City of Independence, Missouri
Power & Light Department

Missouri City Power Plant
Retirement Options Report
Final

July 2015

Project No. 15-0080

ENGINEERING & TECHNICAL SERVICES

TABLE OF CONTENTS

TABLE OF CONTENTS

SECTION 1

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

1.1 INTRODUCTION

On July14, 2014, the City of Independence, Missouri City Council passed Resolution Bill 14-758, Resolution 5933 for support of renewable energy that included:

> SECTION 5. That the City Manager is hereby authorized and directed to end production of energy at the Missouri City power plant by January 31, 2016 in compliance with the Industrial Boiler MACT rule.
>
> SECTION 6. That the City Manager is hereby authorized and directed to produce a report outlining the options and associated estimated costs for the disposition of the Missouri City Power Plant, ranging from retirement to demolition by July 2015.

Power & Light Department (IPL) was directed by the City Manager to develop this report. IPL retained Sega, Inc. (Sega) to provide opinion of costs for the retirement of Missouri City and investigating retirement options. This report provides the results of Sega's study.

Retirement is comprised of two principal phases: ***decommissioning*** and ***dismantlement***. ***Decommissioning*** is the shutdown, or closure and removal from service, of a generating unit or facility. This includes disconnection, de-energization, cleanout, and securing of the units to render them safe. ***Dismantlement*** is the orderly demolition of the unit in a controlled and safe manner. This process preserves the scrap value of materials for reclamation while appropriately protecting the workers and the environment. Ongoing site maintenance (requiring different levels of effort) is required if IPL is to continue owning the site after decommissioning and dismantlement.

1.2 APPROACH

Sega met with representatives of IPL to gather information about Missouri City and visited the plant site. Discussions were held with plant representatives, further documentation was obtained, and a walkdown of the units was conducted. IPL directed Sega to investigate the following 5 options:

1. Decommission Missouri City and Maintain the Site: IPL is not required to dismantle its plants upon decommissioning. Often a plant site is not dismantled until sometime after it is decommissioned. This option is for the decommissioning of Missouri City and IPL maintaining the site into the future.
2. Dismantle Missouri City and Maintain the Site: This option is for the decommissioning and dismantlement of Missouri City and IPL maintaining the site into the future.
3. Dismantle Missouri City and Sell the Site: This option is for the decommissioning and dismantlement of Missouri City and selling the site. IPL would maintain the site after dismantlement until the site can be sold. This study does not include an opinion of the sale value of the site.
4. Sell Missouri City As-Is: This option does not include the retirement of Missouri City. The plant would be sold as-is. This study does not include an opinion of the sale value of the Missouri City Plant.
5. Continue Missouri City Operations Using Alternate Fuel: The economics of modifying Missouri City to burn biomass or natural gas as an alternate to burning coal has been investigated by IPL in the recent past. The results of these investigations are included in Sections 5 - Coal-to-Biomass Fuel Switching and 6 - Coal-to-Natural Gas Conversion of this report.

1.3 RESULTS

The opinion of probable cost for each of the above options is presented in *Figure 1.1 - Probable Costs for the Missouri City Power Plant Retirement Options*.

The opinion of probable costs of these options are a combination of the opinions of probable costs for decommissioning, dismantlement, site maintenance after decommissioning, site maintenance after dismantlement, coal-to-biomass fuel switching, and coal-to-natural gas conversion (as required for each option). The details and approach to the development of these opinions of probable cost are presented in the body of this report.

The following summarizes the results of each of the five options:

1. Decommission Missouri City and Maintain the Site: Sega developed an opinion of probable cost of $926,733 to decommission the Missouri City Power Plant. The opinion of probable cost is a summary of estimated costs to perform the decommissioning activities to leave the facility in a safe state. Decommissioning activities include the closure and removal from service of plant equipment including disconnection, de-energization, cleanout, and securing the units to render them safe. Once decommissioning is complete, IPL will maintain the site for an annual opinion of cost of $32,400. Site maintenance includes security walkdowns, mowing, clearing of snow, confirming the site is draining properly, confirming the intake has not been compromised, and minimal maintenance on the decommissioned plant.

2. Dismantle Missouri City and Maintain the Site: Sega developed an opinion of probable cost of $16,259,289 to dismantle the Missouri City Power Plant. This opinion of probable cost for dismantlement is based on the completion of the decommissioning activities at an opinion of probable cost of $926,733. Therefore, the overall dismantlement opinion of probable cost is the combination of the decommissioning costs plus the dismantlement costs totaling $17,186,022. Dismantlement is the orderly demolition of the unit in a controlled and safe manner and preserving the scrap value of materials for reclamation. Once dismantlement is complete, IPL will maintain the site for an annual opinion of probable cost of $13,800. Site maintenance includes security walkdowns, mowing, clearing snow, and confirming the site is draining properly.

3. Dismantle Missouri City and Sell the Site: Sega developed an opinion of probable cost for the overall site dismantlement of $17,186,022. Maintenance costs will be incurred between the completion of dismantlement and selling of the site. Sega did not provide an opinion of probable value of the site after the plant has been dismantled.

4. Sell Missouri City As-Is: Sega did not provide an opinion of probable value of the site with the Missouri City Power Plant left as-is in its current state. Based on Sega's current understanding of the used power plant market and the significant costs to continue to operate the plant as a generating facility (see below), it is Sega's opinion that there is a low probability of a buyer willing to purchase Missouri City as-is and continue to operate the plant as a generating facility.

5. Continue Missouri city Operations Using Alternative Fuel: Sega developed an opinion of probable cost of $53,000,000 for modifying Missouri City units to burn biomass and an opinion of probable cost of $55,600,000 to convert Missouri City to burn natural gas. Both of these opinions of probable cost include the costs for non-fuel related projects required for continuing operations, fuel transportation equipment, and environmental equipment modifications.

Option	Description	Decommissioning Opinion of Probable Cost	Dismantlement Opinion of Probable Cost	Total Opinion of Probable Cost, Not Including Ongoing Maintenance Costs	Annual Ongoing Maintenance Opinion of Probable Cost	Study Section
1	Decommission Missouri City and Maintain the Site	$926,733	-	$926,733	$32,400	2, 4
2	Dismantle Missouri City and Maintain the Site	$926,733	$16,259,289	$17,186,022	$13,800	2, 3, 4
3	Dismantle Missouri City and Sell the Site	$926,733	$16,259,289	$17,186,022[2]	See Note 1	2, 3, 4
4	Sell Missouri City As-Is	-	-	-	-	-
5	Continue Missouri City Operations using Alternate Fuel					
	a. Coal-to-Biomass Fuel Switching			$53,000,000		5
	b. Coal-to-Natural Gas Conversion			$55,600,000		6

1 Maintenance costs will be incurred between Dismantlement completion and selling the site.
2 Does not include proceeds from the sale of the site.

Figure 1.1 - Probable Costs for the Missouri City Power Plant Retirement Options

SECTION 2

DECOMMISSIONING

DECOMMISSIONING

2.1 INTRODUCTION

Sega developed an opinion of probable cost of $926,733 to decommission the IPL Missouri City Power Plant. The opinion of probable cost is a summary of estimated costs to perform the decommissioning activities and leave the facility in a safe state. A resource-loaded MS Project schedule was developed for the Missouri City decommissioning. The schedule includes the activity, duration of the activity, resources required for each activity, and the probable cost of each activity. The schedules are provided in Appendix B of this report. Figure 2-1 summarizes the Decommissioning opinion of probable cost.

2.2 OPINION OF PROBABLE COST BASIS

Some decommissioning activities may be performed by IPL's bargaining unit personnel in addition to contractors. The work will be managed by IPL. Man-hour costs for both management and bargaining unit personnel were provided by IPL. At the direction of IPL, the direct man-hour rate was multiplied by 1.29 to account for benefits and overhead loadings.

A 5-percent "Owner Internal Costs" is included in the opinion of probable cost. This line item is included to cover the costs of various internal IPL departments that will charge to the project during the implementation of the decommissioning activities.

A 25-percent "Owner Contingency" is included in the opinion of probable cost. This level of contingency is consistent with Association for the Advancement of Cost Engineering International (AACE International) contingency level guidelines based on the engineering progress completed at the point when the opinion of probable cost was developed.

2.3 DECOMMISSIONING ACTIVITIES

Prior to commencing actual decommissioning activities, a plan, including an environmental assessment, will be developed. This plan will address the laws, ordinances, regulations, and standards governing how ash, slag, and any other wastes are stored and/or removed from the plant site and insure that permits required to complete the decommissioning activities are in place. The retirement plan will address plant safety and plant security during the time interval between plant decommissioning and eventual dismantlement. This plan should include the requirements for periodic inspections to assess the condition and integrity of the plant structures so that contractors can safely dismantle the plant when required. The costs to perform these activities are estimated in the "Pre-Decommissioning Activities" line item of the opinion of probable cost.

The following activities and conditions are required to place the generating facility in a safe, secure weather-tight condition and are included in the opinion of probable cost:

1. All equipment, tanks, vessels, containers, drums, headers, exchangers, and sumps will be drained and vented. Fuel oil, lubricating oil, liquid propane, bulk hydrogen, Halon, liquid ammonia, water treatment chemicals, lab chemicals, cleaning solutions, and Freon will be handled per plant procedures and plant permitting requirements. Man-ways, hand-holes, vents, and drains will be opened to ensure drainage. Drains will remain open. Steps will be taken to eliminate egress for vermin.

2. The coal in the fuel yard will be burned in the boiler prior to final shutdown. The final condition of the fuel yard will be determined as part of the retirement plan and environmental assessment.

3. The electrical sources will be isolated from the facility. The exact details of this scope of work will be determined during the pre-retirement activities phase. If required, 120-volt power will be supplied to the switchyard. The source for this power will be determined as part of the retirement plan. At a minimum, all electrical buses will be disconnected at the source. The medium- and low-voltage switchgear will be racked out by fully withdrawing the circuit breakers. Fuses will be removed, and circuit breakers and disconnect switches will be left in the open position. Motors will be disconnected at the source and motor lube oil will be drained (as applicable).

4. Fuel yard equipment will be cleaned to reduce or eliminate the hazards of fugitive coal dust.

5. To the maximum extent possible, all drains will be emptied and vented. Low-point drains will remain open.

6. City/rural water piping will be cut and capped at the property line.

7. Federal Aviation Agency (FAA) required chimney lighting will be kept in service. The source of electricity for this lighting will be determined as part of the retirement plan.

8. Buildings will be "secured". The determination of the detailed activities required to leave a building in a secure state will be included in the pre-retirement activities. This includes isolating all power sources, draining potable water lines, draining and venting sewage lines, securing doors and windows, capping any means of ingress for vermin, removing hazardous materials, and moving any relevant plant documentation to alternate off-site storage sites.

9. Fuel oil will be drained and removed.

10. Boiler chemicals will be drained and removed.

11. Boilers will be drained. The water and steam side will be vented. The gas side will be vacuumed to remove ash and slag. Drum doors and boiler doors will be left open. Bottom ash systems will be drained, cleaned, and vented.

12. Ductwork will be vacuumed and left opened.

13. Condensate and feedwater piping will be drained and vented.

14. Feedwater heaters will be drained and vented.

15. Deaerator and deaerator storage tanks will be drained and vented.

16. The turbines and condensers will be drained and vented.

17. Turbine lube oil will be removed.

18. The generators will be electrically and mechanically isolated. The generator and exciter cooling water systems will be drained and vented. The generator hydrogen systems will be vented. The hydrogen tank will be disconnected and returned to the rental company.

19. The hydrogen tank will be disconnected and returned to the rental company immediately upon last unit shutdown.

20. Compressed air systems will be drained and vented. Desiccant will be removed from the compressed air dryer systems.

21. Circulating water systems and turbine cooling water systems will be drained and vented. Circulating water chemical feeds will be drained and vented.

22. Baghouse will be opened, cleaned, and vented. Filter bags and cages will be removed.

23. Battery systems will have the battery electrolytes and battery cells removed and disposed.

24. Sewage treatment facilities will be drained, cleaned, and vented.

25. All equipment lubrication oil and coolant reservoirs and piping will be opened, drained, and/or pumped out.

26. Any CO_2 systems used for fire protection will be drained, opened, and vented.

27. Water treatment equipment will be disconnected and returned to the rental company immediately upon last unit shutdown.

28. Water well fields will be closed per current Missouri regulations.

29. Any other activities required by the applicable law, regulation, or permit will be performed.

Once the site decommissioning activities are complete, several months of post-decommissioning activities will begin. These activities include determining the disposition of site documentation, assuring permits are in appropriate compliance status, developing plans to monitor the retired facility, accounting and environmental activities, and re-assigning personnel as required.

Missouri City Decommissioning		
Owner Costs		
Pre-Decommissioning Activities	$ 73,736	
Decommissioning Activities	$ 606,961	
Post-Decommissioning Activities	$ 25,390	
Owner Direct Total		$ 706,087
Owner Internal Cost (5%)		$ 35,300
Owner Contingency (25%)		$ 185,346
Missouri City Decommissioning Opinion of Probable Cost		*$ 926,733*
IPL Internal Costs	$ 759,921	
IPL Contracted Costs	$ 166,811	

Figure 2.1 - Probable Costs for Missouri City Decommissioning

SECTION 3

DISMANTLEMENT

DISMANTLEMENT

3.1 INTRODUCTION

Sega developed an opinion of probable cost of $16,259,289 to dismantle the Missouri City Power Plant. This opinion of probable cost for dismantlement is based on the completion of the decommissioning activities at an opinion of probable cost of $926,733. Therefore, the overall dismantlement opinion of probable cost is the combination of the decommissioning costs plus the dismantlement costs totaling $17,186,022.

The dismantlement opinion of probable cost is a summary of estimated costs to perform the dismantlement activities and remove equipment and building superstructures down to grade-level foundations. Below-grade foundations, piping, and duct banks will be abandoned in place. A resource-loaded MS Project schedule was developed for the dismantlement of the facilities. The schedule includes the activity, duration of the activity, resource required for each activity, and the probable cost of each activity. The schedules are provided in Appendix B. Figure 3-1 summarizes the Dismantlement opinion of probable cost.

3.2 OPINION OF PROBABLE COST BASIS

The project will be managed by IPL staff. IPL will hire an Owner's Engineer to assist with environmental issues and the technical dismantlement details. IPL will hire an abatement contractor to remove hazardous material and a demolition general contractor (DGC) to perform the complete dismantlement of the units.

The opinion of probable cost is presented as the straight netting of the DGC's firm price cost, minus the estimated current (2015) scrap value of the equipment and materials.

At the initiation of dismantlement, this study assumes that Missouri City has been previously decommissioned as detailed in Section 2 - Decommissioning.

Please note that this study does not offer an opinion of probable cost for the closure of the ash pond since this activity will be completed by June 2016.

A resource-loaded MS Project dismantlement schedule and opinion of probable cost were developed for Missouri City.
A 5-percent "Owner Internal Cost" is included in the opinion of probable cost. This line item is included to cover the costs of various internal IPL departments that will charge to the project during the implementation of the dismantlement activities.

A 25-percent "Owner Contingency" is included in the opinion of probable cost. This level of contingency is consistent with the AACE International contingency level based on the engineering progress completed at the point when the cost estimate is developed.

3.3 DISMANTLEMENT ACTIVITIES

The dismantlement of the facility is divided into pre-dismantlement activities, dismantlement activities, and project closure activities.

3.3.1 Pre-Dismantlement Activities

Pre-dismantlement activities consist of the detailed pre-planning of the dismantlement process. This pre-planning includes selecting the IPL project management team; hiring an Owner's Engineer; developing a detailed dismantlement scope of work including how to address any environmental issues; developing a level 1 project schedule; and procuring the contractors to perform the work.

The IPL project management team will be responsible for the project execution and will consist of a full-time project manager, a full-time engineer, a full-time project administrative assistant, and a part-time procurement specialist. This team will have the authority to manage the dismantlement of the plant.

The Owner's Engineer will assist IPL with the technical aspects of executing the project. The Owner's Engineer will help establish the boundaries of demolition, provide environmental consulting, and develop the technical specifications for contract request for proposal(s). The Owner's Engineer will provide one full-time equivalent field engineer during the demolition phase of the project.

The IPL project management team and the Owner's Engineer will review all existing permits to verify that any relevant existing permit requirements are met during demolition. This team will also obtain any additional permits required in place for demolition, if any (outside of the normal permits that are the responsibility of the DGC).

Prior to the dismantlement activities, a specialty contractor will be hired to perform a Detailed Hazardous Material Audit. This audit will quantitatively identify and inventory the hazardous materials on site and will be the basis for the hazardous material contract removal scope of work.

Prior to dismantlement activities, a detailed site characterization study will be performed. This study involves a series of site investigations to determine potential subsurface environmental issues at the site, a description of the hydrological and hydrogeological conditions on the site, and a determination of potential waste streams generated during the demolition work. Based on the outcome of the site characterization study, reclamation and remediation plans that address the environmental issues and site conditions will be developed. The site characterization study and the development of the remediation plans are expected to require up to six months to complete. The site characterization study will be performed by the Owner's Engineer.

The IPL project management team will identify the boundaries of dismantlement and the location of system and equipment isolation points.

The IPL project management team will be responsible for bidding and contracting with a qualified DGC and a qualified hazardous material removal contractor.

Prior to any contractors mobilizing on site, the IPL project management team will confirm that Missouri City is ready to be turned over to the contractors.

3.3.2 Dismantlement Activities

Dismantlement activities will commence once the hazardous material removal contractor is complete.

The demolition contractor will be structured into several crews that will bring equipment and materials to the ground. A separate dedicated crew will be responsible for classifying the scrap by type and removing the scrap from the site.

The units will be demolished in a phased and sequential manner to assure worker safety and to minimize any interferences with surrounding equipment. Please refer to the manpower loaded schedule and graphs in Appendix B for the details of each demolition phase. Both units will be demolished simultaneously. Each activity described in the schedule has a crew assigned for Unit 1 and a crew assigned for Unit 2.

3.3.2.1 Phase 1 Demolition - Boiler and Turbine Equipment Removal

Mechanical and electrical equipment and material inside the boiler and turbine building footprints will be removed. The goal of this phase is to remove the majority of the equipment in the boiler and turbine buildings leaving only the boiler, turbine, building, and structure.

3.3.2.2 Phase 2 Demolition - Boiler and Turbine Removal

The boiler equipment will be removed at the start of this phase. Then, the boiler furnace, backpass, and associated ductwork will be removed from the bottom up (boilers are hung from the top of the boiler structure) and the structure is removed from the top down. Once the structure and all equipment are removed, the boiler equipment foundations will be demolished to existing grade.

Concurrent with the above activities, the turbine, heat exchangers, condenser, and miscellaneous turbine equipment will be removed. The turbine building and turbine pedestal is then demolished to grade.

3.3.2.3 Phase 3 Demolition - Yard Demolition

This phase removes equipment and materials external to the boiler and turbine areas. Underground piping, conduit, and duct banks will be abandoned in place with the exception of the circulating water pipe. The circulating water pipes will be excavated, collapsed by crushing, and then backfilled. Electrical man-holes will be collapsed by crushing and then backfilled. The opinion of probable cost considered site activities that would leave the dismantled portions of the site covered with an average of approximately 2 feet of earthwork but in a state that some existing roads could be utilized in order to maintain access to the existing substation to remain. These covered areas, approximately 10 acres which includes the existing water tank north of the site, would receive a minimum 6 inches of topsoil covering that would be seeded with native grasses that will resist erosion. This effort assumes all required earthwork for the project will be borrowed from an on-site topsoil stockpile location.

Any existing coal in the fuel yard area will be either burned or sold leaving a minimal amount of coal on site. The remaining residual coal will be scraped down to a depth where the exposed soil has not been in contact with coal. The residual coal and soil mixture will be hauled off site to a permitted area, such as a landfill, for such waste. This area will require 6 inches of topsoil covering that will be seeded with native grasses that will resist erosion. See Appendix J for additional fuel yard closure details.

3.3.2.4 Dismantlement Activities of Facilities

The facilities dismantlement activities consist primarily of the removal of chimney, fuel yard equipment, site-specific common equipment, the facility buildings, and coal pile. The removal of the chimney will be the "piece-meal" methodology for safety reasons and to protect and minimize potential damage to the switchyard.

3.3.2.5 Phase 4 - Final Site Grading and Drainage

Final grading and drainage includes a minimum amount of grading. After the residual coal is removed from the fuel yard, top soil is placed and seeding installed. This area will now serve as a retention basin on site for storm water. Reinforced concrete pipe shall be installed from the retention basin to gravity drain back to the existing detention basin on site, requiring a minimal amount of grading inside the retention basin area. All other areas on site will be graded to surface drain to either basin. This will assure that the site drainage facilities remain in place and include final seeding of the site.

Final grading and drainage includes a minimum amount of grading. This will assure that the site drainage facilities remain in place and include final seeding of the site.

3.4 PROJECT CLOSURE ACTIVITIES

This phase of the project confirms that the remediation and reclamation of the site has been successfully completed and that all required "record" documentation, sign-offs, and approvals needed by IPL are complete and on file.

3.5 SCRAP METAL VALUES

Scrap metal weights were developed for Missouri City based on the actual quantities and materials documented.

Please see Appendix C for the opinion of current average scrap values for each unit.

Missouri City Dismantlement[1]		
Owner Costs		
Pre-Dismantlement Activities	$ 328,290	
Overhead During Dismantlement	$ 533,882	
Post-Dismantlement Activities	$ 32,869	
Owner Costs Total		*$ 895,041*
Dismantlement Costs (Contractor)		
Hazardous Material Removal Contract Costs	$ 3,183,960	
Demolition General Contractor (DGC) Costs		
Additional Site Management	$ 581,820	
Equipment Rental	$ 971,954	
Consumables	$ 969,708	
Scrap Crew(s)	$ 980,695	
Dismantlement	$ 3,965,409	
DGC Insurance (2%)	$ 149,391	
Contingency/Profit (15%)	$ 1,142,846	
Performance Bond (2%)	$ 175,236	
Total		$ 8,937,059
Contractor Costs Total		*$ 12,121,019*
Owner and Contractor Direct Total		$ 13,016,060
Owner Internal Costs (5%)		$ 650,803
Owner Contingency (25%)		$ 3,416,715
Missouri City Dismantlement Opinion of Probable Cost		*$ 17,083,578*
IPL Internal Costs	$ 666,255	
IPL Contracted Costs	$ 16,417,323	
Scrap Value		($ 824,289)
Net Terminal Costs (Dismantlement Cost - Scrap Value)		***$ 16,259,289***
Retirement Opinion of Probable Cost		***$ 926,733***
Overall Dismantlement Opinion of Probable Cost[2]		***$ 17,186,022***
[1]All values in 2015 U.S. dollars.		
[2]Retirement opinion of probable cost plus dismantlement opinion of probable cost.		

Figure 3.1 - Probable Costs for Missouri City Dismantlement

SECTION 4

MAINTENANCE OPINION OF PROBABLE COST

MAINTENANCE OPINION OF PROBABLE COST

4.1 OPINION OF PROBABLE COST TO MAINTAIN SITE AFTER DECOMMISSIONING

The opinion of probable cost to maintain the site after retirement is based on the following activities:

1. Weekly ($1,700 Per Month):
   a. Walk down the fence line and intake.
   b. Confirm lights are operational.
   c. Confirm the plant and site are draining properly.
2. Monthly ($750 Per Month): Mow plant site/clear snow
3. Monthly ($250 Per Month): Miscellaneous maintenance.

Total Opinion of Probable Cost to Maintain the Site After Retirement: **$2,700 per month/ $32,400 annually.**

4.2 OPINION OF PROBABLE COST TO MAINTAIN SITE AFTER DISMANTLEMENT

The opinion of probable cost to maintain the site after demolition is based on the following activities:

1. Monthly ($1,150 Per Month):
   a. Walk down the fence line and river.
   b. Confirm the plant and site are draining properly.
   c. Mow plant site/clear snow.

Total Opinion of Probable Cost to Maintain the Site After Demolition: **$1,150 per month/ $13,800 annually.**

SECTION 5

COAL-TO-BIOMASS FUEL SWITCHING

COAL-TO-BIOMASS FUEL SWITCHING

5.1 SUMMARY

Sega previously examined the requirements for converting the Missouri City Power Plant to solid biomass firing in 2013. Sega assisted IPL with responses to proposals it had received at that time from Enginuity of Columbia, Missouri to furnish and test locally developed biomass fuels in the Missouri City boilers. The results of this work are summarized in lieu of a separate coal-to-biomass switching study.

As listed in this summary and further developed in later sections, Sega is of the opinion that it would cost approximately $5.7 million for emissions controls for converting Missouri City Power Plant to biomass fuel or a biomass/coal fuel blend in addition to approximately $15 million for deferred maintenance projects and non-fuel related environmental compliance measures. <u>However, this approximate $20.7 million expenditure does not include the costs for converting the plan's fuel handling systems and boilers to actually burn biomass or a biomass/coal blend</u>.

Based upon Sega's survey of industry experience, conversion or co-firing biomass in a pulverized coal (PC) unit is technically feasible, but could require substantial equipment modifications and possible performance reductions. Sega was unable to identify any PC plants that have utilized an engineered biomass similar to that which Enginuity proposed in 2013 and no PC plant biomass conversions have been identified since then.

However, the cost of equipment modifications and resulting performance capability cannot be determined without test firing biomass in the Missouri City boilers. On-site testing could probably require one year of preparations and are expected to cost between $500,000 to $900,000, not including biomass fuel costs and IPL internal costs. These costs are associated with temporary plant modifications necessary for testing and do not include retrofits and additional equipment and systems that would be necessary for permanent biomass operation. The specifications and costs for permanent modifications to convert the Missouri City Power Plant to biomass cannot be determined with any certainty until the results of a test burn program have been analyzed. Thus, approximately two years of preparation, testing, and analysis would be needed to determine the costs and efficacy of biomass conversions.

5.1.1 Regulatory Requirements/IB MACT Compliance Costs

Sega first examined the air emissions regulatory requirements and cost of compliance with the Industrial Boiler Maximum Achievable Control Technology (IB MACT) rules based on burning 100-percent coal, 100-percent biomass, and a blend of 10-percent biomass/ 90-percent coal mixture (on an annual heat-input basis). In order for the Missouri City Power Plant to comply with IB MACT Rules when burning any amount of coal, dry sorbent injection (DSI) emission controls for Hydrogen Chloride (HCl) will be required. Even if Missouri City were to burn 100-percent biomass, DSI is strongly recommended. Sega is not aware of a biomass fuel that currently exists that is natively compliant with the IB MACT HCl limit. Only the absolute best case theoretical biomass (9,500 Btu/lb., with no more than 0.0002 lb. Cl/lb. coal) could comply without DSI. Due to concerns with biomass fuel development challenges, potential deviation from the fuel design specification, seasonal variability in biomass stocks, sole source of supply of the compliance fuel, and the inherent challenges of 100-percent biomass combustion in PC boilers, DSI is recommended, even for the 100-percent biomass case.

Additional controls for particulate matter (PM) and Mercury (Hg) emissions should not be required for IB MACT compliance whether Missouri City burns coal or biomass. Installation of a PM continuous emissions monitoring system (CEMS) will be required under IB MACT, which should be expected to cost approximately $175,000. It cannot be determined if Missouri City will meet the IB MACT emission requirements for Carbon Monoxide (CO) for any specific fuel without stack testing.

