	A	B	C	D	E	F	G	H	I	J
38		Annual Property Tax expense	-	2,996	39,819	100,368	137,005	132,802	128,599	124,396
39		**Total OE**	$ -	$ 2,996	$ 39,819	$ 10,638,485	$ 12,909,703	$ 13,104,915	$ 13,304,115	$ 13,507,384
40										
41		**Total E(m) - Project**	228,892	3,044,905	7,707,228	21,033,786	22,824,140	22,559,066	22,316,962	22,096,541
42										

	K	L	M	N	O	P	Q	R
38	120,193	115,990						
39	$ 13,714,802	$ 13,926,452						
40								
41	21,896,517	21,715,798						
42								

	A	B	C	D	E	F	G	H	I	J
43										
44							May			
45			2011	2012	2013	2014	2015	2016	2017	2018
46		In-Service					1	2	3	4
47		**Brown 3**								
48	**Project 34**	**Capital Expenditures - Project 34 - BR3 Baghouse**	$ -	$ 1,487,220	$ 19,333,856	$ 34,584,401	$ 25,093,798	$ -	$ -	$ -
49	4	**Accumulated Expenditures**	$ -	$ 1,487,220	$ 20,821,076	$ 55,405,477	$ 80,499,275	$ 80,499,275	$ 80,499,275	$ 80,499,275
50	2	Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	2.800%	2.800%	2.800%	2.800%
51	2	Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%
52		Income tax rate	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
53		Deferred Tax Balance	-	-	-	-	572,994	1,839,024	2,949,772	3,917,272
54		Book Accumulated Depreciation Balance	-	-	-	-	1,408,737	3,662,717	5,916,697	8,170,676
55		Unrecovered Investment -- Book	-	1,487,220	20,821,076	55,405,477	80,499,275	80,499,275	80,499,275	80,499,275
56		Book Depreciation	-	-	-	-	1,408,737	2,253,980	2,253,980	2,253,980
57		Unrecovered Investment -- Tax total	-	1,487,220	20,821,076	55,405,477	80,499,275	80,499,275	80,499,275	80,499,275
58		Tax Depreciation	-	-	-	-	3,018,723	5,811,243	5,374,937	4,972,440
59		Allowed Rate of Return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
60		Book Depreciation expense total	-	-	-	-	1,408,737	2,253,980	2,253,980	2,253,980
61		Tax Depreciation expense total	-	-	-	-	3,018,723	5,811,243	5,374,937	4,972,440
62		Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
63		Deferred Tax Balance	-	-	-	-	572,994	1,266,030	1,110,749	967,500
64										
65		**Revenue Recovery on Capital Expenditure to date**								
66		Eligible Plant, cumulative capital expenditures	-	1,487,220	20,821,076	55,405,477	80,499,275	80,499,275	80,499,275	80,499,275
67	2002	Less: Retired Plant	-	-	-	-	-	-	-	-
68		Less: Accumulated Depreciation	-	-	-	-	(1,408,737)	(3,662,717)	(5,916,697)	(8,170,676)
69		Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-
70		Less: Deferred Tax Balance	-	-	-	-	(572,994)	(1,839,024)	(2,949,772)	(3,917,272)
71		Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-
72		Environmental Compliance Rate Base	-	1,487,220	20,821,076	55,405,477	78,517,544	74,997,535	71,632,806	68,411,326
73		Rate of return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
74		Return on Environmental Compliance Rate Base	$ -	$ 170,420	$ 2,385,881	$ 6,348,899	$ 8,997,304	$ 8,593,947	$ 8,208,384	$ 7,839,235
75										
76		**Operating Expenses**	-	-	-	-	5,433,809	5,542,486	5,653,335	5,766,402
77		Annual Depreciation expense	-	-	-	-	1,408,737	2,253,980	2,253,980	2,253,980
78		Less depreciation on retired plant	-	-	-	-	-	-	-	-
79		Annual Property Tax expense	-	-	2,231	31,232	83,108	118,636	115,255	111,874

	K	L	M	N	O	P	Q	R
43								
44								
45	2019	2020						
46	5	6	Difference				January	1
47							February	2
48	$ -	$ -	$ -				March	3
49	$ 80,499,275	$ 80,499,275					April	4
50	2.800%	2.800%					May	5
51	5.713%	5.285%					June	6
52	35.59%	35.59%					July	7
53	4,751,838	5,463,783					August	8
54	10,424,656	12,678,636					Septembe	9
55	80,499,275	80,499,275					October	10
56	2,253,980	2,253,980					November	11
57	80,499,275	80,499,275					December	12
58	4,598,924	4,254,387						
59	11.46%	11.46%						
60	2,253,980	2,253,980						
61	4,598,924	4,254,387						
62	0.1500%	0.1500%						
63	834,566	711,945						
64								
65								
66	80,499,275	80,499,275						
67	-	-						
68	(10,424,656)	(12,678,636)						
69	-	-						
70	(4,751,838)	(5,463,783)						
71	-	-						
72	65,322,781	62,356,857						
73	11.46%	11.46%						
74	$ 7,485,320	$ 7,145,455						
75								
76	5,881,730	5,999,365						
77	2,253,980	2,253,980						
78	-	-						
79	108,493	105,112						

	A	B	C	D	E	F	G	H	I	J
80		**Total OE**	$ -	$ -	$ 2,231	$ 31,232	$ 6,925,655	$ 7,915,101	$ 8,022,570	$ 8,132,256
81										
82		**Total E(m) - Project**	-	170,420	2,388,112	6,380,130	15,922,959	16,509,048	16,230,954	15,971,491

	K	L	M	N	O	P	Q	R
80	$ 8,244,203	$ 8,358,456						
81								
82	15,729,523	15,503,912						

	A	B	C	D	E	F	G	H	I	J	K
1	**Revenue Requirements**										
2	**Project 35 - KU**										
3						May					
4			2011	2012	2013	2014	2015	2016	2017	2018	2019
5		In-Service				1	2	3	4	5	6
6		**Ghent 1**									
7	**Project 35**	**Capital Expenditures - Project 35 - GH1 Baghouse & SAM Mitigation**	$ 2,178,929	$ 50,248,800	$ 66,924,592	$ 44,857,567	$ -	$ -	$ -	$ -	$ -
8	5	**Accumulated Expenditures**	$ 2,178,929	$ 52,427,728	$ 119,352,320	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888	$ 164,209,888
9	2	Book Depreciation rate, per year	0.000%	0.000%	0.000%	3.840%	3.840%	3.840%	3.840%	3.840%	3.840%
10	2	Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
11		Income tax rate	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
12		Deferred Tax Balance	-	-	-	788,971	2,763,736	4,421,744	5,787,541	6,882,165	7,726,656
13		Book Accumulated Depreciation Balance	-	-	-	3,941,037	10,246,697	16,552,357	22,858,016	29,163,676	35,469,336
14		Unrecovered Investment -- Book	2,178,929	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
15		Book Depreciation	-	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
16		Unrecovered Investment -- Tax total	2,178,929	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
17		Tax Depreciation	-	-	-	6,157,871	11,854,312	10,964,294	10,143,245	9,381,311	8,678,493
18		Allowed Rate of Return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
19		Book Depreciation expense total	-	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
20		Tax Depreciation expense total	-	-	-	6,157,871	11,854,312	10,964,294	10,143,245	9,381,311	8,678,493
21		Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
22		Deferred Tax Balance	-	-	-	788,971	1,974,765	1,658,008	1,365,797	1,094,624	844,491
23											
24		**Revenue Recovery on Capital Expenditure to date**									
25		Eligible Plant, cumulative capital expenditures	2,178,929	52,427,728	119,352,320	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888	164,209,888
26	2002	Less: Retired Plant	-	-	-	-	-	-	-	-	-
27		Less: Accumulated Depreciation	-	-	-	(3,941,037)	(10,246,697)	(16,552,357)	(22,858,016)	(29,163,676)	(35,469,336)
28		Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
29		Less: Deferred Tax Balance	-	-	-	(788,971)	(2,763,736)	(4,421,744)	(5,787,541)	(6,882,165)	(7,726,656)
30		Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
31		Environmental Compliance Rate Base	2,178,929	52,427,728	119,352,320	159,479,879	151,199,454	143,235,787	135,564,330	128,164,046	121,013,896
32		Rate of return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
33		Return on Environmental Compliance Rate Base	$ 249,683	$ 6,007,679	$ 13,676,550	$ 18,274,756	$ 17,325,905	$ 16,413,350	$ 15,534,280	$ 14,686,283	$ 13,866,950
34											
35		**Operating Expenses**	-	-	4,096,370	16,916,997	17,255,337	17,600,444	17,952,452	18,311,501	18,677,732
36		Annual Depreciation expense	-	-	-	3,941,037	6,305,660	6,305,660	6,305,660	6,305,660	6,305,660
37		Less depreciation on retired plant	-	-	-	-	-	-	-	-	-

	L	M	N	O	P	Q	R
1							
2							
3							
4	2020						
5	7	Difference				January	1
6						February	2
7	$ -	$ -				March	3
8	$ 164,209,888					April	4
9	3.840%					May	5
10	4.888%					June	6
11	35.59%					July	7
12	8,339,132					August	8
13	41,774,995					Septembe	9
14	164,209,888					October	10
15	6,305,660					November	11
16	164,209,888					December	12
17	8,026,579						
18	11.46%						
19	6,305,660						
20	8,026,579						
21	0.1500%						
22	612,475						
23							
24							
25	164,209,888						
26	-						
27	(41,774,995)						
28	-						
29	(8,339,132)						
30	-						
31	114,095,761						
32	11.46%						
33	$ 13,074,202						
34							
35	19,051,286						
36	6,305,660						
37	-						

	A	B	C	D	E	F	G	H	I	J	K
38		Annual Property Tax expense	-	3,268	78,642	179,028	240,403	230,945	221,486	212,028	202,569
39		**Total OE**	$ -	$ 3,268	$ 4,175,012	$ 21,037,063	$ 23,801,400	$ 24,137,048	$ 24,479,598	$ 24,829,189	$ 25,165,961
40											
41		**Total E(m) - Project**	249,683	6,010,948	17,851,562	39,311,819	41,127,304	40,550,398	40,013,878	39,515,472	39,052,910
42											
43											

	L	M	N	O	P	Q	R
38	193,111						
39	$ 25,550,057						
40							
41	38,624,259						
42							
43							

	A	B	C	D	E	F	G	H	I	J	K
44						November					
45			2011	2012	2013	2014	2015	2016	2017	2018	2019
46		In-Service				1	2	3	4	5	6
47		**Ghent 2**									
48	**Project 35**	**Capital Expenditures - Project 35 - GH2 Baghouse & SAM Mitigation**	$ 148,784	$ 37,354,857	$ 48,163,861	$ 72,191,638	$ 6,693,304	$ -	$ -	$ -	$ -
49	6	**Accumulated Expenditures**	$ 148,784	$ 37,503,641	$ 85,667,502	$ 157,859,140	$ 164,552,444	$ 164,552,444	$ 164,552,444	$ 164,552,444	$ 164,552,444
50	2	Book Depreciation rate, per year	0.000%	0.000%	0.000%	2.330%	2.330%	2.330%	2.330%	2.330%	2.330%
51	2	Tax Depreciation rate, per year	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
52		Income tax rate	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
53		Deferred Tax Balance	-	-	-	1,943,197	4,806,402	7,352,188	9,605,154	11,586,381	13,316,953
54		Book Accumulated Depreciation Balance	-	-	-	459,765	4,293,837	8,127,909	11,961,981	15,796,053	19,630,124
55		Unrecovered Investment -- Book	148,784	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
56		Book Depreciation	-	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
57		Unrecovered Investment -- Tax total	148,784	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
58		Tax Depreciation	-	-	-	5,919,718	11,879,041	10,987,167	10,164,404	9,400,881	8,696,597
59		Allowed Rate of Return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
60		Book Depreciation expense total	-	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
61		Tax Depreciation expense total	-	-	-	5,919,718	11,879,041	10,987,167	10,164,404	9,400,881	8,696,597
62		Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
63		Deferred Tax Balance	-	-	-	1,943,197	2,863,204	2,545,786	2,252,965	1,981,227	1,730,573
64											
65		**Revenue Recovery on Capital Expenditure to date**									
66		Eligible Plant, cumulative capital expenditures	148,784	37,503,641	85,667,502	157,859,140	164,552,444	164,552,444	164,552,444	164,552,444	164,552,444
67	2002	Less: Retired Plant	-	-	-	-	-	-	-	-	-
68		Less: Accumulated Depreciation	-	-	-	(459,765)	(4,293,837)	(8,127,909)	(11,961,981)	(15,796,053)	(19,630,124)
69		Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
70		Less: Deferred Tax Balance	-	-	-	(1,943,197)	(4,806,402)	(7,352,188)	(9,605,154)	(11,586,381)	(13,316,953)
71		Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
72		Environmental Compliance Rate Base	148,784	37,503,641	85,667,502	155,456,178	155,452,206	149,072,347	142,985,310	137,170,011	131,605,366
73		Rate of return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
74		Return on Environmental Compliance Rate Base	$ 17,049	$ 4,297,532	$ 9,816,616	$ 17,813,681	$ 17,813,226	$ 17,082,160	$ 16,384,648	$ 15,718,274	$ 15,080,623
75											
76		**Operating Expenses**	-	329,460	4,032,590	9,399,385	14,979,237	15,278,822	15,584,399	15,896,087	16,214,008
77		Annual Depreciation expense	-	-	-	459,765	3,834,072	3,834,072	3,834,072	3,834,072	3,834,072
78		Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
79		Annual Property Tax expense	-	223	56,255	128,501	236,099	240,388	234,637	228,886	223,135
80		**Total OE**	$ -	$ 329,683	$ 4,088,846	$ 9,987,651	$ 19,049,408	$ 19,353,282	$ 19,653,107	$ 19,959,044	$ 20,271,215

