 BUILDING
OVERLAND PARK, KANSAS 66202

DESIGN BY RBS — CHECKED BY RBS
DRAWN BY DKL — APPROVED BY TLS

COLUMBIA WATER & LIGHT DEPARTMENT
COLUMBIA, MISSOURI
COMPREHENSIVE POWER PLANT
CONDITION ASSESSMENT REPORT

PLANT & YARD AREA DRY ASH HANDLING SYSTEM
UPGRADE PLAN & ELEVATIONAL VIEWS

DRAWING NO. 541211-M2-RB
FIGURE NO. 4.6 - 2
PAGE NO. 4.0 - 22

The ash collected in the new ash silo could be discharged in dry condition from the conical bottom ash storage silo into either sealed truck compartments and trucked off site to either an environmentally approved ash disposal area remote from the power plant site or used for beneficial purposes. Fugitive ash dust emissions would be controlled by recirculating the ash dust back into the ash transport line to be returned to the top of the ash silo.

Also, ash may be discharged from the new ash silo via a "dustless" unloader which mixes water and ash as the ash is discharged from the ash silo.

Technical descriptions and budgetary construction cost estimates have been received from several ash handling manufacturers. These budgetary cost estimates have been included in Section 6.0 of this Volume 1 PPCA Report.

4.6.7 Retrofit of Impervious Ash Pond Liner: The United States Environmental Protection Agency (USEPA) and Missouri Department of Natural Resources (MDNR) may enact new rules and regulations which will require the retrofit of an impervious ash pond liner to seal off the ash pond from the adjoining soil.

It is noted that the retrofit of an ash pond liner would be a less expensive option as compared to retrofitting a dry ash handling system which is described in Paragraph 4.6.6 above. The installation of an ash pond liner would later need to be analyzed to determine if it is going to be either a short term alternative or a long term solution to these potential future rules and regulations.

4.7 Steam Turbine Generators

4.7.1 ***General***: Two of the three operating steam turbine generators (STG's) at the CWL Municipal Power Plant are STG-5 which has operated since 1957 and STG-7 which has operated since 1964. STG-5 was manufactured by Westinghouse (now Siemens) and is a 16.5 MW preferred standard machine. STG-7 was also manufactured by Westinghouse (now Siemens) and is 22.0 MW preferred standard machine. Both STG-5 and STG-7 have specified inlet steam conditions of 850 psig and 900°F and an exhaust pressure of 1.5" HgA (inches of mercury absolute). Both STG's are non-reheat, single flow steam turbines.

STG-5

STG-7

STG-8, Boiler 8 and its related balance of plant equipment are not part of this PPCA Report.

All three operating boilers have their superheater outlet steam lines headered together so that any operating boiler can serve any operating STG.

4.7.2 *Inspection of Both Steam Turbine Generators*: Both STG's need both physical and metallurgical inspections to better assess the remaining useful life of the two steam turbines generators for continuing operation for another 20 years. TurboCare Inc., an inspection and repair/upgrade company and wholly owned subsidiary of Siemens who purchased Westinghouse Steam Turbine Generators a number of years ago, has prepared a life extension study complete with a budgetary pricing which is included in Volume 3 of this report. STG-5 and STG-7 would need to be disassembled by either CWL or a third party to allow the necessary inspections. The repair and/or replacement of items normally found to be damaged would be performed during the same outage as that when the disassembly and inspection occurs, requiring decisions and potentially major expenditures.

Specific items needing inspection and the type of damage that may be present and/or could occur in STG's approaching 200,000 hours of operation have been identified in the TurboCare Report. It is of interest to note that STG-5 has 215,000 hours of operation and STG-7 has 185,000 hours of operation. Possible and probable damage that can occur within the steam turbine for units that have been operated for 200,000 hours are cracks resulting from metallurgical creep, low cycle fatigue and high cycle fatigue. Recommended inspections that are discussed in the TurboCare Report in Section 1.0 of Volume 3 are as follows:

1. Steam turbine rotors
2. Blades and nozzles with the same damage potentials
3. Nozzle plates and diaphragms
4. Casing and trip throttle valve body

Non destructive testing (NDT) methods can be performed to verify the soundness and metallurgical strengths of the steam turbine items. The Charpy testing and chemical analysis of the items metallurgy require samples of the selected items which would require performing – minor destructive testing (DT). These NDT and DT methods are listed below.

1. Linear measurements
2. Magnetic particle inspections for cracks
3. Ultrasonic testing for thickness
4. Phased array ultrasonic testing for locating submerged crack
5. Hardness testing (micro hardness)
6. Replications for grain microinspection for creep extent with micrographs
7. Boroscope internal inspections
8. Charpy (destructive) testing for impact strength

9. Chemical analysis of metallurgy (destructive)

4.7.3 *<u>Summary of Budgetary Cost Estimates for Probable Extension of STG-5 and STG-7 Remaining Useful Life An Additional 20 Years</u>*: The budgetary cost estimates of the probable improvements for extending the useful life of STG-5 and STG-7 an additional 20 years are included in Section 1.0 of Volume 3 of this Comprehensive PPCA Report and summarized in Section 6.0 of this Volume 1 PPCA Report submittal.

4.7.4 *<u>Conclusions</u>*: The remaining useful life and corrective measures required for STG-5 and STG-7 to achieve an additional 20 years of remaining useful life can be more definitively determined by carrying out an inspection and fact finding program. This STG-5 and STG-7 inspection and fact findings program is summarized below and completely described in Section 1.0 of Volume 3. With additional inspection and testing as well as performing certain predicted upgrades, STG-5 and STG-7's remaining useful life can be extended an additional 20 years.

4.7.5 *<u>Rotor</u>*

1) Replication check of turbine stages 1 thru 4 wheels near root attachments.

2) A complete rotor boresonic inspection.

3) A complete wet magnetic particle inspection of all exposed rotor surfaces to detect fatigue cracks.

4) Phased array inspection of all rotor wheels.

4.7.6 *<u>Casing and Trip Throttle Valve (TTV) Body</u>*

1) Replication checks of select hot and cold internal sections of the casing.

2) Removal of samples from select areas of hot and cold internal surfaces of the casing and TTV body to support analysis of chemistry, and lab work to determine micography, and impact strength.

3) A comprehensive magnetic particle inspection of all exposed surfaces of the casing for signs of fatigue cracks.

4.7.7 *<u>Nozzle Plate and Diaphragms</u>*

1) Replication checks of select high stress areas of hot section diaphragms.

2) Wet magnetic particle inspection of all exposes nozzle plate and diaphragm surfaces.

3) Dimensional inspection to detect distortion or yielding of the main fabrication welds.

4) Destructive examination of the main fabrication welds.

The results of the above described inspection and fact finding program will indicate whether or not the turbine rotor is at risk and whether or not a repair regime or replacement is the most cost effective solution for adding 15 to 20 years renewed reliable operation to STG-5 and STG-7.