Capital investment for IB MACT HCl compliance will require approximately $5.5 million for a common DSI (lime) system using the existing fabric filter house. Operation and maintenance (O&M) costs would vary with biomass characteristics and fuel blends. For 100-percent, biomass-fired operation, O&M costs are expected to be around $100,000 per year, based on a 10-percent capacity factor. For 100-percent, coal-fired operation, the O&M

costs would be approximately $250,000 per year. These costs vary greatly with the type of fuel combusted and should only be considered as general guidelines. Once a specific fuel blend, coal type, and biomass type are selected, the O&M costs can be refined. However, the capital cost of the DSI system is relatively unaffected by changes in these variables.

Sega expects that Missouri City should be able to comply with the IB MACT Hg limit. However, if Hg controls become necessary due to changes in fuel supply, common Brominated Activated Carbon Injection (BACI) using the existing fabric filter would add approximately $2.3 million of capital investments and increase O&M costs by another $82,000 per year.

These costs would be in addition to any deferred maintenance expenditures or the cost of compliance with non-fuel related environmental regulatory requirements that are addressed separately.

5.1.2 Industry Survey of Biomass in Pulverized Coal Boilers

Second, Sega performed a survey of industry experience with burning biomass in PC boilers. Sega found that there was very little experience with co-firing biomass or full conversion to biomass fuel in PC boilers in the United States. Sega utilized various references for investigating biomass use in PC boilers. Most information available relates to co-firing or co-combusting biomass with coal as opposed to complete conversion to biomass firing. The study reviewed publicly available information from technical presentations, industry publications, and news releases. This included documents published by the Electric Power Research Institute (EPRI), Federal Energy Management Program (FEMP), and the National Renewable Energy Laboratory (NREL). In addition, Sega contacted boiler manufacturers, Doosan and Babcock & Wilcox (B&W), to understand the manufacturer's perspective and leverage their experience with these projects.

Over the years, several tests have been performed in PC units and the conclusion has been made that it is possible with appropriate plant modifications. However, biomass burning has been effectively implemented in boilers with combustion technologies that are more accommodating to biomass, such as stoker type and fluidized bed boilers. Conversion or co-firing in a PC unit is technically feasible, but could require substantial equipment modifications and possible performance reductions. Sega was unable to identify any PC plants that have utilized an engineered biomass similar to that proposed by Enginuity in 2013 and no PC plant biomass conversions have been identified since then.

5.1.3 Biomass Tests Paths for Missouri City

In 2013 two biomass test burn paths were identified; a co-fire test (<15-percent biomass) and a 100-percent biomass firing test. Each would vary in the type of fuel utilized, complexity/risk, level of pretesting and evaluation, cost, and schedule. A co-fire test would be a lower commitment and lower risk option for testing the boilers. This test would utilize pelletized (or other shape) biomass. Some off-site pretesting would be beneficial. This option is a relatively low risk test, but Sega recommended involving a boiler/burner original equipment manufacturer (OEM) in pretest planning and test observation. Testing would likely require at least six months of preparations and should be expected to cost $100,000 to $175,000, not including biomass fuel costs and IPL internal costs. A 100-percent biomass firing test would probably utilize pre-milled granular biomass. A temporary conveying system would pneumatically convey fuel into the existing burners. This option would be more complex and would require extensive off-site pretesting and evaluation. Boiler/Burner and fuel handling OEMs should be engaged. On-site testing could probably require one year of preparations. Costs are expected to be between $500,000 to $900,000 for this testing, not including biomass fuel costs and IPL internal costs. These costs are associated with temporary plant modifications necessary for testing and do not include retrofits and additional equipment and systems that would be necessary for permanent biomass operation. The specifications and costs for permanent modifications to convert the Missouri City Power Plant to biomass cannot be determined with any certainty until the results of a test burn program have been analyzed. Thus, approximately two years of preparation, testing, and analysis would be needed to determine the costs and efficacy of biomass conversions.

5.1.4 Deferred Maintenance and other Modifications

Certain expenditures will be required for continuing operation of the Missouri City Power Plant regardless of fuel. These include deferred maintenance, insurance-required upgrades, and non-fuel environmental regulatory requirements. Sega's opinion of the probable capital costs for the non-fuel related projects required for continuing operations is $15 million. These values are overnight costs stated in 2015 U.S. dollars with an accuracy of ±30 percent.

5.2 INTRODUCTION

The Missouri City Power Plant was originally designed to burn pulverized coal with fuel oil for light-off and back up. In 2013, Sega assisted IPL with responses to proposals it had received from Enginuity of Columbia, Missouri to furnish and test locally developed biomass fuels in the Missouri City boilers. Sega reviewed the modifications that would be necessary and developed opinions of cost for those modifications and the expected performance that would result.

This appendix to the Retirement Study summarizes and describes the previous coal-to-biomass fuel switching study that Sega performed in 2013.

5.3 DEFERRED MAINTENANCE AND OTHER MODIFICATIONS

Since retirement of the Missouri City Plant has been contemplated for nearly a decade, IPL prudently chose to minimize expenditures for major maintenance, plant betterment, insurance-recommended upgrades, or anticipated future environmental regulations for coal-firing. Keeping the Missouri City Plant in service regardless of fuel type will now require significant deferred major maintenance expenditures, as well as insurance and environmental regulatory upgrades, in addition to the actual natural gas conversion project. Also, there are increasingly more stringent environmental regulations independent of fuel, such as new Clean Water Act rules, that must also be satisfied to continue operation of the plant.

This study does not address any heat rate improvement projects for enhancing plant efficiency, capacity, start-up duration, or cycling capability, that could increase the likelihood that these now 60-year old units might be dispatched more often. Such projects to improve competitiveness of the plant in the SPP Integrated Market are not considered in this study, and would add significant costs to those considered in this appendix.

Figure 5.1 - Deferred Project Costs for Biomass Conversion provides expected order of magnitude costs for deferred maintenance projects, insurance-required upgrades, non-fuel related mandatory environmental upgrades, and fabric filter and ash handling system maintenance.

Item	Activity Description	Cost
1	Steam Turbine Generators - Major Overhaul (Rotor Out)	$ 5,000,000
2	Boilers - Major Overhaul	$ 2,000,000
3	Fire Protection Upgrades (Insurance Required)	$ 1,000,000
4	Turbine Water Induction Protection System (Insurance Required)	$ 1,000,000
5	Controls Upgrades to DCS with New BMS/CCS	$ 2,000,000
6	316 (a) & (b) (Regulatory Required Cooling Tower & CW Pumps)	$ 3,300,000
7	Allowance for General Upgrades for Codes and Safety	$ 500,000
8	Fabric Filter Refurbishment	$ 110,000
	Bottom Ash System Repairs	$ 100,000
	Total	**$ 15,010,000**

Figure 5.1 - Deferred Project Costs for Biomass Conversion

5.4 REGULATORY REQUIREMENTS / IB MACT COMPLIANCE COSTS

This is a summary of the IPL Missouri City Power Plant's air regulatory requirements and cost of compliance for IB MACT based on burning 100-percent coal, 100-percent biomass, and 10-percent biomass/90-percent coal on an annual heat-input basis.

5.4.1 Industrial Boiler Maximum Achievable Control Technology

Section 112 of the Clean Air Act (CAA) establishes requirements for major sources of hazardous air pollutants (HAPs). As required by 112(d), the U.S. Environmental Protection Agency (EPA) had previously promulgated the IB MACT Rule (under 40 CFR, Part 63, Subpart DDDDD) on September 13, 2004. This rule was vacated by the U.S. Court of Appeals for the District of Columbia on June 8, 2007. In response to the court's vacatur, a new IB MACT Rule was signed by the EPA Administrator, released on April 29, 2010, and was published in the Federal Register on June 4, 2010. This rule was made final on March 21, 2011. On December 2, 2011, the EPA proposed reconsiderations to the final IB MACT Rule. On December 20, 2012, EPA issued its final ruling for the IB MACT. Missouri City will have to comply with the final IB MACT Rule three years after it is published in the Federal Register, January 31, 2016. IPL may be eligible to request a one-year extension if they choose to comply with the rules requirements instead of shutting down the facility. This memorandum addresses the EPA's final ruling of the IB MACT.

A source owner is subject to this rule if they own or operate an industrial, commercial, or institutional boiler or process heater that is located at a major source of HAPs. A major source facility emits or has the potential to emit more than 10 tons per year (tpy) of any single HAP or more than 25 tpy of any combination of HAPs.

In general, the proposed IB MACT Rule requirements include emission limitations, operational limitations, work practice standards, compliance demonstration requirements, notifications, recordkeeping, and reporting. These requirements differ based on type of fuel burned and boiler configuration.

5.4.1.1 Important Definitions under IB MACT

The IB MACT Rule has a definition section that is important to understand when classifying a particular boiler. The following definitions may apply to IPL based on boiler and fuel type:

1. Hybrid Suspension Grate Boiler: A boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat-input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, Dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

2. Limited-Use Boiler: Any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

3. Stokers/Sloped Grate/Others Designed to Burn Wet Biomass Fuel: The unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20-percent moisture.

4. Stokers/Sloped Grate/Others Designed to Burn Kiln-Dried Biomass Fuel: The unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and not in the wet biomass subcategory.

5. Suspension Burners Designed to Burn Biomass/Bio-Based Solids: A unit designed to fire dry biomass/bio-based solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/bio-based fuel combusted in the unit shall not exceed 20-percent moisture on an annual heat-input basis. Fluidized bed, Dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

6. Other Combustor: A unit designed to burn solid fuel that is not classified as a Dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

7. Units in All Subcategories Designed to Burn Solid Fuel: Any boiler or process heater that burns only solid fuels or at least 10-percent solid fuel on an annual heat-input basis in combination with other fuels.

8. Units Designed to Burn Coal/Solid Fossil Fuel: Includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10-percent coal or other solid fossil fuel on an annual heat-input basis in combination with liquid fuels, gaseous fuels, or less than 10-percent biomass and bio-based solids on an annual heat-input basis.

9. Unit Designed to Burn Biomass/Bio-Based Solid Subcategory: Includes any boiler or process heater that burns at least 10-percent biomass or bio-based solids on an annual heat-input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

5.4.2 Missouri City Units Characterization

Figure 5.2 - Summary of the Missouri City Units is a current summary of the Missouri City units and associated emissions control devices.

Unit	Boiler Type	Size (MMBtu/hr)	Permitted Fuel	Emission Control Device
MC 1	PC	265	Coal, Fuel Oil	Common Baghouse
MC 2	PC	265	Coal, Fuel Oil	

Figure 5.2 - Summary of the Missouri City Units

The classification of the units is an important part of determining the applicability of IB MACT Rule requirements. Boilers are divided into units designed to burn solids, liquids, or gases subcategory fuels. If a unit burns more than 10-percent solid fuel on an annual heat-input basis, then it is classified as a unit designed to burn solid fuel.

The solid fuel subcategory is further divided by type of fuel. If a unit burns more than 10-percent biomass on an annual heat-input basis, then it is considered a biomass unit. If a unit burns greater than 10-percent coal and less than 10-percent biomass, the unit is considered a coal-burning unit. The existing solid fuel and fuel type subcategory is further divided by boiler type, for example stoker versus fluidized bed.

Currently, Units 1 and 2 are considered pulverized coal units under the IB MACT. If Units 1 and 2 burn more than 10-percent biomass on an annual heat-input basis, they would be considered biomass units. The biomass boiler type is more complicated as depending on the moisture content of the fuel and where it completes combustion. The units could be considered either a hybrid suspension grate boiler, suspension burners designed to burn biomass/bio-based solids, stokers/sloped grate/others designed to burn wet biomass fuel, or stokers/sloped grate/others designed to burn kiln-dried biomass fuel.

The biomass that would be burned in Missouri City has a moisture content of less than 20 percent. Since combustion of the biomass would be completed in suspension and not on a grate or the floor of the boiler, Missouri City's PC boilers converted to biomass would most likely be in the other combustor burner category which falls under the stokers/sloped grate/others designed to burn kiln-dried biomass fuel subcategory. If changes are made to the boiler to add a combustion grate or the biomass has a higher percentage moisture, then the boiler burner subcategory could change.

5.4.3 Emissions Limits

Figure 5.3 - Summary of Emission Limits for Units 1 and 2 (Existing Coal-Fired PC Boilers) summarizes the IB MACT Rule emission limits for Units 1 and 2 which are classified existing, solid-fueled, coal-fired PC boilers when burning coal. *Figure 5.4 - Summary of Emission Limits for Units 1 and 2 (Existing Kiln-Dried Biomass-Fired Stoke/Sloped Grate/Other Boilers)* summarizes the IB MACT Rule emission limits for Units 1 and 2 which are classified as an existing, solid-fueled, kiln-dried, biomass-fired stoker/sloped grate/other boilers. The PM emission limit in the IB MACT Rule is for filterable PM only. As an alternative to meeting the PM emission limit, Missouri City can elect to meet the total selected metals (TSM) limit. The total selected metals include arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium. Depending on the biomass fuel analysis, the biomass TSM limit might be easier to comply with the IB MACT limits than the PM emission limit.

Pollutant	Heat-Input Based Limits	Units
Hydrogen Chloride	0.022	lb/MMBtu
Mercury	5.7E-6	lb/MMBtu
PM (Filterable)	0.04	lb/MMBtu
Total Selected Metal	5.3E-5	lb/MMBtu
CO (Stack Test)	130	ppmvd @ 3 percent O_2
CO (CEMS)	320	ppmvd dry @ 3 percent O_2

Figure 5.3 - Summary of Emission Limits for Units 1 and 2 (Existing Coal-Fired PC Boilers)

Pollutant	Heat-Input Based Limits	Units
Hydrogen Chloride	0.022	lb/MMBtu
Mercury	5.7E-6	lb/MMBtu
PM (Filterable)	0.32	lb/MMBtu
Total Selected Metal	4.0E-3	lb/MMBtu
CO (Stack Test)	460	ppmvd @ 3 percent O_2
CO (CEMS)	460	ppmvd dry @ 3 percent O_2

Figure 5.4 - Summary of Emission Limits for Units 1 and 2 (Existing Kiln-Dried Biomass-Fired Stoke/Sloped Grate/Other Boilers)

5.4.4 Projected Compliance Status

The IB MACT compliance status of Missouri City will be dependent on what fuel is burned. Based on data from IPL, the current coal burned at Missouri City has a chlorine content of 0.08 percent and a heating value of 11,046 Btu/lb. Based on available biomass fuel analysis and comments from Enginuity, the biomass has a chlorine content of 0.02 to 0.21 percent and a heating value of 7,000 to 10,000 Btu/lb. *Figure 5.5 - Summary of Emission from Missouri City* is a summary of the IB MACT pollutant emissions based on available stack testing and fuel analysis.

Pollutant	Coal Emissions	Biomass Emissions	Units
Hydrogen Chloride	0.074[1]	0.021 - 0.31[2]	lb/MMBtu
Mercury	2.35E-6[3]	?	lb/MMBtu
PM (Filterable)	0.038[3]	?	lb/MMBtu
CO (CEMS)	?	?	ppmvd dry @ 3 percent O_2
1. Based on current coal analysis. 2. Based on a range of biomass analysis. 3. From stack test(9/11/07).			

Figure 5.5 - Summary of Emission from Missouri City

As seen in Figure 5.5, if Missouri City continued to burn coal, HCl emissions would exceed the IB MACT limits. If Missouri City converted to burning 100-percent biomass, then the HCl emissions would still exceed the IB MACT limits unless the biomass had the lowest chlorine content and highest heating value of the assumed biomass fuel ranges. There is no case where IPL could burn coal and biomass while staying under the IB MACT HCl limits.

It should be noted that this assumes that 100 percent of the Cl in the fuel exists in the stack as HCl. There is the possibility some of the Cl is to be natively captured in the fly ash and not exit the stack, but that is not quantifiable based on available data.

5.4.5 Compliance Demonstration Requirements

The IB MACT Rule will require Missouri City to install a CEMS, conduct stack tests and/or fuel analysis, and track operational parameters to demonstrate compliance with certain emission limits. The specific equipment and demonstration method depends on the boiler unit and the compliance option selected. Additionally, if compliance is demonstrated with a continuous monitoring system, Missouri City must develop a site-specific monitoring plan. A summary of Missouri City's options to demonstrate compliance with each pollutant is shown in *Figure 5.6 - Compliance Options by Pollutant.*

Compliance Option	Pollutant				
	Hydrogen Chloride	Mercury	PM (Filterable)	Total Selected Metal (TSM)	CO
Fuel Analysis[1]	X	X		X	
Stack Testing[2,3]	Method 26 or 26A	Method 29, 30A, or 30B		Method 29	Method 10[5]
Continuous Analyzer[4]	X		X		X

1. Monthly analysis based on 3 samples per mont5.
2. Frequency every 3 years if continue to meet 75 percent of initial emission limits.
3. Must use operating load of each unit that does not exceed 110 percent of average operating load recorded in previous test.
4. Option exempts performance testing and operating limit requirements.
5. Must include O_2 analyzer system maintained below lowest hourly average O_2 concentration measured.

Figure 5.6 - Compliance Options by Pollutant

IB MACT regulation requires the installation of a PM CEMS which is expected to cost approximately $150,000.

5.4.6 Operational Limits and Work Practice Standards

Missouri City will have to meet a variety of operational limits and work practice standards. *Figure 5.7 - Operating Limits and Work Practice Standards* identifies which standard is required for Missouri City.

Unit	Operating Limits	Work Practice Standards	
		One-Time Energy Assessment	Annual Boiler Tune-Up
MC1 & MC2	Bag leak detection system[1] or Opacity <10 percent[2]	X	X
1) Alarm must not sound more than 5 percent of operating time during each 6 month period. 2) Daily Block Average.			

Figure 5.7 - Operating Limits and Work Practice Standards

5.4.7 Construction Permitting Requirements

Air construction permitting requirements could be triggered if IPL chooses to retrofit or modify one or more of the boilers in order to burn biomass. Changes made to the facility by modifying the emission sources, installing emission reduction equipment, or other associated facility changes may trigger certain air quality permitting requirements. IPL will be required to follow a permitting process because of these changes, and regulatory agency approval may be required prior to the start of construction. At a minimum, an applicability determination will need to be made for the specific action to be taken.

5.4.7.1 New Source Performance Standards

Burning biomass by IPL could trigger regulatory and emission limit requirements under Section 111 of the CAA. These requirements are found in 40 CFR, Part 60 - New Source Performance Standards (NSPS).

If the modifications trigger the applicability criteria, they would be subject to 40 CFR, Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Subpart Db applies to boilers that commence modification or reconstruction after June 19, 1984 and that have a heat-input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr. In order to assess if the retrofit of the boilers is subject to this NSPS, the definition of modification must be understood. The definition of modification under NSPS is a physical change or change in the method of operation that results in an increase in hourly emissions to which the standard applies. Use of an alternate fuel, if prior to the applicability date of Subpart Db (June 19, 1984) the existing facility was designed to accommodate that alternative fuel, shall not be considered a modification. So if IPL could burn biomass without modification to the boiler prior to June 19, 1984, then it will not be considered a modification to burn biomass. For this study, it is assumed that the boiler could burn up to 10-percent biomass prior to June 19, 1984. If burning 100-percent biomass increases either the NO_X, SO_2, or PM hourly emissions rate, this would trigger modification under NSPS.

The Subpart Db NSPS could also be triggered for NO_X, SO_2, and PM if the biomass retrofit project would be considered a reconstruction of the boiler unit. The definition of reconstruction under NSPS is when an installation's components are replaced to such an extent that the fixed capital cost of the new components exceeds 50 percent of the capital cost of constructing a comparable new boiler.

5.4.7.2 Prevention of Significant Deterioration

The facility is located in Missouri City, Missouri which has been designated by the EPA as "attainment" for all criteria pollutants; thus, the Prevention of Significant Deterioration (PSD) rules apply to new major sources and major modifications at existing major sources. The facility is considered an existing major PSD source because its potential annual emission of at least one PSD pollutant is greater than 100 tpy. As such, modifications at the facility that result in "significant" emission increases are subject to PSD permitting. Use of an alternate fuel, if prior to January 6, 1975 the existing facility was designed to accommodate that alternative fuel, shall not be considered a modification. For this study, it is assumed that the boiler could burn up to 10-percent biomass prior to January 6, 1975. It should be noted that burning up to 10-percent biomass would not be considered a modification of the boiler. Other changes at the facility, including material handling, would still need to be evaluated for PSD applicability.

Burning 100-percent biomass would be considered a modification. Thus, any potential emission increases resulting from the retrofit of the boilers need to be compared to the PSD significant emission rate (SER) to determine if PSD permitting may be required. This applicability is determined on a pollutant-by-pollutant basis. If triggered, PSD permitting requirements apply to only the pollutants that increase beyond the SER.

In order to evaluate if a project exceeds an SER to trigger PSD review, the "actual-to projected-actual" applicability test would be used on a pollutant-by-pollutant basis. In this test, the baseline (past) actual emissions at the facility would be compared to the projected (future) actual emissions of the modified facility. In addition to the boilers, other sources that are part of the project also need to be included in this applicability test. PSD permitting focuses on emissions changes caused by the entire project, not just the changes made to the boilers. All additional emission sources created by this project will need to be evaluated for their impact on PSD permitting. Since the facility has a low capacity factor, its past actual emissions are low which leads to PSD being triggered more easily.

The addition of new biomass material handling sources also creates new sources of PM. New sources would include the biomass haul roads, storage piles or silos, and the transfer points for the biomass. These additional sources would need to be evaluated for PSD permitting. This study will not assess specific annual emission increases from all these sources. However, depending on how much biomass is burned, these emission sources might be significant and might require PM reduction options such as the paving of haul roads or enclosing material transfer points.

5.4.8 National Ambient Air Quality Standards

The National Ambient Air Quality Standards (NAAQS) is a U.S. EPA ambient air standard designed to protect public health and welfare. There are primary and secondary standards for six criteria pollutants (Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particulate Matter, and Sulfur Dioxide). The U.S. EPA frequently reviews, and if necessary updates, these standards to ensure that they continue to protect public health and welfare. Recently, the U.S. EPA revised the primary or secondary PM2.5, SO_2, NO_2, and ozone standards.

5.4.8.1 SO_2 NAAQS

The recently revised NAAQS for SO_2 could impact the facility. On June 2, 2010, the EPA established a new one-hour SO_2 standard of 75 parts per billion (ppb). This new standard replaced the existing primary standards of 140 ppb (24-hour standard) and 30 ppb (annual standard). If the facility causes or contributes to an area being designated non-attainment for this standard, then the Missouri Department of Natural Resources (MDNR) might require the facility to install additional air pollution control equipment. SO_2 NAAQS will not be a concern if the facility burns 100-percent biomass.

Recently, MDNR recommended that a section of Kansas City, Missouri be declared non-attainment for SO_2. This section does not include the facility, but the facility may impact this non-attainment area. MDNR will be required to issue a State Implementation Plan (SIP) to bring the area into attainment status that might require SO_2 reductions from facilities in the area.

5.4.8.2 NO_2 NAAQS

The recently revised NAAQS for NO_2 could impact the facility. On January 22, 2010, the EPA established a new one-hour NO_2 standard of 100 ppb. The EPA also retained the current annual average NO_2 standard of 53 ppb. The U.S. EPA has indicated they will rely on the use of ambient air monitoring (three years) to demonstrate compliance with the standard. If the facility causes or contributes to an area being designated non-attainment for this standard, then MDNR might require the facility to install additional air pollution control equipment.

5.4.8.3 Ozone NAAQS

The U.S. EPA issued an eight-hour ozone NAAQS in July 1997. The eight-hour ozone standard was 0.08 ppm, averaged over eight hours. Because of rounding, this standard was essentially 0.084 ppm in practice. This standard is based on the average of the highest values measured over the previous three years. In 2008, the U.S. EPA lowered the NAAQS for ozone to 0.075 ppm. The U.S. EPA was scheduled to again lower the standard in 2013; however, President Obama has instructed the U.S. EPA to cancel plans for this revision. This revision will most likely take place in 2014.

5.4.8.4 PM NAAQS

In July 1997, the EPA issued a NAAQS for fine particles ($PM_{2.5}$), or particles less than 2.5 micrometers in diameter. The standards included an annual limit of 15 $\mu g/m^3$ designed to mitigate health effects caused by long-term exposure, and a 24-hour limit of 65 $\mu g/m^3$ to provide additional protection on days with high peak concentrations. In September 2006, the EPA strengthened this 24-hour standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ while retaining the annual standards of 15 $\mu g/m^3$ of $PM_{2.5}$ and 150 $\mu g/m^3$ of PM_{10}, or inhalable coarse particles smaller than 10 micrometers. Per the latest update of this rule in December 2012, the EPA retained the 24-hour standard of 35 $\mu g/m^3$ and further strengthened the $PM_{2.5}$ annual standard to 12 $\mu g/m^3$. These standards are based on a three-year average of annual mean concentrations.

5.4.9 Emissions Control Technologies

Only emissions control technologies for IB MACT compliance were considered in this analysis. Compliance with the other environmental regulations discussed in this document has not been considered. These additional regulations were not considered due to the unknown compliance timelines and the uncertain applicability of the regulations at Missouri City.

5.4.9.1 CO Emissions Control

A detailed analysis of CO emissions controls is not possible. The current CO emissions from the units are unknown. Performing emissions testing for CO IB MACT compliance is recommended. If the current CO emissions do not meet the IB MACT limit, limited options are available. The primary method of limiting CO emissions is combustion tuning. Post-combustion control of CO emissions is not feasible on solid-fuel units. It is expected that biomass blending will impact CO emissions negatively, but some relief is provided by the higher IB MACT CO limit for units classified as biomass burning (at least 10-percent biomass, by annual heat input). It is important to note that the NO_x reduction performance of potential future low NO_x burners to address NO_2 NAAQS will likely be limited by both the IB MACT CO emissions limit and burning biomass.

5.4.9.2 HCl Emissions Control

HCl is an acidic gas formed due to chlorine content in the fuel strongly competing for available hydrogen in the fuel. Once formed, HCl remains in the gas phase and is strongly acidic. There are two main pathways to reduce HCl emissions: reduce the chlorine content in the fuel or remove the HCl from the flue gas after combustion. Sega is unaware of a financially viable method of removing chlorine from coal prior to combustion.

Post-combustion reduction of HCl is achieved by contacting the acidic HCl gas with an alkali reagent. HCl is much easier to remove than SO_2, which similarly forms an acidic gas from the sulfur content in the fuel. Because the control technology for these two acid gases is the same, it is not possible to remove only HCl; some SO_2 will be co-removed, leading to decreased HCl removal efficiencies. For Missouri City, this means burning higher sulfur fuels will increase the operating costs associated with IB MACT HCl compliance. Beneficially, biomass fuels tend to have lower sulfur content than bituminous coals.

The HCl removals achievable with DSI of lime typically vary from 60 to 90 percent and are very dependent on flue gas temperatures, HCl inlet concentrations, and residence time. If lime is not sufficient to achieve HCl compliance, removals of 80 to 98 percent are achievable with DSI of Trona or milled sodium bicarbonate. However, these reagents must be purchased at a cost premium and suffer an O&M cost penalty due to their higher affinity for SO_2 co-removal.

5.4.9.3 Hg Emissions Control

Mercury (Hg) in the fuel is vaporized in the combustion process. The vaporized Hg can be removed from the flue gas through the use of powdered activated carbon (PAC) injection in conjunction with a particulate control device. Based on the available historical emissions information, Missouri City is expected to be in compliance with the IB MACT Hg emission limit. However, the cost of an activated carbon injection (ACI) system for Hg control has been provided in this analysis for reference.

5.4.9.4 PM Emissions Control

Based on the information provided to Sega, Missouri City is currently in compliance with the future IB MACT PM limit. MC1 and MC2 have a common fabric filter, which is the best available control device for PM. If PM emissions reductions are needed in the future, the following fabric filter improvement options should be considered: bag replacement, tube sheet leak repair, cold air in-leakage prevention, acid gas management, and cleaning cycle optimization.