	L	M	N	O	P	Q	R
44							
45	2020						
46	7	Difference				January	1
47						February	2
48	$ -	$ -				March	3
49	$ 164,552,444					April	4
50	2.330%					May	5
51	4.888%					June	6
52	35.59%					July	7
53	14,815,026					August	8
54	23,464,196					Septembe	9
55	164,552,444					October	10
56	3,834,072					November	11
57	164,552,444					December	12
58	8,043,323						
59	11.46%						
60	3,834,072						
61	8,043,323						
62	0.1500%						
63	1,498,073						
64							
65							
66	164,552,444						
67	-						
68	(23,464,196)						
69	-						
70	(14,815,026)						
71	-						
72	126,273,222						
73	11.46%						
74	$ 14,469,614						
75							
76	16,538,289						
77	3,834,072						
78	-						
79	217,383						
80	$ 20,589,744						

	A	B	C	D	E	F	G	H	I	J	K
81											
82		**Total E(m) - Project**	17,049	4,627,215	13,905,462	27,801,332	36,862,635	36,435,442	36,037,755	35,677,319	35,351,838
83											
84											

	L	M	N	O	P	Q	R
81							
82	35,059,358						
83							
84							

	A	B	C	D	E	F	G	H	I	J	K
85							October				
86			2011	2012	2013	2014	2015	2016	2017	2018	2019
87		In-Service					1	2	3	4	5
88		**Ghent 3**									
89	**Project 35**	**Capital Expenditures - Project 35 - GH3 Baghouse & SAM Mitigation**	$ 1,307,716	$ 4,809,001	$ 47,890,171	$ 56,057,325	$ 84,049,087	$ 3,898,032	$ -	$ -	$ -
90	7	**Accumulated Expenditures**	$ 1,307,716	$ 6,116,717	$ 54,006,888	$ 110,064,213	$ 194,113,300	$ 198,011,331	$ 198,011,331	$ 198,011,331	$ 198,011,331
91	2	Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	2.630%	2.630%	2.630%	2.630%	2.630%
92	2	Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%
93		Income tax rate	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
94		Deferred Tax Balance	-	-	-	-	2,212,157	5,446,128	8,298,139	10,797,789	12,970,448
95		Book Accumulated Depreciation Balance	-	-	-	-	1,063,579	6,271,277	11,478,975	16,686,673	21,894,371
96		Unrecovered Investment -- Book	1,307,716	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331
97		Book Depreciation	-	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698
98		Unrecovered Investment -- Tax total	1,307,716	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331
99		Tax Depreciation	-	-	-	-	7,279,249	14,294,438	13,221,217	12,231,160	11,312,387
100		Allowed Rate of Return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
101		Book Depreciation expense total	-	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698
102		Tax Depreciation expense total	-	-	-	-	7,279,249	14,294,438	13,221,217	12,231,160	11,312,387
103		Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
104		Deferred Tax Balance	-	-	-	-	2,212,157	3,233,971	2,852,011	2,499,650	2,172,659
105											
106		**Revenue Recovery on Capital Expenditure to date**									
107		Eligible Plant, cumulative capital expenditures	1,307,716	6,116,717	54,006,888	110,064,213	194,113,300	198,011,331	198,011,331	198,011,331	198,011,331
108	2002	Less: Retired Plant	-	-	-	-	-	-	-	-	-
109		Less: Accumulated Depreciation	-	-	-	-	(1,063,579)	(6,271,277)	(11,478,975)	(16,686,673)	(21,894,371)
110		Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
111		Less: Deferred Tax Balance	-	-	-	-	(2,212,157)	(5,446,128)	(8,298,139)	(10,797,789)	(12,970,448)
112		Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
113		Environmental Compliance Rate Base	1,307,716	6,116,717	54,006,888	110,064,213	190,837,564	186,293,927	178,234,217	170,526,869	163,146,512
114		Rate of return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
115		Return on Environmental Compliance Rate Base	$ 149,851	$ 700,913	$ 6,188,635	$ 12,612,228	$ 21,868,025	$ 21,347,371	$ 20,423,811	$ 19,540,628	$ 18,694,915
116											
117		**Operating Expenses**	-	-	3,894,132	4,796,132	11,080,590	17,614,507	17,966,797	18,326,133	18,692,656
118		Annual Depreciation expense	-	-	-	-	1,063,579	5,207,698	5,207,698	5,207,698	5,207,698
119		Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
120		Annual Property Tax expense	-	1,962	9,175	81,010	165,096	289,575	287,610	279,799	271,987
121		**Total OE**	$ -	$ 1,962	$ 3,903,307	$ 4,877,142	$ 12,309,265	$ 23,111,780	$ 23,462,106	$ 23,813,630	$ 24,172,341

	L	M	N	O	P	Q	R
85							
86	2020						
87	6	Difference				January	1
88						February	2
89	$ -	$ -				March	3
90	$ 198,011,331					April	4
91	2.630%					May	5
92	5.285%					June	6
93	35.59%					July	7
94	14,841,486					August	8
95	27,102,069					Septembe	9
96	198,011,331					October	10
97	5,207,698					November	11
98	198,011,331					December	12
99	10,464,899						
100	11.46%						
101	5,207,698						
102	10,464,899						
103	0.1500%						
104	1,871,038						
105							
106							
107	198,011,331						
108	-						
109	(27,102,069)						
110	-						
111	(14,841,486)						
112	-						
113	156,067,776						
114	11.46%						
115	$ 17,883,764						
116							
117	19,066,509						
118	5,207,698						
119	-						
120	264,175						
121	$ 24,538,383						

	A	B	C	D	E	F	G	H	I	J	K
122											
123		**Total E(m) - Project**	149,851	702,874	10,091,942	17,489,370	34,177,290	44,459,151	43,885,916	43,354,258	42,867,256
124											
125											

	L	M	N	O	P	Q	R
122							
123	42,422,147						
124							
125							

	A	B	C	D	E	F	G	H	I	J	K
126							December				
127			2011	2012	2013	2014	2015	2016	2017	2018	2019
128		In-Service					1	2	3	4	5
129		**Ghent 4**									
130	**Project 35**	**Capital Expenditures - Project 35 - GH4 Baghouse & SAM Mitigation**	$ 1,458,737	$ 4,321,807	$ 35,116,729	$ 57,307,535	$ 77,571,909	$ 8,984,440	$ -	$ -	$ -
131	8	**Accumulated Expenditures**	$ 1,458,737	$ 5,780,544	$ 40,897,273	$ 98,204,808	$ 175,776,717	$ 184,761,157	$ 184,761,157	$ 184,761,157	$ 184,761,157
132	2	Book Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	2.790%	2.790%	2.790%	2.790%	2.790%
133	2	Tax Depreciation rate, per year	0.000%	0.000%	0.000%	0.000%	3.750%	7.219%	6.677%	6.177%	5.713%
134		Income tax rate	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%	35.59%
135		Deferred Tax Balance	-	-	-	-	2,273,235	5,185,590	7,741,545	9,968,718	11,890,780
136		Book Accumulated Depreciation Balance	-	-	-	-	204,340	5,359,177	10,514,013	15,668,849	20,823,686
137		Unrecovered Investment -- Book	1,458,737	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157
138		Book Depreciation	-	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836
139		Unrecovered Investment -- Tax total	1,458,737	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157
140		Tax Depreciation	-	-	-	-	6,591,627	13,337,908	12,336,502	11,412,697	10,555,405
141		Allowed Rate of Return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
142		Book Depreciation expense total	-	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836
143		Tax Depreciation expense total	-	-	-	-	6,591,627	13,337,908	12,336,502	11,412,697	10,555,405
144		Annual Property Tax Rate	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%	0.1500%
145		Deferred Tax Balance	-	-	-	-	2,273,235	2,912,355	2,555,955	2,227,173	1,922,062
146											
147		**Revenue Recovery on Capital Expenditure to date**									
148		Eligible Plant, cumulative capital expenditures	1,458,737	5,780,544	40,897,273	98,204,808	175,776,717	184,761,157	184,761,157	184,761,157	184,761,157
149	2002	Less: Retired Plant	-	-	-	-	-	-	-	-	-
150		Less: Accumulated Depreciation	-	-	-	-	(204,340)	(5,359,177)	(10,514,013)	(15,668,849)	(20,823,686)
151		Plus: Accumulated Depreciation on Retired Plant	-	-	-	-	-	-	-	-	-
152		Less: Deferred Tax Balance	-	-	-	-	(2,273,235)	(5,185,590)	(7,741,545)	(9,968,718)	(11,890,780)
153		Plus: Deferred Tax Balance on Retired Plant	-	-	-	-	-	-	-	-	-
154		Environmental Compliance Rate Base	1,458,737	5,780,544	40,897,273	98,204,808	173,299,141	174,216,390	166,505,599	159,123,590	152,046,691
155		Rate of return	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%	11.46%
156		Return on Environmental Compliance Rate Base	$ 167,156	$ 662,391	$ 4,686,407	$ 11,253,262	$ 19,858,302	$ 19,963,409	$ 19,079,831	$ 18,233,929	$ 17,422,989
157											
158		**Operating Expenses**	-	-	4,294,702	5,331,000	11,281,941	17,468,789	17,818,164	18,174,528	18,538,018
159		Annual Depreciation expense	-	-	-	-	204,340	5,154,836	5,154,836	5,154,836	5,154,836
160		Less depreciation on retired plant	-	-	-	-	-	-	-	-	-
161		Annual Property Tax expense	-	2,188	8,671	61,346	147,307	263,359	269,103	261,371	253,638
162		**Total OE**	$ -	$ 2,188	$ 4,303,373	$ 5,392,346	$ 11,633,589	$ 22,886,983	$ 23,242,104	$ 23,590,735	$ 23,946,493

	L	M	N	O	P	Q	R
126							
127	2020						
128	6	Difference				January	1
129						February	2
130	$ -	$ -				March	3
131	$ 184,761,157					April	4
132	2.790%					May	5
133	5.285%					June	6
134	35.59%					July	7
135	13,531,405					August	8
136	25,978,522					Septembe	9
137	184,761,157					October	10
138	5,154,836					November	11
139	184,761,157					December	12
140	9,764,627						
141	11.46%						
142	5,154,836						
143	9,764,627						
144	0.1500%						
145	1,640,625						
146							
147							
148	184,761,157						
149	-						
150	(25,978,522)						
151	-						
152	(13,531,405)						
153	-						
154	145,251,230						
155	11.46%						
156	$ 16,644,299						
157							
158	18,908,779						
159	5,154,836						
160	-						
161	245,906						
162	$ 24,309,521						

	A	B	C	D	E	F	G	H	I	J	K
163											
164		**Total E(m) - Project**	167,156	664,579	8,989,780	16,645,608	31,491,891	42,850,392	42,321,935	41,824,664	41,369,482