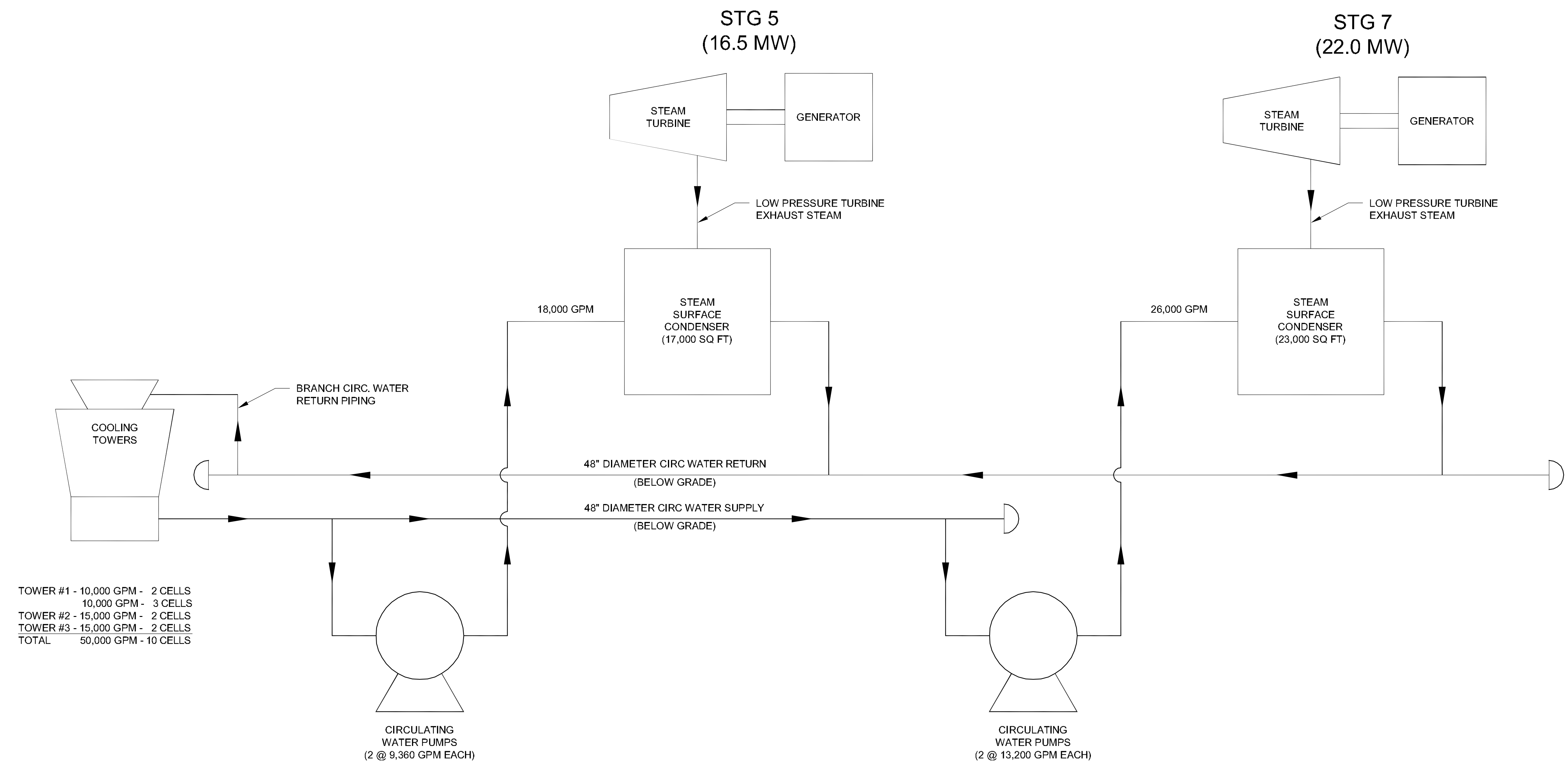
4.8 Plant Turbine Cooling Water System (STG-5 & STG-7)

4.8.1 *General*: Cooling towers CT-1, CT-2 and CT-3, circulating water system, steam surface condensers and other turbine exhaust cooling system components provide a means for condensing the exhaust steam from steam turbine generators STG-5 and STG-7. These plant turbine cooling water system components also provide a means for transporting the heated circulating water from the steam surface condensers to the cooling towers on the west side of the power plant, rejecting the heat to the atmosphere via the cooling towers and transporting the cooled circulating water via large diameter below grade piping system back to the steam surface condensers as schematically shown on Figure No. 4.8-1.

The respective steam surface condenser enables STG-5 and STG-7 to maintain a sub-atmospheric steam turbine exhaust pressure during high ambient wet bulb temperature as well as during other atmospheric conditions. Maintaining a sub-atmospheric steam turbine exhaust pressure in the 1.5 to 2.5 inches mercury absolute (HgA) range helps enable these two STG's to maintain their rated electrical output.

The turbine exhaust cooling water system consists of the cooling towers, the circulating water piping, circulating water pumps, and a separate steam surface condenser for steam turbine generators STG-5 and STG-7. An overview of the condition assessment of each of these turbine exhaust cooling system components is given below and in the remainder of this section of our report.

4.8.2 *West Cooling Towers (Towers #1, 2 and 3)*: There currently are three cooling towers providing cooled circulating water to STG-5 and STG-7 steam surface condensers as shown on the aerial view in Figure No. 4.8-2. One of the three cooling towers (CT-1, sometimes referred to as the Marley Tower) was installed in the early 1960's. Another tower (CT-3, sometimes referred to as the United Tower) was installed in 1955. The third cooling tower (CT-2, sometimes referred to as the Lillie-Hoffman tower) was installed in 1983 to replace a failed cooling tower. All three cooling towers provide cooled circulating water to the condensers for the two steam turbine generators, STG-5 and -7, using a common headered circulating water piping system.