Traditionally, the industry has demonstrated a preference of using electrostatic precipitators (ESP) instead of fabric filters when firing biomass. This preference is due to the potential for fire in the fabric filter systems due to smoldering biomass exiting the furnace and impinging on the collection bags while still burning. A fire suppression system is recommended if Missouri City burns biomass.

5.4.9.5 Emissions Control Summary

Regardless of the level of biomass blending and type of biomass fuel, Sega recommends DSI for additional HCl control based on conservative assumptions, limited biomass information, and unknown demonstration testing results. Additionally, a fire suppression system should be added to prevent fabric filter fires. Further testing of these boilers is recommended prior to finalization of the specific compliance options. The compliance options can be revisited and costs adjusted accordingly after these tests are conducted and results reviewed.

5.4.10 Cost of Emissions Controls

Sega has obtained budgetary quotations for the considered air quality control (AQC) equipment from various technology suppliers in the AQC market. These budgetary quotations are from units similar to Missouri City Units 1 and 2 and have been used to prepare the cost estimates. Excluded from these budgetary estimates were the costs of construction and Owners' costs.

The equipment makes up only a portion of the total capital investment associated with the installation of new air pollution control equipment. Installation and erection costs vary greatly by air pollution control technology and site-specific factors. The large number of facilities required to comply with upcoming regulations is expected to further increase the cost of both materials and labor. Therefore, it is important to realize that these quotations may become quickly obsolete in a rapidly escalating marketplace.

The final cost consideration of any major capital project is the indirect costs. These are the costs incurred during the course of the project that are not equipment and installation costs. The indirect costs are typical on all major projects and while difficult to estimate at a study level, the aggregate of all these costs tends to be fairly consistent for similar AQC retrofits. These costs have been estimated based on previous project experience and good engineering practices since firm pricing information availability for such costs is unavailable.

There are potentially other balance-of-plant (BOP) issues that will be a part of any significant AQC retrofit project. The items in this section were not considered in this study as they are beyond the scope of detail in this analysis. The all-in capital cost estimates prepared by Sega have an accuracy of ±30 percent. This level of certainty is consistent with the EPA's Office of Air Quality Planning and Standards (OAQPS) guidance on study cost estimates.

The cost estimates for DSI for HCl control and ACI are provided on the following pages.

IPL, Missouri City - Units 1 and 2					
Common Dry Sorbent Injection System (Lime) with Existing Fabric Filter					
Cost Categories					**Comments**
A	**Equipment**			**{$}**	
A1	Reagent Storage and Handling			Included	Engineering Est
A2	Reagent Injection System			1,700,000	Engineering Est
A3	Field Engineering Service Time			Included	Engineering Est
A5	Auxiliary Electrical Equipment (Breakers, Switchgear, Etc.)			34,000	2% of A2
A6	Instrumentation and Controls			75,000	Engineering Est
A7	Sales Tax			Exempt	@ 7% of Capital
A8	Freight			90,000	5% of Capital
	Subtotal Equipment Cost			**1,899,000**	**[A]**
B	**Installation**				
B1	Handling and Erection			855,000	45% of [A]
B2	Demolition/Relocation			75,000	Engineering Est
B3	Mechanical Piping (Material and Installation)			456,000	24% of [A]
B4	Insulation and Lagging (Material and Installation)			228,000	12% of [A]
B5	Electrical (Material and Installation)			152,000	8% of [A]
B6	Instrumentation and Control Installation			133,000	7% of [A]
B7	Supports, Walkways, Platforms, and Stairways			114,000	6% of [A]
B8	Painting			19,000	1% of [A]
	Subtotal Installation Cost			**2,032,000**	**[B]**
C	**Project Indirect Cost**				
C1	Owner's Engineer			190,000	10% of [A]
C2	Owners Costs (Spare Parts, Management, Etc.)			152,000	8% of [A]
C3	Construction and Field Expenses			183,000	9% of [B]
C4	Contractor Fees			81,000	4% of [B]
C5	Start-Up and Performance Testing			75,000	Engineering Est
C6	Contingency			393,000	@ 10% of [A] + [B]
	Subtotal Indirect Cost			**1,074,000**	**[C]**
D	**Capital Expenditures Summary**				
[A]	Equipment	38%	of total	1,899,000	
[B]	Installation	41%	of total	2,032,000	
[C]	Indirects	21%	of total	1,074,000	
	Capital Cost			**5,005,000**	**[D] = [A]+[B]+[C]**

Figure 5.8 - Cost for HCl Compliance

IB MACT HCl compliance will require a capital investment of approximately $5 million. The estimated O&M costs vary with biomass characteristics and fuel blends. For 100-percent, biomass-fired operation, O&M costs are expected to be around $100,000 per year, based on a 10-percent capacity factor. For 100-percent, coal-fired operation, the O&M costs would be approximately $250,000 per year. These costs vary greatly by the type of fuel combusted and should only be considered as general guidelines. Once a specific fuel blend, coal type, and biomass type are selected, the O&M costs can be refined. However, the capital cost of the DSI system is relatively unaffected by changes in these variables.

IPL, Missouri City - Units 1 and 2					
Common Brominated Activated Carbon Injection (BACI) with Existing Fabric Filter					
Cost Categories					**Comments**
A	**Equipment**			**{$}**	
A1	ACI Equipment			750,000	Engineering Est
A2	CFD Flow Model			50,000	Engineering Est
A3	Storage and Unloading Facilities			Included	Engineering Est
A4	Instrumentation and Controls			15,000	2% of [A1]
A5	Sales Tax			Exempt	@ 7% of Capital
A6	Freight			41,000	@ 5% of Capital
	Subtotal Equipment Cost			**856,000**	**[A]**
B	**Installation**				
B1	Handling and Erection			385,000	@ 45% of [A]
B2	Mechanical Piping (Material and Installation)			154,000	@ 18% of [A]
B3	Electrical (Material and Installation)			51,000	6% of [A]
B4	Instrumentation and Control Installation			34,000	4% of [A]
B5	Supports, Walkways, Platforms, and Stairways			103,000	@ 12% of [A]
	Subtotal Installation Cost			**727,000**	**[B]**
C	**Project Indirect Cost**				
C1	Owner's Engineer			68,000	@ 8% of [A]
C2	Owners Costs			68,000	@ 8% of [A]
C3	Construction and Field Expenses			65,000	@ 9% of [B]
C4	Contractor Fees			29,000	@ 4% of [B]
C5	Start-Up and Performance Testing			50,000	Engineering Est
C6	Contingency			190,000	@ 10% of [A] + [B]
	Subtotal Indirect Cost			**470,000**	**[C]**
D	**Capital Expenditures Summary**				
[A]	Equipment	41.7%	of total	856,000	
[B]	Installation	35.4%	of total	727,000	
[C]	Indirects	22.9%	of total	470,000	
	Capital Cost			**2,053,000**	**[D] = [A]+[B]+[C]**
E	**Variable Annual Cost**				
E1	Reagent			26,000	27 lbs/hr of carbon
E2	Aux. Electrical			1,000	10 hp blower
E3	Water			0	
E4	Waste Treatment/Disposal			0	27 lbs/hr added waste
	Subtotal Variable Annual Cost			**27,000**	**[E]**

IPL, Missouri City - Units 1 and 2					
Common Brominated Activated Carbon Injection (BACI) with Existing Fabric Filter					
F	**Fixed Annual Cost**				
F1	Operations			25,000	25% of FTE
F2	Maintenance			25,000	25% of FTE
	Subtotal Fixed Annual Cost			**50,000**	**[F]**
G	**Annual Expenditures Summary**				
[E]	Variable Annual Cost	35%	of total	27,000	
[F]	Fixed Annual Cost	65%	of total	50,000	
	Annual Cost			**77,000**	**[G]=[E]+[F]**

Figure 5.9 - ACI System Cost

Missouri City is expected to comply with the IB MACT Hg limit. The ACI system information presented in *Figure 5.9 - ACI System Cost* is for reference only.

5.4.11 Regulatory Timeline

An update of the regulatory timeline is shown in *Figure 5.10 - Updated Regulatory Timeline*. For continued operation at MC1 and MC2, a capital expenditure of $5 million (2013 dollars) will be required for DSI by 2016. Low NO_X burner/overfire air will be required by 2019, selective non-catalytic reduction by 2020, and a closed-loop evaporative cooling system by 2020. An update of the costs provided in the Master Plan was not part of the scope of this analysis.

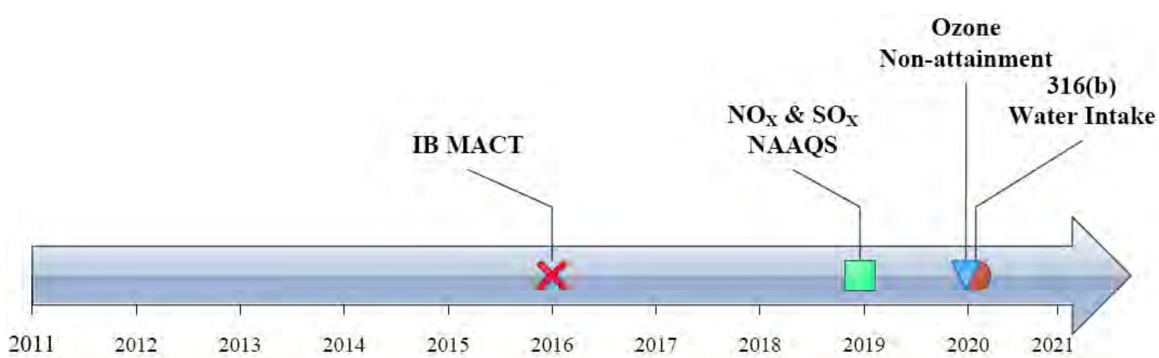

Figure 5.10 - Updated Regulatory Timeline

5.4.12 Conclusion

In order for IPL Missouri City to comply with the IB MACT when burning any amount of coal, HCl emission reduction by DSI will be required. Even if IPL burns 100-percent biomass, DSI is strongly recommended. Sega is not aware of a biomass fuel that currently exists that is natively compliant with the IB MACT HCl limit. Only the absolute best case theoretical biomass (9500 Btu/lb, 0.0002 lb Cl/lb coal) would comply without DSI. Due to concerns with biomass fuel development challenges, potential deviation from the fuel design specification, seasonal variability in biomass stocks, sole source of supply of the compliance fuel, and the inherent challenges of 100-percent biomass combustion in PC boilers, DSI is recommended, even for the 100-percent biomass case.

Whether IPL burns coal or biomass, PM and Hg emissions should not require any additional emission control equipment. However, the IB MACT regulation requires the installation of a PM CEMS, which is expected to cost approximately $150,000. It is unknown if Missouri City will meet the CO emission requirements without stack testing.

5.5 INDUSTRY SURVEY OF BIOMASS IN PULVERIZED COAL BOILERS

This summarizes Sega Inc.'s (Sega) survey of industry experience with burning biomass in pulverized coal (PC) boilers. This document was prepared for the City of Independence, Missouri Power and Light Department's (IPL) initiative to investigate options for burning biomass in the PC units at the Missouri City Power Plant.

5.5.1 Survey Approach

Sega has used various references for investigating the biomass use in PC boilers. Most information available relates to co-firing or co-combusting biomass with coal as opposed to complete conversion to biomass firing. This study reviewed publicly available information from technical presentations, industry publications, and news releases. This includes published documents by the Electric Power Research Institute (EPRI), Federal Energy Management Program (FEMP), and the National Renewable Energy Laboratory (NREL).

In addition, Sega worked with boiler manufacturers, Doosan and Babcock & Wilcox (B&W), to understand the manufacturer's perspective and leverage their experience with these projects.

5.5.1.1 Steam and Electrical Production Facilities with Biomass

Biomass combustion in solid-fuel boilers is well documented within the United States and across the world. Biomass can be the primary fuel or can be co-fired with other solid fuels, normally coal. Fluidized bed boilers and stoker boilers are the most common boiler technologies for use with biomass due to the nature of combustion and the ability to introduce fuel into the boiler with minimal processing. PC boilers and cyclone boilers less frequently utilize biomass. The goal of this review was to find examples of steam and electrical production facilities that utilize biomass in PC boilers; either through co-firing, co-combustion, or use of biomass as the primary fuel.

B&W and Doosan were both unfamiliar with any facilities in the United States that currently continually burn biomass in a PC boiler. Both manufacturers acknowledged that several plants have tested co-firing or co-combustion to a limited extent, but were not aware of plants that used biomass fuel in this application on a continual basis. They both acknowledged that wood chips (approximately 4,500 Btu/lb and 40- to 50-percent moisture) or wood pellets (approximately 7,000 Btu/lb and 10-percent moisture) were the most common forms of biomass used.

Doosan has more experience with biomass firing in PC units outside of the United States. They are currently participating in a project for Ontario Power Generation Inc. (OPGI) at the Atikokan Plant in Ontario, Canada where they are responsible for the conversion of a lignite-fired PC unit to full biomass firing. This is summarized following. In addition, they acknowledged that this was a more common practice in Europe, particularly due to financial incentives and renewable standards.

5.5.1.2 OPGI Atikokan PC Boiler Conversion

The OPGI Atikokan plant is a nominal 215-MW plant that was installed in 1985. This plant utilizes a wall-fired B&W PC boiler designed to fire lignite fuel. OPGI is proceeding to convert this unit to 100-percent biomass firing to meet environmental and renewable goals, to positively impact the local forestry sector and local jobs, because the conversion was more cost effective than building a new gas plant, and it added some flexibility to their fleet.

This conversion project started in January 2010 and is expected to be operable later this year. Per Doosan, the plant was able to reach 100-percent biomass firing rate during testing prior to a major dust explosion. Since that time, they have proceeded with a conversion that includes measures to prevent dust explosions during normal operation.

The project budget is approximately $175 million, which includes $75 million for a pellet plant and internal OPGI costs and $100 million for the conversion itself. Conversion costs are highly dependent on the type of boiler to co-fire biomass, the fuel handling and processing system, and the type of biomass. *Figure 5.11 - Biomass Conversion Cost Rules of Thumb* following presents "rules of thumb" conversion costs for converting a PC plant to fire biomass, as presented by EPRI and Doosan.

Method of Plant Conversion	Doosan	EPRI
Co-Firing Biomass (<20% By Heat Input)*	$200/kW	$100 to $500/kW
Biomass Conversion	$450 to $600/kW	$900 to $1,500/kW
New Biomass Stoker Unit	$3500 to $4,000/kW	$2,600 to $3,000/kW
* Without separate fuel feed		

Figure 5.11 - Biomass Conversion Cost Rules of Thumb

Per 2003 documentation, the plant was originally designed to use a low-sulfur lignite fuel with an equivalent HHV of 7,100 Btu/lb. Through this conversion, the plant will begin wood pellets which would be expected to have a similar heating value as lignite. This similar fuel heating value was more accommodating to the conversion. The boiler furnace was sized for the lower Btu lignite fuel which allowed them to avoid a de-rate of the unit.

The conversion is requiring the installation of a new fuel handling system for the biomass that includes a biomass fuel unloading facility, storage silos, transfer building, and a series of conveyers. The plant is expected to burn approximately 100,000 tpy.

Prior to this conversion, the plant operated with a capacity factor of approximately 9 percent. OPGI plans to continue operating with a similar capacity factor after the conversion.

Following are some specific changes that are being made to the combustion system at Atikokan, as presented by Doosan:

1. New wall-fired burners including natural gas, ignitors, and scanners.
2. Pulverizers modified for wood pellets.
3. Upgrading fuel feeders and rotary valves.
4. ESP internals and T/R sets changes.
5. Modifying ash systems (both bottom and fly ash).
6. Installing primary air cooler (heat recovery system) to lower the primary air temperature.
7. Upgrading mill fire and explosion detection and suppression.

5.5.1.3 AES Greenidge Station, Unit 6, Dresdon, New York

Another example of biomass co-firing in a PC boiler was identified at the AES Greenidge Station. Unit 6 of this plant was a tangentially fired PC boiler with a capacity of 108 MW. In 1994, they began a co-firing test program to burn wood waste in their PC boiler which produced steam at 665 kpph at 1465 psig and 1,005 degrees F. Original tests were conducted with sawdust that was unloaded directly into the fuel feed hopper. A coal burner was later replaced with a “wood fuel pipe” for injection into the boiler. This program was successful and they started to burn woody biomass at 5 percent by heat input in a new biomass fuel feed system that utilized a hammer mill to reduce fuel to a 1/8-inch size.

The biomass was received at 2 to 3 inches in size, varied from 10- to 40-percent moisture, and varied in energy content from 4,500 to 8,000 Btu/lb. At that time, co-firing rates of nearly 10 percent were possible, but mill upgrades were required to maintain a 10-percent co-fire rate. It appears that the plant was burning bituminous coal.

The plant utilized a cyclone separator and ESP for emissions controls. During original biomass testing, the CEMS indicated reductions in NO_X emissions and SO_2 emissions. In addition, ESP operation did not appear to be affected adversely.

Preliminary estimates indicated that the net plant heat rate would increase by 1 to 1-1/2 percent at a 10-percent co-fire rate and would increase by 10 percent for a full biomass. Over the years, the plant invested in biomass firing and increased the co-firing capability. However, additional operating and testing data could not be found publicly. In March 2011, the plant was closed due to economic conditions.

5.5.1.4 EPRI Testing at Various Plants

In the late 1990s, EPRI worked with several utilities to test co-firing in 10 different utility scale boilers. A summary of the tested units is available in *Figure 5.12 - Tests sponsored…within the DOE/EPRI Program* below, from the EPRI "Utility Coal-Biomass Co-Firing Tests" document. Three of the tested units were wall-fired PC units: TVA Colbert Plant, GPU Seward Plant, and MG&E Blount Street Plant.

Utility and Plant	Boiler Capacity and Type, MWe (Firing 100% Coal)	Biomass Heat Input	Biomas sMW	Biomass Type	Average Biomass Moisture	Range of Biomass Moisture
TVA Allen	272, Cyclone	10%	27	Sawdust	44%	14-48%
TVA Colbert	190, Wall-Fired	1-1/2%	3	Sawdust	44%	30-50%
NYSEG Greenridge	108, Tangential	10%	10	Wood	30%	20-50%
GPU Seward	32, Wall-Fired	10%	3	Sawdust	44%	10-52%
MG&E Blount St.	50, Wall-Fired	10%	5	Switchgrass	10%	8-13%
NIPSCO Mic5. City	425, Cyclone	6-1/2%	28	Urban Wood Waste	30%	15-45%

Figure 5.12 - "Tests sponsored…within the DOE/EPRI Program"

Conclusions from this testing include the following:

1. SO_2 and CO_2 reductions achieved with co-firing are directly related to the quantity and chemical contents of coal displaced by biomass.

2. Boiler efficiency with co-firing is normally slightly lower due to higher fuel moisture.

3. A trend of lower NO_x emissions was observed with increased co-firing up to co-fire rates of 10 percent by heat input.

EPRI continued their testing in the Seward plant to confirm these conclusions. In addition, they concluded that it was more cost effective for larger plants (>100 MW) to co-fire compared to the test plant at 32 MW. EPRI has continued to perform renewable energy tests since that time and publish a "Renewable Energy Technical Assistance Guide" on a regular basis.

5.5.2 Biomass Processing, Storage, and Handling Considerations

5.5.2.1 Biomass Density

Biomass bulk density is much lower than for coal. For a woody biomass, it may take 7 to 8 times the volume of the biomass for the same energy input of coal. This requires additional space for processing and storage. In addition, this requires greater quantities of delivery vehicles for the fuel. This requirement would be lower with a higher density processed biomass, including torrefied wood. Doosan provided a rule of thumb that approximately 5,000 tons/year is required for every MW generated.

5.5.2.2 Fuel Particle Size

According to B&W, biomass firing in a PC unit requires a maximum particle size of 1/16 inch for effective suspension burning (assuming a relatively low moisture wood fuel). Fuel grindability needs to be considered. This typically results in a 1 to 1-1/2 second residence time in the furnace. Oversized biomass results in higher amounts of unburned biomass in the bottom ash and fly as5. If incomplete combustion occurs, carryover embers could result in a fire or safety hazard. According to B&W, this has not been a common problem.

5.5.2.3 Water Considerations

Most biomass fuel handling experience in the United States is based on using wood pellets or wood chips. Wood pellets/chips and other biomass, without specialized processing, are hydrophilic by nature meaning they absorb water. Thus, this biomass requires special handling to prevent exposure to water, including covered conveyors or bucket elevators, silos, covered unloading facilities, and "closed" means of transportation. Some biomass has been processed to allow it to become hydrophobic which means they tend to repel water. In these cases, biomass can be handled more similarly to coal.

5.5.2.4 Mills/Pulverizers

Colorado Springs Utilities performed a fuel feed test to their PC boilers using 1/2-inch wood chips. The test included processing these wood chips with coal (co-milling) in a hammer mill as well as processing them in a B&W EL-model pulverizer (rolling race ball mill). The plant was able to process through the hammer mill with some success. However, processing the chips in the B&W EL-model pulverizer resulted in "flattened woody biomass" with particles that "plugged the pulverizer" which was deemed a failed test. B&W and Doosan both provided feedback that hammer mills are much more appropriate for processing biomass than ball mills. While it is possible to use ball mills, they are more problematic.

If existing mills are used to process biomass, they will experience a de-rate on their capacity due to the lower fuel density. Through this review, no plants were identified that delivered biomass fuel to the plant in a pulverized form. Doosan was unfamiliar with any plants that used this method, but expressed concerns of explosion potential. EPRI testing did include pneumatically conveying sawdust into some of the boilers.

5.5.2.5 Explosion Potential

Biomass is inherently "dusty" and is a cause for concern for safety related to combustible dust that results from processing and handling. The Atikokan plant had a major combustible dust explosion on their tripper deck during their recent biomass firing test. While this did not result in injury or major equipment damage, it highlights a safety matter related to the different explosion characteristics between coal and biomass dust. The Atikokan plant has not run with biomass since this event and has incorporated substantial deflagration prevention and mitigation measures into their biomass conversion project.

Several NFPA standards exist to address combustible dust and mitigation devices, including NFPA 654, NFPA 68, and NFPA 69. Biomass explosibility testing at test laboratories can provide insight into the level of risk. Biomass co-fire tests should address combustible dust concerns and biomass handling systems should include measures to reduce explosion potential, including deflagration vents, mechanical dust removal devices, or other measures.

5.5.3 Boiler Performance and Plant Considerations

5.5.3.1 Methods of Combustion

There are several methods by which biomass can be used as a fuel in the combustion process for a PC boiler. This includes fuel handling approaches where the coal and biomass are processed and injected into the boiler in separate burners (called co-combustion). This also includes approaches where biomass and coal are blended prior to injection into the boiler. If they are blended upstream of the mills, it is called co-milling. If the biomass and coal (regardless of processing) are fired in the same burner, it is called co-firing.

For PC boilers, co-milling and co-firing limit the amount of biomass that can be combusted due to limitations on the existing processing equipment. According to the FEMP, this results in co-fire rates that are typically less than 5 percent of biomass by heat input. These arrangements are the least costly, but are limited by the fuel handling equipment and burners. According to FEMP, co-combustion of 5- to 15-percent biomass can be achieved, but “a separate injection system is normally required.” This may require a separate biomass fuel handling system and even new burners. Per Doosan, natural gas is often still used for startup and stabilization.

5.5.3.2 Combustion Air and Burners

Primary air requirements are higher for biomass fuels than for coal fuels with higher densities and energy contents. According to B&W, the secondary air to primary air ratio needs to be greater than two to avoid problems with flame stability. For bituminous coals, this ratio may typically be closer to four compared to biomass fuels with ratios that are typically less than two. If biomass fuels were processed to increase their density and energy content, this would result in more favorable ratios to improve flame stability. For low-energy content fuels, co-firing may be limited based on the ability to maintain flame stability.

Special PC burners have been developed for biomass firing to address flame stability, NO_X emissions, and unburned combustibles. For the Atikokan project, all existing coal burners are being replaced with burners designed for 100-PERCENT biomass firing. For long term firing (i.e. beyond test firing) in PC units, replacement of coal burners would be expected. For co-firing, B&W recommends that middle and upper burners be used for biomass as opposed to lower burners. This allows for more “upsweep” and reduces drop outs. In addition, they recommend that burners be interior burners for “better burnout, flame stability, and reduce corrosion”. Depending on the existing burner design, biomass can be combined with coal in the coal pipe upstream of the burner or injected through a separate nozzle into the burner. Each arrangement has advantages and disadvantages.

5.5.3.3 Furnace Flame and Boiler Arrangement

Considerations need to be given to the arrangement of burners and the flame characteristics in the furnace. B&W and Doosan have performed studies using computational fluid dynamics (CFD) to model and predict the boiler performance. The furnace flame may increase in size due to the higher fuel flow associated with biomass firing and due to the high volatility of biomass fuel compared to coal. This needs to be understood prior to proceeding to higher co-fire rates.

Furnace size is dictated by the boiler's design fuel. Lower energy content fuels, such as lignite, require a larger furnace compared to higher energy content fuels such as bituminous coal. Biomass typically has a lower energy content and, thus, is more easily fired in a lignite boiler. For boilers that fire higher energy content coal, firing biomass in the unit may lead to a de-rate of the boiler.

5.5.3.4 Chlorine and Alkalis

Biomass fuels with higher chlorine contents result in creation of higher quantities of hydrochloric acid (HCl), which could result in a higher potential for corrosive flue gas. While there are environmental and permitting for HCl emissions, implications on potential corrosion should also be addressed, particularly with high chlorine agricultural biomass. In addition to the chlorine content of the fuel, furnace temperatures impact the corrosion effects.

Biomass fuels have higher levels of alkali metals, including potassium oxide and sodium oxide (as well as silica). The quantity of alkali metals is higher in faster growing crops like agricultural biomass compared to woody biomass. Alkali metals lower the ash fusion temperature of the fuel, which can cause them to become "sticky" and cause slagging and fouling on boiler tubes and walls.

5.5.3.5 Air Heater Modifications

Biomass ignition occurs at much lower temperatures than for coal. Biomass also has a higher volatile matter content than coal. This limits the primary air temperatures that carry the biomass. Thus, primary air temperatures need to be evaluated to determine whether air heaters can be used or removed from service and whether primary air cooling needs to be deployed. At the Atikokan plant, they are adding a feedwater heat exchanger after the primary air heater to reduce the primary air temperature to the mills.

5.5.3.6 Ash Disposal

Biomass is lower in ash content than coal. Co-firing with biomass or firing with biomass alone will change the quantity and constituents of as5. This will impact the method of ash disposal or reuse. At the Atikokan plant, their ash was approved for disposal at the local landfill.

5.5.4 Conclusions

1. ***Steam and Electrical Production Facilities with Biomass***: Biomass co-firing of PC units is uncommon in the United States, but deployed in Europe. The Atikokan Plant is the only known PC conversion project to use 100-percent biomass in North America. PC boilers are the least accommodating for biomass conversions or co-firing compared to fluidized bed or stoker technologies. The Atikokan plant is a PC unit that previously fired lignite, but is converting to 100-percent biomass. This conversion required a new fuel handling system, new burners, several additional plant upgrades, and was more easily accommodated by a replacement fuel (biomass wood pellets) with a similar heating value as the design fuel. The AES Greenidge Plant successfully co-fired biomass in a PC boiler at rates up to 10 percent with a separate fuel feed system. EPRI testing in the late 1990s indicated a reduction in NO_X and SO_X emissions and acknowledged that boiler efficiency is normally lower for co-firing due to higher moisture contents of biomass.