	L	M	N	O	P	Q	R
163							
164	40,953,820						

	A	B	C	D	E	F	G	H	I	J	K
1	**Year in Service**	**Tax Depreciation, 20 yr HL**			**Book Depreciation**			Assumes all investments to plant account 312			
2	1	3.75%		**Ghent 1PC**	3.87%			Updated using Depreciation Rates in effect as of 2/6/09			
3	2	7.22%		**Ghent 1**	3.84%			Source: KU and LG&E ECR Databases			
4	3	6.68%		**Ghent 2**	2.33%						
5	4	6.18%		**Ghent 3**	2.63%						
6	5	5.71%		**Ghent 4**	2.79%						
7	6	5.29%		**Brown 1**	2.98%			**PC = Scrubber/FGD**			
8	7	4.89%		**Brown 2**	3.01%			**NPC = All other Pollution Control**			
9	8	4.52%		**Brown 3**	2.80%						
10	9	4.46%		**Ghent 1,3,&4**	3.09%						
11	10	4.46%		**Mill Creek 1PC**	4.50%						
12	11	4.46%		**Mill Creek 1NPC**	4.24%						
13	12	4.46%		**Mill Creek 2PC**	4.28%						
14	13	4.46%		**Mill Creek 2NPC**	4.70%						
15	14	4.46%		**Mill Creek 3PC**	3.85%						
16	15	4.46%		**Mill Creek 3NPC**	3.87%						
17	16	4.46%		**Mill Creek 4NPC**	3.85%						
18	17	4.46%		**Mill Creek 4PC**	3.71%						
19	18	4.46%		**TrimblePC**	3.62%						
20	19	4.46%		**TrimbleNPC**	3.62%						
21	20	4.46%		**All Plants-LGE**	4.59%						
22	21	2.23%		**All Plants-KU**	3.07%						
23	22	0.00%									
24	23	0.00%									
25	24	0.00%									
26	25	0.00%									
27	26	0.00%		**Cane Run 4**	5.88%						
28	27	0.00%		**Cane Run 5**	6.11%						
29	28	0.00%		**Cane Run 6**	4.46%						
30	29	0.00%		**Green River 3**	3.08%						
31	30	0.00%		**Green River 4**	4.20%						
32	31	0.00%									
33	32	0.00%									
34	33	0.00%									
35	34	0.00%									
36	35	0.00%									
37	36	0.00%									
38	37	0.00%									
39	38	0.00%									
40	39	0.00%									
41	40	0.00%									
42	41	0.00%									
43	42	0.00%									
44	43	0.00%									
45	44	0.00%									
46	45	0.00%									
47	46	0.00%									
48	47	0.00%									
49	48	0.00%									
50	49	0.00%									
51	50	0.00%									
52	51	0.00%									
53	52	0.00%									
54	53	0.00%									
55	54	0.00%									
56	55	0.00%									
57	56	0.00%									

	A	B	C	D	E	F	G	H	I	J	K
58	57	0.00%									

	A	B	C	D
1		12/31/1995	1/1/2005	2/6/2009
2	Unit	Rate	Rate	
3	BR1N.1311	2.90%	2.90%	0.60%
4	BR1N.1312	2.88%	2.88%	2.98%
5	BR1N.1314	2.88%	2.88%	1.12%
6	BR1N.1315	2.88%	2.88%	2.10%
7	BR1N.1316	2.88%	2.88%	2.26%
8	BR2N.1311	2.88%	2.88%	0.08%
9	BR2N.1312	2.88%	2.88%	3.01%
10	BR2N.1314	2.88%	2.88%	2.91%
11	BR2N.1315	2.88%	2.88%	0.48%
12	BR2N.1316	2.88%	2.88%	0.71%
13	BR3N.1311	3.91%	3.91%	0.54%
14	BR3N.1312	3.91%	3.91%	2.80%
15	BR3N.1314	3.91%	3.91%	3.17%
16	BR3N.1315	3.91%	3.91%	0.54%
17	BR3N.1316	3.91%	3.91%	2.33%
18	BR3S.1311	3.91%	3.91%	2.65%
19	BR3S.1312	3.91%	3.91%	3.87%
20	BR3S.1314	3.91%	3.91%	0.00%
21	BR3S.1315	3.91%	3.91%	2.70%
22	GH1N.1311	3.12%	3.12%	0.39%
23	GH1N.1312	3.12%	3.12%	3.84%
24	GH1N.1314	3.12%	3.12%	2.23%
25	GH1N.1315	3.12%	3.12%	0.55%
26	GH1N.1316	3.12%	3.12%	1.38%
27	GH1S.1311	3.12%	3.12%	2.65%
28	GH1S.1312	3.12%	3.12%	3.87%
29	GH1S.1314	3.12%	3.12%	0.00%
30	GH1S.1315	3.12%	3.12%	2.70%
31	GH1S.1316	3.12%	3.12%	2.87%
32	GH2N.1311	1.84%	1.84%	0.50%
33	GH2N.1312	1.84%	1.84%	2.33%
34	GH2N.1314	1.84%	1.84%	2.08%
35	GH2N.1315	1.84%	1.84%	0.60%
36	GH2N.1316	1.84%	1.84%	1.07%
37	GH2S.1311	1.84%	1.84%	2.65%
38	GH2S.1312	1.84%	1.84%	3.87%
39	GH2S.1314	1.84%	1.84%	0.00%
40	GH2S.1315	1.84%	1.84%	2.70%
41	GH2S.1316	1.84%	1.84%	2.87%
42	GH3N.1311	2.22%	2.22%	1.19%
43	GH3N.1312	2.22%	2.22%	2.63%
44	GH3N.1314	2.22%	2.22%	2.03%
45	GH3N.1315	2.22%	2.22%	1.03%
46	GH3N.1316	2.22%	2.22%	1.40%
47	GH3N.1392	2.22%	2.22%	0.00%
48	GH3S.1311	5.67%	5.67%	2.65%
49	GH3S.1312	5.67%	5.67%	3.87%
50	GH3S.1314	5.67%	5.67%	0.00%
51	GH3S.1315	5.67%	5.67%	2.70%
52	GH3S.1316	5.67%	5.67%	0.00%
53	GH4N.1311	2.16%	2.16%	1.41%
54	GH4N.1312	2.16%	2.16%	2.79%
55	GH4N.1314	2.16%	2.16%	2.20%
56	GH4N.1315	2.16%	2.16%	1.22%
57	GH4N.1316	2.16%	2.16%	2.03%

	A	B	C	D
58	GH4S.1311	2.16%	5.67%	2.65%
59	GH4S.1312	2.16%	5.67%	3.87%
60	GH4S.1314	2.16%	5.67%	0.00%
61	GH4S.1315	2.16%	5.67%	2.70%
62	GH4S.1316	2.16%	5.67%	0.00%
63	GR2N.1311	0.00%	1.94%	0.00%
64	GR2N.1312	0.00%	1.94%	2.18%
65	GR2N.1314	0.00%	1.94%	0.00%
66	GR2N.1315	0.00%	1.94%	0.00%
67	GR2N.1316	0.00%	1.94%	0.00%
68	GR3N.1311	0.00%	1.94%	0.00%
69	GR3N.1312	0.00%	1.94%	3.08%
70	GR3N.1314	0.00%	1.94%	2.90%
71	GR3N.1315	0.00%	1.94%	0.00%
72	GR3N.1316	0.00%	1.94%	3.97%
73	GR4N.1311	3.10%	3.10%	0.00%
74	GR4N.1312	3.10%	3.10%	4.20%
75	GR4N.1314	3.10%	3.10%	3.79%
76	GR4N.1315	3.10%	3.10%	1.46%
77	GR4N.1316	3.10%	3.10%	2.71%
78	KUTR.1392	2.22%	5.67%	20.00%
79	SW00.1391	20%	20%	10.14%
80	TY3N.1311	2.13%	2.13%	0.00%
81	TY3N.1312	2.13%	2.13%	3.99%
82	TY3N.1314	2.13%	2.13%	3.44%
83	TY3N.1315	2.13%	2.13%	0.00%
84	TY3N.1316	2.13%	2.13%	3.12%

	A	B	C	D
1		12/31/1995	1/1/2005	2/6/2009
2	Unit	Rate	Rate	
3	CR4N.131100	2.94%	2.94%	1.14%
4	CR4N.131200	2.94%	2.94%	5.88%
5	CR4N.131500	2.94%	2.94%	3.18%
6	CR4S.131100	3.47%	3.47%	0.95%
7	CR4S.131200	3.47%	3.47%	4.93%
8	CR4S.131500	3.47%	3.47%	0.82%
9	CR5N.131100	2.87%	2.87%	1.92%
10	CR5N.131200	2.87%	2.87%	6.11%
11	CR5N.131500	2.87%	2.87%	2.97%
12	CR5S.131100	3.47%	3.47%	1.56%
13	CR5S.131200	3.47%	3.47%	4.07%
14	CR5S.131500	3.47%	3.47%	1.49%
15	CR6N.131100	3.06%	3.06%	2.13%
16	CR6N.131200	3.06%	3.06%	5.19%
17	CR6N.131500	3.06%	3.06%	2.80%
18	CR6S.131100	2.18%	2.18%	2.04%
19	CR6S.131200	2.18%	2.18%	4.46%
20	CR6S.131500	2.18%	2.18%	1.44%
21	CRLF.131200	2.82%	2.82%	2.13%
22	MC1N.131100	2.39%	2.39%	1.64%
23	MC1N.131200	2.39%	2.39%	4.24%
24	MC1N.131500	2.39%	2.39%	2.75%
25	MC1S.131100	3.90%	3.90%	1.65%
26	MC1S.131200	3.90%	3.90%	4.50%
27	MC1S.131500	3.90%	3.90%	1.67%
28	MC2N.131100	2.29%	2.29%	1.42%
29	MC2N.131200	2.29%	2.29%	4.70%
30	MC2N.131500	2.29%	2.29%	2.03%
31	MC2S.131100	3.99%	3.99%	1.81%
32	MC2S.131200	3.99%	3.99%	4.28%
33	MC2S.131500	3.99%	3.99%	1.69%
34	MC3N.131100	3.03%	3.03%	1.51%
35	MC3N.131200	3.03%	3.03%	3.87%
36	MC3N.131500	2.29%	2.29%	1.58%
37	MC3S.131100	4.54%	4.54%	1.47%
38	MC3S.131200	4.54%	4.54%	3.85%
39	MC3S.131500	3.99%	3.99%	1.56%
40	MC4N.131020	2.82%	2.82%	0.00%
41	MC4N.131100	2.82%	2.82%	1.85%
42	MC4N.131200	2.82%	2.82%	3.85%
43	MC4N.131500	2.29%	2.29%	1.75%
44	MC4S.131100	5.38%	5.38%	1.76%
45	MC4S.131200	5.38%	5.38%	3.71%
46	MC4S.131500	3.99%	3.99%	1.71%
47	MSUB.135310	2.10%	2.10%	1.32%
48	SW00.339130	20.00%	20.00%	21.96%
49	TC1N.131100	2.41%	2.41%	2.08%
50	TC1N.131200	2.41%	2.41%	3.62%
51	TC1N.131500	2.41%	2.41%	2.13%
52	TC1S.131100	3.47%	3.47%	2.28%
53	TC1S.131200	3.47%	3.47%	3.62%
54	TC1S.131500	3.47%	3.47%	2.12%
55	TC2N.131100	2.41%	2.41%	2.10%
56	TC2N.131200	2.41%	2.41%	4.28%
57	TC2N.131500	2.41%	2.41%	2.49%