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REVISION: REV A 12-28-2012

LUTZ, DAILY & BRAIN, LLC
CONSULTING ENGINEERS
6400 GLENWOOD
CLOVERLEAF 4 BUILDING
OVERLAND PARK, KANSAS 66202

DESIGN BY	-	CHECKED BY	RBS 12/12
DRAWN BY	MRR 12/12	APPROVED BY	TLS 12/12

COLUMBIA WATER & LIGHT DEPARTMENT
COLUMBIA, MISSOURI
COMPREHENSIVE POWER PLANT
CONDITION ASSESSMENT REPORT

MUNICIPAL POWER PLANT
SIMPLIFIED PLANT COOLING WATER SYSTEM SCHEMATIC
FOR STEAM TURBINE GENERATORS 5 & 7

DRAWING NUMBER
541211-2
FIGURE NUMBER
4.8 - 1
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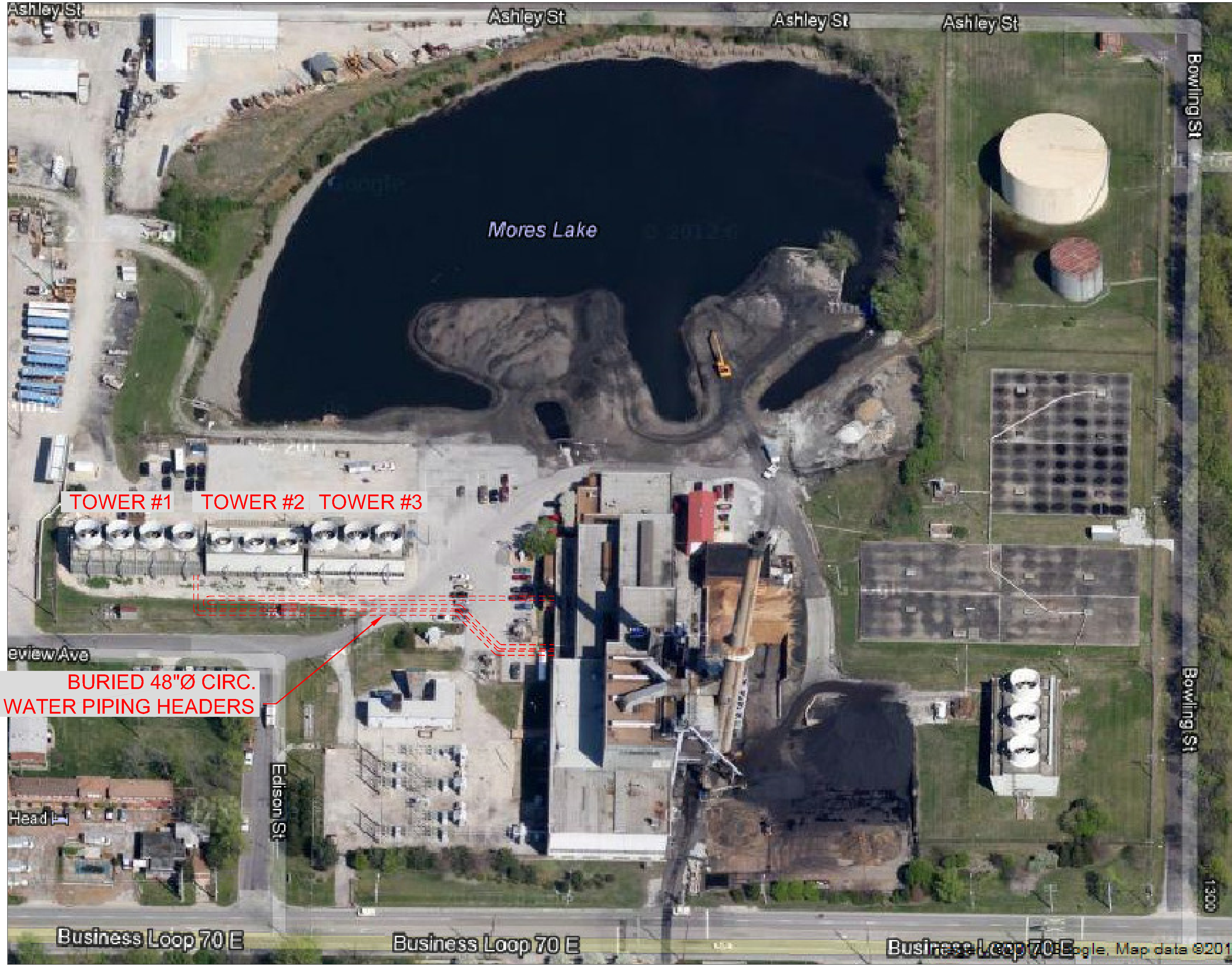

NORTH

100 50 0 100 200

SCALE: 1" = 100'

CAD DATA FILENAME: 541211-A1 PLOT SCALE: 1:1 (11x17) REVISION: REV B 12-28-2012 © 2012 LUTZ, DAILY & BRAIN, LLC	LUTZ, DAILY & BRAIN, LLC CONSULTING ENGINEERS 6400 GLENWOOD CLOVERLEAF 4 BUILDING OVERLAND PARK, KANSAS 66202 DESIGN BY - CHECKED BY MWR 12/12 DRAWN BY DKL 12/12 APPROVED BY TLS 12/12	WATER & LIGHT COLUMBIA WATER & LIGHT DEPARTMENT COLUMBIA, MISSOURI COMPREHENSIVE POWER PLANT CONDITION ASSESSMENT REPORT	MUNICIPAL POWER PLANT AERIAL PLAN VIEW SHOWING COOLING TOWERS & CIRCULATING WATER PIPING SERVING STEAM TURBINE GENERATORS #5 & 7

DRAWING NUMBER 541211-A1

FIGURE NUMBER 4.8 - 2

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Cooling Tower Inspection Reports along with construction cost estimates have been received from three cooling tower manufacturers--SPX Marley, Evap Tech and CCS. These reports and cost estimates are included in Section 6.0 of this Volume 1 PPCA Report. A summary of cooling tower inspections by these three cooling tower manufacturers are given below and in more detail in Section 4.0 of Volume 3 of this Comprehensive PPCA Report.

These three cooling towers which are located west of the main Municipal Power Plant Building are constructed end-to-end shown on Figure No. 4.8-2 on page 4.0-28 with the Marley tower (CT-1) being located on the west end of the string of cooling tower cells; the Lillie-Hoffman tower (CT-2) being centered between the two other towers and the United tower (CT-3) being located on the east end of the tower string.

The Marley cooling tower (CT-1) is a cross-flow design that was constructed of old-growth redwood as two, two-cell towers in 1963. The major repairs to permit 20 years additional use of this tower has been estimated by several cooling tower manufacturers be nearly equal to the cost of a new cooling tower with the same capacity. Cooling Tower CT-1 needs replacement in the near future.

The Lillie-Hoffman cooling tower (CT-2) is a counter-flow design that was constructed as a three-cell tower of new-growth douglas fir lumber that has been found to have an expected life in cooling tower service of 25 to 30 years. Since CT-2 was installed in 1983, it is 29 years of age now and reported to have severe structural member damage in the lower supports. It is not reasonable to anticipate that repairs to this tower would permit operation for another 20 years. This Lillie-Hoffman cooling tower needs replacement in the near future.

Constructing a new cooling tower with structural members of fiberglass reinforced plastic (FRP) would provide a life of the replacement tower of 40 or so years.

The United cooling tower (CT-3) is a counter-flow design that was constructed in 1955 as a four-cell tower of old-growth redwood. The United tower is 58 years of age and needs total replacement in the near future.

New cooling tower capacity needs to be constructed that would provide the required cooling capacity, 18,000 gpm and 26,000 gpm to serve STG-5 and STG-7 respectively. Another option would be to install one 44,000 gpm cooling tower that could serve both STG-5 and STG-7. The new cooling tower(s) would be constructed of fiberglass reinforced plastic (FRP) in the same location as the existing cooling towers. The new cooling towers could utilize most of the existing circulating water piping (with repairs and/or replacement to portions of the 48” diameter buried circulating water headers). Most of the existing concrete cooling tower basins could be reused and modified to meet the basin requirements of the new cooling tower(s).

4.8.3 *Circulating Water Pumps (For West Cooling Towers)*: There are a total of four circulating water pumps installed in the basement of the plant. The cooled circulating water received from the underground circulating piping system that serve STG-5 & STG-7 is pumped through the steam surface condensers and back to the cooling towers as shown on Figure No. 4.8-1 on page 4.0-27. Two circulating water pumps serve each STG that are connected to the (common) circulating water piping supply and return headers. There are no known problems with these circulating water pumps.