2. ***Biomass Processing, Storage, and Handling Considerations:*** Biomass density is much lower than coal, for the same energy content. This requires consideration for fuel handling and storage as it may take 7 to 8 times more storage volume and processing for woody biomass compared to pellets. This would be less with processed biomass. A particle size of 1/16 inch is ideal for solid biomass for firing in a PC boiler. Industry experience was based on processing biomass onsite as opposed to offsite. Pulverizing biomass is most effectively accomplished using hammer mills, while ball-and-race mills and roller mills are more problematic. Biomass handling systems should prevent water from contact with biomass unless hydrophobic biomass is used. Biomass handling systems and biomass co-fire tests should address the explosion potential of combustible dust created by biomass processing and handling. Explosibility tests should be performed to understand the risk potential. For long-term firing or co-firing, a new biomass handling system would likely be required.

3. ***Boiler Performance and Plant Considerations***: There are several methods by which coal and biomass can be fired in a boiler, including co-firing and co-combustion. Interior and top burners are the best choice for co-firing burners. For 100-percent biomass firing, coal burners would likely need to be replaced. Flame stability issues would need to be addressed. For higher co-fire rates, CFD would be required to predict furnace performance. Combustion air temperatures would need to be evaluated to confirm that primary air temperatures would not be greater than the biomass combustion temperatures. If so, changes may need to be made to air heaters or primary air cooling may need to be implemented. Ash constituents and quantities would likely change which would impact disposal methods.

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SECTION 6

COAL-TO-NATURAL GAS CONVERSION

COAL-TO-NATURAL GAS CONVERSION

6.1 SUMMARY

Sega examined the requirements for converting the Missouri City Power Plant from pulverized-coal to only natural gas. Certain expenditures will be required for continuing operation of the Missouri City Power Plant regardless of fuel. These include deferred maintenance, insurance-require upgrades, and non-fuel environmental regulatory requirements. Sega's opinion of the probable capital costs for the non-fuel related projects required for continuing operations is $14.8 million. The additional costs for installing a natural gas pipeline extension to the plant and converting the plant to burn natural gas would be approximately $13 million. Sega's opinion of the total capital cost for continuing operation of the Missouri City Power Plant by converting it to burn natural gas in compliance with known applicable environmental regulations is $27.8 million. These values are overnight costs stated in 2015 U.S. dollars with an accuracy of ±30 percent.

6.2 INTRODUCTION

The Missouri City Power Plant was originally designed to burn pulverized coal with fuel oil for light-off and back up. The Retirement Study scope includes development of an opinion of probable costs to construct a natural gas supply pipeline and convert the Missouri City Plant to burn 100-percent natural gas.

6.3 DEFERRED MAINTENANCE AND MODIFICATIONS

Since retirement of the Missouri City Plant has been contemplated for nearly a decade, IPL prudently chose to minimize expenditures for major maintenance, plant betterment, insurance-recommended upgrades, or anticipated future environmental regulations for coal-firing. Keeping the Missouri City Plant in service regardless of fuel type will now require significant deferred major maintenance expenditures, as well as insurance and environmental regulatory upgrades, in addition to the actual natural gas conversion project. Also there are increasingly more stringent environmental regulations independent of fuel, such as new Clean Water Act rules, that must also be satisfied to continue operation of the plant.

This study does not address any heat rate improvement projects for enhancing plant efficiency, capacity, start-up duration, or cycling capability, that could increase the likelihood that these now 60-year old units might be dispatched more often. Such projects to improve competitiveness of the plant in the SPP Integrated Market are not considered in this study, and would add significant costs to those considered in this appendix.

Figure 6.1 - Deferred Project Costs provides expected order of magnitude costs for deferred maintenance projects, insurance-required upgrades, and non-fuel related mandatory environmental upgrades.

Item	Activity Description	Cost
1	Steam Turbine Generators - Major Overhaul (Rotor Out)	$ 5,000,000
2	Boilers - Major Overhaul	$ 2,000,000
3	Fire Protection Upgrades (Insurance Required)	$ 1,000,000
4	TWIPS (Insurance Required)	$ 1,000,000
5	Controls Upgrades to DCS with New BMS/CCS	$ 2,000,000
6	316 (a) & (b) (Regulatory Required Cooling Tower & CW Pumps)	$ 3,300,000
7	Allowance for General Upgrades for Codes and Safety	$ 500,000
	Total	$ **14,800,000**

Figure 6.1 - Deferred Project Costs

6.4 FUEL GAS REQUIREMENTS

The Missouri City Units 1 and 2 turbine/generators are each rated at 19 MW net with non-reheat boilers operating at steam conditions of 850 psig and 900 degrees F. The average net plant heat rate for these units was approximately 13,600 Btu/kWh when burning pulverized coal at base load. Heat rate would be expected to increase when converting a coal-fired boiler to gas fuel without making significant modifications to optimize the boiler and flue gas systems. Without a detailed analysis of the boilers and the plant that is beyond the scope of this study, it is not possible to accurately predict the heat rate impact of switching to natural gas. However, an average heat rate of 14,000 Btu/kWh would be a reasonable expectation for 60-year old units in such a low-pressure, non-reheat steam cycle. Therefore, maximum natural gas requirements for running both units at base load are expected to be on the order of 550 million Btu/hour or about 13,100 Dth/day. A gas supply pressure of approximately 100 psig at the plant boundary will be needed for the ultra-low NO_X burners that would likely be required if the plant was switched to firing only natural gas.

6.5 AVAILABLE GAS SUPPLY

Located along the Missouri River on the southern boundary of Clay County, the Missouri City Power Plant was built in the early 1950s for the Northwest Electric Cooperative in a remote area that did not have natural gas service. After more than 60 years, there is still no natural gas service near the plant.

Recent searches for natural gas transmission pipelines in the vicinity of the plant produced the same results as were found during the 2007 Master Plan Study. Missouri Gas Energy (MGE) operates the nearest gas pipeline at River Bend, Missouri, approximately 6 miles west/southwest of the Missouri City Plant. Known as the Liberty Lateral Pipeline, it is a 12-inch diameter main trunkline that operates at a nominal pressure of 100 psig. MGE has not provided available volumes of gas from this line. F*igure I-2 - Distance to MGE Gas Pipeline* is an overhead view of the location of the Missouri City Plant relative to the Liberty Pipeline in River Bend, Missouri at the junction of Missouri Highways 291 and 210.

The gas volume available from the MGE system has not been confirmed, although Sega believes that sufficient supply resources exist. Within the last three years MGE interconnected with the Rocky Mountain Express (REX) transmission line approximately 30 miles to the north between the Missouri towns of Lathrop and Turney. This interconnection provides increased gas supply and pressure reinforcement for the MGE Liberty Lateral which was formerly supplied only from the south. Tallgrass Interstate Gas Transmission (TIGT) Pipeline and Southern Star Central Gas Pipeline (Southern Star) both supply MGE from interconnections in southern Jackson County, Missouri. The new northern REX interconnection is significant because it indicates sufficient gas volumes should be available to MGE for supplying Missouri City Plant operations. REX is the closest high-pressure, interstate natural gas transmission pipeline on the north side of the Missouri River, and is about 30 miles away from the Missouri City Plant. If the Missouri City Plant were to bypass the local distribution company to connect directly with an interstate gas transmission pipeline, construction of a 30-mile pipeline would be required.

Figure 6-2 - Distance to MGE Gas Pipeline

Sega expects that a 12-inch diameter gas pipeline would be required to deliver the required volume of gas from the MGE Liberty Lateral along 291 Highway to the Missouri City Plant with less than a 10-percent pressure drop.

6.6 PROJECT DESCRIPTION

Converting from pulverized coal to natural gas would be a significant project. IPL could negotiate an agreement with MGE for the capital costs for extending a gas service pipeline to the plant by direct capital payment (with potential tax gross up) or through transportation rates for a minimum volume and time period. Once MGE constructs the natural gas pipeline to the site boundary, IPL will install high accuracy metering and filtration equipment with pressure regulating valves and piping into the boiler burner front. The two pulverized coal burners in each boiler will be replaced with low NO_X emission burners (LNB) and overfired-air (OFA) systems. In order to minimize NO_X emissions to avoid the addition of selective catalytic reduction (SCR) systems that utilize ammonia and catalysts, flue gas recirculation (FGR) systems would also be installed.

IPL will be required to first obtain a permit-to-construct from the Missouri Department of Natural Resources (MDNR) before making such significant modifications to the units. If IPL seeks unlimited hours of operation when the units are converted to gas, the units will likely be classified as major sources, triggering regulatory and permitting activities under Section 111 of the Clean Air Act (CAA) for New Source Performance Standards (NSPS). It is also likely that Continuous Emissions Monitoring (CEM) systems may be required.

The order of magnitude costs for these modifications are provided in *Figure 6.3 - Opinion of Probable Costs for Natural Gas Conversion*.

Item	Activity Description	Cost
1	MGE Gas Pipeline Extension (7 Miles, 12-Inch Diameter) to Site	$ 7,000,000
2	MGE Metering Station & Regulating Valve Set	$ 400,000
3	U/G Pipeline into Plant	$ 250,000
4	High Accuracy Gas Meter Skid	$ 750,000
4	Ultra Low NO_X Burners (2 per boiler) with Overfire Air	$ 2,000,000
5	Flue Gas Recirculation Systems with Ductwork & Fans	$ 1,500,000
6	Electrical Switchgear & Wiring for Burners & FGR System	$ 600,000
7	Permitting (NSPS/Major Source/Modeling)	$ 200,000
8	Continuous Emissions Monitoring System	$ 300,000
	Total	$ **13,000,000**

Figure 6.3 - Opinion of Probable Costs for Natural Gas Conversion

SECTION 7

APPENDICES

APPENDIX A

STATION DESCRIPTION

STATION DESCRIPTION

A.1 MISSOURI CITY POWER STATION DESCRIPTION

The Missouri City Power Station is located approximately 20 miles northeast of Independence, Missouri (see Appendix F for a site map). Missouri City consists of two identical coal-fired generating units that are rated at 19 MW net per unit. The power station was originally owned by Northwest Electric Power Cooperative and started commercial operation in 1954. A fire destroyed many critical electrical components at the power station in 1975. It was purchased by IPL in 1979, refurbished, and returned to commercial operation in the early 1980s.

IPL initially operated the power station for base load and intermediate and peaking loads. IPL has relied less on power produced at the Missouri City Power Station beginning in the mid-1980s when IPL entered into base load power purchase agreements. IPL is contemplating decommissioning of the Missouri City Power Plant on or before January 31, 2016 because the high capital costs for compliance with the U.S. EPA's IB MACT regulations.

Each unit at the Missouri City Power Station consists of a Foster Wheeler steam generator operating at 875 psig, 900 degrees F with a nameplate capacity of 220,000 pounds per hour. The boilers are each equipped with two Babcock & Wilcox Type E pulverizers and a bare tube tubular air heater. The boilers do not have economizers. The turbines are Westinghouse 20,000-kW, single-cylinder machines designed to operate at 850 psig, 900 degrees F throttle steam conditions, 1.5 inHg absolute exhaust conditions. Each turbine cycle utilizes four stages of feedwater heating. Circulating water is supplied from the Missouri River by two pumps per unit.

Each unit has a forced draft fan, induced draft fan, and air heater. Two electric-driven boiler feed pumps per unit provide feedwater to each boiler. In conjunction with the fire repairs, a common baghouse (reverse air type manufactured by Research-Cottrell), induced draft booster fans, and a 300-foot reinforced concrete chimney were added.

The Missouri City fuel yard has an abandoned rail spur and a coal receiving hopper reclaim pit. Coal is stored in a common fuel yard. Coal is transferred from the bunkers via a common conveyor system to individual bunkers (two per unit).

Both Missouri City units have a fuel oil igniter system. The units are supplied with fuel oil from a common fuel oil unloading and storage facility.

Coal combustion products are disposed of off site for a beneficial use.

The following are the major systems and equipment that are included in the decommissioning and dismantlement of each unit:

1. Boiler and boiler auxiliaries.
2. Turbine, heat balance equipment, and turbine auxiliaries.
3. Baghouse.
4. Circulating water intake structure.
5. Coal handling conveyors and river barge unloading structure.
6. Fuel oil handling equipment.
7. Administration building.
8. Coal handling building.
9. Maintenance shop.
10. Fuel oil pump house.
11. Water treatment.
12. Miscellaneous small buildings and enclosures.
13. Fire water systems.
14. Common tack.
15. Medium- and low-voltage electrical equipment.

APPENDIX B

OPINIONS OF PROBABLE COST

OPINIONS OF PROBABLE COST

This section contains the following documents:

1. Missouri City Power Plant Decommissioning Opinion of Probable Cost (May 2015).
2. Missouri City Decommissioning Manpower Loaded Schedule (May 2015).
3. Missouri City Power Plant Dismantlement Opinion of Probable Cost (May 2015).
4. Missouri City Dismantlement Manpower Loaded Schedule (May 2015).

DECOMMISSIONING

Missouri City Power Plant
Decommissioning Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
1	**Missouri City Decommissioing**	**$706,088.81**
2	IPL - Missouri City Decommissioning Project Start	$0.00
3	**Pre-Engineering**	**$73,736.64**
4	Permit review and engineering analysis, establish isolation points, and confirm fuel yard inventory has been reduced to zero tons.	$73,736.64
5	**IPL Overhead Costs**	**$139,930.00**
6	IPL Decommissioning Manager	$74,020.00
7	IPL Supervisor	$65,910.00
8	**Equipment Rentals**	**$27,380.00**
9	Vacuum truck	$25,350.00
10	IPL Temporary Construction Trailer and Misc.	$2,030.00
11	**Decommissioning**	**$439,651.77**
12	**Administration Building**	**$28,288.80**
13	Secure Administration Building	$28,288.80
14	**Maintenance Shop**	**$14,708.00**
15	Secure Maintenance Shop	$14,708.00
16	**Coal Handling Building**	**$4,412.40**
17	Secure Coal Handling Building	$4,412.40
18	**F.O. Pump House**	**$4,412.40**
19	Secure F.O. Pump House	$4,412.40
20	**Yard Fire Water Systems**	**$4,758.72**
21	Drain Yard Fire Water Systems	$4,758.72
22	**Electrical**	**$28,030.08**
23	**13.8 kV and 480 V Switchgear**	**$7,633.44**
24	De-energize all buses at the source.	$1,696.32
25	Open all circuit breakers.	$1,696.32
26	Rack all circuit breakers into the fully withdrawn, disconnected position.	$848.16
27	Verify that the closing/tripping springs are discharged.	$848.16
28	De-energize control power and auxiliary power circuits of each circuit breaker at the source and by opening control power circuit breakers or removing fuses in each breaker cubicle.	$2,544.48
29	**Motor Control Centers**	**$3,392.64**
30	De-energize all buses at the source.	$848.16
31	Open all circuit breakers and disconnect switches.	$848.16
32	Remove all fuses in control circuits.	$1,696.32
33	**Low-voltage Switchboards and Panelboards**	**$1,696.32**
34	De-energize all buses at the source.	$848.16
35	Open all circuit breakers and disconnect switches.	$848.16
36	**Oil-Filled Power Transformers**	**$6,031.68**
37	De-energize all transformer primaries and verify that the secondary is de-energized.	$848.16

Missouri City Power Plant
Decommissioning Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
38	De-energize all low-voltage AC or DC power sources for space heaters, cooling equipment, controls, etc. at the source and open circuit breakers or remove fuses at transformer end.	$848.16
39	Drain and dispose of oil.	$3,320.96
40	Clean up and dispose of oil on surface areas around the transformers and in containment pits.	$1,014.40
41	**Dry-type Power Transformers**	**$3,392.64**
42	De-energize all transformer primaries and verify that the secondary is de-energized.	$1,696.32
43	De-energize all low-voltage AC or DC power sources for space heaters, cooling equipment, controls, etc. at the source and open circuit breakers or remove fuses at transformer end.	$1,696.32
44	**Motors**	**$5,883.36**
45	De-energize all primary power at the source.	$1,696.32
46	De-energize all low-voltage power sources for space heaters or other auxiliary equipment at the source.	$1,696.32
47	Drain lube oil system (if applicable) and dispose of oil.	$2,490.72
48	**Coal Handling**	**$37,747.20**
49	Empty Track Hopper	$652.00
50	Empty all transfer hoppers.	$652.00
51	Empty coal silos.	$1,304.00
52	Confirm all fuel lines, conveyors and trippers are clear of fuel.	$1,811.20
53	Perform cleaning of the coal handling equipment to assure that all coal and coal dust has been removed from site.	$33,328.00
54	**Fuel Oil, Igniter System, and Heating Boiler**	**$7,805.36**
55	Drain fuel oil system	$3,028.80
56	Remove Heating Boiler Chemicals	$631.60
57	Open Heating Boiler Doors	$631.60
58	Remove fuel oil from fuel oil storage and vent	$3,513.36
59	**Boiler Chemical Feed**	**$2,019.20**
60	Drain all chemical feed tanks.	$2,019.20
61	**Boiler**	**$31,590.85**
62	Open boiler doors.	$1,660.48
63	Gas side - perform cleaning of the boiler and bottom ash system.	$25,360.00
64	Drain boiler, drum, downcomers and headers.	$756.00
65	Open drum doors.	$830.24
66	Drain and clean the bottom ash hoppers, leave doors open	$2,984.13
67	**Stack and Ductwork**	**$10,974.24**
68	Open ductwork doors.	$830.24
69	Perform extensive cleaning of the ductwork.	$10,144.00
70	**Condensate and Feedwater Piping**	**$2,268.00**
71	Drain water from the system.	$1,512.00

Missouri City Power Plant
Decommissioning Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
72	Leave open vents and drains.	$756.00
73	**Well Field**	**$92,805.00**
74	Close 4 Wells	$92,805.00
75	**Feedwater heaters**	**$3,024.00**
76	Drain feedwater heaters	$1,512.00
77	Leave open vents and drains.	$1,512.00
78	**500 ,000 Gallon Water Reservoir**	**$1,586.24**
79	Drain Tank and open doors	$1,586.24
80	**Deaerator and Deaerator Storage Tank**	**$1,512.00**
81	Drain Deaerator and Storage Tank	$756.00
82	Leave open vents and drains.	$756.00
83	**Water Treatment**	**$4,905.76**
84	Drain all piping	$756.00
85	Remove and dispose of RO chemicals	$1,009.60
86	Un-hook interface points and have rental company pick up equipment	$3,140.16
87	**Baghouse**	**$16,002.72**
88	Multiple cleaning cycles for filter bags.	$2,268.00
89	Open all vent and drain lines on bag cleaning air and control air lines. Leave in open position or remove vent valves.	$756.00
90	Remove all filter bags and cages.	$830.24
91	Clear hoppers of all ash	$2,526.40
92	Mechanically secure all compartment dampers and hopper outlet valves in open position.	$830.24
93	Disconnect ash transport piping and washdown baghouse hoppers and interior of casing.	$1,300.32
94	Install bird screens across hopper ash outlet and ash line flanges.	$830.24
95	Padlock or tack weld all hopper doors shut. (note: if ash hopper doors are indoors, they could be removed and the opening covered with bird screens.)	$830.24
96	If walk-in plenum, padlock or tack weld all outlet plenum doors and compartment ventilation dampers shut.	$830.24
97	If top-door plenum, close and secure top doors and remove/disable door lift hoist.	$1,586.24
98	If top-door plenum, establish natural ventilation or maintain HVAC fan to provide minimum air changes per hour in penthouse enclosure.	$870.08
99	Pull electrical supply breakers on all electrical equipment except lighting and HVAC components that are to remain in service.	$2,544.48
100	**Turbine(s) and Condenser**	**$7,249.44**
101	Drain hotwell and leave doors open.	$1,586.24
102	Open main turbine doors.	$830.24
103	Remove lube oil.	$4,832.96
104	**Generator**	**$11,323.84**

Missouri City Power Plant
Decommissioning Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

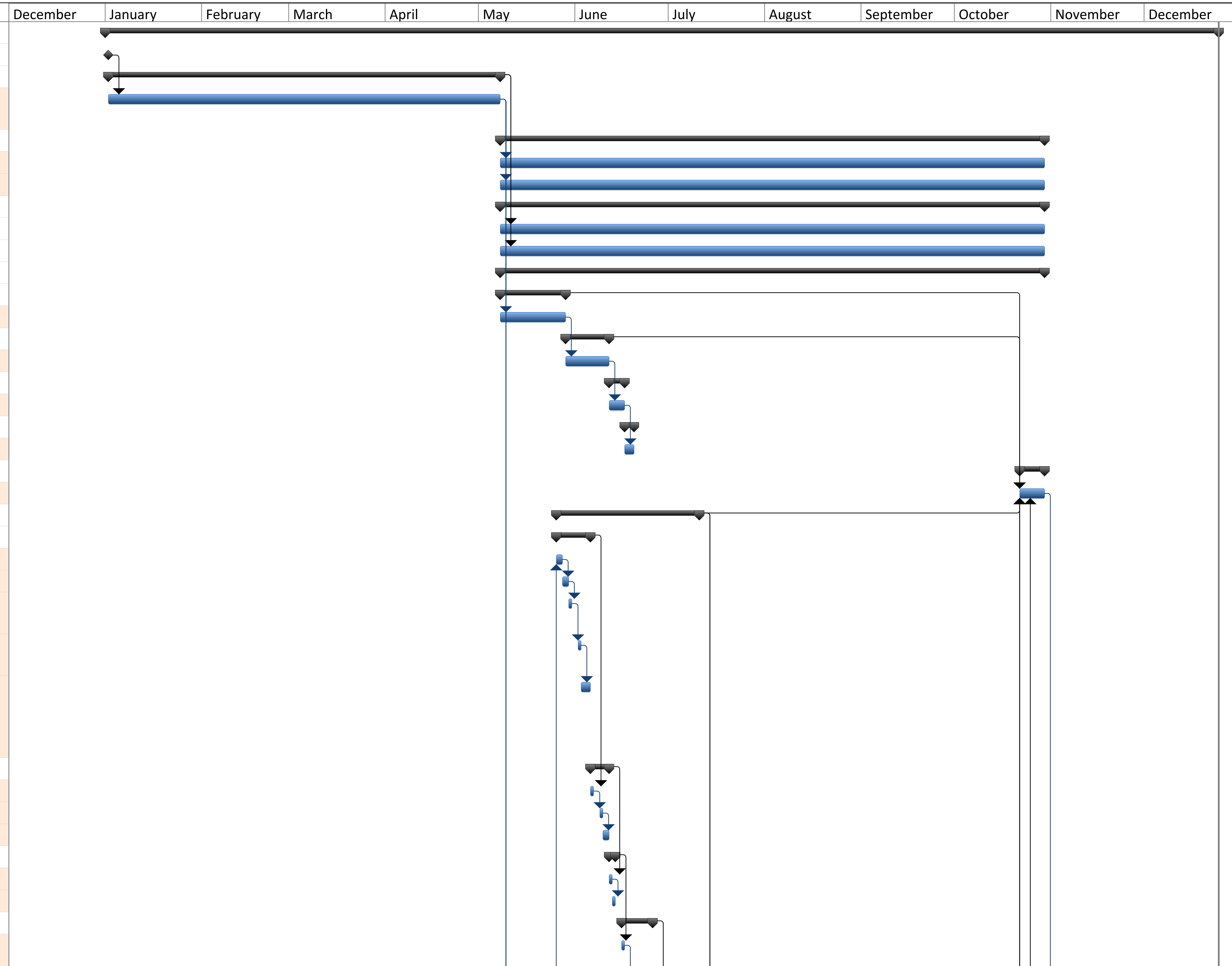
ID	Task Name	Cost
105	Verify that generator circuit breaker is open and racked out or that high-voltage disconnect switch on substation side of GSU transformer is locked in the open position.	$848.16
106	Verify that generator field breaker or contactor (if applicable) is open.	$848.16
107	De-energize power supplies to generator excitation system at the source.	$848.16
108	De-energize AC and DC power supplies to generator and exciter space heaters, cooling equipment, controls, lighting, etc. at the source and open circuit breakers or remove fuses at the generator and exciter.	$848.16
109	Drain generator and exciter cooling water systems (if applicable).	$1,586.24
110	Disconnect and remove hydrogen gas tanks and purge generator hydrogen system.	$2,268.00
111	Disconnect and remove fire protection system gas/foam tanks and purge fire protection system.	$2,490.72
112	Hydrogen Tank Removal by Rental Company	$1,586.24
113	**Circulation Water and Turbine Cooling Water System**	**$3,098.24**
114	Drain.	$1,512.00
115	Open water box doors.	$830.24
116	Drain any circulating water chemical feed tanks.	$756.00
117	**Intake**	**$3,624.72**
118	Close Sluice Gates	$2,416.48
119	Drain and secure the sluice gate hydraulic system	$1,208.24
120	**Compressed Air System**	**$2,478.24**
121	Open vents and drains.	$756.00
122	Remove desiccant from desiccant dryers.	$1,722.24
123	**Auxiliary Steam System**	**$1,512.00**
124	Drain water from system.	$756.00
125	Remove aux boiler chemicals.	$756.00
126	**Bearing Cooling Water System**	**$1,512.00**
127	Drain water from system.	$1,512.00
128	**Condenser Running and Hogging Ejectors**	**$756.00**
129	Drain water from system.	$756.00
130	**Septic System**	**$5,856.96**
131	Remove sewage	$507.20
132	Cap piping	$1,337.44
133	Fill in with gravel	$4,012.32
134	**Building Heating System**	**$756.00**
135	Drain water from system.	$756.00
136	**Battery System**	**$3,891.36**
137	De-energize all battery chargers from the source.	$424.08
138	Open all AC and DC circuit breakers and/or fused switches on battery chargers and disconnect cables from batteries.	$424.08

Missouri City Power Plant
Decommissioning Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
139	Remove and dispose of battery electrolyte.	$1,521.60
140	Remove and dispose of battery cells.	$1,014.40
141	Clean up and dispose of electrolyte on surface areas around batteries.	$507.20
142	**Security Fencing**	**$100,742.00**
143	Install Security Fencing around the perimeter of site.	$100,742.00
144	**Post Decommisioning Activities**	**$25,390.40**
145	Post Decommissioning Activities	$25,390.40