	A	B	C	D
58	TC2S.131100	3.47%	3.47%	2.10%
59	TC2S.131200	3.47%	3.47%	4.28%
60	TC2S.131500	3.47%	3.47%	2.49%

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	LG&E-Project 21	Year in Service	Plant Amt	Tax Depreciation		Book Depreciation		Def Tax										
2	Opacity Monitors	1984	-	3.75%	-	4.24%	-	-	6.5			167.4801						
3	**Mill Creek 1NPC**	1985	-	7.22%	-	4.24%	-	-	12									
4		1986	-	6.68%	-	4.24%	-	-	12									
5	-	1987	-	6.18%	-	4.24%	-	-	12				**Do not delete this sheet. Retiremen**					
6		1988	-	5.71%	-	4.24%	-	-	12									
7		1989	-	5.29%	-	4.24%	-	-	12									
8		1990	-	4.89%	-	4.24%	-	-	12									
9		1991	-	4.52%	-	4.24%	-	-	12									
10		1992	-	4.46%	-	4.24%	-	-	12									
11		1993	-	4.46%	-	4.24%	-	-	12									
12		1994	-	4.46%	-	4.24%	-	-	12									
13		1995	-	4.46%	-	4.24%	-	-	12									
14		1996	-	4.46%	-	4.24%	-	-	12									
15		1997	-	4.46%	-	4.24%	-	-	12									
16		1998	-	4.46%	-	4.24%	-	-	12									
17		1999	-	4.46%	-	4.24%	-	-	12									
18		2000	-	4.46%	-	4.24%	-	-	12									
19		2001	-	4.46%	-	4.24%	-	-	12									
20		2002	-	4.46%	-	4.24%	-	-	12									
21		2003	-	4.46%	-	4.24%	-	-	9									
22		2004	-	2.23%	-	4.24%	-	-	12									
23		2005	-	0.00%	-	4.24%	-	-	12									
24		2006	-	0.00%	-	4.24%	-	-	12									
25		2007	-	0.00%	-	4.24%	-	-	12									
26		2008	-	0.00%	-	4.24%	-	-	12									
27																		
28			-		-		-	-			-							
29																		
30	KU-Project 27	Year in Service	Plant Amt	Tax Depreciation		Book Depreciation		Def Tax										
31	Precip Inlet Duct Rep	1976	267,426	3.75%	10,028	3.01%	5,031	(4,998)	7.5									
32	Brown 2	1977	267,426	7.22%	19,305	3.01%	8,050	(11,256)	12									
33		1978	267,426	6.68%	17,856	3.01%	8,050	(9,807)	12									
34	28,069	1979	267,426	6.18%	16,519	3.01%	8,050	(8,469)	12									
35		1980	267,426	5.71%	15,278	3.01%	8,050	(7,229)	12									
36		1981	267,426	5.29%	14,133	3.01%	8,050	(6,084)	12									
37		1982	267,426	4.89%	13,072	3.01%	8,050	(5,022)	12									
38		1983	267,426	4.52%	12,093	3.01%	8,050	(4,043)	12									
39		1984	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
40		1985	267,426	4.46%	11,930	3.01%	8,050	(3,880)	12									
41		1986	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
42		1987	267,426	4.46%	11,930	3.01%	8,050	(3,880)	12									
43		1988	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
44		1989	267,426	4.46%	11,930	3.01%	8,050	(3,880)	12									
45		1990	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
46		1991	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
47		1992	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
48		1993	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
49		1994	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
50		1995	267,426	4.46%	11,933	3.01%	8,050	(3,883)	12									
51		1996	267,426	2.23%	5,964	3.01%	8,050	2,086	12									
52		1997	267,426	0.00%	-	3.01%	8,050	8,050	12									
53		1998	267,426	0.00%	-	3.01%	8,050	8,050	12									
54		1999	267,426	0.00%	-	3.01%	8,050	8,050	12									
55		2000	267,426	0.00%	-	3.01%	8,050	8,050	12									
56		2001	267,426	0.00%	-	3.01%	8,050	8,050	12									
57		2002	267,426	0.00%	-	3.01%	8,050	8,050	12									

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58		2003	267,426	0.00%	-	3.01%	6,037	6,037	9									
59		2004	267,426	0.00%	-	3.01%	-	-	12									
60		2005	267,426	0.00%	-	3.01%	-	-	12									
61		2006	267,426	0.00%	-	3.01%	-	-	12									
62			267,426		267,431		220,356	(47,076)			47,070							

From:	Garrett, Chris
To:	Schram, Chuck; Wilson, Stuart
CC:	Adhitama, Prasetya
Sent:	1/4/2011 9:02:17 AM
Subject:	FW: Air Totals With No SCRs and with Only Ghent 2 SCR
Attachments:	Environmental Summary Breakdown 1-3-11 R1.xlsx

We would like to run the numbers behind these two scenarios and were wondering whether a new prosym/powerym output would be available.

Chris

From: Hudson, Rusty
Sent: Monday, January 03, 2011 5:20 PM
To: Garrett, Chris
Cc: Ritchey, Stacy; Straight, Scott
Subject: Air Totals With No SCRs and with Only Ghent 2 SCR

Chris, at Paul's 4:00 meeting it was determined that we should provide a range between none of the SCR's being built, and just the Ghent 2 SCR being built. Given that new EPA allocations will be issued in March of 2011 and that we are right on the margin until the Cane Run combined cycle unit comes on line, that should give us room in case the allocations go against us. Also included in the numbers is $7m per unit for turn-down capabilities on the existing units of Ghent 1,3, and 4, and MC 3 and 4 (adding hot water recirc similar to what is being done on Brown 3). The range therefore is a reduction of $379m if Ghent 2 is still built, to $641m if none of the SCR's are built. Rusty

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	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), Excluding all SCR except Ghent 2**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - SCR	$262,878		$12,217	$76,235	$105,712	$68,713	$0	$0	$0		
32	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
33	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
34	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
35	Total Ghent 2	**$427,787**	**$375**	**$19,592**	**$76,235**	**$111,301**	**$120,778**	**$76,195**	**$23,311**	**$0**		
36												
37	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
38	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
39	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
40	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
41												
42	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
43	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
44	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
45	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
47	**Total Ghent**	**$954,101**	**$1,250**	**$28,267**	**$91,575**	**$148,777**	**$293,065**	**$324,115**	**$67,052**	**$0**		
48												
49	**Mill Creek**											
50	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		
52	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
53	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
54	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
55												
56	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
57	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
58	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
59	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
60	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
61	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
62												
63	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
64	Mill Creek 3 - FGD (Unit 3 Removal)	$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
65	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
66	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
67	Total Mill Creek 3	**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
68												
69	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
70	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
71	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
72	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
73	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
74	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
75												
76	**Total Mill Creek**	**$1,044,205**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$308,371**	**$101,241**	**$5,705**	**$539**		
77												
78	**Trimble**											
79	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
80	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
81	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
82												
83	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
84												
85	**Environmental Air Studies**											
86	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
87	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
88												
89												
90	**Total Environmental Compliance - Air**	**$2,343,848**	**$2,500**	**$80,455**	**$330,887**	**$556,712**	**$711,731**	**$565,256**	**$95,766**	**$539**		
91												
92	Variance to MTP (Only SCR Ghent 2)	($378,754)	$0	($13,078)	($44,194)	($95,869)	($91,563)	($81,855)	($49,553)	($2,643)		
93	LGE Variance to MTP (Only SCR Ghent 2)	($226,458)	$0	$0	$3,742	($28,016)	($68,134)	($81,855)	($49,553)	($2,643)		
94	KU Variance to MTP (Only SCR Ghent 2)	($152,296)	$0	($13,078)	($47,936)	($67,853)	($23,429)	$0	$0	$0		
95												
96	$7m for each of five SCR's (three KU and two LG&E) has been added back in (above) for turn-down capabilities (1/2 in 2012 and 1/2 in 2013).											
97	LG&E (two Mill Creek units)				7000	7000						
98	KU (three Ghent units)				10500	10500						

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	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
45												
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,044,205**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$308,371**	**$101,241**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,080,970**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$643,018**	**$565,256**	**$95,766**	**$539**		
90												
91	Variance to MTP (No SCR Amounts)	($641,631)	$0	($25,295)	($120,429)	($201,581)	($160,276)	($81,855)	($49,553)	($2,643)		
92	LGE Variance to MTP (No SCR Amounts)	($226,458)	$0	$0	$3,742	($28,016)	($68,134)	($81,855)	($49,553)	($2,643)		
93	KU Variance to MTP (No SCR Amounts)	($415,174)	$0	($25,295)	($124,171)	($173,565)	($92,142)	$0	$0	$0		
94												
95	$7m for each of five SCR's (three KU and two LG&E) has been added back in (above) for turn-down capabilities (1/2 in 2012 and 1/2 in 2013).											
96	LG&E (two Mill Creek units)				7000	7000						
97	KU (three Ghent units)				10500	10500						

From: Wilson, Stuart
To: Schram, Chuck
Sent: 1/4/2011 12:20:56 PM
Subject: B&V Cost Estimates for Environmental Controls
Attachments: 20100630_2011MTPEnvironmentalSummary-B&VvsEPARegs_LAK.xlsx

Chuck,

I'll give you a call...

Stuart

	A	B	C	D	E	F	G	H	I
1									
2									
3			**2011 MTP Black & Veatch Study**		**nmental Scenario Plannin**		**Primary Regulation**	**Secondary Regulation**	**Tertiary Regulation**
4									
5	**Brown**								
6	Brown 1 - SCR		59,000				Revised CAIR	EGU MACT	New 1-hour NAAQS for NOx
7	Brown 1 - SNCR				11,000		Revised CAIR	EGU MACT	New 1-hour NAAQS for NOx
8	Brown 1 - Baghouse		34,000				EGU MACT		
9	Brown 1 - PAC Injection		1,599				EGU MACT		
10	Brown 1 - Hg Control				3,000		EGU MACT		
11	Brown 1 - Neural Networks		500				EGU MACT		
12	Brown 1 - SAM Mitigation		4,000				Brown Consent Decree		
13	Brown 1 - Escalation		21,238				Escalation		
14	Brown 1 - CO2				3,000				
15	Total Brown 1		**120,337**		**17,000**				
16									
17	Brown 2 - SCR		92,000				Revised CAIR	EGU MACT	New 1-hour NAAQS for NOx
18	Brown 2 - SCNR				11,000		Revised CAIR	EGU MACT	New 1-hour NAAQS for NOx
19	Brown 2 - Baghouse		34,000				EGU MACT		
20	Brown 2 - PAC Injection		2,476				EGU MACT		
21	Brown 2 - Hg Control				3,000		EGU MACT		
22	Brown 2 - Neural Networks		500				EGU MACT		
23	Brown 2 - Lime Injection		2,739				EGU MACT		
24	Brown 2 - SAM Mitigation		4,000				Brown Consent Decree		
25	Brown 2 - Escalation		48,799				Escalation		
26	Brown 2 - CO2				5,000				
27	Total Brown 2		**184,514**		**19,000**				
28									
29	Brown 3 - Baghouse		61,000				EGU MACT		
30	Brown 3 - PAC Injection		5,426				EGU MACT		
31	Brown 3 - Hg Control				4,000		EGU MACT		
32	Brown 3 - Neural Networks		1,000				EGU MACT		
33	Brown 3 - Escalation		16,952				Escalation		
34	Brown 3 - CO2				13,000				
35	Total Brown 3		**84,378**		**17,000**				
36									
37	**Total Brown**		**389,229**		**53,000**				
38									
39	**Ghent**								
40	Ghent 1 - Baghouse		131,000				EGU MACT		
41	Ghent 1 - PAC Injection		6,380				EGU MACT		
42	Ghent 1 - Hg Control				77,000		EGU MACT		
43	Ghent 1 - Neural Networks		1,000				EGU MACT		
44	Ghent 1 - Escalation		22,965				Escalation		
45	Ghent 1 - CO2				15,000				
46	Total Ghent 1		**161,345**		**92,000**				

	J	K	L
1			
2			
3	**Comments**	**Subtract**	
4			
5			
6	With SCR at BR3, NAAQS is probably not a concern		59,000
7	With SCR at BR3, NAAQS is probably not a concern		0
8			34,000
9			1,599
10			0
11			500
12	May not need SAM mitigation for unit 1 with I	1	0
13			21,238
14			0
15			
16			
17	With SCR at BR3, NAAQS is probably not a concern		92,000
18	With SCR at BR3, NAAQS is probably not a concern		0
19			34,000
20			2,476
21			0
22			500
23			2,739
24	May not need SAM mitigation for unit 2 with I	1	0
25			48,799
26			0
27			
28			
29			61,000
30			5,426
31			0
32			1,000
33			16,952
34			0
35			
36			
37			
38			
39			
40	May not need baghouse or other controls; SCF	1	0
41		1	0
42		1	0
43		1	0
44		1	0
45			0
46			