4.8.4 *Circulating Water Piping (For West Cooling Towers)*: Portions of the below grade 48-inch diameter circulating water piping headers were inspected internally during the summer of 2012 by CWL staff. The walls of the 48” diameter pipe had wall thickness reductions to ¼ the original thickness. Portions of both 48-inch diameter circulating water piping headers will likely need replacement during the next 20 years. All cooling towers are connected to the same buried 48” diameter supply and return circulating piping headers.

CWL power plant staff has inspected some of the 48” diameter headered piping and reports that replacement may be needed in some areas. An inspection needs to be performed at the joints that have been installed for the longest times where there may be some water leakage. Of the estimated 2600 feet of buried 48” diameter piping, it has been assumed for purposes of estimating repair costs that approximately 600 lineal feet of pipe and nine of the estimated six 48” diameter fittings will need repair or replacement during the next 20 years. An approximate estimate of the costs of these replacements/repairs is included in Section 6.0 of this Volume 1 PPCA Report.

4.8.5 *Steam Surface Condensers (STG-5 & STG-7)*: The steam surface condenser for each STG (5 & 7) have approximately 10% of the admiralty tubes plugged. No progression of plugging tubes have reportedly been found during the past few years.

The other elements of the two steam surface condensers are in acceptable condition. Water boxes may need cathodic protection upgrade or cleaning and corrosive resistant coatings installed on the interior of the water boxes. These items are considered routine maintenance.

When the turbine backpressures rise above 3" HgA the plugged/leaking tubes should be replaced and an inspection of all condenser tubes should be performed to identify additional tubes to be replaced which have low minimum wall thicknesses or other damage detected with eddy current testing.

4.9 Mechanical Auxiliaries & Piping Systems

4.9.1 ***General:*** Mechanical auxiliaries include the condensate pumps, boiler feed pumps, closed heat exchangers, deaerators, evaporators, boiler water makeup system, and air compressors.

4.9.2 ***Condensate Pumps & Boiler Feed Pumps***: The 16.5 MW and 22.0 MW power plant additions included two and three condensate pumps respectively which take suction from the condensate hotwell and pump condensate through the steam air ejector, low pressure closed heat exchangers to the deaerator where dissolved oxygen and other dissolved condensate gases are removed. The condensate pumps have electric motor drives in the 40 to 50 hp range. These condensate pumps are reported to be in good condition and would be a relative low cost to replace.

The boiler feed pumps on each unit consist of two 100% capacity pumps with one being a steam turbine driven pump while the other being an electric driven pump. These boiler feed pumps have been periodically repaired over the years and one boiler feed pump on Boiler 6 was recently replaced. At the present time, the boiler feed pumps are reported to be in good condition.

With continued proper operation and maintenance, these pumps should have a remaining useful life of at least another 20 years.

4.9.3 ***Closed Heat Exchangers***: There is one low pressure closed heat exchanger on each of the 16.5 MW and 22.0 MW power plant additions. The closed heat exchangers is used to heat condensate prior to its entry into the deaerator using extraction steam from steam turbine generators (STG) 5 and 7 to increase cycle efficiency. Condensate flows on the inside of these tubes in the closed heat exchanger and steam on the shell side or outside of the tubes. Condensed steam is recovered and pumped ahead by a heater drip pump.

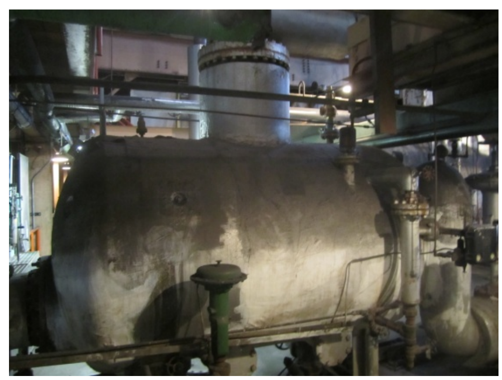
The closed heat exchangers on the 16.5 MW and 22.0 MW plant additions are reported to be in satisfactory condition. With continued proper operation and maintenance, the closed heat exchangers should have a remaining useful life of at least 20 years.

4.9.4 *Deaerators*: The deaerators on the 16.5 MW and 22.0 MW power plant additions are used to remove dissolved oxygen and other dissolved gases. Deaerators also provide additional preheating of the feedwater before entering the boiler economizers. These two deaerators are pressure vessels which have been inspected and tested by Thielsch Engineering Inc. (TEI) on site test team during the Summer of 2012.

Corrosion induced pitting in the deaerator storage section has been repaired by the CWL on call Contractor, Enerfab, after the TEI inspection was performed during the Summer of 2012. The Enerfab repairs have been inspected and the deaerators have been determined by TEI to be suitable for operation and that the deaerators be re-inspected in 2015.

The remaining useful life of the two deaerators will need periodic re-evaluation as will other equipment to extend the equipment's remaining useful life. In any event, the replacement cost of the deaerators is estimated to be a relatively small part of the overall cost of these two power plant additions.

4.9.5 *Evaporators*: The two evaporators appear to be in relatively good condition and have a remaining useful life of at least 20 years given that the evaporators are continued to receive proper operation and maintenance.



Since CWL retrofitted a reverse osmosis (RO) in the 2004 timeframe, the evaporators are no longer required to produce high purity water for the boilers. CWL has opted to maintain the operation of the evaporators to provide an added measure of protection against impure boiler feedwater makeup.

The evaporators are used to distill the makeup water using steam to evaporate the makeup water to produce high purity water for makeup to the boilers. The accumulated mineral deposits in the evaporators are removed by blow down and subsequently discharged.

4.9.6 *Boiler Water Makeup System*: The original boiler makeup system included the evaporation of city water

in the evaporators using steam. Since the 1960's technology advances have been made including the use of RO system which included sodium zeolite softeners, carbon filters, two 5800 gallons capacity of fiberglass construction high purity water storage tanks, pumps and PLC based controls to provide the ability to produce 60 gallons per minute (gpm) of high purity boiler makeup water that is sometimes referred to as permeate for the boilers in the CWL Municipal Power Plant.

The RO skid membranes are replaced every few years as a part of the CWL routine maintenance program.

Also, there are condensate storage tanks that are used to store high purity boiler makeup water and condensate. The condensate storage tanks have recently been drained, cleaned and recoated on the inside to extend their life.

The boiler water makeup system should have a remaining useful life in excess of 20 years with continued good operating and maintenance practices.

4.9.7 *Air Compressors*: There are several air compressors which are used to provide both station air and instrument compressed air for the CWL Municipal Power Plant. These current air compressors are replacement air compressors which are reported to be in good condition.

With proper operation and maintenance, these current operating air compressors should have a remaining useful life of at least 20 years.

4.9.8 *Piping Systems*: The high energy piping systems (main steam and feedwater) which are associated with the two solid fuel fired boilers (Boilers 6 & 7), steam turbine generators (STG-5 & STG-7) and associated balance of plant (BOP) systems have been inspected by Thielsch Engineering Inc. (TEI) earlier this year and found to be in good condition.