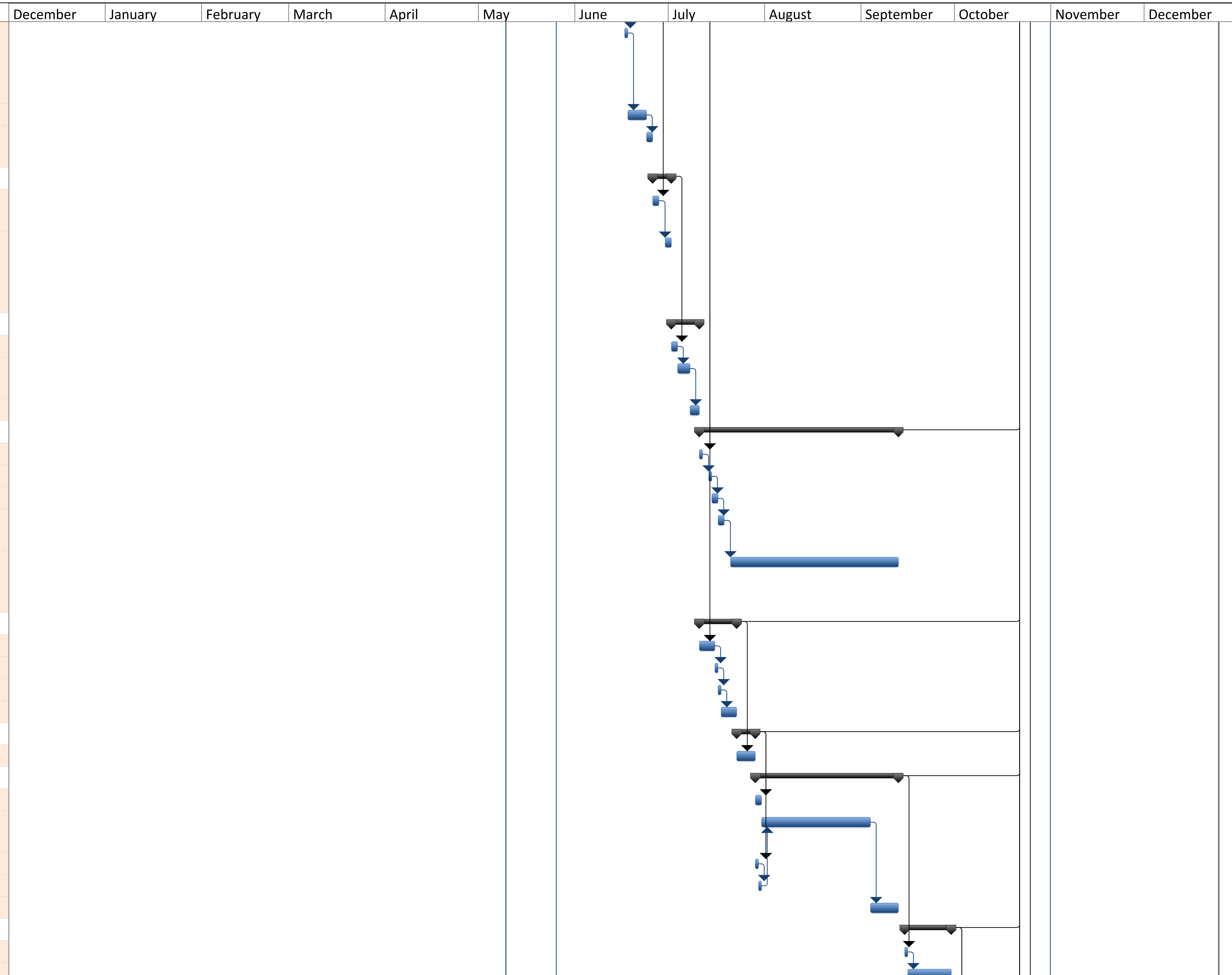
Missouri City Decommissioning
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
1	**Missouri City Decommissioing**	**256 days**
2	IPL - Missouri City Decommissioning Project Start	1 day
3	**Pre-Engineering**	**90 days**
4	Permit review and engineering analysis, establish isolation points, and confirm fuel yard	90 days
5	**IPL Overhead Costs**	**125 days**
6	IPL Decommissioning Manager	125 days
7	IPL Supervisor	125 days
8	**Equipment Rentals**	**125 days**
9	Vacuum truck	125 days
10	IPL Temporary Construction Trailer and Misc.	125 days
11	**Decommissioning**	**125 days**
12	**Administration Building**	**15 days**
13	Secure Administration Building	15 days
14	**Maintenance Shop**	**10 days**
15	Secure Maintenance Shop	10 days
16	**Coal Handling Building**	**3 days**
17	Secure Coal Handling Building	3 days
18	**F.O. Pump House**	**3 days**
19	Secure F.O. Pump House	3 days
20	**Yard Fire Water Systems**	**6 days**
21	Drain Yard Fire Water Systems	6 days
22	**Electrical**	**34 days**
23	**13.8 kV and 480 V Switchgear**	**9 days**
24	De-energize all buses at the source.	2 days
25	Open all circuit breakers.	2 days
26	Rack all circuit breakers into the fully withdrawn, disconnected position.	1 day
27	Verify that the closing/tripping springs are discharged.	1 day
28	De-energize control power and auxiliary power circuits of each circuit breaker at the source and by opening control power circuit breakers or removing fuses in each	3 days
29	**Motor Control Centers**	**4 days**
30	De-energize all buses at the source.	1 day
31	Open all circuit breakers and disconnect sw	1 day
32	Remove all fuses in control circuits.	2 days
33	**Low-voltage Switchboards and Panelboards**	**2 days**
34	De-energize all buses at the source.	1 day
35	Open all circuit breakers and disconnect sw	1 day
36	**Oil-Filled Power Transformers**	**8 days**
37	De-energize all transformer primaries and verify that the secondary is de-energized.	1 day



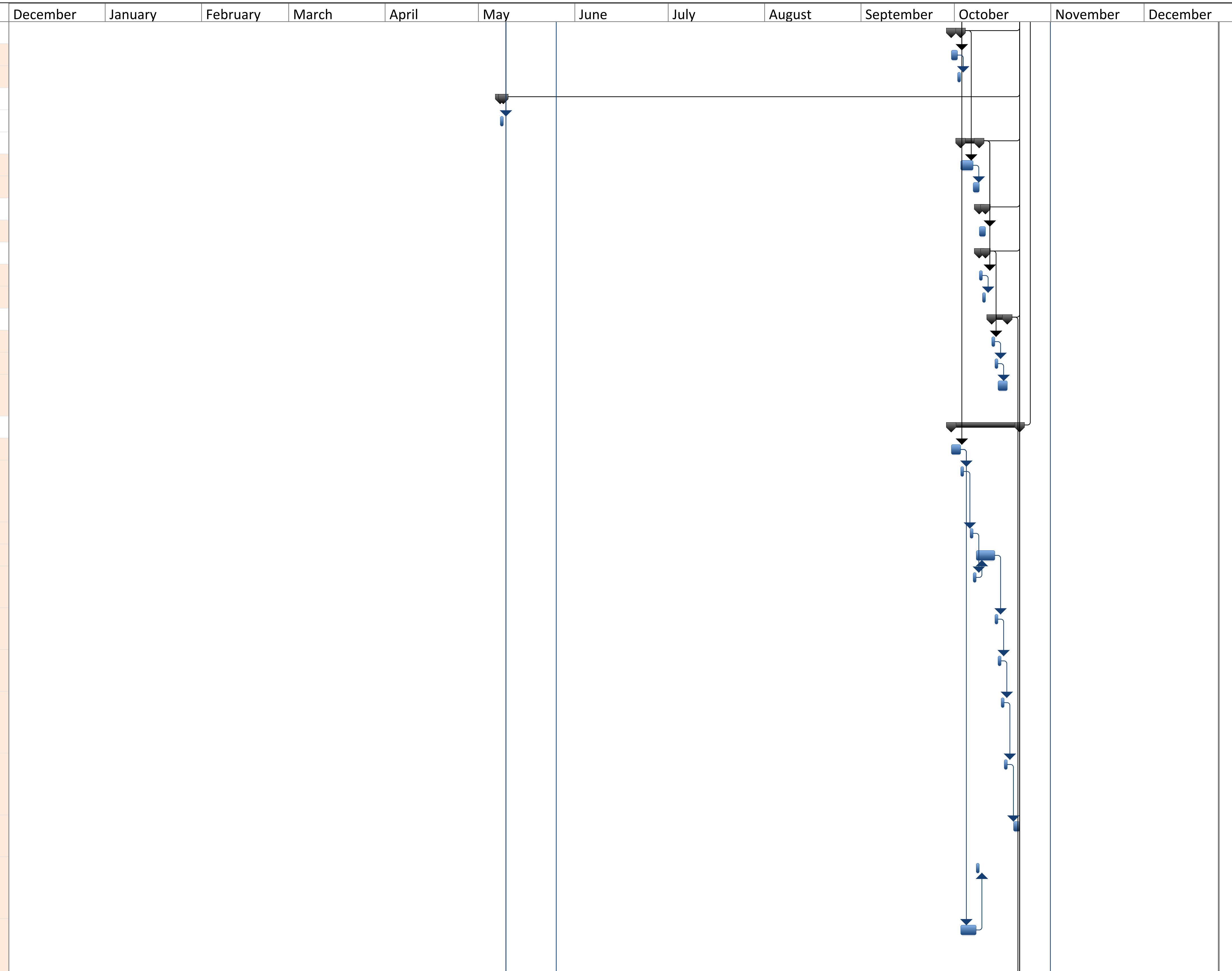
Missouri City Decommissioning
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
38	De-energize all low-voltage AC or DC power sources for space heaters, cooling equipment, controls, etc. at the source and open circuit breakers or remove fuses at	1 day
39	Drain and dispose of oil.	4 days
40	Clean up and dispose of oil on surface areas around the transformers and in	2 days
41	**Dry-type Power Transformers**	**4 days**
42	De-energize all transformer primaries and verify that the secondary is de-energized.	2 days
43	De-energize all low-voltage AC or DC power sources for space heaters, cooling equipment, controls, etc. at the source and open circuit breakers or remove fuses at	2 days
44	**Motors**	**7 days**
45	De-energize all primary power at the sourc	2 days
46	De-energize all low-voltage power sources for space heaters or other auxiliary	2 days
47	Drain lube oil system (if applicable) and dis	3 days
48	**Coal Handling**	**46 days**
49	Empty Track Hopper	1 day
50	Empty all transfer hoppers.	1 day
51	Empty coal silos.	2 days
52	Confirm all fuel lines, conveyors and trippers are clear of fuel.	2 days
53	Perform cleaning of the coal handling equipment to assure that all coal and coal dust has been removed from site.	40 days
54	**Fuel Oil, Igniter System, and Heating Boiler**	**8 days**
55	Drain fuel oil system	3 days
56	Remove Heating Boiler Chemicals	1 day
57	Open Heating Boiler Doors	1 day
58	Remove fuel oil from fuel oil storage and vent	3 days
59	**Boiler Chemical Feed**	**4 days**
60	Drain all chemical feed tanks.	4 days
61	**Boiler**	**34 days**
62	Open boiler doors.	2 days
63	Gas side - perform cleaning of the boiler and bottom ash system.	25 days
64	Drain boiler, drum, downcomers and headers	1 day
65	Open drum doors.	1 day
66	Drain and clean the bottom ash hoppers, leav	7 days
67	**Stack and Ductwork**	**11 days**
68	Open ductwork doors.	1 day
69	Perform extensive cleaning of the ductwork.	10 days



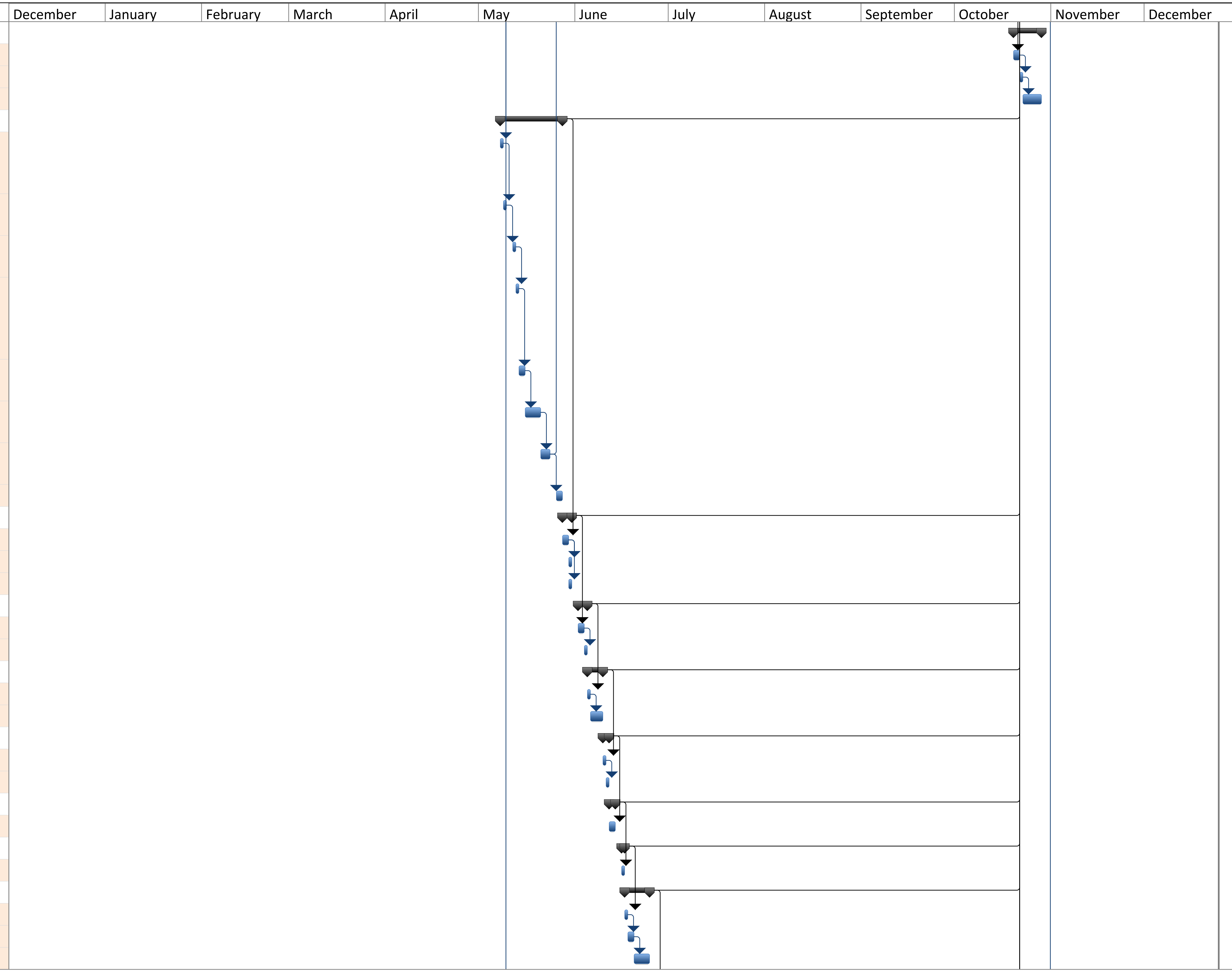
Missouri City Decommissioning
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
70	**Condensate and Feedwater Piping**	**3 days**
71	Drain water from the system.	2 days
72	Leave open vents and drains.	1 day
73	**Well Field**	**1 day**
74	Close 4 Wells	1 day
75	**Feedwater heaters**	**4 days**
76	Drain feedwater heaters	2 days
77	Leave open vents and drains.	2 days
78	**500 ,000 Gallon Water Reservoir**	**2 days**
79	Drain Tank and open doors	2 days
80	**Deaerator and Deaerator Storage Tank**	**2 days**
81	Drain Deaerator and Storage Tank	1 day
82	Leave open vents and drains.	1 day
83	**Water Treatment**	**5 days**
84	Drain all piping	1 day
85	Remove and dispose of RO chemicals	1 day
86	Un-hook interface points and have rental company pick up equipment	3 days
87	**Baghouse**	**16 days**
88	Multiple cleaning cycles for filter bags.	3 days
89	Open all vent and drain lines on bag cleaning air and control air lines. Leave in open position or remove vent valves.	1 day
90	Remove all filter bags and cages.	1 day
91	Clear hoppers of all ash	4 days
92	Mechanically secure all compartment dampers and hopper outlet valves in open	1 day
93	Disconnect ash transport piping and washdown baghouse hoppers and interior of	1 day
94	Install bird screens across hopper ash outlet and ash line flanges.	1 day
95	Padlock or tack weld all hopper doors shut. (note: if ash hopper doors are indoors, they could be removed and the opening covered	1 day
96	If walk-in plenum, padlock or tack weld all outlet plenum doors and compartment ventilation dampers shut.	1 day
97	If top-door plenum, close and secure top doors and remove/disable door lift hoist.	2 days
98	If top-door plenum, establish natural ventilation or maintain HVAC fan to provide minimum air changes per hour in penthouse	1 day
99	Pull electrical supply breakers on all electrical equipment except lighting and HVAC components that are to remain in service.	3 days



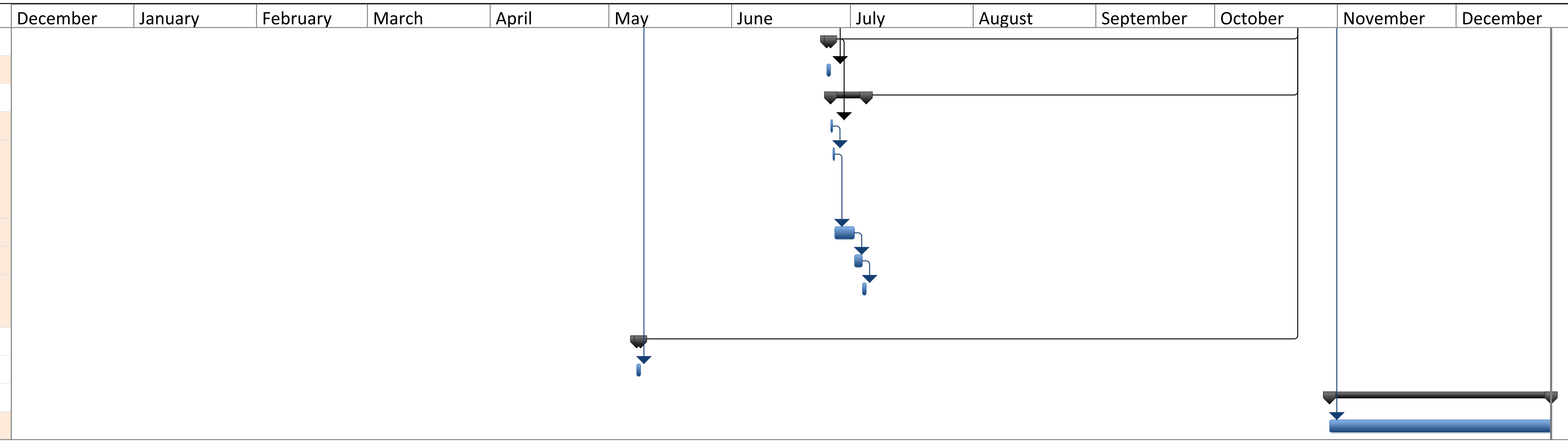
Missouri City Decommissioning
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
100	**Turbine(s) and Condenser**	**7 days**
101	Drain hotwell and leave doors open.	2 days
102	Open main turbine doors.	1 day
103	Remove lube oil.	4 days
104	**Generator**	**14 days**
105	Verify that generator circuit breaker is open and racked out or that high-voltage disconnect switch on substation side of GSU	1 day
106	Verify that generator field breaker or contactor (if applicable) is open.	1 day
107	De-energize power supplies to generator excitation system at the source.	1 day
108	De-energize AC and DC power supplies to generator and exciter space heaters, cooling equipment, controls, lighting, etc. at the source and open circuit breakers or remove	1 day
109	Drain generator and exciter cooling water systems (if applicable).	2 days
110	Disconnect and remove hydrogen gas tanks and purge generator hydrogen system.	3 days
111	Disconnect and remove fire protection system gas/foam tanks and purge fire	3 days
112	Hydrogen Tank Removal by Rental Company	2 days
113	**Circulation Water and Turbine Cooling Water S**	**3 days**
114	Drain.	2 days
115	Open water box doors.	1 day
116	Drain any circulating water chemical feed tanl	1 day
117	**Intake**	**3 days**
118	Close Sluice Gates	2 days
119	Drain and secure the sluice gate hydraulic sys	1 day
120	**Compressed Air System**	**3 days**
121	Open vents and drains.	1 day
122	Remove desiccant from desiccant dryers.	2 days
123	**Auxiliary Steam System**	**2 days**
124	Drain water from system.	1 day
125	Remove aux boiler chemicals.	1 day
126	**Bearing Cooling Water System**	**2 days**
127	Drain water from system.	2 days
128	**Condenser Running and Hogging Ejectors**	**1 day**
129	Drain water from system.	1 day
130	**Septic System**	**6 days**
131	Remove sewage	1 day
132	Cap piping	2 days
133	Fill in with gravel	3 days



Missouri City Decommissioning
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
134	**Building Heating System**	**1 day**
135	Drain water from system.	1 day
136	**Battery System**	**7 days**
137	De-energize all battery chargers from the sou	0.5 days
138	Open all AC and DC circuit breakers and/or fused switches on battery chargers and disconnect cables from batteries.	0.5 days
139	Remove and dispose of battery electrolyte.	3 days
140	Remove and dispose of battery cells.	2 days
141	Clean up and dispose of electrolyte on surface areas around batteries.	1 day
142	**Security Fencing**	**1 day**
143	Install Security Fencing around the perimeter	1 day
144	**Post Decommisioning Activities**	**40 days**
145	Post Decommissioning Activities	40 days



DISMANTLEMENT

Missouri City Power Plant
Dismantlement Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
1	**Missouri City Dismantlement**	**$11,548,591.46**
2	**Pre-Demolition Activities**	**$328,290.90**
3	Detailed Planning and Hire Owners Engineer	$25,827.52
4	Detailed Hazardous Material Audit	$76,050.00
5	**Detailed Site Characterization Study**	**$42,985.20**
6	IPL Labor	$16,418.40
7	OE Labor	$26,566.80
8	**Prepare Hazardous Material Removal RFP**	**$56,605.20**
9	IPL Labor	$16,755.00
10	OE Labor	$39,850.20
11	**Hazardous Material Removal RFP Bid Period**	**$53,132.80**
12	IPL Labor	$19,468.00
13	OE Labor	$33,664.80
14	**Hazardous Material Removal Contract Bid Evaluation, Negotiation and Award**	**$18,099.60**
15	IPL Labor	$5,475.30
16	OE Labor	$12,624.30
17	**Prepare Demolition RFP**	**$27,621.30**
18	IPL Labor	$7,696.20
19	OE Labor	$19,925.10
20	**Demolition RFP Bid Period**	**$14,033.44**
21	IPL Labor	$6,327.04
22	OE Labor	$7,706.40
23	**Demolition Contract Bid Evaluation, Negotiation and Award**	**$13,935.84**
24	IPL Labor	$7,202.88
25	OE Labor	$6,732.96
26	Hazardous Material Removal Contractor Mobilizes on Site	$0.00
27	**IPL Overhead during Dismantlement**	**$533,882.32**
28	IPL Project Manager	$123,465.36
29	IPL Administrative Support	$60,870.88
30	IPL Engineer	$135,308.16
31	Owners Engineer Project Manager	$78,929.76
32	Owners Engineer - Engineer	$135,308.16
33	**Hazardous Material Removal Contract**	**$3,183,960.00**
34	Hazardous Material Removal Contract Activity	$3,183,960.00
35	**Demolition Contractor Mobilizes to Site**	**$0.00**
36	Demolition Contractor Mobilizes to Site	$0.00
37	**Demoliton Contractor Overhead during Dismantlement**	**$581,820.64**
38	Demolition Contractor Construction Manager	$164,620.48
39	Demolition Contractor Safety Manager	$146,583.84
40	Demolition Contractor Superintendent	$270,616.32
41	**Demolition Contractor Equipment Rental Costs**	**$971,954.72**

Missouri City Power Plant
Dismantlement Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
42	Equipment Rental	$971,954.72
43	**Demolition Contractor Consummables**	**$969,708.48**
44	Consummables	$969,708.48
45	**Scrap Crew**	**$980,695.04**
46	Crew to Handle Scrap Material(s)	$980,695.04
47	**Demolition**	**$3,965,409.92**
48	**Phase 1 Demolition**	**$357,231.68**
49	**Phase 1 Electrical Demolition**	**$79,372.80**
50	Electrical Demolition of Phase 1 Equipment	$79,372.80
51	**Condensate System**	**$29,157.44**
52	Condensate Pumps	$3,527.68
53	Condensate Cooler	$1,763.84
54	Hydrogen Coolers	$1,763.84
55	Air Ejectors	$1,763.84
56	Heater No. 1	$2,699.84
57	Heater No. 2 - Deaerator	$3,527.68
58	Deaerator Storage Tank	$7,055.36
59	Condensate Piping	$7,055.36
60	**Boiler Feed System**	**$24,693.76**
61	TD Boiler Feed Pump	$7,055.36
62	MD Boiler Feedpump	$7,055.36
63	Heater No. 3	$1,763.84
64	Heater No. 4	$1,763.84
65	Boiler Feedpump Piping	$7,055.36
66	**Critical Piping**	**$10,583.04**
67	Main Steam Piping	$10,583.04
68	**Extraction Steam System**	**$3,527.68**
69	Piping	$3,527.68
70	**Heater Drips**	**$7,055.36**
71	Heater Drip Pumps	$3,527.68
72	Piping	$3,527.68
73	**Auxiliary Steam**	**$10,583.04**
74	Remove Cleaver Brooks Auxiliary Boiler	$3,527.68
75	Auxiliary Steam Piping and Equipment	$7,055.36
76	**Circulating Water (plant side)**	**$14,110.72**
77	Waterboxes	$14,110.72
78	**Bearing Cooling Water**	**$21,166.08**
79	Bearing Water Pumps	$3,527.68
80	Bearing Water Cooler	$3,527.68
81	Bearing Cooling Water Piping	$7,055.36
82	Bearing Water Sump Tank	$3,527.68
83	Bearing Water Storage Tank	$3,527.68

Missouri City Power Plant
Dismantlement Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
84	**Turbine Cooling Water**	**$3,527.68**
85	Turbine Cooling Water Piping	$3,527.68
86	**Service Water**	**$3,527.68**
87	City Water Piping	$3,527.68
88	**Fuel Oil System (plant side)**	**$17,638.40**
89	Fuel Oil Pumps	$3,527.68
90	Igniter Fuel Oil and Atomizing Air Piping	$10,583.04
91	Igniters	$3,527.68
92	**Condenser Air Extraction System**	**$7,055.36**
93	Running and Hogging Air Ejectors	$3,527.68
94	Air Ejector Piping	$3,527.68
95	**Turbine Seals and Drains**	**$7,055.36**
96	Piping	$7,055.36
97	**Turbine Auxiliary Systems**	**$21,166.08**
98	Turbine Lube Oil Coolers and Strainers	$7,055.36
99	Seal Oil Supply Tank	$3,527.68
100	Gas Dryer	$3,527.68
101	Gland Seal Tank	$3,527.68
102	Auxiliary Oil Pump Turbine	$3,527.68
103	**Generator Auxiliary Systems**	**$17,638.40**
104	Hydrogen Seal Oil Skid	$7,055.36
105	Miscellaneous Systems	$3,527.68
106	Isophase Bus Duct	$7,055.36
107	**Chemical Feed Systems**	**$10,583.04**
108	Tanks	$3,527.68
109	Pumps	$3,527.68
110	Piping	$3,527.68
111	**Sampling Systems**	**$7,055.36**
112	Field Mounted Heat Exchangers	$3,527.68
113	Piping	$3,527.68
114	**Building Heating Systems**	**$24,693.76**
115	Steam Unit Heaters	$17,638.40
116	Steam Piping	$7,055.36
117	**Compressed Air System**	**$12,346.88**
118	Air Compressors	$3,527.68
119	Air Drying Equipment	$3,527.68
120	Air Reciever Tanks	$3,527.68
121	Compressed Air Piping	$1,763.84
122	**Miscellaneous Equipment**	**$24,693.76**
123	Miscellaneous Equipment (including Fire Protection)	$14,110.72
124	Evaporator	$7,055.36
125	Blowdown Tank	$3,527.68

Missouri City Power Plant
Dismantlement Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