	A	B	C	D	E	F	G	H	I
47									
48	Ghent 2 - SCR		227,000		152,000		EGU MACT	Revised CAIR	
49	Ghent 2 - Baghouse		120,000				EGU MACT		
50	Ghent 2 - PAC Injection		6,109				EGU MACT		
51	Ghent 2 - Hg Control				7,000		EGU MACT		
52	Ghent 2 - Lime Injection		5,483				EGU MACT		
53	Ghent 2 - Neural Networks		1,000				EGU MACT		
54	Ghent 2 - Escalation		57,338				Escalation		
55	Ghent 2 - CO2				15,000				
56	Total Ghent 2		**416,930**		**174,000**				
57									
58	Ghent 3 - Baghouse		138,000				EGU MACT		
59	Ghent 3 - PAC Injection		6,173				EGU MACT		
60	Ghent 3 - Hg Control				77,000		EGU MACT		
61	Ghent 3 - Neural Networks		1,000				EGU MACT		
62	Ghent 3 - Escalation		33,368				Escalation		
63	Ghent 3 - CO2				15,000				
64	Total Ghent 3		**178,541**		**92,000**				
65									
66	Ghent 4 - Baghouse		117,000				EGU MACT		
67	Ghent 4 - PAC Injection		6,210				EGU MACT		
68	Ghent 4 - Hg Control				77,000		EGU MACT		
69	Ghent 4 - Neural Networks		1,000				EGU MACT		
70	Ghent 4 - Escalation		28,313				Escalation		
71	Ghent 4 - CO2				15,000				
72	Total Ghent 4		**152,523**		**92,000**				
73									
74	**Total Ghent**		**909,338**		**450,000**				
75									
76									
77	**Mill Creek**								
78	Mill Creek 1 - FGD		297,000		20,000		New 1-hour NAAQS for SO2	EGU MACT	Revised CAIR
79	Mill Creek 1 - SCR		97,000		121,000		EGU MACT	New 1-hour NAAQS for NOx	Revised CAIR
80	Mill Creek 1 - Baghouse		81,000				EGU MACT		
81	Mill Creek 1 - Electrostatic Precipitator		32,882				EGU MACT		
82	Mill Creek 1 - PAC Injection		4,412				EGU MACT		
83	Mill Creek 1 - Hg Control				60,000		EGU MACT		
84	Mill Creek 1 - SAM Mitigation		8,000				Mill Creek BART		
85	Mill Creek 1 - Lime Injection		4,480				EGU MACT		
86	Mill Creek 1 - Neural Networks		1,000				EGU MACT		
87	Mill Creek 1 - Escalation		120,469				Escalation		
88	Mill Creek 1 - CO2				10,000				
89	Total Mill Creek 1		**646,243**		**211,000**				
90									
91	Mill Creek 2 - FGD		297,000		20,000		New 1-hour NAAQS for SO2	EGU MACT	Revised CAIR
92	Mill Creek 2 - SCR		97,000		121,000		EGU MACT	New 1-hour NAAQS for NOx	Revised CAIR
93	Mill Creek 2 - Baghouse		81,000				EGU MACT		
94	Mill Creek 2 - Electrostatic Precipitator		32,882				EGU MACT		

	J	K	L
47			
48	Already meeting NAAQS for Nox		227,000
49	May not need baghouse or other controls; SCF	1	0
50		1	0
51		1	0
52		1	0
53		1	0
54		1	0
55			0
56			
57			
58	May not need baghouse or other controls; SCF	1	0
59		1	0
60		1	0
61		1	0
62		1	0
63			0
64			
65			
66	May not need baghouse or other controls; SCF	1	0
67		1	0
68		1	0
69		1	0
70		1	0
71			0
72			
73			
74			
75			
76			
77			
78			297,000
79	SCR may not be needed if baghouse is installe	1	0
80			81,000
81			32,882
82			4,412
83			0
84			8,000
85	With upgraded FGD, may not need lime inject	1	0
86			1,000
87			120,469
88			0
89			
90			
91			297,000
92	SCR may not be needed if baghouse is installe	1	0
93			81,000
94			32,882

	A	B	C	D	E	F	G	H	I
95	Mill Creek 2 - PAC Injection		4,412				EGU MACT		
96	Mill Creek 2 - Hg Control				60,000		EGU MACT		
97	Mill Creek 2 - SAM Control		8,000				Mill Creek BART		
98	Mill Creek 2 - Lime Injection		4,480				EGU MACT		
99	Mill Creek 2 - Neural Networks		1,000				EGU MACT		
100	Mill Creek 2 - Escalation		101,752				Escalation		
101	Mill Creek 2 - CO2				10,000				
102	Total Mill Creek 2		**627,526**		**211,000**				
103									
104	Mill Creek 3 - FGD		392,000		20,000		New 1-hour NAAQS for SO2	EGU MACT	Revised CAIR
105	Mill Creek 3 - Baghouse		114,000				EGU MACT		
106	Mill Creek 3 - PAC Injection		5,592				EGU MACT		
107	Mill Creek 3 - Hg Control				69,000		EGU MACT		
108	Mill Creek 3 - Neural Networks		1,000				EGU MACT		
109	Mill Creek 3 - Escalation		111,307				Escalation		
110	Mill Creek 3 - CO2				12,000				
111	Total Mill Creek 3		**623,899**		**101,000**				
112									
113	Mill Creek 4 - FGD		455,000		20,000		New 1-hour NAAQS for SO2	EGU MACT	Revised CAIR
114	Mill Creek 4 - Baghouse		133,000				EGU MACT		
115	Mill Creek 4 - PAC Injection		6,890				EGU MACT		
116	Mill Creek 4 - Hg Control				77,000		EGU MACT		
117	Mill Creek 4 - Neural Networks		1,000				EGU MACT		
118	Mill Creek 4 - Escalation		157,787				Escalation		
119	Mill Creek 4 - CO2				15,000				
120	Total Mill Creek 4		**753,677**		**112,000**				
121									
122	**Total Mill Creek**		**2,651,346**		**635,000**				
123									
124									
125	**Trimble**								
126	Trimble 1 - Baghouse		128,000				EGU MACT		
127	Trimble 1 - PAC Injection		6,451				EGU MACT		
128	Trimble 1 - Hg Control				4,000		EGU MACT		
129	Trimble 1 - Neural Networks		1,000				EGU MACT		
130	Trimble 1 - Escalation		30,738				Escalation		
131	Trimble 1 - CO2				16,000				
132	Total Trimble 1		**166,189**		**20,000**				
133									
134	**Total Trimble**		**166,189**		**20,000**				
135									
136	**Total Env. Compliance Air - Main Plan**		**4,116,101**		**1,158,000**				
137									
138									
139									
140									
141									
142									

	J	K	L
95			4,412
96			0
97			8,000
98	With upgraded FGD, may not need lime inject	1	0
99			1,000
100			101,752
101			0
102			
103			
104			392,000
105			114,000
106			5,592
107			0
108			1,000
109			111,307
110			0
111			
112			
113			455,000
114			133,000
115			6,890
116			0
117			1,000
118			157,787
119			0
120			
121			
122			
123			
124			
125			
126	TC currently meets 90% Hg standard - may no	1	0
127		1	0
128		1	0
129		1	0
130		1	0
131			0
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134			
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143									
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151									
152	**Sensitivities**								
153	**Green River**								
154	Green River 3 - SCR		29,000						
155	Green River 3 - CDS-FF		38,000						
156	Green River 3 - PAC Injection		1,112						
157	Green River 3 - Neural Networks		500						
158	Green River 3 - Escalation		17,899						
159	Total Green River 3		**86,511**						
160									
161	Green River 4 - SCR		42,000						
162	Green River 4 - CDS-FF		54,000						
163	Green River 4 - PAC Injection		1,583						
164	Green River 4 - Neural Networks		500						
165	Green River 4 - Escalation		20,877						
166	Total Green River 4		**118,960**						
167									
168	**Total Green River**		**205,471**						
169									
170									
171	**Cane Run**								
172	Cane Run 4 - FGD		152,000						
173	Cane Run 4 - SCR		63,000						
174	Cane Run 4 - Baghouse		33,000						
175	Cane Run 4 - PAC Injection		2,326						
176	Cane Run 4 - Lime Injection		2,569						
177	Cane Run 4 - Neural Networks		500						
178	Cane Run 4 - Escalation		45,571						
179	Total Cane Run 4		**298,966**						
180									
181	Cane Run 5 - FGD		159,000						
182	Cane Run 5 - SCR		66,000						
183	Cane Run 5 - Baghouse		35,000						
184	Cane Run 5 - PAC Injection		2,490						
185	Cane Run 5 - Lime Injection		2,752						
186	Cane Run 5 - Neural Networks		500						
187	Cane Run 5 - Escalation		59,628						
188	Total Cane Run 5		**325,370**						
189									
190	Cane Run 6 - FGD		202,000						

	J	K	L
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	A	B	C	D	E	F	G	H	I
191	Cane Run 6 - SCR		86,000						
192	Can Rune 6 - Baghouse		45,000						
193	Cane Run 6 - PAC Injection		3,490						
194	Cane Run 6 - Lime Injection		3,873						
195	Cane Run 6 - Neural Networks		500						
196	Cane Run 6 - Escalation		60,222						
197	Total Can Run 6		401,085						
198									
199	**Total Cane Run**		**1,025,422**						
200									
201	**nmental Compliance Air - Sensitivities**		**1,230,892**						
202									
203									
204	**nd Total Environmental Compliance Air**		**5,346,993**						

	A	B	C	D	E	F	G
1		**B&V**	**Modified B&V - Per Discussions w/ Gary Revlett**				
2		**Total ($M)**	**Total ($M)**				
3	Revised CAIR	151	151				
4	EGU MACT	1,749	870				
5	Brown Consent Decree	8	-				
6	New 1-hour NAAQS for SO2	1,441	1,441				
7	Mill Creek BART	16	16				
8		3,365	2,478				
9							
10	Escalation	751	578				
11		4,116	3,057				
12							
13	Please note: The 'modified B&V' information is based on high-level discussions with						
14	Gary Revlett regarding 'possible/potential' savings. The differences between the						
15	two columns highlight areas where additional discussions may be warranted. Gary is						
16	not saying the B&V numbers are wrong. He simply identified equipment that 'may'						
17	not be necessary – depending on the impact of other/existing controls.						

From: Schram, Chuck
To: Sinclair, David
Sent: 1/10/2011 6:42:20 AM
Subject: FW: EPA Regs Timeline
Attachments: EPA Regs Schedule 20110107.docx

David,
FYI...this is a current draft calendar of key activities related to EPA regs responses.
Chuck

From: Schram, Chuck
Sent: Friday, January 07, 2011 5:03 PM
To: Voyles, John
Subject: RE: EPA Regs Timeline

John, this is the updated version.

Chuck

From: Voyles, John
Sent: Friday, January 07, 2011 4:59 PM
To: Schram, Chuck
Subject: RE: EPA Regs Timeline

C,

Based on this and our conversation, will you send any updated version to me by Monday mid-morning?

Thanks

J

Please note that my e-mail address has changed from john.voyles@eon-us.com to john.voyles@lge-ku.com. Please take this opportunity to update my address in your address book and delete the old e-mail address immediately. The old e-mail address will soon expire, and I will no longer be able to receive e-mails at that address.

From: Straight, Scott
Sent: Friday, January 07, 2011 1:21 PM
To: Schram, Chuck
Cc: Voyles, John
Subject: RE: EPA Regs Timeline

Chuck,
In general, looks okay. The only thing to consider is whether we should develop the April ECR filing both with/without the Ghent 2 SCR while understanding that we could file either.
Scott

From: Schram, Chuck
Sent: Monday, January 03, 2011 3:19 PM
To: Straight, Scott
Cc: Voyles, John
Subject: EPA Regs Timeline

Scott,
Attached is a draft containing some tentative dates for decisions related to EPA Regs. I used the April 1 ECR filing date that we discussed in the 12/6/2010 meeting. The dates later in 2011 are only placeholders at this point. Please review and consider other key decision dates that should be included.