Other piping systems have been investigated and found to be in good condition except for the 48-inch diameter buried circulating water piping that located between the plant and West Cooling Tower. There is some severe pitting and some leaking joints which will need some repair during the next 20 years.

Also, there has been excessive scale buildup on the plant bearing water piping which will likely require either chemical treatment or replacement during the next 20 years.

4.10 Electric Auxiliaries, Raceways & Cabling

4.10.1 *General*: The condition of the electrical auxiliaries is addressed in Volume 3, Section 5.0 in this Comprehensive Power Plant Condition

Assessment (PPCA) Report. With continued proper operation and maintenance, the electric auxiliaries can expected to have a remaining useful life of at least 20 years.

A summary of our electrical equipment condition assessment is given below and described in more detail in Volume 3, Section 5.0.

4.10.2 *Plant Substation*: While the 69 KV breakers are 1968 vintage, spare parts are still readily available on the surplus market. While the reliability of these 69 KV breakers is problematic, loss of a single 69 KV breaker has little impact on the availability STG-5 and 7 since there are two other breakers that allow access to plant generation.

4.10.3 *2.4 KV Switchgear*: While this 2400 volt switchgear is over 50 years old, spare parts are still available. It is recommended that the Westinghouse Type CO relays be replaced with modern Schweitzer micro-processor based relays as part of the CWL Arc Flash Reduction Program which CWL has already initiated with engineering support from LD&B.

4.10.4 *Generator System*: The existing electric mechanical relays will likely need to be replaced with modern micro-processor based generator relays within the next 20 years. Also, it is likely that the existing turbine supervisory system will need to be replaced with digital units complete with historian and data acquisition system. In addition, the voltage regulator on STG-5 will likely need replacement within the next 20 years.

4.10.5 *STG-5 & 7 480 Volt Auxiliary Power*: With continued proper operation and maintenance, no major improvements should be needed to extend the useful life of this 480 volt auxiliary power system another 20 years.

4.10.6 *Common 480 Volt System*: The baghouse transformer is a non-redundant unit which would result in both STG-5 and STG-7 having to be shutdown on failure of this one baghouse transformer. Addition of a second baghouse transformer is recommended. With proper operation and maintenance, the one existing baghouse transformer should have an additional 20 years of remaining useful life.

4.10.7 *Emergency Power:* The station battery system is relatively new and should last an additional 20 years with proper operation and maintenance. B Battery needs to have its cracked tops repaired or replaced. A new natural gas fired 130 KW emergency engine generator (DEG) is in the process of being placed in service.

4.10.8 *Raceways and Cables*: The existing raceways and cables should last an additional 20 years with proper operation and maintenance.

4.10.9 *Grounding & Lightning Protection*: Electrical grounding and lightning protection appears to be adequate and should last additional 20 years with proper maintenance. The opacity monitor ground needs to be modified to provide better lightning protection.

4.11 Control System & Instrumentation: The existing power plant control system is outdated and in need of replacement. The control system on Boilers 6 & 7 includes numerous single loop controllers. The turbine supervisory has pneumatic controllers that are outdated.

The proposed new distributed control system (DCS) would consist of the following:

1. Boiler I/O panel to replace the controls in the Fireman's Shack/Control room--This controls upgrade would handle all present I/O and gauges that currently are in the Fireman's Shack. Fuel, feedwater, steam systems would be included.

2. Turbine I/O panel to replace the existing STG and voltage regulator control panels.

3. Generator I/O panel at switchgear to replace the existing generator controls.

4. HMI's, controllers, engineering HMI, and data servers in the existing electrical control room.

This approach will accommodate the movement of the electrical system operators to a new facility which will free up space for the new equipment in the control room.

Installation of the above described new DCS is needed to provide a plant control system that should be adequate for the next 20 years. The new DCS should be make capable of integrating into it any future air quality control system (AQCS) upgrades.

The installation of a new DCS may enable the reduction of one person per shift which may offset additional operating and maintenance requirements of AQCS related upgrades.

4.12 General Site:

4.12.1 *General*: The two solid fuel fired 16.5 MW and 22.0 MW steam electric generating plant additions at the CWL Municipal Power Plant have generally performed well over the past 40 to 50 years. The preferred standard 16.5 MW and 22.0 MW system turbine generators have been a proven design that have performed well for many decades for many power plants.

The CWL Municipal Power Plant site is located within an area that is surrounded by security fencing. In addition, there are security cameras which enable control room operators to monitor the site. The plant entrance gate is kept closed and voice request must be made by all visitors to gain access to the site.

Overall, the site is in good condition with no major site improvements scheduled.

4.12.2 *Plant Discharge*: There are two plant discharges from the site. The plant discharge at the south edge of the property on the east side of the main power plant structure is routed beneath I-70 Business Loop into a creek on the east side.

On the north side of the plant at the southwest corner of the ash storage area, there is a discharge that is routed to a storm drain manhole to the north along the west edge of More's Lake.

There are no improvements scheduled to the plant discharge system.

4.12.3 *Fire Protection System*: City water is used to supply water for CMPP fire protection. There is no fire loop installed around the CMPP buildings although there are some fire hydrants which are installed outside. CWL is planning to add 2 to 3 additional fire hydrants around the outside perimeter of their plant to provide improved coverage.

There is a water deluge system complete with fire panel for the plant steam turbine generator lube oil systems. The server room is protected by a fire panel and Ecar25 suppressant. Fire extinguishers are provided in the control room and at various locations in the plant.

A dedicated fire protection and deluge system is installed for the Units 5 and 7 steam turbine generators lubrication oil systems.

The substation has no fire protection system except for fire hydrants which are located in the vicinity. The substation transformers and auxiliary transformers are located close together and have no fire walls.

Also, the wood framed cooling towers have no fire sprinklers. Providing fire sprinklers on cooling towers is an item which the City insurance carrier may or may not request. The number of reported cooling tower fires are reported by Edison Electric Institute (EEI) to be very small.

4.12.4 *Asbestos Abatement*: CWL has performed asbestos abatement as needed to continue operating and maintaining plant equipment and devices.

5.0 PLANT PERFORMANCE TESTS

5.1 General: Plant performance tests which were conducted on August 28, 2012 on Boilers 6 and 7 steam turbine generators 5 and 7 and related balance of plant (BOP) systems are summarized below and described in more detail in Volume 3, Section 6.0.

5.2 Performance Test Results: A summary of the August 28, 2012 plant performance tests on the two solid fuel fired steam electric generating unit additions is given below.

5.2.1 *Oklahoma Coal*: The Oklahoma coal which was fired during the tests is not well suited to be fired in Boilers 6 and 7 by itself. The characteristics of this fuel are such that the coal/ash bed on the stoker grate partially to glaze over causing the formation of large clinkers. This partially glazed over of the coal/ash bed is likely due to ash fusion temperatures being too low and to a lesser extent due to the slagging and fouling tendencies of this coal. The CWL has taken steps to blend this Oklahoma coal with Illinois coal as well as wood chips which provides better firing characteristics.