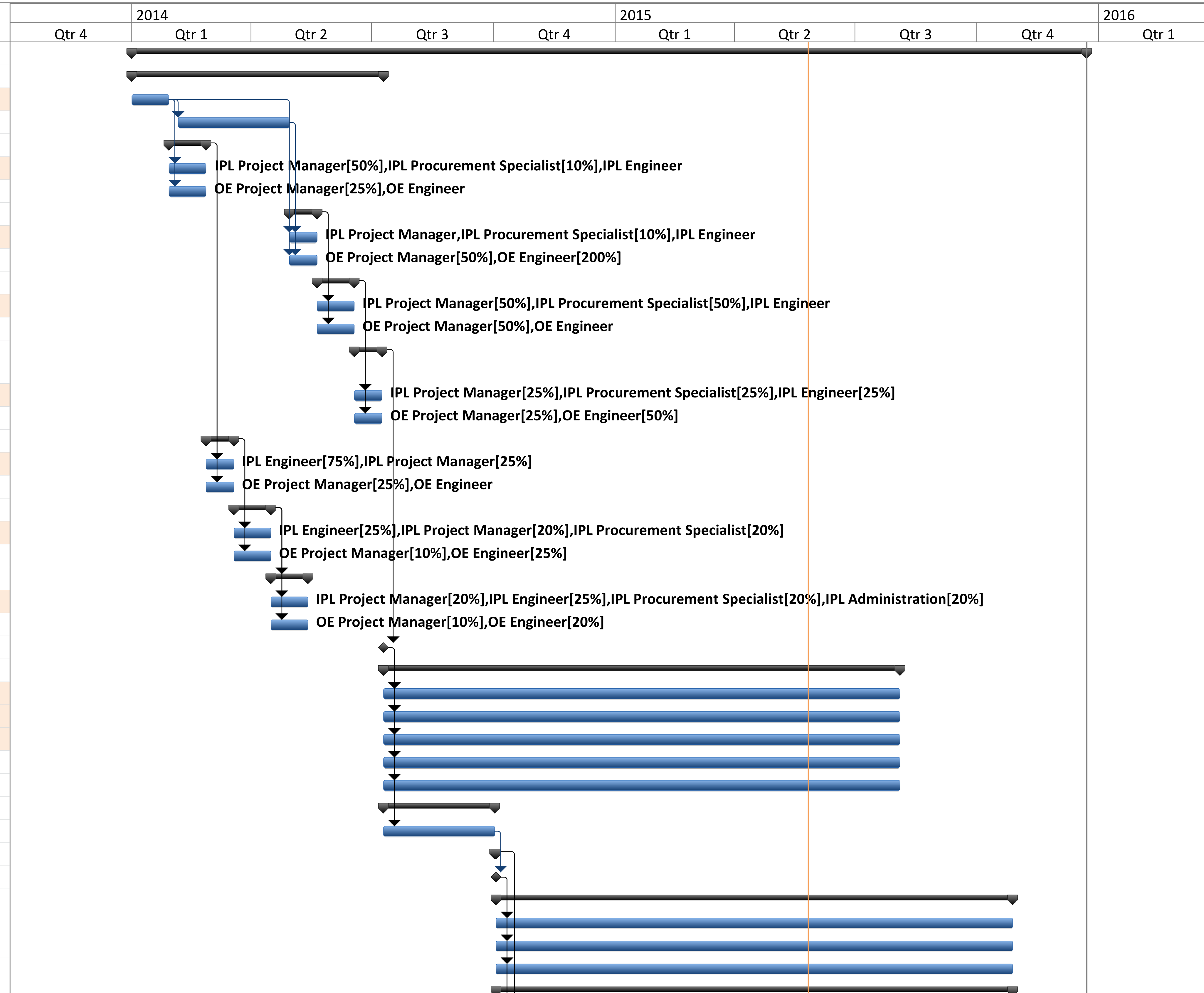
ID	Task Name	Cost
126	**Phase 2 Demolition**	**$933,071.36**
127	**Boiler Equipment**	**$218,716.16**
128	ID Fans, ID Fan Booster, and F.D. Fan	$35,276.80
129	Pulverizers	$35,276.80
130	Bottom Ash System (Ash Sluicing Booster Pump, Ash Sluicing Pumps, Ash Pump and Ash Bilge Pump)	$7,055.36
131	Tubular Air Heater	$17,638.40
132	Steam Drums	$35,276.80
133	Coal Bunkers	$17,638.40
134	Coal Feeders	$7,055.36
135	Soot Blowers	$7,055.36
136	Ductwork	$35,276.80
137	Miscellaneous Other	$21,166.08
138	**Boiler Removal**	**$116,413.44**
139	Furnace	$79,372.80
140	Burners	$10,583.04
141	Back Pass	$26,457.60
142	**Boiler Steel Framing**	**$185,203.20**
143	Hanger Girders at Top	$26,457.60
144	All Other Framing / Brickwork	$79,372.80
145	Bracing and Girts	$26,457.60
146	Columns	$52,915.20
147	**Boiler Foundations**	**$63,498.24**
148	Equipment Foundation Demolition to Grade	$63,498.24
149	**Remove Turbine/Generator**	**$349,240.32**
150	Remove Turbine	$15,874.56
151	Remove Generator	$26,457.60
152	Remove Condenser	$15,874.56
153	Remove Misc. Auxiliary Turbine Equipment	$15,874.56
154	**Turbine Pedestal Demolition to Grade**	**$74,081.28**
155	Top Slab and Beams	$37,040.64
156	Columns	$37,040.64
157	**Remove Turbine Building**	**$148,162.56**
158	Siding and Roofing	$37,040.64
159	All Framing Elevations	$63,498.24
160	Bracing and Girts	$15,874.56
161	Columns	$31,749.12
162	**Baghouse Removal**	**$52,915.20**
163	Remove Baghouse	$52,915.20
164	**Phase 3 Yard and Buildings Demolition**	**$2,152,106.88**
165	**Buildings**	**$52,915.20**
166	Remove Administration Building/Maintenance Facility	$35,276.80

Missouri City Power Plant
Dismantlement Opinion of Probable Cost
Note: Shaded Items are Internal IPL Costs

ID	Task Name	Cost
167	Remove Crusher Building	$8,819.20
168	Remove F.O. Pump House	$8,819.20
169	**Stack**	**$1,776,748.00**
170	Stack Demolition	$1,776,748.00
171	**Intake**	**$143,341.12**
172	Remove Circulating Water Pumps, Screens and Intake Auxiliaries	$5,291.52
173	Remove Concrete Intake Structure	$111,592.00
174	Complete Intake Grading and Drainage	$8,819.20
175	Remove Barge Unloading Facility	$17,638.40
176	**Circulating Water Pipe (yard)**	**$17,638.40**
177	Excavate Circulating Water Pipe	$5,291.52
178	Collapse Circulating Water Pipe	$5,291.52
179	Backfill Circulating Water Pipe	$7,055.36
180	**Remove Ash Handling Equipment and Piping**	**$10,583.04**
181	Remove DSS Silo	$5,291.52
182	Remove Ash Piping and Misc. Equipment	$5,291.52
183	**Fuel Yard**	**$40,568.32**
184	Remove Receiving Hopper Equipment	$5,291.52
185	Backfill and Compact Receiving Hopper	$7,055.36
186	Remove Conveyor Belt No. 1	$3,527.68
187	Remove Conveyor Belt No. 2	$3,527.68
188	Remove Coal Crusher and Feed Chute	$8,819.20
189	Remove Storage Yard Conveyor Belt	$3,527.68
190	Remove Dust Collectors	$3,527.68
191	Remove Belt Scale, Car Shaker and Hoist	$5,291.52
192	**Remove Large Tanks**	**$110,312.80**
193	Remove Water Storage Tank on Hill	$35,276.80
194	Remove the 250,000 Gallon Fuel Oil AST	$75,036.00
195	**Final Site Grading and Drainage**	**$523,000.00**
196	Final Site Grading and Drainage	$130,000.00
197	Fuel Yard Pile Closure	$393,000.00
198	**Post Dismantlement Activities**	**$32,869.44**
199	**Post Dismantlement Activities**	**$32,869.44**
200	IPL Labor	$25,081.92
201	OE Labor	$7,787.52

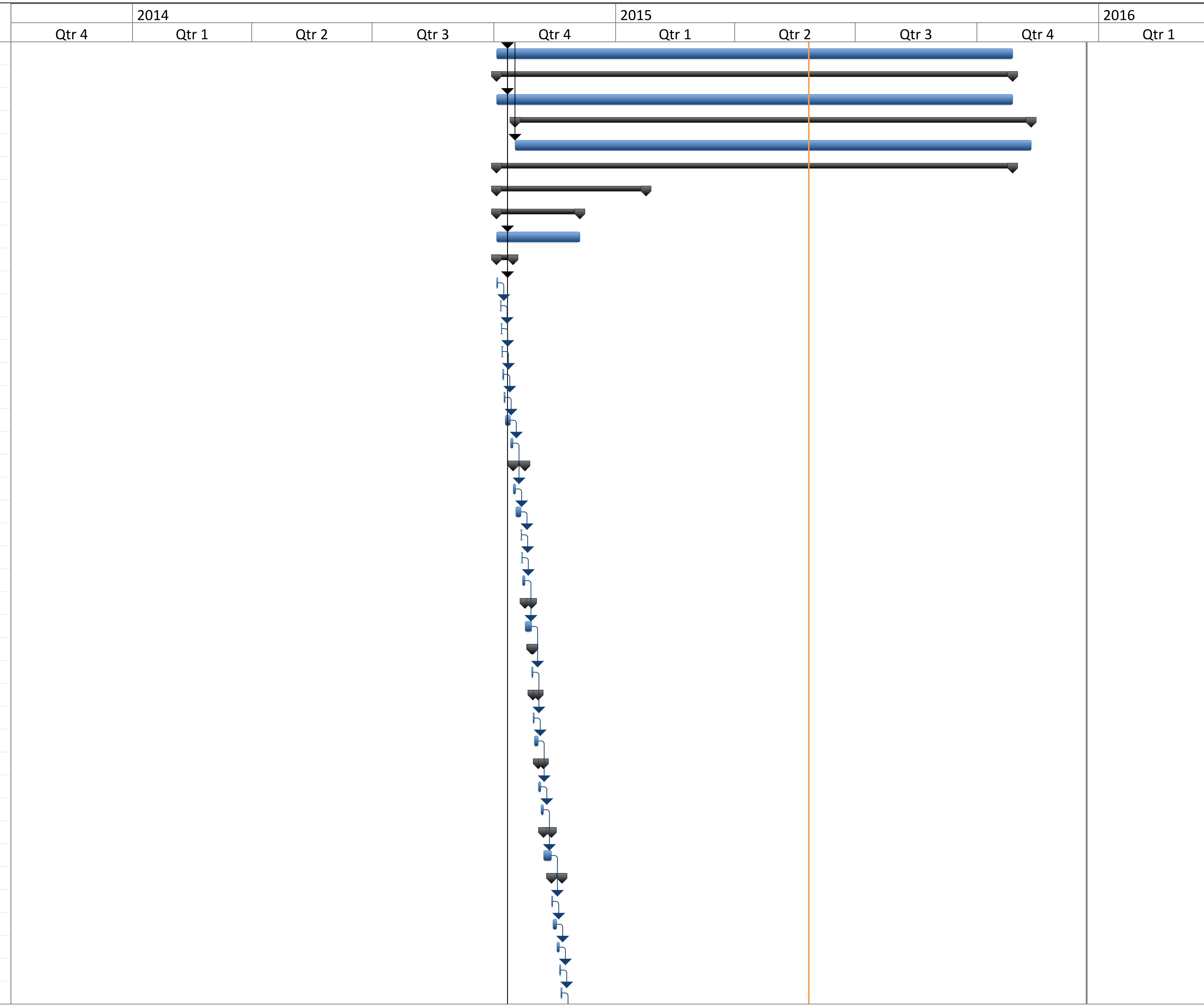
Missouri City Demolition
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
1	**Missouri City Dismantlement**	**515 days**
2	**Pre-Demolition Activities**	**136 days**
3	Detailed Planning and Hire Owners Engineer	1 mon
4	Detailed Hazardous Material Audit	3 mons
5	**Detailed Site Characterization Study**	**20 days**
6	IPL Labor	20 days
7	OE Labor	20 days
8	**Prepare Hazardous Material Removal RFP**	**15 days**
9	IPL Labor	15 days
10	OE Labor	15 days
11	Hazardous Material Removal RFP Bid Period	20 days
12	IPL Labor	20 days
13	OE Labor	20 days
14	Hazardous Material Removal Contract Bid Evaluation, Negotiation and Award	15 days
15	IPL Labor	15 days
16	OE Labor	15 days
17	Prepare Demolition RFP	15 days
18	IPL Labor	15 days
19	OE Labor	15 days
20	**Demolition RFP Bid Period**	**20 days**
21	IPL Labor	20 days
22	OE Labor	20 days
23	**Demolition Contract Bid Evaluation, Negotiation and Awar**	**20 days**
24	IPL Labor	20 days
25	OE Labor	20 days
26	Hazardous Material Removal Contractor Mobilizes on Site	1 day
27	**IPL Overhead during Dismantlement**	**278 days**
28	IPL Project Manager	278 days
29	IPL Administrative Support	278 days
30	IPL Engineer	278 days
31	Owners Engineer Project Manager	278 days
32	Owners Engineer - Engineer	278 days
33	**Hazardous Material Removal Contract**	**60 days**
34	Hazardous Material Removal Contract Activity	3 mons
35	**Demolition Contractor Mobilizes to Site**	**1 day**
36	Demolition Contractor Mobilizes to Site	1 day
37	**Demoliton Contractor Overhead during Dismantlement**	**278 days**
38	Demolition Contractor Construction Manager	278 days
39	Demolition Contractor Safety Manager	278 days
40	Demolition Contractor Superintendent	278 days
41	**Demolition Contractor Equipment Rental Costs**	**278 days**



Missouri City Demolition
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
42	Equipment Rental	278 days
43	**Demolition Contractor Consummables**	**278 days**
44	Consummables	278 days
45	**Scrap Crew**	**278 days**
46	Crew to Handle Scrap Material(s)	278 days
47	**Demolition**	**278 days**
48	**Phase 1 Demolition**	**81 days**
49	**Phase 1 Electrical Demolition**	**45 days**
50	Electrical Demolition of Phase 1 Equipment	45 days
51	**Condensate System**	**8.5 days**
52	Condensate Pumps	1 day
53	Condensate Cooler	0.5 days
54	Hydrogen Coolers	0.5 days
55	Air Ejectors	0.5 days
56	Heater No. 1	1 day
57	Heater No. 2 - Deaerator	1 day
58	Deaerator Storage Tank	2 days
59	Condensate Piping	2 days
60	**Boiler Feed System**	**7 days**
61	TD Boiler Feed Pump	2 days
62	MD Boiler Feedpump	2 days
63	Heater No. 3	0.5 days
64	Heater No. 4	0.5 days
65	Boiler Feedpump Piping	2 days
66	**Critical Piping**	**3 days**
67	Main Steam Piping	3 days
68	**Extraction Steam System**	**1 day**
69	Piping	1 day
70	**Heater Drips**	**2 days**
71	Heater Drip Pumps	1 day
72	Piping	1 day
73	**Auxiliary Steam**	**4 days**
74	Remove Cleaver Brooks Auxiliary Boiler	2 days
75	Auxiliary Steam Piping and Equipment	2 days
76	**Circulating Water (plant side)**	**4 days**
77	Waterboxes	4 days
78	**Bearing Cooling Water**	**6 days**
79	Bearing Water Pumps	1 day
80	Bearing Water Cooler	1 day
81	Bearing Cooling Water Piping	2 days
82	Bearing Water Sump Tank	1 day
83	Bearing Water Storage Tank	1 day

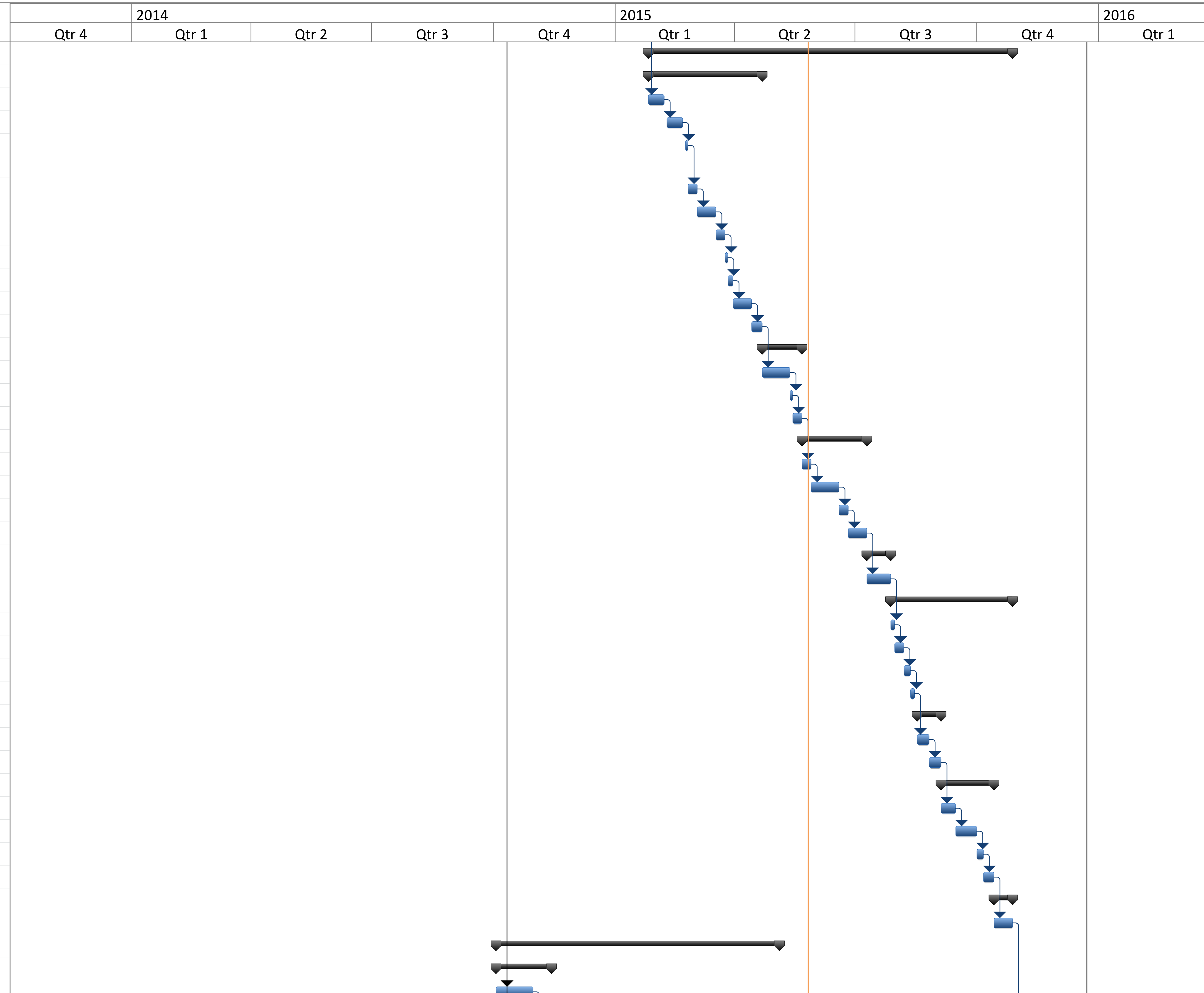


Missouri City Demolition
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

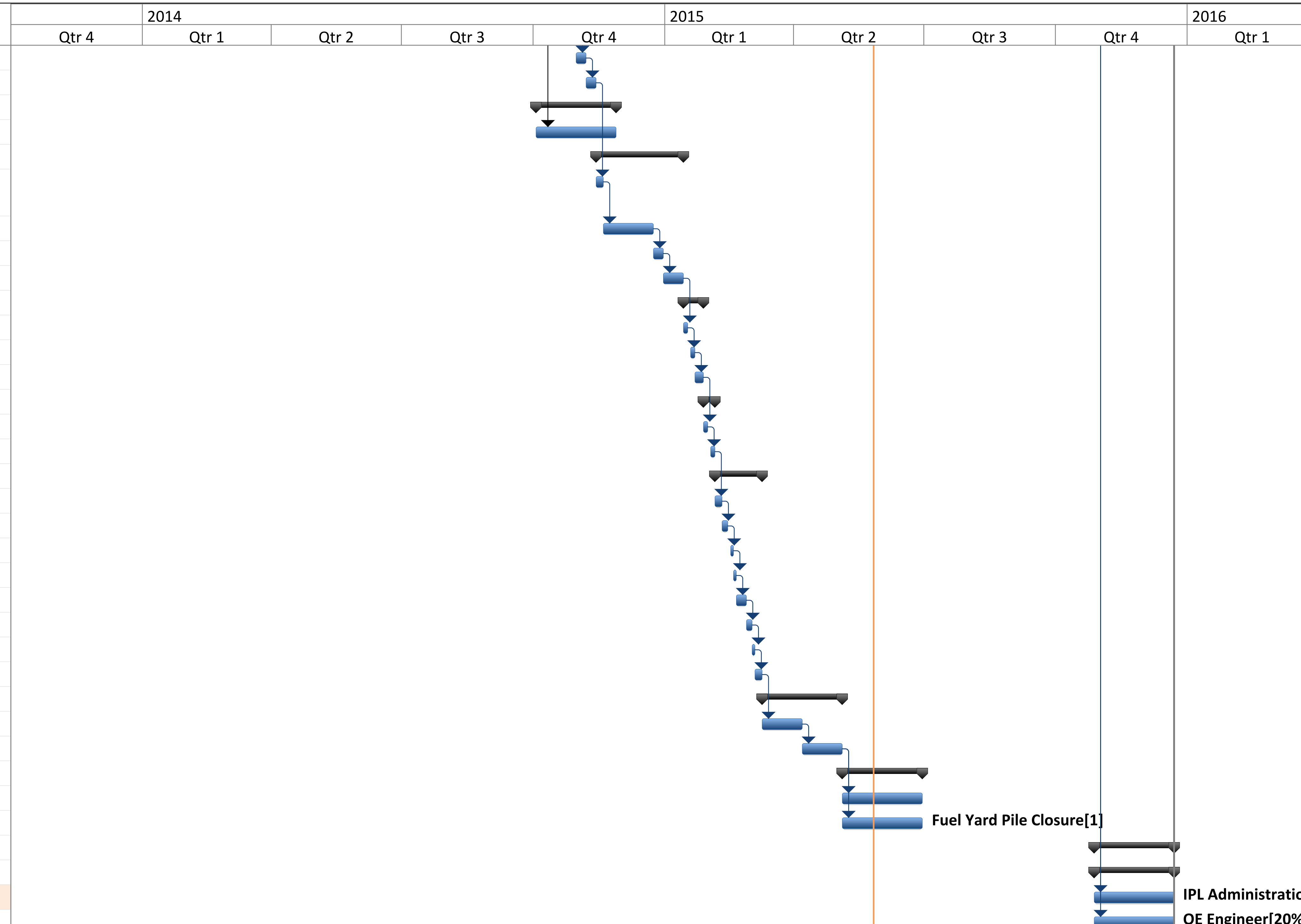
ID	Task Name	Duration
84	**Turbine Cooling Water**	**1 day**
85	Turbine Cooling Water Piping	1 day
86	**Service Water**	**1 day**
87	City Water Piping	1 day
88	**Fuel Oil System (plant side)**	**6 days**
89	Fuel Oil Pumps	1 day
90	Igniter Fuel Oil and Atomizing Air Piping	3 days
91	Igniters	2 days
92	**Condenser Air Extraction System**	**2 days**
93	Running and Hogging Air Ejectors	1 day
94	Air Ejector Piping	1 day
95	**Turbine Seals and Drains**	**2 days**
96	Piping	2 days
97	**Turbine Auxiliary Systems**	**6 days**
98	Turbine Lube Oil Coolers and Strainers	2 days
99	Seal Oil Supply Tank	1 day
100	Gas Dryer	1 day
101	Gland Seal Tank	1 day
102	Auxiliary Oil Pump Turbine	1 day
103	**Generator Auxiliary Systems**	**5 days**
104	Hydrogen Seal Oil Skid	2 days
105	Miscellaneous Systems	1 day
106	Isophase Bus Duct	2 days
107	**Chemical Feed Systems**	**3 days**
108	Tanks	1 day
109	Pumps	1 day
110	Piping	1 day
111	**Sampling Systems**	**2 days**
112	Field Mounted Heat Exchangers	1 day
113	Piping	1 day
114	**Building Heating Systems**	**7 days**
115	Steam Unit Heaters	5 days
116	Steam Piping	2 days
117	**Compressed Air System**	**3.5 days**
118	Air Compressors	1 day
119	Air Drying Equipment	1 day
120	Air Reciever Tanks	1 day
121	Compressed Air Piping	0.5 days
122	**Miscellaneous Equipment**	**7 days**
123	Miscellaneous Equipment (including Fire Protection)	4 days
124	Evaporator	2 days
125	Blowdown Tank	1 day

Missouri City Demolition
Man-Power Loaded Schedule
Note: Shaded Items are IPL Activities

ID	Task Name	Duration
126	**Phase 2 Demolition**	**197 days**
127	**Boiler Equipment**	**62 days**
128	ID Fans, ID Fan Booster, and F.D. Fan	10 days
129	Pulverizers	10 days
130	Bottom Ash System (Ash Sluicing Booster Pump, Ash Sluicing Pumps, Ash Pump and Ash Bilge Pump)	2 days
131	Tubular Air Heater	5 days
132	Steam Drums	10 days
133	Coal Bunkers	5 days
134	Coal Feeders	2 days
135	Soot Blowers	2 days
136	Ductwork	10 days
137	Miscellaneous Other	6 days
138	**Boiler Removal**	**22 days**
139	Furnace	15 days
140	Burners	2 days
141	Back Pass	5 days
142	**Boiler Steel Framing**	**35 days**
143	Hanger Girders at Top	5 days
144	All Other Framing / Brickwork	15 days
145	Bracing and Girts	5 days
146	Columns	10 days
147	**Boiler Foundations**	**12 days**
148	Equipment Foundation Demolition to Grade	12 days
149	**Remove Turbine/Generator**	**66 days**
150	Remove Turbine	3 days
151	Remove Generator	5 days
152	Remove Condenser	3 days
153	Remove Misc. Auxiliary Turbine Equipment	3 days
154	**Turbine Pedestal Demolition to Grade**	**14 days**
155	Top Slab and Beams	7 days
156	Columns	7 days
157	**Remove Turbine Building**	**28 days**
158	Siding and Roofing	7 days
159	All Framing Elevations	12 days
160	Bracing and Girts	3 days
161	Columns	6 days
162	**Baghouse Removal**	**10 days**
163	Remove Baghouse	10 days
164	**Phase 3 Yard and Buildings Demolition**	**152 days**
165	**Buildings**	**30 days**
166	Remove Administration Building/Maintenance Facility	20 days



ID	Task Name	Duration
167	Remove Crusher Building	5 days
168	Remove F.O. Pump House	5 days
169	**Stack**	**40 days**
170	Stack Demolition	40 days
171	**Intake**	**43 days**
172	Remove Circulating Water Pumps, Screens and Intake Auxiliaries	3 days
173	Remove Concrete Intake Structure	25 days
174	Complete Intake Grading and Drainage	5 days
175	Remove Barge Unloading Facility	10 days
176	**Circulating Water Pipe (yard)**	**10 days**
177	Excavate Circulating Water Pipe	3 days
178	Collapse Circulating Water Pipe	3 days
179	Backfill Circulating Water Pipe	4 days
180	**Remove Ash Handling Equipment and Piping**	**6 days**
181	Remove DSS Silo	3 days
182	Remove Ash Piping and Misc. Equipment	3 days
183	**Fuel Yard**	**23 days**
184	Remove Receiving Hopper Equipment	3 days
185	Backfill and Compact Receiving Hopper	4 days
186	Remove Conveyor Belt No. 1	2 days
187	Remove Conveyor Belt No. 2	2 days
188	Remove Coal Crusher and Feed Chute	5 days
189	Remove Storage Yard Conveyor Belt	2 days
190	Remove Dust Collectors	2 days
191	Remove Belt Scale, Car Shaker and Hoist	3 days
192	**Remove Large Tanks**	**40 days**
193	Remove Water Storage Tank on Hill	20 days
194	Remove the 250,000 Gallon Fuel Oil AST	20 days
195	**Final Site Grading and Drainage**	**40 days**
196	Final Site Grading and Drainage	40 days
197	Fuel Yard Pile Closure	40 days
198	**Post Dismantlement Activities**	**40 days**
199	Post Dismantlement Activities	40 days
200	IPL Labor	40 days
201	OE Labor	40 days



APPENDIX C

OPINIONS OF COST FOR SCRAP

OPINIONS OF COST FOR SCRAP

The opinion of scrap value[1] was based on a scrap value of:

1. Mixed Scrap: $232.00/GT.
2. Insulated Cables: $2.13/lb.
3. Motors: $0.32/lb.

These scrap values were taken from www.scrapmonster.com. This website is an industry-recognized source of scrap information that provides daily scrap pricing for the worldwide scrap market.