<< File: EPA Regs Schedule 20110103.docx >>
Chuck

January 7, 2011

Key Dates for EPA Regulations Actions

Date	Item	Input/Review
Jan 14, 2011	Complete review of EPA's two alternate CATR allowance allocation methods	Env, Gen Planning
Jan 28, 2011	RFP responses for CR replacement capacity due	ES
Jan 31, 2011	Finalize content and timing of ECR filing	ES, RR
Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 18, 2011	Evaluation of RFP responses complete	Gen Plan
Mar 31, 2011	Receive updated CATR NOx/SO_2 allocation information; MACT/HAPS proposed rule issued	Env, Proj Eng, Gen Plan
Apr 1, 2011	Potential ECR filing for MC FGDs, BR landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	Prj Eng, Gen Plan, RR
Apr 18, 2011	Finalize CATR control plan based on revised NOx/ SO_2 allocations	Prj Eng, Gen Plan
Apr 29, 2011	Finalize scope of meeting MACT/HAPS proposed rule	Prj Eng, Gen Plan
Jun 30, 2011	File CCN for CR replacement	ES, RR
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls, SCRs (if any result from revised CATR allowance allocation)	Prj Eng, Gen Plan, RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	Prj Eng

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

From:	Voyles, John
To:	Thompson, Paul; Sinclair, David; Bowling, Ralph; Staton, Ed; Hudson, Rusty; Hincker, Loren
CC:	Schram, Chuck; Yussman, Eric
Sent:	1/10/2011 10:04:30 AM
Subject:	EPA Regs Timeline
Attachments:	EPA Regs Schedule 20110110.docx

For the staff meeting action item, please see the latest draft with expanded dates and milestones of decisions for discussion.

2012 already has some high level timing that can be added going forward as we progress during the first quarter this year, but have not been added here at this point.

JV

January 10, 2011

Key 2011 Dates for EPA Regulations Actions

Date	Item	Input/Review
Jan 14, 2011	Complete review of EPA's two alternate CATR allowance allocation methods	Env, Gen Planning
Jan 28, 2011	RFP responses for CR replacement capacity due	ES
Jan 31, 2011	Finalize content and timing of ECR filing	ES, RR
Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 18, 2011	Evaluation of RFP responses complete	Gen Plan
Mar 31, 2011	Receive updated CATR NOx/SO_2 allocation information; MACT/HAPS proposed rule issued	Env, Proj Eng, Gen Plan
Apr 1, 2011	Potential ECR filing for MC FGDs, BR landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	Prj Eng, Gen Plan, RR
Apr 18, 2011	Finalize CATR control plan based on revised NOx/ SO_2 allocations	Prj Eng, Gen Plan
Apr 29, 2011	Finalize scope of meeting MACT/HAPS proposed rule	Prj Eng, Gen Plan
May 31, 2011	Inv Committee/internal approvals before public mtgs	ES
Jun 1, 2011	Public ROW meetings – gas pipeline (conclude by Jul 18)	ES, RR
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Sep 1, 2011	File CCN for CR replacement	ES, RR
Oct-Dec, 2011	Prepare Transmission CCN for CR replacement	Trans, RR
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls, SCRs (if any result from revised CATR allowance allocation)	Prj Eng, Gen Plan, RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	Prj Eng

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

From:	Sinclair, David
To:	Schram, Chuck; Wilson, Stuart; Brunner, Bob; Pfeiffer, Caryl
Sent:	1/13/2011 5:33:14 PM
Subject:	FW: Project Engineering's ES Bi-Weekly Report - January 14, 2011
Attachments:	PE's Bi-Weekly Update of 1-14-11.docx

Note in particular the discussion on TC2.

From: Straight, Scott
Sent: Thursday, January 13, 2011 4:55 PM
To: Straight, Scott; Thompson, Paul; Voyles, John; Bowling, Ralph; Hudson, Rusty; Hincker, Loren; Sinclair, David; Schetzel, Doug; Yussman, Eric; Jackson, Fred
Cc: Waterman, Bob; Imber, Philip; Lively, Noel; Saunders, Eileen; Gregory, Ronald; Heun, Jeff; Hance, Chuck; Clements, Joe; Cooper, David (Legal); Jones, Greg; Keeling, Chip; Hendricks, Claudia; Ray, Barry; O'brien, Dorothy (Dot); Bellar, Lonnie; Blake, Kent; Sturgeon, Allyson; Conroy, Robert; Cornett, Greg
Subject: RE: Project Engineering's ES Bi-Weekly Report - January 14, 2011

Resending with the correct 2010 Year's End Safety Chart.

From: Straight, Scott
Sent: Thursday, January 13, 2011 1:25 PM
To: Straight, Scott; Thompson, Paul; Voyles, John; Bowling, Ralph; Hudson, Rusty; Hincker, Loren; Sinclair, David; Schetzel, Doug; Yussman, Eric; Jackson, Fred
Cc: Waterman, Bob; Imber, Philip; Lively, Noel; Saunders, Eileen; Gregory, Ronald; Heun, Jeff; Hance, Chuck; Clements, Joe; Cooper, David (Legal); Jones, Greg; Keeling, Chip; Hendricks, Claudia; Ray, Barry; O'brien, Dorothy (Dot); Bellar, Lonnie; Blake, Kent; Sturgeon, Allyson; Conroy, Robert; Cornett, Greg
Subject: Project Engineering's ES Bi-Weekly Report - January 14, 2011

<< File: PE's Bi-Weekly Update of 1-14-11.docx >>

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Energy Services - Bi-Weekly Update
PROJECT ENGINEERING
January 14, 2011

- **KU SOx**
  - Safety – NTR
  - Schedule/Execution:
    - Ghent Elevators – in progress.
    - Ghent Misc. - Fluor demobilized in December. Two Fluor engineers returned to the site to oversee ID Fan Testing which is taking place the week of January 10, 2011.
    - Brown Unit 2 - ID fan and damper control implementation was completed during the last week of the outage as planned and scheduled.
    - Brown Gypsum - De-watering continues
    - Brown Coal Pile Modification – in progress.

- **TC2**
  - Safety – NTR
  - Schedule/Execution:
    - Bechtel EPC – Performance Guarantee Tests (on restricted coals) were completed 12/23/10. Bechtel's preliminary results indicate all guaranteed values for thermal performance and air emissions were met for Final Completion except for ammonia consumption, which met the Substantial Completion guarantee value. The preliminary results also indicate the Net Electrical Output Guarantee was surpassed by about 10 MW and Bechtel will qualify for the maximum performance bonus of $6M if major changes to the combustion system are not performed during the amendment period. PE officially rejected Bechtel's petition for Substantial Completion because the work is not complete with respect to the burners and the ammonia forwarding system. An Amendment to the EPC Agreement is being negotiated with Bechtel that allows care, custody, and control of the unit to transfer to Owners while suspending delay LD's to Bechtel while Bechtel completes the burner and ammonia forwarding system work. The Amendment reserves our rights to LD's, warranty, performance, risk of loss, among other key business points, during this Interim Operation period.
  - Contract Disputes/Resolution:
    - Bechtel completed a wire transfer of LD payments totaling just over $25.6M on 1/12/11. This represents the undisputed amount of our $38.1M demand letter for LD's accumulated through 11/20/10.
    - Finalization of the Amendment is targeted for week of Jan 10.
  - Issues/Risk:
    - Design of the DBEL burners for our coal specification
    - Completion of the ammonia forwarding system.
    - Long-term life of the coal mill gearbox bearings.

- **Brown 3 SCR**
  - Safety – NTR
  - Permitting – NTR
  - Engineering – proceeding as planned to support the spring 2012 in-service.
  - Schedule/Execution – SCR ductwork deliveries nearly complete.

- Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
  - Safety – Received and reviewing Voith Hydro Health and Safety Plan
  - Engineering
    - Voith Hydro proceeding with equipment orders and pre-mobilization issues for a restart of rehabilitation on Unit 5 in June, 2011.
    - RFQ for underwater repairs to Unit 5 gate slots to be out by Monday, 1/17.
    - B&V continues engineering on gate modifications; RFQ expected to be out in early February.
    - Continued review and edit of Aquarius Marine's submittal of underwater inspection report for entire plant as required by FERC.
    - PE reviewing potential change in SOW for possible 240/480 VAC station auxiliary system upgrade.
    - PE completed work with Voith (VHMS) generator group on application for grid interconnection; information forwarded.
    - PE continues assembling SOW documents for Historic Maintenance Plan repairs to concrete building façade.
  - Issues/Risks
    - NTR

- **Mill Creek Limestone Project**
  - Safety - NTR
  - Schedule/Execution
    - East and Westbrook nearing completion of the building erection. Final work will take place the week of 1/10/11 with a punch list walk-down scheduled for 1/18/11.
    - Detailed Engineering - The award recommendation has been signed and notifications to the successful and non-successful bidders are in progress.

- **Cane Run CCP Project**
  - Permitting
    - 404 and Landfill Permit applications remain under review by the agencies. To date permitting process has gone well. The 401 permit was received on 8/4/10. The Flood Plain permit was received 11/22/10.
  - Engineering
    - The review of constructing the smaller landfill versus modifying the existing landfill and trucking balance of CCR to Mill Creek is nearing completion. Preliminary results indicate no financial benefit to NOT building the landfill; however, while cons exist for long-term trucking to Mill Creek (i.e. Safety, emissions off of trucks, bad weather handling, etc.) there are pros as well with regards to local issues. Initial review held with Bowling and a final review held with Bowling and Voyles. Currently looking at a third alternative, MSE wall around existing landfill to determine if it's a viable option. Review meeting planned for 2/14/11.
    - Finalization of construction drawings are on hold until the KYDWM permit review is completed and any necessary changes can be incorporated.
    - Working on finalizing design, currently 60% complete, of the smaller landfill to support the proposed 2016 CCGT. A revised estimate for the smaller landfill has been completed by STANTEC and is under review with PE. The revised estimate is lower than the 2011 MTP amount that was a prorate from the original landfill scope.

- **Trimble Co. Barge Loading/Holcim**
  - Finalized order with UCC to purchase pneumatic Fly Ash handling system.
  - The permit has been published on the USACE's website.
  - Received 401 Stream Crossing permit on 20-Dec-10.
  - Working to issue BOP engineering contract.

- **TC CCP Project – BAP/GSP**
  - Safety – NTR
  - Schedule/Execution:
    - GSP's liner system installation completed. Placement of ballasting water for the liner was completed on 1/10/11. Preparations are now being made to set the GSP Raft.
    - All fill and mechanically stabilized earth wall work on the BAP is completed except for a small section of the South Dike. Work continues on erection of the new Pipe Rack, electrical duct banks to GSP Electrical Building and to Ash Pond Raft.
    - Actions being taken to prevent deer from entering the GSP. Fencing was completed at the GSP on 1/7/11.
  - Contract Disputes/Resolution
    - Minor issues to resolve with Riverside.
    - IC approved $4.2m increase in Riverside contract authorization.
  - Issues/Risk
    - Weather remains the biggest risk; however, the weather over the last 4 months has been exceptional for this project.

- **TC CCP Project – Landfill**
  - Engineering
    - Detailed Engineering in progress with GAI.
    - Drill crews continue the geotechnical exploration.
  - Permitting:
    - The 401 Permit Application was submitted to the Kentucky Division of Water on 12/10/10.
    - The 404 Permit Application was submitted to the US Army Corps of Engineers on 12/21/10.
    - The final review with MACTEC and Environmental Affairs occurred 12/9/10 along with meetings with Legal and Right of Way on potential acquisition of small land parcels for right of ways and stream mitigation.

- **Ghent CCP Projects - Landfill**
  - Safety – NTR
  - Engineering:
    - Detailed Engineering of gypsum fines continues with B&V.
      - Issued tank foundation contract to E&W.
    - Detailed Engineering of the CCR Transport System awarded to B&V. The first conceptual scope meeting is scheduled for 1/17/11 to finalize the conceptual scope of the transport and handling systems.
    - Drawings and Specifications for the Detailed Engineering for the Landfill have been submitted for review within EON-US.
  - Permitting:
    - **All permit applications have been submitted.**
  - Miscellaneous

- Issues/Risk:
  - Land Acquisition – A meeting was held in LG&E Building on 12/17/10 with the remaining land owner's counsel (Mr. Crawford) and the Deatons. A final offer will be submitted to Deatons counsel the by mid-January that positions them to accept the offer or we move to condemnation

- **E.W. Brown Ash Pond Project**
  - Safety – NTR
  - Issues/Risk:
  - Continue to work with Summit on contract settlement payout/resolution.
  - Engineering – Detailed Engineering in progress by MACTEC.
  - Schedule/Execution:
    - All work in the field is currently related to the Aux. Pond Scope of Work.
    - Placement of Gypsum on hold for favorable weather conditions. Gypsum will be stockpiled instead of sluicing to Aux Pond.
    - Continue to provide BR Landfill design information to MACTEC.
    - BR Landfill design Kick-Off was held on 1/11/11.