5.2.2 *Stokers Nearing End of Their Useful Life*: Uniform air flow through the fuel/ash bed on the grate is not possible to achieve due to the condition of the existing Hoffman Stokers. Seals are in need of replacement. Numerous grate bars are damaged and in need of replacement. Stoker steel framework is damaged and in need of either extensive repair or replacement. The overfire air (OFA) system needs to be updated.

CWL power plant staff have had to custom fabricate some of these stoker components since the stoker manufacturer is no longer in business.

While it may be possible to continue repairing the stokers for a few more years, it is not reasonable to expect the stokers on Boilers 6 and 7 to last an additional 20 years.

5.2.3 *Baghouse Pressure Drop*: There is a common fabric filter 10 component reverse air type baghouse that removes the fly ash (fine ash particles) before the flue gas is discharged to the atmosphere from the 300 foot tall chimney.

The flue gas pressure drop through the baghouse is over 50% higher than it what it should be at 100% of the combined Boilers 6 and 7 maximum related steam flow (9 inches water gauge [wg] vs. 6 inches wc). Since there are earlier baghouse performance tests with significantly lower flue gas pressure drop, it is anticipated that there are modifications which can be achieved to lower the flue gas pressure drop through the baghouse.

CWL has had three bags tested during the November/December 2012 timeframe by a qualified bag test firm who determined that these bags are not blinded which sometimes does happen and results in high pressure drop.

Further investigation is needed to determine the root cause(s) of this excessive flue gas pressure drop through the baghouse which is beyond the scope of this report.

5.2.4 *Boiler Thermal Efficiency*: The calculated thermal efficiency of Boiler 7 of 83.58% using the August 28, 2012 performance test data is very close to what it was during the original plant performance test which was conducted in 1969 (81.34%) which is somewhat of a surprise given the poor condition of the grate. The boiler thermal efficiency for Boiler 6 using the August 28, 2012 test data is 77.53% which is lower than the predicted Boiler 6 boiler thermal efficiency by several percentage points. This lower Boiler 6 thermal efficiency is likely due to the poor condition of the stoker.

5.2.5 *Steam Turbine Generators (STG) 5 & 7 And Other Balance of Plant Equipment*: These components performed well and no problems appeared.

5.2.6 *Elimination of Load Restrictions*: The August 28, 2012 identified the stokers, baghouse and coal being the sources of load restrictions on the 16.5 MW and 22.0 MW power plant additions (STG 5 & 7, Boilers 6 & 7, Common Baghouse and BOP). Replacement of the stokers on Boilers 6 & 7 is the long term recommended solution to eliminating this load restriction. The common baghouse excessive pressure drop problem can be eliminated by further investigation that is needed to determine the root cause(s) and then taking corrective action to either restore its past performance or to increase its capacity by the addition of one or two additional compartnents. CWL has already taken stops to eliminate the load restrictions due to firing Oklahoma coal.

6.0 CONSTRUCTION COST ESTIMATES FOR EXTENDING USEFUL LIFE OF 16.5 MW & 22.0 MW POWER PLANT ADDITIONS AN ADDITIONAL 20 YEARS

6.1 General: Construction cost estimates for extending the useful life an additional 20 years of the two solid fuel fired steam electric generating units, namely the 16.5 MW and 22.0 MW power plant additions that Lutz, Daily & Brain, (LD&B) designed in the 1950's and 1960's, which consist of steam turbine generators (STG's) 5 and 7, Boilers 6 and 7 and related Balance of Plant (BOP) systems such as the west cooling towers, common baghouse, Stack 5, controls, fuel handling, ash handling, etc. have been prepared.

There are three categories of construction cost estimates that have been included in this Comprehensive Power Plant Condition Assessment (PPCA) Report. These three categories are as follows:

1) Routine Maintenance Related Projects
2) Potential Future Environmental Related Projects (Excluding Air Quality Control System [AQCS] Related Improvements)
3) Capital Related Projects

The construction cost estimates which have been presented for each of the above categories in this section of the Volume 1 Comprehensive PPCA Report have been estimated at December 2012 cost level.

6.2 Routine Maintenance Related Projects: Routine maintenance related items which have been described below is not intended to be a complete list, but instead is intended to supplement other routine maintenance related items that CWL management develops as part of their budget planning process.

6.2.1 *Replacement of Boiler 6 Economizer Tube Bends ($274,000)*: During the Summer of 2012, wall thickness testing was performed on the Boiler 6 pressure parts which included the economizer. The wall thickness of a number of economizer tube bends had likely been thinned from ash induced erosion to thicknesses below the American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code minimum recommended wall thickness for boilers operating in the same pressure and temperature range (875 psig/900F at the superheater outlet) as Boilers 6 and 7. The CWL on-call contractor, Enerfab, estimated that the replacement cost of these thinned tube bends to be approximately $274,000.

CWL is proceeding to make these repairs to avoid future forced unit outages from rupture of these thinned wall tube bends.

6.2.2 *Boiler 6 Mechanical Collector Collection Tube Replacement ($20,000)*: Periodic replacement of collection tubes in mechanical collectors that are provided to remove the larger fly ash particles by creating a cyclonic swirl of the ash particles which drop out the bottom of the collection tubes is a typical, routine maintenance item. Enerfab has estimated the cost to replace the two broken collection tubes to be $20,000. This work should be scheduled within the next two to three years.

6.2.3 *Boiler 7 Attemperator Repair & Replacement ($274,000)*: During the Summer 2012 onsite inspection, the attemperator header on Boiler 7 was found to be cracked and in need of repair/replacement. It has been recommended by Thielsch Engineering Inc. (TEI) that the condition of the attemperator be monitored and that repairs be made at the first available opportunity. Enerfab, the CWL on-call contractor, has developed the $274,000 construction cost estimate.

6.2.4 *Boilers 6 & 7 Chemical Cleaning ($380,000)*: The buildup of mineral deposits or scale on the inside surface of the tubes in Boilers 6 and 7 are considered to be substantial enough that these boilers may be classified as being “dirty” by various industry sources such as the Electric Power Research Institute (EPRI) and boiler manufacturers. Buildup of scale on the inside surface of the “miles and miles” of boiler tubing in these boilers will make these tubes more susceptible to overheating and in some cases be the cause of tube ruptures. Also, the boiler thermal efficiency is lowered by the buildup of internal scope tube deposits.

LD&B received budgetary cost estimates from Hydrochem, Rocky Mountain Industrial Services and other companies who regularly perform this work.

Chemically cleaning boilers must be done with care to be termed a successful chemical clean. Otherwise, damage can be done by the chemicals being used to remove the scale. CWL has reportedly had a bad experience with boiler chemically cleaning in the 1980’s. However, there are many successful boiler chemical cleans.

6.2.5 *Boilers 6 & 7 Common Flue Gas Ductwork Replacement at Stack ($367,000)*: The approximate 20 foot long section of flue gas ductwork which enters the stack is reported to be in need of replacement. Several years ago this large cross-sectional area section of ductwork had a gunite (shot concrete) liner installed to extend its useful life. Periodic inspection of this section of ductwork is needed to better define when this ductwork section replacement should be made. Also, replacement of this section of ductwork should be coordinated with any future AQCS improvements since this section of ductwork would likely need to be modified to accommodate these future AQCS improvements.