Sega's opinion of scrap value for the Missouri City Plant is shown in *Figure C.1 - Missouri City Scrap Value Cost*:

Description					**Cost**
Pipe Weight	95,108	lbs	$232.00	GT	$ 11,032
Boiler Weight	2,243,900	lbs	$232.00	GT	$ 260,292
Baghouse	408,000	lbs	$232.00	GT	$ 47,328
Turbine Hall Steel	230,000	lbs	$232.00	GT	$ 26,680
Ganty Crane	120,000	lbs	$232.00	GT	$ 13,920
Administration Building Steel	230,000	lbs	$232.00	GT	$ 26,680
F.O. Tank	730,000	lbs	$232.00	GT	$ 84,680
Condensers	670,000	lbs	$232.00	GT	$ 77,720
Turbines	400,000	lbs	$232.00	GT	$ 46,400
Motor Weights	92,399	lbs	$0.32	lb	$ 29,567
Cable	83,000	lbs	$2.13	lb	$ 176,790
Fuel Yard and other Miscellaneous	200,000	lbs	$232.00	GT	$ 23,200
				Total	$ 824,289

Figure C.1 - Missouri City Scrap Value Cost

[1] Scrap value as of April 16, 2015.

IPL - Missouri City
Boiler Weights (per Unit)

Boiler:		220,000	lbs
Structural Steel Framing for Boiler, Superheater, Waterwalls, Air Heater, Fans, etc:		230,000	lbs
Superheater:		108,000	lbs
Water Walls:		190,000	lbs
Air Heater:		265,000	lbs
Duct Work:		79,950	lbs
ID Fan:		29,000	lbs

Total Weight (per Unit): 1,121,950 lbs
Total Weight: 2,243,900 lbs

Pipe Description	Length (ft)	Material Spec.	Equipment List #	Found on sheet:	Pipe Diameter	Unit Weight (lbs.)	Total Weight (lbs.)
8" Main Steam	112	P1	A01	8, 9, 18, 19	8	50.9	5700.8
4" Aux from Main to PRV	15	P1	A02	19	4	14.98	224.7
6" Steam from A2 to Desuperheating nozzle	8.5	P1	A03	19	6	28.57	242.845
3" Aux Steam	99	P1	A04	8, 9, 18, 19	3	10.25	1014.75
2" Aux Steam	13	P1	A05	8	2	5.02	65.26
1.5" Steam from A5 to Aux Oil Turbine Pump	58	P1	A06	8	1.5	3.63	210.54
1" Aux Steam from A5 to Starting Ejector	16.5	P1	A07	8	1	2.17	35.805
Auxillary steam PRV to flange past 260# safty valve	45	P2	A08	18	6	28.57	1285.65
A8 to 260# header	5	P5	A09	18	6	18.97	94.85
260# common header	25	P5	A11	18, 21	6	18.97	474.25
A11 to 150# safty valve	1	P5	A12	18	1	28.57	28.57
150# steam header	7	P5	A13	18	6	18.97	132.79
A13 to boiler burner header	10	P5	A14	18	6	18.97	189.7
A22 to building heating system	70	P5	A23	18	6	18.97	1327.9
A22 to intake structure heating system	45	P5	A24	18, 21	3	18.97	853.65
10" Extraction No. 4 to Heater No. 1	21	P5	B01	11, 13	10	40.5	850.5
8" Extraction No. 3 to Heater No. 2	135	P5	B02	11, 14, 16	8	28.6	3861
6" Extraction No. 2 to Heater No. 3	36	P5	B03	11, 13	6	18.97	682.92
6" Extraction (B3) to 8" Extraction (B2)	20	P5	B04	11	6	18.97	379.4
6" Extraction (B3) to Evaporator	96	P5	B05	11, 14, 16	6	18.97	1821.12
4" Extraction No. 1 to Heater No. 4	54	P5	B06	11, 14	4	10.79	582.66
4" Extraction (B6) to 8" Extraction (B2)	22	P5	B07	11, 14	4	10.79	237.38
4" Extraction (B6) to B5	11	P5	B08a	11	4	10.79	118.69
4" Extraction (B6) to B5	18	P5	B08b	11	6	18.97	341.46
8" Line from B2 to Back Pressure Valve	16	P5	C01	16	8	28.6	457.6
8" line from Evaporator to C1	8.5	P5	C02	16	8	28.6	243.1
Evaporator to Evaporator Feed Heater	7.5	P5	C03	16	8	28.6	214.5
8" Steam Exhaust	134	P5	C04a		8	28.6	3832.4
6" Disch. From Priming Eject	28.5	P5	C04b	8, 9	6	18.97	540.645
4" Exhaust from Aux Oil Pump	45.5	P5	C05	8, 9	4	10.79	490.945
B.F.P. Turbine Exhaust to line B2	7	P5	C06	15	8	28.6	200.2
B.F. Pumps Disch. To and including Header	153	P3	D01	11, 15, 18, 19, 20,	4	14.98	2291.94
Header to Heater No. 3 including bypass	25	P3	D02	12	4	14.98	374.5
Heater No. 3 to Heater No. 4 including bypass	30	P3	D03	12	4	14.98	449.4
Heater No. 4 to Boiler stop check valve	30	P3	D04	14	4	14.98	449.4
Emergency feed from D1 to boiler stop check valve	30	P3	D05	14	4	14.98	449.4
T.D.B.F. Pump recirculation to Htr. No. 2	64	P3	D06a	12, 16	1.25	3	192
T.D.B.F. Pump recirculation to Htr. No. 2	18	P3	D06b	12, 16	1	2.17	39.06
M.D.B.F. Pump recirculation to D6	5	P3	D07	12	1	2.17	10.85
D1 to desuperheater in line A8	42	P3	D08	19	1	2.17	91.14
D8 to Chem Feed Tank	57	P3	D09	11, 12, 15, 19	1.25	3	171
Chem Feed tank to boiler connection	28	P3	D10	19	1	2.17	60.76
Hotwell to Condensate Pumps	2	P6	E01	13	6	18.97	37.94
Condensate pump to condensate cooler including bypass	35	P6	E02	11, 15	4	10.79	377.65
Condensate cooler to hyd. Cooler including bypass	16	P6	E03a	11	4	10.79	172.64

Condensate cooler to hyd. Cooler including bypass	35	P6	E03b	11	6	18.97	663.95
Hyd. Cooler to air ejector	15	P6	E04	11, 13	4	10.79	161.85
E3 to bearing water make-up	25	P6	E05a	11	2	3.65	91.25
E3 to bearing water make-up	14	P6	E05b	11	1.5	1.09	15.26
E5 to gland water storage	103	P6	E06	11, 16	1.5	1.09	112.27
Air ejector to Heater No. 1 including bypass	35	P6	E07	13	4	10.79	377.65
Recirculation line from E7 to condenser	20	P6	E08	13	2.5	5.79	115.8
bypass from E7 to lower surge tank	15	P6	E09	14	3	7.58	113.7
Heater No. 1 to Heater No. 2	62	P6	E10	14, 16	6	18.97	1176.14
Heater No. 1 to Drip Pump	18	P6	E11	15	2.5	5.79	104.22
Drip Pump to E10	9	P6	E12	14	2.5	5.79	52.11
Recirculation line from E12 to Heater No. 1	21	P6	E13	14	3	7.58	159.18
Drip Pump bypass from E11 to condenser.	6	P6	E14	15	3	7.58	45.48
Return line from lower surge tank to condenser	40	P6	E15	12, 14	3	7.58	303.2
Lower Surge Tank to transfer pump	5	P6	E16	14	4	10.79	53.95
Transfer pump to E10	18	P6	E17	12	3	7.58	136.44
Heater No. 2 to B.F. Pumps	74	P6	E18	12, 15, 16	1.25	3	222
Heater No. 2 overflow to lower surge tank	58	P6	E19	12, 15, 16	6	18.97	1100.26
Heater No. 2 drain to line E19	4.5	P6	E20	16	2	3.65	16.425
Line E19 to drain	25	P6	E21	14, 15	6	18.97	474.25
Lower surge tank overflow to line E21	10	P6	E22	14	3	7.58	75.8
Gland seal water tank to turbine	same as E6	same as E6	E23	same as E6	same as E6		n/a
Heater No. 1 bypass from line E29 to E14	10	P6	E24	15	2.5	5.79	57.9
Condensate return header from lower surge tank No. 1 to lower surge tank No. 2	60	P6	E25	17	4	10.79	647.4
Heater No. 4 drips to Heater No. 3	13	P6	E26	13, 14	2.5	5.79	75.27
Heater No. 3 bypass from line E26 to line E28	10	P6	E27	14	2.5	5.79	57.9
Heater No. 3 drips to Heater No. 2	53	P6	E28	15, 16	4	10.79	571.87
Line E28 to Heater No. 1	19	P6	E29	15	2.5	5.79	110.01
Boiler drum safety valve vents through roof	63	P6	G01	22	8	28.6	1801.8
superheater safety valve vent thru roof	61.5	P6	G02	22	6	18.97	1166.655
Drip pan elbows to line F8		P6	G03				0
Safety valve drains to line G3		P6	G04				0
Condensate pump vents to condenser	21	P6	G05	13, 15	4	10.79	226.59
Heater No.1 vent to condenser	15	P6	G06	15	3	7.58	113.7
Drip Pump vent to Heater No. 1	10	P6	G07	15	3	7.58	75.8
Blowdown tank vent thru roof	102	P6	G08	20	8	28.6	2917.2
Drain header to ash sump	43	P6	G09	17	3	7.58	325.94
Evaporator drain to line G9	56	P6	G10	17	3	7.58	424.48
Evaporator Feed Heater drain to line G10	71	P6	G11	16, 17	3	7.58	538.18
6" Air Suction	51	P6	K1 & K2	8, 9	6	18.97	967.47

Total Weight (per Unit): **47,554** lbs
Total Weight: **95,108** lbs

EQUIPMENT DATA: The Bidder shall fill in the following blanks on the equipment he proposes to furnish:

ITEM 1, BOILER

Name of Manufacturer: Foster Wheeler

Type of Boiler: 2 Drum

Boiler heating surface, effective: 13550

Net weight of boiler, empty: 220,000

With water: 300,000

Drums - Number: 2

Size: 60" 42"

Thickness: In Acc. with A.S. M.E. Code

Tubes - Number: 672 36

SA 210 material
use rod E7015
E7016
E7018
American Welding Standard
Procedure A-5.1

Size: 2 1/2" 3"

Gauge: .180 ~~.200~~ .180

Type and make of baffle material: Tile, A.P. Green or Equal

Size of water inlets: 4"

Size of steam outlet: 18-3" Tube

Blow-off valves - Make: Hancock

Number: 2 Tandem Sets

Size: 1 1/2"

Safety valves - Make: Crosby HNA 55

Number: 2

Size: 1-3" 1-4"

Make and type of water column: Reliance WM-900

Maximum water level variation indicated by gauge glasses, inches: 12 1/2"

Weight of structural steel framing for Boiler, superheater, waterwalls,

air heater, fans, etc.: 230,000

ITEM II, SUPERHEATER

Name of Manufacturer: Foster - Wheeler

Type of Superheater: Bare Tube

Effective heating surface: 8700 Sq. Ft.

Velocity of gas through - First stage: 25 ft/sec. Max.

Second stage: 60 " " "

Net weight of superheater: 108,000

Size and thickness of headers: Inlet - 16" OD x 1¼" Outl. 12¾ OD x 1¼" Int 10¾ OD x 1⅛

Size of superheater outlet: As Req'd.

Tubes - Number: 116 Elements

Inlet tubes-Carbon Steel
outlet tubes
T11 - T22

Size: 2" -

T22 section leading to superheater header outlet

weld rod

Gauge: ~~.185~~" - .165 according to FW's Partslist

B-3
E-9015
E-9016
E-9018

P8H 90LE

Safety valves - Make: Crosby

Number: HNA 5 7

Size: 2½"

Type of superheat control (heat exchanger or damper): Heat Exchanger

Maximum temperature of gas passing dampers: —

Automatic temperature regulator - Make: General Regulator

Type: electric

Temperature reducing capacity of equipment, (at rated unit capacity) F : 50°F

ITEM III WATERWALLS

Name of Manufacturer: Foster Wheeler

Effective hearing surface: 6895 sq. ft.

Velocity of gases entering first row of screen tubes, fps 29 max.

Size and gauge of bare tubes: 3" x .200"

Size and gauge of stud tubes: —

Total lineal feet of tube: 16625

Total area of flat projected surface: 4050

Spacing of tubes: 3 1/4"

Size and thickness of headers: 12 3/4" OD x 1.312"

Type of furnace bottom: Hopper

Total cu ft of furnace volume: 15700

Weight of water walls, empty 190,000

filled with water: 240,000

Blow-off valves - Make: Hancock

Number: 2 Tandem Sets

Size: 1 1/2"

ITEM IV, AIR HEATER

Name of manufacturer: Foster Wheeler

Type of air heater: Tubular

Effective heating surface: 49800

Weight of heater: 265000

Tubes - Number, hot section: 1166

cold section: 1166

Size: 2 1/2"

Gauge: 14

Length, hot section: 39'

cold section: 26'

Approximate load, assuming 80 F inlet air, at which it will be necessary to start re-circulating air to the air heater, lbs per hr: 80,000

ITEM V, DUST COLLECTOR

Name of manufacturer: Western Precip

Type: 9 x B12

Size: 171-9

Number of cyclones per collector: 171

Individual inlets to each cyclone: (Yes) (X) (No) ( )

Storage hopper capacity (hours): 8 Hr.

Guaranteed collections efficiency at rated boiler load: 80%

Particle size	0-5 Microns	15%
	5-10 Microns	25%
	10-20 "	20%
	20-30 "	20%
	30-43 "	10%
	over 43 "	10%

Guaranteed overall collection efficiency based on specified fly ash analysis: 80%

ITEM VI FIRING EQUIPMENT

Name of manufacturer of burners: Babcock & Wilcox

Type of burners: Circular P.C., Oil, Gas

Maximum gas pressure required: 7.5 Psig

Maximum oil pressure required: 125 Psig

Maximum capacities (~~lbs steam~~ BTU per hr, each burner)

Gas: 100,000,000

Oil: "

Pulverized coal: "

Name of manufacturer of pulverizers: B & W

Type pulverizer: E-47

Capacity, lbs of coal per hr: 16,000

Maximum temperature of air that can be used in pulverizer: 600°F

Speed of pulverizer, rpm: 600 RPM

Make of motor: G.E.

Size: 200 Speed: 600

Type of fan (blower or exhauster): ~~B~~ Blower

Speed of fan, rpm: 1800

Make of motor: (mill motor)

Size: — Speed: —

Name of manufacturer of feeder: B & W

Type of feeder: Table

Make of motor: G.E.

Size: 1½/¾ Speed: 1800/900

ITEM VII, SOOT BLOWERS

Name of manufacturer: Vulcan

Type of head: 10 Retract. P-3

Size of elements: 1½"

Number of elements: 11

ITEM VIII, DUCT WORK

Name of fabricator: Foster-Wheeler or Equal

Maximum velocity of air or gases in ducts, fpm: 3000

Total weight of duct work: 79,950

ITEM IX, FORCED DRAFT FAN

Name of manufacturer: Sturtevant

Type: TV 10 #100 DW DI Arrangement 3 Class 3

Single or double width: Double

Fan characteristics at rated capacity - Capacity: 257,000 # Air/Hr @ 120°F

Discharge pressure: 9.7" Speed: 1170

Diameter of rotor:

Type of bearings: Double Ring Water Cooled Self Al.

Thickness of housing: In Acc. W Specs.

Thickness of inlet duct: "

Kind of Damper: "

Overall dimension of fan, width: "

height: "

Overall length of fan and motor: "

Make of motor: G. E. or Westinghouse

Size: 150 HP

Speed: 1200

Make and kind of coupling: Waldron or Equal

Net weight of - Motor: 2200

Fan: 6500

ITEM X, INDUCED DRAFT FAN AND STACK

Make of fan: Buffalo Forge

Size of fan: #13 Shld.

Rotor - Type: Modified Radial

Diameter: 70 3/8"

Fan characteristics at rated speed - Capacity: 335,000 # Gas @ 308°F

Discharge pressure: 11.80

Type of bearings: In Acc. W Specs.

Thickness of housing: "

Thickness of bearings: "

Size of shaft: "

Kind of damper: "

Make of higher speed motor: G. E. or Westinghouse

Size: 300 HP

Speed: 900

Make of lower speed motor: GE or Westinghouse

Size: 150

Speed: 720

Type of motor bearings - Higher speed motor: In Acc. W Specs.

Lower speed motor: "

Maximum capacity of unit, using gas as fuel, with dust collector by-passed and using lower speed motor, lbs/hr: 220,000

Make and kind of couplings: Waldron or Equal

Net weights - Fan only: 22000

Higher speed motor: 7000

Lower speed motor:

Overall dimensions - Length of fan and motors:

Height of fan: 106"

Width of fan: 58"

Approximate overall height of stack: 67½" incl. 20' Supp. Cyl.

Diameter of stack: 8'

Weight of stack: 65,000

ITEM XI, INSULATION

Make of high temperature insulation: Baldwin Hill Mono Block

Make of 85% magnesia insulation: —

Make of plastic insulation: Eagle Picher

ITEM XII, SETTING

Location : State type and thickness of materials used :

Furnace front wall

(a) Area around burner: 13½" F. B. 1" H.T.

(b) Other areas: 1½" Tile 4" Rock Wool

Furnace side walls: " "

Furnace rear wall: " "

Furnace bottom: 1½" Lt. Wt. Castable; 4" Rock Wool + ½" H.F. on Housing

Furnace top: 1½" Tile; 1" H.T.; 4" Rock Wool

Boiler side walls: 3" Tile; 1" H.T.; 4" Rock Wool

Boiler rear wall: 3" Tile; 3" Rock Wool

Boiler roof: 4" Rock Wool + ½" H.F. on Housing

Soot hopper: 4" H.T.; 4½" #1 F.B.

Type and make of setting: Foster Wheeler

Make and trade name of - Tile: A.P. Green Empire

Firebrick: " Empire or Ozark

Insulating block: Baldwin Hill Mono Block

Insulating cement: A.P. Green

High temperature cement: "

Type of expansion joint material: Foster Wheeler STD

Make of expansion joint material: " " "

Total weight of - Supporting castings: Incl. Below

Structural steel: " "

Suspended refractory: " "

Setting: & Casings $38,000

Maximum internal pressure setting will withstand, lbs/sq ft: 36

The following radiation losses shall be based on the maximum furnace temperature using coal as fuel when generating steam at the rate of 220,000 pounds per hour and with boiler room temperature at 80 F. The losses shall include loss due to castings, studs, doors, etc.

Location	Radiation losses (Btu/sq ft/hr)
Furnace side walls:	40
Boiler side walls:	35
Furnace roof:	50

PERFORMANCE DATA: Each bidder shall furnish complete information on the equipment he proposes to furnish by completing the following tabulation. The bidder guarantees the following performance, burning coal as fuel, at 200,000 pounds of steam per hour. Each bidder shall estimate the performance at other indicated loads and shall also estimate the performance as indicated using natural gas and oil as fuel.

USING COAL AS FUEL

Steam Generation, lbs per hr	130,000	200,000	220,000
Pressure at superheater outlet, psig	875	875	875
Pressure drop through superheater and control, psig	14	33	40
Pressure in steam drum, psig	889	908	915
Percent excess air in boiler exit gases	20	20	20
CO_2 in first pass, percent	16	16	16
CO_2 at boiler outlet, percent	15½	15½	15½
Temperature of boiler feedwater, F	325	355	365
Temperature at superheater outlet, F	840	900	900
Temperature of air to airheater, F	80	80	80
Maximum temperature of gas entering first row of boiler tubes, F	1660	1850	1895
Temperature of gas leaving boiler, F	600	645	653
Temperature of gas leaving airheater, F	268	300	308
Temperature of air leaving airheater, F	530	540	542
Heat losses, percent			
Dry gas	4.35	5.10	5.26
Moisture and Hydrogen (fuel)	5.47	5.54	5.56
Moisture in air	.07	.09	.09
Unburned combustible	.70	.50	.50
Radiation	.88	.56	.50
Unaccountible	1.50	1.50	1.50
Total Heat Losses	12.97	13.29	13.49

Overall Efficiency, percent	87.13	86.71	86.51
Fuel fired, lbs per hr	14820	23000	26000
Gas leaving air heater, lbs per hr	170,500	267,000	291,000
Furnace heat release (fuel only), Btu/ cu ft / hr	10,700	16,600	18,000
Carry over of solids to superheater, ppm	1.0	1.0	1.0
Draft Losses, inches of water			
Furnace	.1	.1	.1
Boiler and superheater	.64	1.57	1.86
Air heater	1.24	3.05	3.60
Dust collector	1.02	2.50	2.96
Ducts and Dampers	.18	.45	.54
Total static suction at fan	3.18	7.67	9.06
Air Pressure, inches of water			
Drop through air heater	1.12	2.80	3.30
Ducts and dampers	.28	.70	.82
Wind box pressure	2.50	2.20	2.50
Total static pressure at fan	3.90	5.70	6.62
Power input, KW			
To mill motors	55	97.8	10.3
To exhauster or blower motors	81.3	143	149.4
To feeder motors	Incl in mill power		
To F. D. fan motor		63.5	
To I. D. fan motor		112	
To other motors (if any) by Contractor	—	—	—
Total to motors (one unit only)	(As follows)	416.3	(As follows)

USING NATURAL GAS AS FUEL

Steam Generation, lbs per hr	130,000	200,000	220,000
Pressure at superheater outlet, psig	875	875	875
Pressure drop through superheater and control, psig	14	33	40
Pressure in steam drum, psig	889	908	915
Percent excess air in boiler exit gases	15	15	15
CO_2 in first pass, percent	11	11	11
CO_2 at boiler outlet, percent	10½	10½	10½
Temperature of boiler feedwater, F	325	355	365
Temperature at superheater outlet, F	848	900	900
Temperature of air to airheater, F	80	80	80
Maximum temperature of gas entering first row of boiler tubes, F	1630	1790	1850
Temperature of gas leaving boiler, F	603	640	651
Temperature of gas leaving airheater, F	278	298	305
Temperature of air leaving airheater, F	511	530	535
Heat losses, percent			
Dry gas	3.78	4.28	4.42
Moisture and Hydrogen (fuel)	10.55	10.65	10.70
Moisture in air	.10	.12	.12
Unburned Combustible	—	—	—
Radiation	.88	.56	.50
Unaccountable	1.50	1.50	1.50
Total Heat Losses	16.81	17.11	17.24
Overall Efficiency, percent	83.19	82.89	82.76
Fuel fired, cu ft per hr	180,000	280,000	306,000
Air supplied to furnace, lbs per hr	142,000	220,000	240,000

Gas leaving airheater, lbs per hr	162,000	251,000	274,000
Furnace heat release (fuel only), Btu/cu ft/hr	11,100	17,300	18900
Carry over of solids to superheater, ppm	1.0	1.0	1.0
Draftlosses, inches of water			
Furnace	.1	.1	.1
Boiler and Superheater	.50	1.22	1.44
Air heater	.98	2.35	2.80
Dust collector	by pass	by pass	by pass
Ducts and Dampers	.14	.35	.42
Total static suction at fan	1.72	4.02	4.76
Air pressure, inches of water			
Drop through air heater	1.37	3.25	3.85
Ducts and dampers	.34	.82	.96
Wind box pressure	3.00	2.50	3.00
Total static pressure at fan	4.71	6.57	7.81
Power input, KW			
To F. D. fan motor		To	
To I. D. fan motor		Follow	
Total to motors (one unit only)			

USING ~~OIL~~ AS FUEL

Steam Generation, lbs per hr	130,000	200,000	220,000
Pressure at superheater outlet, psig	875	875	875
Pressure drop through superheater and control, psig	14	~~6~~ 33	40
Pressure in steam drum, psig	889	908	915
Percent excess air in boiler exit gases	15	15	15
CO_2 in first pass, percent	14½	14½	14½

CO_2 at boiler outlet, percent	14	14	14
Temperature of boiler feedwater, F	325	355	365
Temperature at superheater outlet, F	825	900	900
Temperature of air to airheater, F	80	80	80
Maximum temperature of gas entering first row of boiler tubes, F	1690	1850	1890
Temperature of gas leaving boiler, F	597	636	643
Temperature of gas leaving air heater, F	261	280	286
Temperature of air leaving air heater, F	500	525	527
Heat losses, percent			
Dry gas	3.78	4.17	4.30
Moisture and Hydrogen (fuel)	5.91	5.96	6.00
Moisture in air	.10	.11	.11
Unburned Combustible	—	—	—
Radiation	.88	.56	.50
Unaccountable	1.50	1.50	1.50
Total Heat losses	12.17	12.30	12.41
Overall Efficiency, percent	87.83	87.70	87.59
Fuel fired, cu ft per hr	9050	13900	15,200
Air supplied to furnace, lbs per hr	137000	212000	231,000
Gas leaving airheater, lbs per hr	156000	241000	263000
Furnace heat release (fuel only) Btu/cu ft/hr	10600	16400	18000
Carry over of solids to superheater, ppm	1.0	1.0	1.0
Draft losses, inches of water			
Furnace	.1	.1	.1
Boiler and superheater	.54	1.28	1.52
Air heater	1.04	2.50	2.95

Dust Collector	by pass	by pass	by pass
Ducts and dampers	.14	.37	.44
Total static suction at fan	1.82	4.25	5.01
Air Pressure, inches of water			
Drop through air heater	1.26	3.03	3.58
Ducts and dampers	.32	.76	.89
Wind box pressure	3.00	2.50	3.00
Total static pressure at fan	4.58	6.29	7.47
Power input, KW			
To F. D. fan motor		20	
To I. D. fan motor		Follow	
Total to motors (one unit only)			

IPL - Missouri City
Baghouse Weights

Baghouse Ductwork and Paneling Weights

Member	Number	Length (foot)	lb/foot	weight (lb)	
L2X2X1/4	4	6	3.19	76.56	
C5X6.7	4	36	6.7	964.8	
C6X8.2	4	25	8.2	820	
L3X2X1/4	4	13	4.1	213.2	
C5X6.7	2	45	6.7	603	
C7X9.8	1	52	9.8	509.6	
W10X26	1	30	26	780	
L2 1/2X1 1/2 X 1/4	1	23	3.22	74.06	
C5X6.7	1	60	6.7	402	
W10X26	1	20	26	520	
C5X6.7	1	2332	6.7	15624.4	
C5X6.7	2	3424	6.7	45881.6	
C4x5.4	2	440	5.4	4752	
C5X6.7	1	990	6.7	6633	
W10X26	1	1164	26	30264	
				108,118	lbs
Assume plate adds 50% additional weight:				162,177	lbs
Weight of Ductwork:				**270,296**	lbs

Drawings of the baghouse structural steel was not available.
Assume that the steel weighs approximately 60% of the boiler steel: **138,000** lbs

Total Estimated Scrap Weight of Baghouse: **408,000** lbs

IPL - Missouri City
Motor Weights

Service	Hp	Estimated Weight
MC2 Low Speed ID Fan	150	2461
MC1 Low Speed ID Fan	150	2461
MC1 Ash Booster Pump	75	875
MC2 Ash Booster Pump	75	875
MC Tripper Car Motor	10	215
MC River Booster Pump	125	2057
MC River Booster Pump	125	2057
MC 1A Pulverizer	200	3270
MC 1B Pulverizer	200	3270
MC 2B Pulverizer	200	3270
MC 2A Pulverizer	200	3270
MC Conveyor Belt No. 4	20	300
MC Crusher	75	875
MC Magnetic Separator	15	263
MC 2 Reverse Air Fan	125	2057
MC 1 Reverse Air Fan	125	2057
MC 1A CW Pump	125	2057
MC 2A CW Pump	125	2057
MC 1B CW Pump	125	2057
MC 2B CW Pump	125	2057
MC 1A Boiler Feed Pump	600	9743
MC 1B Boiler Feed Pump	600	9743
MC 2A Boiler Feed Pump	600	9743
MC 2B Boiler Feed Pump	600	9743
MC 2 High Speed ID Fan	300	4600
MC 1 High Speed ID Fan	300	4600
MC 2 FD Fan Motor	150	2461
MC 1D FD Fan Motor	150	2461
MC 1 Turning Gear Motor	3	138
MC 2 Turning Gear Motor	3	138
MC Hydrogen Seal Oil	3	138
MC 1A Condensate Pump	50	515
MC 2 Condensate Pump	50	515
		92,399 lb

APPENDIX D

TRC REPORT - REMOVAL, ABATEMENT, MANAGEMENT, AND DISPOSAL OF REGULATED MATERIALS

415 South 18th St.
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314.241.2743 FAX

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October 25, 2013

Mr. Jeffrey Fleenor, PE
Sega, Inc.
16041 Foster
PO Box 1000
Overland Park, Kansas 66085-1000

**RE: Budgetary Cost Estimate
Removal, Abatement, Management and Disposal of Regulated Materials
Independence Power & Light
Missouri City Power Plant**

Dear Mr. Fleenor:

TRC Environmental Corporation (TRC) is pleased to provide Sega, Inc. (Sega) with this Budgetary Cost Estimate for the removal, abatement, management and disposal of regulated materials associated with decommissioning the Independence Power & Light Missouri City Power Plant (the Plant). The Missouri City Power Plant is located at 22225 State Route 210, Missouri City, Missouri and consists of two 19-megawatt coal-fired units that were constructed in the 1950s. Figure 1, attached, presents a Site Plan. Independence Power & Light is considering retiring the Plant in 2015, at which time the Plant structures will be demolished, repurposed or placed into long-term layup.