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3, Ghent)**
  - Safety – NTR
  - Schedule/Execution – all projects essentially on hold until resolution of Ghent with EPA and Air Compliance planning with B&V study nears finalization in 1Q of 2011.
  - Next EPA discussion with respect to Ghent is the week of January 17th.
  - Planning further testing at Brown in conjunction with FGD Performance Testing utilizing high sulfur coal in March.

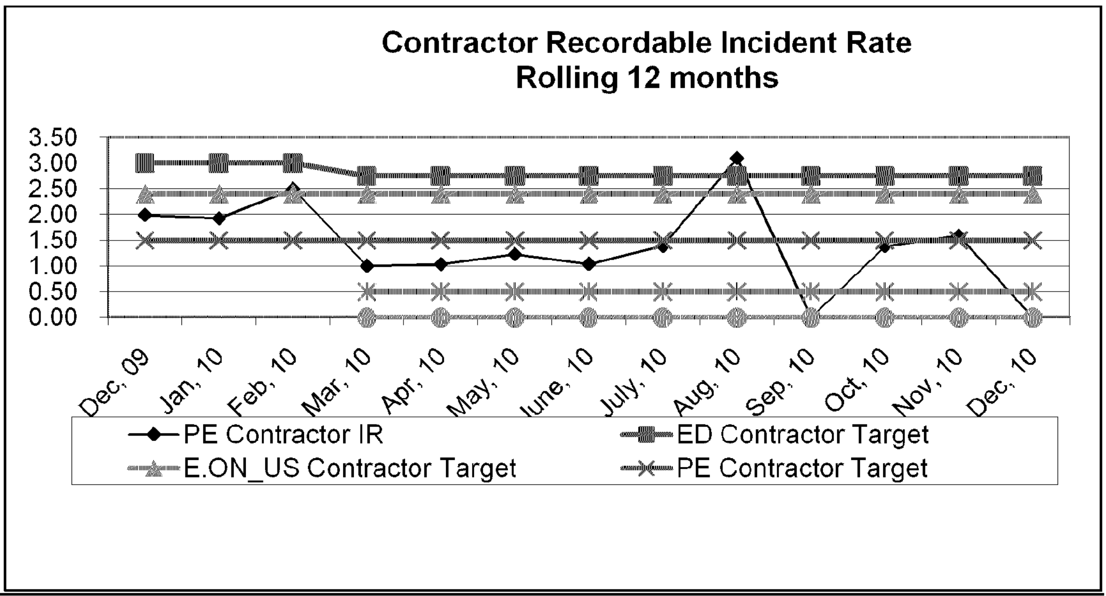
- **Cane Run CCGT**
  - Gas Pipe Line Routing – EMS has submitted and LGE has commented on a gas pipeline Routing Report. Planning second phase of design and engineering considering EMS for continued effort on this project.
  - Owner's Engineer – HDR awarded $200k to begin OE efforts. Preparing IC paper for February to increase AIP to $5.5m to cover continued development efforts including full release of OE. Held NGCC primer to further educate Operations, EA, PE, Generation Planning on the CR7 design basis. Booked NGCC technology plant due diligence trips for the week of 1/24/11.
  - Sound Survey –. Survey complete and distributed. Note concerning results from survey.
  - Set-back Survey of Neighbors at Cane Run – OE has submitted new layout meeting the 2000' foot residential setback requirements.
  - Start Up Emissions – Preparing all heat balances and emissions based on 640 net MW 1% summer design condition which equates to 690 net MW winter condition. Planned kickoff meeting with Trinity on week of 1/31/11.

- **Other Generation Development**
  - LFG - NTR.
  - Biomass – BCAP rules promulgated. Working to complete forms for submittal.
  - CCS 100 MW Project –
  - EPRI questionnaire released to 13 technology suppliers; response date January 31st.
  - KGS ongoing. 1 set of geology data under contract. Negotiating licensing agreement for 2nd set of data.
  - KBR under contract. Site visit planned for week of January 17th.

- FutureGen –Surface Team completed evaluations on schedule.

- **General**
  - Environmental Scenario Planning:
    - All stations (MC, Ghent and Brown) are under review.
    - Various meetings being held with Gen Planning, Rates & Regulatory to continue honing the plan and various compliance scenarios.
    - SCRs not in plan for Hg co-benefit. This will lead towards several (if not all but Ghent 2) SCRs not being needed, pending final allowance allocation by EPA.
  - 2011 MTP ECR/CCN Filings – working closely with Rates on PSC submittals and presentations/updates. **A filing date has been preliminarily set with Rates for April 1 2011.**
  - Continue to work with Legal and EA on Ghent SAM compliance.
  - Continue to work with Legal on asbestos litigation regarding construction of TC1.

Metrics



PE finished 2010 with an IR of 1.49, just under the goal of 1.50.

Upcoming PWT Needs:

Project Engineering
Investment Committee Schedule

INVESTMENT COMMITTEE SCHEDULE

Project Manager	Description	Contract, Project SSA	Amount $000s	Month of I/C Meeting	SEP10	OCT10	NOV10	DEC10	JAN11	FEB11	MAR11	APR11	MAY11	JUN11	JUL11	Aug11
Heun	CR CCP - Landfill Phase I - Construction	C	15,000	Aug												
Heun	GH CCP - Landfill Phase I - Construction	C														
Heun	GH CCP - Gypsum Fines and Transport - Engineering	C	4.000	Oct												
Heun	GH CCP - Gypsum Fines and Transport - Equipment/Construction	C														
Heun	GH CCP - Biannual Update	C														
Imbe	BR 3 SAM Mitigation	C	8.000	Dec												
Imbe	GH 1 -4 SAM Mitigation	P	32,000	Dec												
Imbe	MC 3 and MC4 SAM Mitigation - On Hold	P														
Imbe	Biomass Coal Firing															
Imbe	Land Fill Gas Engineering															
Lively	CCGT 2016 - Cane Run	P	589,200	Apr												
Saunders	MC Limestone Mill EPC Contract	C	12,000	Dec												
Saunders	BR 2 SCR Technology	P														
Saunders	BR 2 SCR EPC	P														
Saunders	GH 2 SCR Technology	P														
Saunders	GH 2 SCR EPC	P														
Waterman	TC CCP - Landfill Phase I - Construction	C														
Waterman	TC CCP - Gypsum Fines and Transport - Engineering	C														
Waterman	TC CCP - Gypsum Fines and Transport - Equipment/Construction	C														
Williams	BR CCP - Landfill	P	66,000	Oct												
Williams	BR CCP - Landfill Phase I - Construction	C		Jun												
Williams	BR CCP - Ash Handling Dry Conversion	C		Jun												

Staffing

- Significant staffing increases in PE expected to manage the current slate of projects in PE's 2011 MTP and to account for retirements. Headcount planning is in process now that the MTP has been approved by LG&E and KU Energy. The revised PE headcount plan is expected to be in final draft in January 2011.
- The new position to manage project approval documentation and schedules is expected to be posted within two weeks. The position description is under final review with HR.

From: Hudson, Rusty
To: Schram, Chuck
Sent: 1/14/2011 8:49:43 AM
Subject: FW: SCR numbers by year
Attachments: Environmental Summary Breakdown 1-3-11.xlsx

Chuck, this is what it would be by technology by unit without the SCR's. Rusty

Draft

	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,044,205**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$308,371**	**$101,241**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,080,970**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$643,018**	**$565,256**	**$95,766**	**$539**		
90												
91	Variance to MTP (SCR Amounts)	($676,631)	$0	($25,295)	($137,929)	($219,081)	($160,276)	($81,855)	($49,553)	($2,643)		

Draft

	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Without Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$0		$0	$0	$0	$0	$0	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$216,888**	**$0**	**$0**	**$2,455**	**$38,297**	**$109,686**	**$66,450**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,018,705**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$301,996**	**$82,116**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,055,470**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$636,643**	**$546,131**	**$95,766**	**$539**		
90												
91	Variance to MTP (SCR Amounts)	($676,631)	$0	($25,295)	($137,929)	($219,081)	($160,276)	($81,855)	($49,553)	($2,643)		

From: Schram, Chuck
To: Thomson, Robert
Sent: 1/14/2011 9:01:28 AM
Subject: FW: SCR numbers by year
Attachments: Environmental Summary Breakdown 1-3-11.xlsx

From: Hudson, Rusty
Sent: Friday, January 14, 2011 8:50 AM
To: Schram, Chuck
Subject: FW: SCR numbers by year

Chuck, this is what it would be by technology by unit without the SCR's. Rusty

Draft

	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,044,205**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$308,371**	**$101,241**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,080,970**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$643,018**	**$565,256**	**$95,766**	**$539**		
90												
91	Variance to MTP (SCR Amounts)	($676,631)	$0	($25,295)	($137,929)	($219,081)	($160,276)	($81,855)	($49,553)	($2,643)		

Draft

	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Without Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
45												
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$0		$0	$0	$0	$0	$0	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$216,888**	**$0**	**$0**	**$2,455**	**$38,297**	**$109,686**	**$66,450**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,018,705**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$301,996**	**$82,116**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,055,470**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$636,643**	**$546,131**	**$95,766**	**$539**		
90												
91	Variance to MTP (SCR Amounts)	($676,631)	$0	($25,295)	($137,929)	($219,081)	($160,276)	($81,855)	($49,553)	($2,643)		

From: Schram, Chuck
To: Jefferson, Tangila
Sent: 3/14/2011 12:48:44 PM
Subject: RE: Project List
Attachments: Project List 3 1 11 J G S 20110314.docx

Comments attached:

Thanks,
Chuck

From: Jefferson, Tangila
Sent: Monday, March 14, 2011 8:42 AM
To: Schram, Chuck
Subject: Project List
Importance: High

Do you have any corrections or changes to add to the Project List before I send it out?

From: Jefferson, Tangila
Sent: Wednesday, March 02, 2011 11:21 AM
To: Schram, Chuck
Subject: Bi Weekly Report

<< File: Project List 3 1 11 J G S.docx >>

Tangila Jefferson
LG&E/KU
Senior Secretary/Chuck Schram
Energy Planning, Forecasting & Analysis
(502) 627-3621
(502) 217-2330 fax

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Generation Planning and Analysis

Project	Status	Schedule
PowerSimm Implementation	• Major issues moving forward are speed and getting our system up and running smoothly. Ascend is addressing the speed issue. Working with Ascend and our IT group to get our system up and running smoothly.	• Planning to use PowerSimm to evaluate top RFP responses. Add some details about specific uses post-March 18
Determine least-cost strategy for complying with NOX and SO2 environmental regulations	• Met with senior managers on November 22 to review recommendation. • Reviewed follow-up items and further analysis with senior managers on December 10.	Will update analysis when additional information regarding CATR allocations becomes available (in March?). For now, analysis is complete.
Integrated Resource Plan	• 1st draft of IRP submitted for internal review on March 1. • Received Astrape Consulting's DRAFT optimal reserve margin report on February 28.	• Second draft of IRP due for Sr. Manager review on March 18.
Evaluate responses to RFP	• Completed Phase I and Phase II screening of RFP responses.	• Analysis to be completed by March 18.
Finalize unit ratings for 2011 ratings sheet	• Following up on winter ratings for Brown CTs. • Documented methodology for establishing Ghent ratings.	When we receive feedback from Brown, we will get necessary plant manager approvals and then schedule follow-up meetings with Compliance, Legal, etc. to discuss findings [Is this settled for IRP?]
Conduct revenue requirements analysis for Brown landfill project	Performed preliminary analysis based on inputs from PE.	Analysis will be finalized in preparation for 2011 ECR filing. [Please incorporate this into a "2011 ECR Filing" project along with the other relevant items]
Evaluate decision to modify LG&E's ANNSTLF model to forecast net load (versus gross load)	Draft recommendation/presentation being reviewed by Regulated Trading/Dispatch	Will move forward when we receive feedback from Regulated Trading/Dispatch.