Enerfab, the CWL on-call contractor, has provided cost estimates for this work excluding the insulation and lagging work which has been separately estimated by LD&B.

6.2.6 *Replace Baghouse Controls & Install Additional Monitoring Instrumentation ($250,000)*: The existing baghouse controls and wiring will need to be replaced with a PLC based control system complete with remote I/O panel and wiring as further described in Table 6.2-1.

6.2.7 *Direct Buried 48-Inch Diameter Circulating Water Piping Repairs/Replacement ($500,000)*: The 48-inch diameter direct buried cast iron circulating water piping has been inspected during the past Summer. Deep pitting was found at some locations along with leaking joints. It is likely that major repairs of some type will be required something during the next 20 years. These repairs could consist of repairing leaking joints, replacing sections of piping and possible lining of the existing piping in place. An allowance of $500,000 has been included for these potential repairs/replacements.

6.2.8 *Miscellaneous Electrical Systems Improvements Capital Projects ($596,000)*: A summary of the miscellaneous electrical systems improvements which are described in more detail in Volume 3, Section 2.0 is tabulated below.

Item No.		**Description of Item**		**Estimated 20 Year Cost (Dec 2012 Cost Level)**
SWGR-2		Add bus differential relay to 2400 V Buses – Schweitzer SEL-387.		$120,000
GEN-2		Replace existing generator electromechanical relays with new Schweitzer SEL-300G microprocessor-based generator relays.		60,000
GEN-3		Replace turbine supervisory system with digital unit complete with historian and data acquisition for temperature. (Already included as part of proposed DCS controls project.)		--
GEN-4		Replace voltage regulator for STG-5.		75,000
480V-1		Add another 480 volt feed to baghouse to back up single transformer.		50,000
GND-1		Route opacity monitor ground away from stack ground to eliminate potential rise during lightning strike.		1,000
FIRE-1		Install fire walls between transformers that could fail, catch on fire, or explode in close proximity to other transformers.		100,000
VIB-1		Replace existing turbine vibration monitoring system with a new one.		50,000
ARCFLASH-1		Perform arc flash improvements to reduce arc flash hazard levels (being implemented).		140,000
--		Total Miscellaneous Electrical Improvements Capital Cost (Nearest $1000)		$596,000

Table 6.2-1
Columbia Water & Light Department
Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Baghouse Controls Upgrade

Item No.	Item Description	Estimated Costs December 2012 Cost Level
1.	Programmable Logic Controller (PLC) & Related Programming	$ 65,000
2.	Remote I/O Cabinet	20,000
3.	Additional Field Devices	50,000
4.	Installation Labor & Wiring	68,000
5.	Subtotal	$ 203,000
6.	Engineering Contingency (25%) Rounded to nearest $1,000	51,000
7.	Total Estimated Cost (Rounded to nearest $10,000)	$ 250,000

6.2.9 *Routine Maintenance Electrical Related Items ($90,000)*: A summary of the estimated routine maintenance related cost for electrical systems are given below.

Item No.	Description of Item	Estimated 20 Year Cost (Dec 2012 Cost Level)
SWGR-1	Clean & test 2400 volt switchgear biannually and replace bus insulation as required.	$60,000
GEN-1	Tighten generator stator wedges.	30,000
	Total Routine Maintenance Electrical Items (Nearest $1000) (Includes Engineering & Contingency Allowance of 25%)	$90,000

6.3 Potential Future Environmental Related Upgrades Other Than Air Quality Control System (AQCS) Improvement Projects ($435,000 & $6,100,000)

6.3.1 *Retrofit of Impervious Ash Storage Area Liner ($436,000)*:This approximate 5 acre area may later need to be retrofitted with an impervious liner. The estimated cost of this liner is tabulated in Table 6.3-1.

6.3.2 *Installation of Dry Type Ash Handling System ($6,100,000)*: If later required to comply with future environmental rules and regulations, the estimated cost to install a dry type ash handling system has been developed and shown in Table 6.3-2.

6.3.3 *Potential Future Addition of Two Baghouse Compartments ($750,000)*: There have been longstanding concerns that have been expressed by CWL power plant staff that the existing baghouse capacity may be insufficient. With the potential future addition of dry sorbent injection (DSI) systems such as activated carbon for mercury (Hg) reduction, trona or sodium bicarbonate injection for acid gas (HCl) reduction, and possibly other sorbents, there is the potential to have to add one or two additional compartments on the existing 10 compartment reverse air type fabric filter baghouse.

The budgetary cost estimate to design, fabricate and install two additional compartments complete with foundations of $750,000 has been provided by Amerair, an air quality control system manufacturer.

Table 6.3-1
CWL Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Construction Cost Estimate for Ash Pond Liner

December 2012 Cost Level

Asl Pond Liner

	Area (SF)	Perimeter (ft)	Depth (ft)	Width (ft)	Area (SF)	Unit ($/SF)	Subtotal
More's Lake Liner	211,280				211,280	$1.15	$243,000
Walls		2,090	20		41,800	$1.15	$48,100
Curb		2,090		10	20,900	$1.15	$24,000
Total					273,980		

Ash Pond Liner Subtotal:	$316,000
Contractor's O&P (20%):	$63,200
Install Cost:	$379,200
Design & On-Site Engineering Allowance (15%)	$56,900
Total (nearest $1000):	$436,000

Table 6.3-2
CWL Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Construction Cost Estimate for Dry Ash Handling System Replacement

Item No.	Item Description	Estimated Costs December 2012 Cost Level
1.	Dry Ash Handling System Including New Ash Silo	$ 1,800,000
2.	Installation of New Dry Ash Handling System Including New Ash Silo	2,700,000
3.	Foundations, Elevated Pipe Supports & Mechanical Exhauster Building	200,000
4.	Electrical Equipment, Wiring & Controls	200,000
5.	Subtotal	$ 4,900,000
6.	Engineering Contingency (25%) Rounded to nearest $1000	1,225,000
7.	Total Estimated Cost (Rounded to nearest $100,000)	$ 6,100,000

6.4 Capital Related Projects

6.4.1 *General*: The construction cost estimates for various designated capital projects are presented in the following paragraphs.

6.4.2 Steam Turbine Generators (STG's) 5 and 7 Upgrades Over Next 20 Years ($3,000,000 STG-5 & $3,000,000 STG-7)

6.4.2.1 *General*: It was mutually deemed not feasible to spend over $500,000 to open up (remove casings and enclosures) to perform a detailed inspection as a part of this Comprehensive PPCA Report. Instead, TurboCare Inc. was retained to perform an analysis that reviews the operating history of these two STG's along with their repair history.

Using the operating and repair histories of these units along with a statistical analysis of hundreds of these 16.5 MW and 22.0 MW preferred standard Westinghouse (now Siemens who also owns TurboCare) has been performed to arrive at the projected repairs and upgrades over the next 20 years. Depending on the future operation of these units, these repairs may not be needed for 10 or more years.

A summary of these repairs are given in Table 6.3-3 on page 6.0-9.