SCOPE OF WORK

TRC reviewed existing information provided by the Plant and Sega, performed a visit and tour of the Plant, and conducted interviews with Plant personnel to identify known or suspected regulated materials. Documentation that TRC reviewed included: a partial set of construction blueprints; original construction specifications for the Plant; and a "Report on the Life Management Study", prepared by Sega and dated January 1997. The list of drawings reviewed is presented as Table 1, attached. Additionally, TRC utilized Great Plains Asbestos Control, Inc. (Great Plains) of Kearney, Nebraska as a subcontractor to assist TRC in evaluating means and methods constraints, and developing asbestos abatement costs. The results of this work were used to develop a budgetary cost estimate for abatement, recycling and/or disposal of regulated materials at the Missouri City Station.

FINDINGS

Regulated materials at the Plant include:

- Asbestos-containing materials (ACM).
- Metal-based coatings.
- Polychlorinated biphenyls (PCBs).
- Universal wastes.
- Refrigerant-containing equipment.
- Petroleum products.
- Fire Suppressants/Extinguishers.
- Miscellaneous Materials.

Asbestos-Containing Material

Asbestos-containing material (ACM) is material containing greater than one percent (1%) asbestos. The United States Environmental Protection Agency (USEPA) distinguishes between friable and non-friable forms of ACM. Friable ACM contains more than 1% asbestos and can be "crumbled, pulverized, or reduced to powder by hand pressure when dry." USEPA also identifies three (3) categories of ACM used in facilities: Surfacing Materials, Thermal System Insulation, and Miscellaneous Materials. ACM must be properly abated and managed during demolition activities by licensed contractors.

Suspect ACM identified at the Plant included boiler insulation, insulation on piping and duct work, the coating on the condensers, gaskets, sheet packing, transite panels and sealant on transite, cloth pipe wrap, window glazing, window sealant, floor tiles, and floor tile and baseboard mastic.

Based on information obtained from Plant personnel, building roofs have recently been replaced and do not contain asbestos. Plant personnel also reported that ACM abatement has occurred in select locations to permit repairs or maintenance of equipment; however, no documents describing the locations and extent of abatement were available for TRC's review. Additionally, Plant personnel indicated that a comprehensive asbestos survey of the Plant has not been prepared.

Metal-Based Coatings Assessment

Painted metal and concrete were observed throughout the Plant during the site visit. Based on the age of the Plant, it is anticipated that the observed coatings contain concentrations of metals (e.g., lead, cadmium, chromium, etc.) that will require testing and possibly abatement prior to demolition and reuse as on-site backfill.[1]

Coated steel was not considered in this assessment, as it is exempt from lead disposal regulations if recycled by a certified recycling facility. Steel coatings were assumed to contain lead and the abatement/demolition contractor will be required to comply with 29 CFR 1926.62, the "Lead in Construction" rule.

PCBs

PCBs are commonly found in electrical equipment that requires dielectric fluid such as transformers and capacitors as well as hydraulic machinery, vacuum pumps, compressors and heat exchanger fluids. PCBs were also used in fluorescent lighting ballasts and caulking.

Potential sources of PCBs at the Site include fluorescent light ballasts and caulking. TRC typically assumes that all fluorescent light ballasts contain over 50 parts per million (ppm) of PCBs, and all ballasts must be removed into 55-gallon drum(s) and recycled pursuant to 40 CFR 761.60-62. This is cost effective even for those ballasts labeled "No PCB", as it has been determined by the USEPA that although ballast may not contain PCBs, the potting material must be considered suspect as the potting material has been found to contain greater than 50 ppm PCBs in ballasts labeled "No PCB". Consequently, it is recommended that, during demolition activities, all ballasts, including those labeled "No PCB" be containerized for disposal as PCB waste due to the presence of potting material.

The 1997 "Report on the Life Management Study" indicated that the auxiliary supply and lighting transformers, installed in 1953 and tested in 1981, contain PCBs. However, interviews with Plant personnel indicated that all PCB-containing transformers, capacitors, and switch gear were removed and replaced after a fire at the Plant in the 1970s. Based on this information, TRC has assumed that the electrical equipment present at the Site does not contain PCBs; however, it was reported that at the time of the fire, transformers and other oil-filled electrical equipment were damaged. PCB-containing oils may have been released from this equipment potentially contaminating building materials (e.g., concrete). If present, elevated PCB concentrations in building materials would preclude their use as on-site fill and result in increased disposal costs. TRC has not included costs for PCB-impacted building materials in the budgetary estimate since there is insufficient information to determine the quantity of material that is potential impacted.

Universal Waste

40 CFR Part 273 establishes requirements for managing universal wastes. Universal wastes are those wastes that would reasonably be expected to be classified as hazardous wastes but, due to

[1] It is typically advantageous to crush concrete on-site and use it to backfill below grade areas (e.g., basements, pits, etc.) because it reduces the costs for disposal and importation of backfill. The Missouri Department of Natural Resources (MDNR) requires the removal of metal-based paint from concrete prior to its placement as fill.

their universal use in industrial and residential properties, regulations were created to ensure that they are managed in a manner that prevents harm to the environment while reducing the regulatory burden on generators of these wastes. Universal wastes include the following waste types:

- Batteries as described in 40 CFR Section 273.2
- Pesticides as described in 40 CFR Section 273.3
- Mercury containing equipment as described in 40 CFR Section 273.4 (e.g., electrical switches, lamps, manometers, regulators, and thermometers)
- Lamps as described in 40 CFR Section 273.5

At the Plant, TRC observed lead-acid batteries and suspect mercury-containing equipment. Mercury-containing equipment potentially present at the Plant includes electrical switches, lamps, manometers, regulators, and thermometers. Lamp types potentially present at the Plant include fluorescent lamps, high-pressure sodium lamps, mercury vapor lamps and metal halide lamps. Pesticides were not observed within the Plant during the Site visit.

Refrigerant-Containing Equipment

Refrigerant-containing equipment present at the Plant includes air conditioners, refrigerators, condenser units, and water coolers.

Petroleum Products

Diesel fuel, various lubricants, fuel oil, gasoline, and mineral oil are stored at the Plant. An approximately 250,000 gallon fuel oil aboveground storage tank (AST) is located at the Plant. It is anticipated that most of the petroleum products stored on-site will either be consumed through Plant operations or transferred to Independence Power & Light's Blue Valley Plant. Prior to demolition, residual quantities of petroleum will be removed, and storage tanks will be cleaned and removed. The concrete containment structure for the 250,000 gallon fuel oil AST will be removed to surrounding grade.

An underground product line connecting the AST to the boiler house failed two years ago. Plant personnel reported that the line was repaired; however, repair documentation was not available for TRC review. Petroleum-contaminated soil may be present in subsurface soils in the vicinity of the failed line.

Fire Suppressants/Extinguishers

The fire suppression system at the Plant consists of reeled hoses for Unit 1 and Unit 2. Water is supplied from on-site wells to the hoses via a fire suppression piping system. A fire hydrant system is in place for exterior fire suppression. Hand-held fire extinguishers are found throughout the Plant.

Miscellaneous Materials

TRC identified miscellaneous stored containers containing oils, oxidizers, compressed gases, antifreeze, cleaning solutions, paint, corrosion inhibitor, neutralizing acid, water treatment products, absorbent material and other materials which do not fall into one of the other categories.

DATA GAPS

As noted above, the documentation of hazardous and regulated materials at the Plant is limited. TRC recommends the performance of a Regulated Materials Survey (RMS) to fully define the presence and quantity of these materials for use in developing plans and specifications for Plant demolition. Additionally, TRC recommends collecting samples of building materials for laboratory analysis to determine material handling requirements.

ASSUMPTIONS

To develop the cost estimate, TRC made certain assumptions regarding the presence and quantity of regulated and hazardous materials at the Plant. These assumptions include:

- Certain asbestos-containing materials have been abated and replaced with non-asbestos insulation materials. These replacement materials and previously abated areas are not considered in this report. The thoroughness of prior abatement efforts cannot be ascertained with removal of jackets and insulation.
- Certain components of the equipment (primarily boilers) have been stripped of asbestos with some remnant material remaining; however, no credit has been assigned to these areas (e.g., all boiler insulation is considered to be asbestos containing. Additionally, interior packing and components of the boilers (e.g., firebrick, refractory, interior packing, etc.) are considered asbestos-containing.
- The removal of regulated and hazardous materials would be performed in conjunction with Plant demolition.
- The cost estimate for demolition of the 250,000 gallon AST and concrete containment structure to surrounding grade (included under the petroleum products heading in Table 3) does not include does not include a credit for scrap value for the steel.
- Due to their inaccessibility and lack of drawings, no costs have been included for potential ACM in cable raceways, pipe trenches or equipment pits.
- Labor costs have been projected at current Union Labor rates. No allowance was given for non-working Laborers (Steward, etc.).
- It is assumed that Laborers rather than Operating Engineers will be permitted to operate lift equipment and fork lifts.
- It is assumed that the Plant will provide the Contractor with electrical, water and sanitary sewer connections.

- Abatement activities are assumed to be performed between March and November, when temporary heat will not be required.
- Below grade piping will be capped and abandoned in place.
- Remediation of subsurface soil and groundwater conditions is not required.
- No soils or building materials require disposal as waste regulated by the Resource Conservation and Recovery Act (RCRA) or Toxic Substances Control Act (TSCA).
- Oversight of Abatement Contractor is not included in the estimate.

BUDGETARY COST ESTIMATE

Using the results of the site inspection and document review, TRC and its subcontractor developed the budgetary cost estimate by utilizing data from comparable plants. Specifically, costs were developed using the following methodologies:

- For asbestos abatement and petroleum product removal, assumptions were developed regarding the durations for work crews based on the field observed conditions. This method is consistent with the approach taken by abatement contractors to this type of project (e.g., they erect containments that encompass entire sections of the structures and abate all the materials within). Abatement contractors estimate projects in this manner because unit rates lose accuracy at larger scales because the cost assumptions aren't maintained. Without a comprehensive asbestos survey, it is not possible to accurately quantity ACM by linear or square foot.
- For the removal and disposal of metal-based coatings from concrete, TRC relied on costs received earlier this year from a demolition contractor for a similar sized plant in Missouri.
- For the PCB-containing light ballasts and caulk, universal wastes, refrigerant-containing equipment, fire extinguishers and other miscellaneous materials, TRC developed estimates of material quantities and applied unit rates from competitively bid projects. The estimated quantities are presented in Table 2, attached.

Table 3, attached, presents the budgetary cost estimate for the removal, abatement, management and disposal of regulated materials at the Independence Power & Light Missouri City Power Plant.

As requested, TRC has not added contingencies to the estimated costs. TRC recommends that Independence Power and Light include a +/- 20% contingency on all costs, with the exception of the asbestos abatement task. TRC recommends a + 10% and - 30% contingency for the asbestos abatement task since the estimated costs are based on the assumption that all suspect materials (with the exception of the roof) are asbestos-containing.

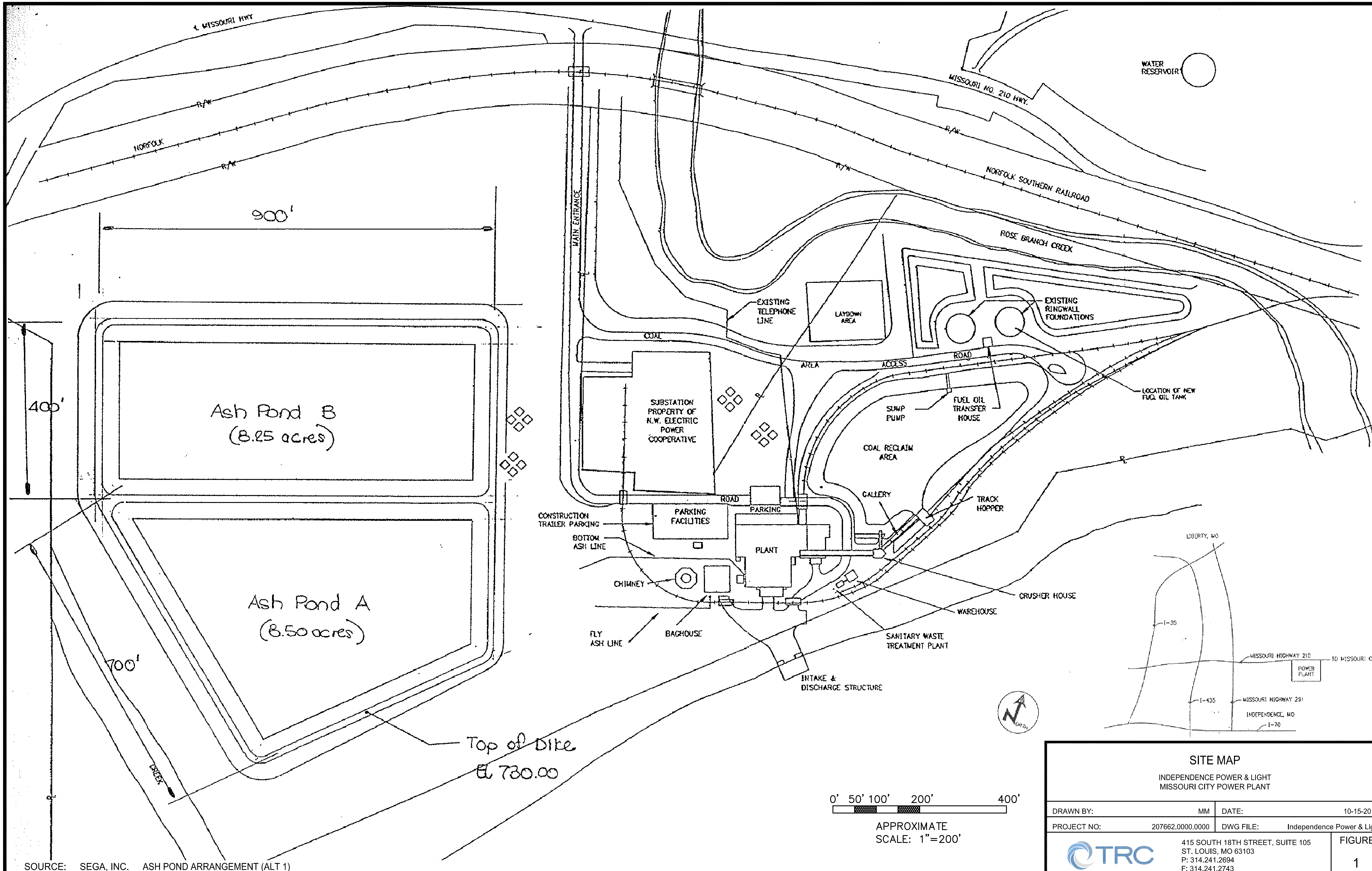
Thank you for this opportunity and if you have any questions regarding this cost estimate, do not hesitate to contact me directly at 314.241.2694, ext. 12.

Sincerely,
TRC ENVIRONMENTAL CORPORATION

Richard Wetherbee, RG
Project Manager

Attachments

Cc. K. Piontek/TRC
J. Lanan/TRC



SOURCE: SEGA, INC. ASH POND ARRANGEMENT (ALT 1)

SITE MAP

INDEPENDENCE POWER & LIGHT
MISSOURI CITY POWER PLANT

DRAWN BY:	MM	DATE:	10-15-2013
PROJECT NO:	207662.0000.0000	DWG FILE:	Independence Power & Light

TRC

415 SOUTH 18TH STREET, SUITE 105
ST. LOUIS, MO 63103
P: 314.241.2694
F: 314.241.2743

FIGURE 1

\\STLOUIS-FP1\PERSONAL\MMCFADDEN\PROJECTS\RICH W\INDEPENDENCE POWER & LIGHT\INDEPENDENCE POWER & LIGHT.DWG

TABLE 1
LIST OF MISSOURI CITY POWER PLANT DRAWINGS

1. Flow Diagrams
   A. Auxiliary Steam
   B. Natural Gas
   C. Fuel Oil
   D. Compressor Air
   E. Miscellaneous Lines
   F. Bearing Water
   G. Well Water
   H. Water Treatment
2. Plot Plan
   A. Exterior Piping
3. Piping Specifications
4. Piping Section Drawings
5. Tanks
6. Turbine Basement Floor and Mezzanine – LP Steam & Condensate Piping
7. Sections
   A. Turbine Room
   B. Main Steam
   C. Desuperheating Piping
8. Auxiliary Bay Piping
9. Evaporator Drain Piping
10. Plan & Sections – Boiler Feed & Blowdown Piping
11. Tanks & Miscellaneous Details
12. Safety Valve Vent Piping
13. Well Water Piping/Station Air Piping
14. Typical Piping Supports
15. Transverse – Looking East
16. Operating Floor Plan
    A. Basement
    B. Mezzanine
17. Flow Diagrams
    A. Auxiliary Steam
    B. Natural Gas
    C. Fuel Oil
    D. Compressor Air
    E. Sampling
    F. HP Steam
    G. Boiler Feed Water
    H. Extraction Steam
    I. Exhaust Steam
    J. Condensate
18. Fan Floor Layout
19. Ash Handing System
20. Coal Handling System
21. Detailed Elevations – Sections of Superstructure
22. Building Elevations – Intake and Discharge Structure

TABLE 2
ESTIMATED QUANTITIES

Regulated or Hazardous Material	Estimated Quantity	Assumptions
PCBs		
1. Fluorescent Light Ballasts	175 Ballasts	Approximately 80 Ballasts per Drum – Assume 3 Drums
2. PCB Caulk	19,200 Linear Feet (LF)	Assume ACM Caulk on 300 Windows Contains PCBs. Assume Incremental Increase in Disposal. 3,000 LF of PCB/ACM Materials per Drum – Assume 7 Drums
Universal Wastes		
1. Batteries	75 Large Batteries 15 Small Batteries 7,725 lbs total	Assume Large Batteries Approximately 100 lbs/battery and Small Batteries 15 lbs/battery
2. Fluorescent Light Bulbs	325 4-ft Lamps	
3. Floodlights and High Pressure Halide Lamps	40 Lamps	Assume 1 Drum
4. Mercury-Containing Equipment	4 Switches and 1 Thermostat	Assume 1 Drum
Refrigerant-Containing Equipment		
1. Refrigerator, Condenser Units, Vending Machine	8 Units	2 Units per Drum – Assume 4 Drums
2. Drinking Water Fountains	4 Units	2 Units per Drum – Assume 2 Drums
3. Window Mounted A/C Units	5 Units	
Fire Extinguishers	80 Units	

TABLE 3
REMOVAL, ABATEMENT, MANAGEMENT AND DISPOSAL OF HAZARDOUS AND REGULATED MATERIALS

Description		Expected Cost
Asbestos Abatement	$	3,140,000
Metal Coating Abatement	$	335,000
PCBs	$	3,000
Universal Waste	$	10,000
Refrigerant Containing Equipment	$	2,000
Petroleum Products	$	74,000
Fire Suppressants/Extinguishers	$	1,000
Miscellaneous Materials	$	10,000
Total	**$**	**3,575,000**

TRC Results you can rely on

APPENDIX E

REFERENCE DOCUMENTS

REFERENCE DOCUMENTS

1. *Decommissioning Handbook for Coal-Fired Power Plants*, EPRI, Palo Alto, CA: 2004. (1011220)

2. *Decommissioning Process for Fossil-Fueled Power Plants*, EPRI, Palo Alto, CA: 2010. (1020652)

3. Association for the Advancement of Cost Estimating (AACE) International, *Skills and Knowledge of Cost Engineering*, 5th Edition, 2004.

4. Combustion Fossil Power, Fourth Edition, 1991.

5. Steam Its Generation and Use, 40th Edition, 1992.

APPENDIX F

SITE LOCATION MAP

16041 FOSTER STREET
OVERLAND PARK, KANSAS 66085
(913) 681-2881

Independence Power & Light
Missouri City Power Station

Site Location Map
Missouri City, Clay County, Missouri

SUPPLEMENTAL SKETCH NO.

Figure 1

DRAWN BY: ZPM

DATE:5/27/15

APPENDIX G

MEMORANDUM - DECOMMISSIONING EXISTING COAL PILE, REVISION 1

PROJECT MEMORANDUM

DATE:	May 8, 2015
TO:	Marty Barker, IPL
FROM:	Zach Michels, Sega
Re:	City of Independence, Missouri Missouri City Plant Retirement Options Project No. 15-0080, PM
SUBJECT:	DECOMMISSIONING EXISTING COAL PILE, REV. 1

For the City of Independence, Missouri Power & Light Company (IPL) Missouri City Power Plant Decommissioning Study, Sega Inc. (Sega) was asked to look into acceptable ways to decommission an existing coal pile. One example brought to Sega's attention was Chamois Power Plant which was recently decommissioned, including the existing coal pile. The plan of action taken to decommission this plant and coal pile was accepted by the Missouri Department of Natural Resources (DNR). Sega searched their website for any available information, plans, permits, or record documents. After no success, Sega then sent an email to a DNR staff member inquiring about the Chamois Power Plant project and any available documentation. Sega was emailed back promptly from an Administrative Assistant in the Water Resources Center informing us we should make a Sunshine Law Request (http://dnr.mo.gov/sunshinerequests.htm).

Under Missouri Sunshine Law, Chapter 610, Revised Statutes of Missouri, all open and responsive records maintained by the Missouri Department of Natural Resources are made available to the public. In order to obtain this information, a fee for services including time to prepare and find the documents as well as cost of paper copies for the plans may be requested by the Department. Sega received a confirmation for the request two days after submittal but was made aware that due to the volume of Sunshine Law requests received, we should expect to hear back from the DNR on or before May 28, 2015, five weeks after request. With a delivery date for the Decommissioning Study at the beginning of June, this option did not seem promising.

Sega was then contacted by two separate employees of the DNR, Chris Wieberg, Chief of Operating Permit Section of the Water Resources division, and Darrell Hartley of the Solid Waste Management Program. From both of these phone conversations, Sega gained the following information on the Chamois Power Plant Decommissioning and how they treated the coal pile removal:

1. The existing coal pile was small (the excess coal was either sold or burned) and little residue remained on site.

2. The site practiced Beneficial Reuse, which is the reuse of industrial byproducts such as coal ash, bottom ash, fly ash, and gypsum for geotechnical and non-geotechnical fill projects. The partnership is created between industrial companies and landowners for such activities.

3. The Chamois Power Plant combined the residual coal with fly ash and filled existing clay pits with the mixture. The areas were then capped and fertilized to prevent siltation and excess runoff. The site received a clay pit mining permit for the operation, but Sega was informed that this practice was site specific due to the amount of clay pits in the Chamois area.

Both Chris and Darrell made it clear that the main focus and most stringent permitting requirements deal with decommissioning of existing ash ponds, which is not in Sega's scope for the Missouri City Decommissioning Study. Based on the information received from DNR, the following steps are recommended to close the Missouri City coal pile:

1. Once the majority of the existing coal has been removed or sold, the footprint of the coal pile should be stripped down and excavated to a point where the exposed soil has not been in contact with coal and is free of any residuals.

2. The soil and residual coal stripped from site should then be transported and dumped to permitted sites approved for residual coal, such as landfills.

3. Once the site has been cleared, grading and drainage efforts shall be made to the site for storm water runoff. Any large pit areas or voids shall be backfilled with suitable materials, such as clay, in order to grade to drain. Installation of storm water structures such as area inlets, manholes, and underground storm water pipe may also be installed, if applicable.

4. As soon as the grading efforts cease, the site shall immediately be fertilized and seeded in order to reduce sedimentation and runoff on site.

5. It was mentioned that in accordance with federal Effluent Limitation Guidelines (ELG) requirements, water monitoring wells shall be installed on site, and the ground and surface water shall be "perpetually monitored" until it can be proven the water is clean and free of contaminants. It is IPL's belief that this step is not necessary due to the fact that the site has a 100-percent compliance record and has no recorded violations regarding discharges from the retention basin associated with coal pile runoff

As far as permit documents for this project, an application for a land disturbance permit should be submitted to the governing authority for the construction activity on site. Additionally, the existing National Pollutant Discharge Elimination System (NPDES) Permit, the Storm Water Pollution Prevention Plan (SWPPP), and DNR General Operating Permit for the Missouri City Power Plant should be updated to include the removal of the existing coal pile and the associated runoff from the coal pile.

ZPM/kge

c: Paul Mahlberg, IPL
Randy Hughes, IPL
Eric Holder, IPL
Chris Rogers, Sega
Jeffrey Fleenor, Sega