6.4.3 *Cooling Tower Replacement (STG-5 Related $1,625,000 & STG-7 Related $1,820,000)*: As described in Section 4.0 of this Volume 1 and in Section 4.0 of Volume 3, the existing cooling towers are nearing the end of their useful life and will need replacement during the next 20 years.

Budgetary cost estimates have been received from three cooling tower manufacturers---SPX, Evap Tech and CCS. Also, construction cost estimates have been developed by LD&B on other related cost. The construction cost estimates for two cooling towers--one to serve STG-5 and one to serve STG-7 have been tabulated in Table 6.4-1 on page 6.0-10.

6.4.4 *Replacement of Stokers, Fuel Feeders & Overfire Air (OFA) Systems on Boilers 6 and 7 ($1,650,000 and $1,920,000)*: The estimated construction cost to replace the existing Hoffman stokers, fuel feeders and overfire air system on Boilers 6 and 7 is presented in Table 6.4-2 on page 6.0-11.

Reference may be made to Volume 3, Section 2.0 as well as Section 4.0 of Volume 1 for additional information.

Table 6.3-3
CWL Comprehensive Power Plant Condition Assessment Report
Projected Budgetary Cost Estimates for STG-5 & STG-7 Over Next 20 Years

Item No.	Scenario #1 (Steam Turbine Rotor Found in Satisfactory Condition) Item	Budgetary Cost Estimate (2012 Cost Level) Per Unit
1-1	Conduct Inspection & Fact Finding Program	$150,000 to 200,000
1-2	Open/Close STG	350,000
1-3	Total Estimated Cost	$500,000 to $550,000
	Scenario #2 (Steam Turbine Rotor Found in Unsatisfactory Condition) Item	
2-1	Conduct Inspection & Fact Finding Program	$150,000 to 200,000
2-2	Open/Close STG	150,000 to 200,000
2-3	Total Estimated Cost	$350,000
Item	**Description**	**Budgetary Pricing***
1.	**Steam Turbine Rotor**	
	A) Creep damage found – Retire rotor and replace with new.	$2,250,000
	B) High cycle and / or low cycle fatigue damage – Repair by implementing a machining or welding solution, or replace with new, depending on economics.	$225,000
	C) High cycle and / or low cycle fatigue damage to blades – Replace blades with new.	$145,000
2.	**Casing and Trip Throttle Valve Body**	
	A) Creep damage found – Retire and replace with new.	N/A
	B) High cycle and / or low cycle fatigue damage – Repair by implementing a machining or welding solution or replace with new, depending on economics.	T&M*
	C) Loss of material properties due to chemistry and age – Heat treatment program to normalize properties and reverse degradation, or replace with new, depending on economics.	T&M*
3.	**Nozzle Plate and Diaphragms**	
	A) Creep damage Found – Retire and replace with new.	$175,000
	B) High cycle and / or low cycle fatigue damage to areas outside of structural welds. Repair by implementing a machining or welding solution, or replace with new, depending on economics.	T&M (Est $5,000-$50,000)
	C) High cycle and / or low cycle fatigue damage of structural welds. Retire and replace with new.	$175,000
	Total Estimated Cost (Nearest $100,000)	$3,000,000

* Note that this pricing, which has been prepared by TurboCare, is for budgetary estimation purpose only and should not be considered firm pricing. Firm pricing can be provided upon receipt of additional dimensional data. Budgetary pricing is at 2012 cost level. Casing and Trip Throttle pricing cannot be estimated until a full inspection has been completed.

Source: TurboCare STG-5 & 7 Life Extension Study Page 21 in Section 1.0 of Volume 3.

Table 6.4-1
CWL Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Construction Cost Estimate for Cooling Tower Replacement

		Estimated Costs December 2012 Cost Level	
Item No.	**Item Description**	**STG-5**	**STG-7**
--	Circulation Rate, gpm	16,000	28,000
1.	Cooling Tower Delivered & Erected	$ 635,000	$ 906,000
2.	Demolition of Existing Towers		
	- Tower #1	54,000	
	- Tower #2		62,000
	- Tower #3		65,000
3.	Piping, Wiring & Controls	125,000	175,000
4.	Miscellaneous (Bonding & Hazardous Material Disposal)	50,000	75,000
5.	Subtotal	$ 864,000	$ 1,283,000
6.	Engineering & Contingency (25%) Rounded to nearest $1000	$ 216,000	$ 321,000
7.	Total Estimated Cost (Rounded to nearest $10,000)	$ 1,080,000	$ 1,600,000

Table 6.4-2
CWL Comprehensive PPCA Report
Two Solid Fuel Fired Steam Electric Generating Units
Construction Cost Estimate for Stokers, Fuel Feeders & Overfire Air Systems

Item No.	Item Description	Estimated Costs December 2012 Cost Level Boiler 6	Boiler 7
1.	Stoker, Fuel Feeders & Overfire Air System f.o.b. CWL Power Plant	$ 930,000	$ 1,122,000
2.	Technical Advisor (20 Days of Service at $2000/day)	$ 40,000	40,000
3.	Installation Including Demolition & Removal	350,000	375,000
4.	Subtotal	$ 1,320,000	$ 1,537,000
5.	Engineering & Contingency (25%) Rounded to nearest $1000	$ 330,000	$ 384,000
6.	Total Estimated Cost (Rounded to nearest $10,000)	$ 1,650,000	$ 1,920,000

6.4.5 *Distributed Control System (DCS) Upgrade ($1,000,000)*: The existing power plant control system is outdated and in need of replacement. The control system on Boilers 6 & 7 includes numerous single loop controllers. The turbine supervisory has pneumatic controllers that are outdated.

The proposed new distributed control system (DCS) would consist of the following:

1. Boiler I/O panel to replace the controls in the Fireman's Shack/Control room--This controls upgrade would handle all present I/O and gauges that currently are in the Fireman's Shack. Fuel, feedwater, steam systems would be included.

2. Turbine I/O panel to replace the existing STG and voltage regulator control panels.

3. Generator I/O panel at switchgear to replace the existing generator controls.

4. HMI's, controllers, engineering HMI, and data servers in the existing electrical control room.

This approach will accommodate the movement of the electrical system operators to a new facility which will free up space for the new equipment in the control room.

Installation of the above described new DCS is needed to provide a plant control system that should be adequate for the next 20 years. The new DCS should be make capable of integrating into it any future air quality control system (AQCS) upgrades.

The installation of a new DCS may enable the reduction of one person per shift which may offset additional operating and maintenance requirements of AQCS related upgrades.

7.0 ENVIRONMENTAL ASSESSMENT

7.1 General: The option which has been included in the City-approved authorization includes the preparation of an environmental assessment. This optional environmental assessment may later be performed and made a part of this Comprehensive Power Plant Condition Assessment (PPCA) Report.

This supplemental report is to provide an independent environmental assessment of the impact and applicability of recently implemented environmental rules and regulations as well as those anticipated to be implemented in the future.

7.2 Development of Compliance Strategy: The environmental assessment of these environmental rules and regulations will be used to develop a compliance strategy for these two solid fuel fired steam electric generating units over the next 20 years (steam turbine generator STG–5 and STG-7; Boilers 6 and 7; common baghouse, fuel handling system; ash handling system and related balance of plant (BOP) systems).