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Project	Status	Schedule
Develop list of standard inputs for evaluating CCP projects	First draft complete and ready to be reviewed by S. Wilson.	Q1 2011 [Still correct?]
Evaluate Sterling Materials' offer to dispose of CCP at Ghent	• Completed initial evaluation and summary report. • Discussions with SM are underway to better define contract terms.	Will support analysis as needed.
Develop SDG Presentation	• Held first two workshops.	• A third workshop will be scheduled for the end of April.
On-going Generation Planning study topics	• Min gen issues. With additional SCRs, to what extent do we have min gen issues and on what units do we need additional turn-down capacity? • CT maintenance costs. What is the best way to model CT maintenance costs?	As time permits
Evaluate CCCT operating characteristics and impact of CCCT on other units	Comparing CCCT operation with MTP operating constraints to unconstrained CCCT operation	Will be completed alongside optimal expansion plan study.
Losses Project	Mike Sebourn is leading a team to validate the calculation and uses of losses data within the company.	March 2011 [Final items for wrapup?]

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Economic Analysis

Project	Status	Schedule
EEI disposition project: strategy and valuation	No change (awaiting next phase of project, if any)	
Strategy for dealing with atypical rate requests	Howard Bus is aware of Bob's departure, but Economic Analysis will still be involved.	Comments due by 2/18
Aurora power market model implementation – mid-term market pricing analysis	Benchmarking against other data sources continues. (No change)	Ongoing
Aurora power market model implementation – long-term scenario planning	EPA impact analysis: using AURORA model to determine economic solution to retrofit vs retirement decision for coal-fired plant (for compliance with proposed EPA regulations)	Will refine view through May 2011 in preparation for planning activities.
EPA CATR emissions allowance balances	Comparison of emissions allowance allocations vs expected consumption – for Kentucky as a whole, and by company within the state	Completed; awaiting additional info on allocations.
Coal inventory optimization model	Developing modeling approach combining economic optimization guidelines with predefined reliability targets.	In progress
'Extreme green' capacity expansion scenario for IRP (?)	Assessment of the volume (and cost) of wind/solar capacity necessary to meet 100% of native load energy and peak load requirements	First-cut spreadsheet model completed 2/11; optional for IRP
LG&E/KU environmental retrofit rate impact, by company and rate class	Update completed using 2011 Plan capital profile; 2016 revenue requirements allocated between rate classes on revenue-share basis	Provisional estimate to J Voyles 1/21.
Forthcoming EPA regulation – economic impact assessment (higher electricity prices)	Final report received from Paul Coomes 12/22	Final edits/questions in process.
Review of (State) HB 239 (promoting renewables and energy efficiency)	Updating earlier assessment (last year's review of HB 408) of potential utility rate impacts of RPS and energy efficiency measures. Current bill has similar impact through 2020 – but no further escalation thereafter	High level assessment complete; similar to 2010 impact.
2011 IRP	Preparing contribution for Section 6 – Significant Changes	Complete

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Review of bi-weekly Trading Meeting objectives, participation and content	Questionnaire circulated (2/10) to elicit views on most interesting/relevant topics for discussion	Combined with Fcast meeting.
Legislation monitoring (EPA regulation, RPS, energy efficiency initiatives)	Summary of current bills (Federal and State)	Ongoing
Regular analyses/deliverables	Commodities Markets Update; Trading Group meeting presentations Month-end OSS review (CinHub and PJM-W price forecast variance)	Monthly Bi-weekly Monthly

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Operational Analysis

Project	**Status**	**Schedule**
Generation Fleet - Coal Unit Variable O&M Costs Project	Historical analysis and scenarios complete. The MTP $ and data has been checked and incorrect or incomplete has been obtained. We have discussed the actual and MTP cost and generation data used to calculate average incremental variable maintenance costs. Finalizing calculation and procedure documents. Planning meeting with key staff to review coal fleet and CT recommendations.	March 2011
Development of a dashboard to provide a near real time snapshot view of large industrial customer usage.	We have determined meters for which data is already available on a weekly basis. Jason has volunteered to pull this data in weekly. Will meet this week to assess next set of meters to move to remote read and plan going forward with remaining meters. Will determine presentation of data in the interim until it updates are available with a enough frequency to build a dashboard.	Business Case presentation to mgmt 1st week of March
WKEC Unwind activities • WKEC/BREC IT Service Agreement	• Ongoing activities, prepare monthly punch list for Paul Thompson • BREC picked up the back-up tapes Feb 22nd; however the listing of tapes was not fully correct; we also have additional tapes to send to BREC; IT is correcting and we will have to send an email to BREC. • The host system hard drives were destroyed. • Due to an error in the non-FAC PPA, the Company is due a small refund from Century; the exact amount is	Ongoing

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

	being determined by the Parties. • The final piece of equipment in BREC data center will be relocated to the City by 3/11. • BREC submitted an invoice for 75% of its HMPL arbitration proceeding costs; a response was sent to BREC indicating that such payment is not provided for in the Indemnification Agreement. • Obtained Telecommunications Unwind files to retain. • Coordinated filing and removal of supplies from the secured LEM 4th floor office area; space has been turned over to Facilities for use by others.	
• Power Supply System Agreement (PSSA) Operating Committee • Transmission Coordination Agreement (TCA) Coordinating Committee	• Ongoing quarterly and semi-annual meetings • Drafted the December 10th meeting minutes and the 2010 periodic company reports for committee review.	Ongoing
New Project – CT Fleet Optimal Dispatch Project	• Draft Project outline/scope - completed • Discuss plan and resources • Complete analysis work • Prepare summary report	• TBD
New Project - Firm Gas for CTs Analysis Project Complete analysis that categorizes firm day ahead natural gas purchases, actual purchases vs. burn and seek to determine reasons for variances and suggest optimal strategies.	• Drafted project outline/scope • Compiled data on gas purchases and CT usage. • Preliminary data assembled and reviewed.Documenting budget and categorizing optimal conditions. • Prepare report and review with management.	• March 2011
Unbilled Processes/ Methodology/Losses	• Work with Rates and Revenue Accounting	• 2011
Electric Energy, Inc. (EEI) Quarterly Review	• 1st Quarter 2011 Review	April 2011
BTF Analysis Financial Impact	• Scheduled informational gathering meeting with Generation Planning	TBD

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Regular analyses/deliverables Notes:	OSS and Native Load Report Month-end OSS Review OSS Forecast Update KPI s OSS Activity / MTP Support / PEPs Energy Services Audit Report	Daily Monthly Monthly Monthly Ongoing/As needed Monthly

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Sales Analysis & Forecasting

Project	**Status**	**Schedule**
Load Research	Continually extracting monthly data. Updated the recorder map for the census class and in the process of validating the representation of the sample classes. Next, recorders will be installed to the appropriate customers. KU and ODP mapping complete.	Completing LG&E mapping for recorders. Completion in early 2011. [Please include a completion date (at least month)].
2011 IRP • Update tables with 2010 data • Complete write-up of load forecasting sections	In process. Tables and commentary in the process of being updated and developed. Sections 5, 6, & 7 almost complete. Technical appendix to complete.	In review stage.
Weather Normalization Coefficients for 2011 MTP	In progress	Complete
2012 MTP Forecasts	Preparation of historical data	Feb 2011 Complete
Populate CCS with NAICS data for Commercial and Industrial customers	Have developed a 3-digit NAICS code. Revenue and Major Accounts are in agreement to the level of detail. Next is to update the BP Industry field in CCS for all C&I customers that do not have a BP Industry value.	The BP Industry field in CCS was found to be incomplete and/or inaccurate. This project is on hold for now.
Substation demand forecast	Confirming that no changes are needed.	Complete
Commercial End-Use Survey	Survey complete. Data still to be analyzed and incorporated into the SAE model.	Feb 2011 [Schedule for remainder of activities?]
ODP rate case support	Began downloading MV90 data for rate case filing (test year Jan-Dec 2010)	Class data due from SAF on Feb 12011; filing scheduled for Apr 2011 Complete.
ODP fuel adjustment filing	Routine filing takes place in Q1 2011	Complete

Energy Planning, Analysis & Forecasting Projects

March 14, 2011

Project	Status	Schedule
KU Jurisdictional Study	Routine filing takes place in Q1 2011	Complete
Reviewing approaches to economic sensitivities for commercial and industrial sales forecasts	IHS Global Insight information was used to put assumptions around economic forecasts for industrial and large commercial class rates. [Redefine as review of oil price impact on economy]	March 21
Opportunities and challenges associated with growing PHEV penetration In utility service territory	Updated earlier analysis by Chris Heiniger to take account of data on (existing) hybrid vehicle registrations obtained from RL Polk	Polk data analysis to be completed by end-February [Update??]

From: Voyles, John
To: Schram, Chuck
Sent: 3/15/2011 8:02:26 AM
Subject: EPA Regs Schedule 20110312.docx
Attachments: EPA Regs Schedule 20110312.docx

Chuck,

Per my voice mail.

Let's discuss your thoughts on this update.

JV

March 14, 2011

Key 2011 Dates for EPA Regulations Actions

Date	Item	Input/Review
Jan 14, 2011	Complete review of EPA's two alternate CATR allowance allocation methods	Env, Gen Planning
Jan 28, 2011	RFP responses for CR replacement capacity due	ES
Jan 31, 2011	Finalize content and timing of ECR filing	ES, RR
Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 14-18, 2011	EPA releases EGU MACT and 316(b) draft of proposed rules	Env, ES
Mar 18, 2011	Evaluation of capacity RFP responses complete	Gen Plan
Mar 31, 2011	Complete initial engineering assessments for fleet ESPs and MC FGD options	Proj Eng
Mar 31, 2011	Receive updated CATR NOx/SO_2 allocation information;	Env, Proj Eng, Gen Plan
Apr 8, 2011	ECR project engineering studies and 3rd party cost estimates for all plants	Proj Eng
Apr 15, 2011	ECR project least cost analysis	Gen Plan
Apr 18, 2011	Finalize CATR control plan based on revised NOx/ SO_2 allocations	Prj Eng, Gen Plan
Apr 22, 2011	Final ECR PVRR and Bill Impact analyses	RR
May 1, 2011	Potential ECR filing for MC FGDs, BR landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	Prj Eng, Gen Plan, RR
May 15, 2011	Final draft ECR application and testimony	ES, RR
May 31, 2011	Inv Committee/internal approvals before public mtgs for NGCC construction project	ES
Jun 1, 2011	ECR and CCN filing for MC FGDs, BR landfill, GH SAM mitigation and EGU MACT response	ES, RR

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

March 14, 2011

Jun 1, 2011	Public ROW meetings – gas pipeline (conclude by Jul 18)	ES, RR
July 1, 2010	Air permit application for NGCC project	ES, Env
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Sep 1, 2011	File CCN for CR replacement	ES, RR
Oct-Dec, 2011	Prepare Transmission CCN for CR replacement	Trans, RR
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls, SCRs (if any result from revised CATR allowance allocation)	Prj Eng, Gen Plan, RR
Nov 28, 2011	ECR Order due from KPSC	RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	Prj Eng

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

From: Schram, Chuck
To: Voyles, John
Sent: 3/15/2011 10:38:29 AM
Subject: RE: EPA Regs Schedule 20110312.docx
Attachments: EPA Regs Schedule 20110315.docx

John,
Please see my attached edits related to CATR (discussed with Gary Revlett) and additions related to RFP timeline.

Chuck

-----Original Message-----
From: Voyles, John
Sent: Tuesday, March 15, 2011 8:02 AM
To: Schram, Chuck
Subject: EPA Regs Schedule 20110312.docx

Chuck,

Per my voice mail.

Let's discuss your thoughts on this update.

JV

March 14, 2011

Key 2011 Dates for EPA Regulations Actions

Date	Item	Input/Review
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Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 14-18, 2011	EPA releases EGU MACT and 316(b) draft of proposed rules	Env, ES
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Apr 8, 2011	ECR project engineering studies and 3rd party cost estimates for all plants	Proj Eng
Apr 15, 2011	ECR project least cost analysis	Gen Plan
Apr 18, 2011	Finalize CATR control plan based on potential NOx/ SO_2 allocations	Prj Eng, Gen Plan
Apr 22, 2011	Final ECR PVRR and Bill Impact analyses	RR
May 1, 2011	Potential ECR filing for MC FGDs, BR landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	Prj Eng, Gen Plan, RR
May 15, 2011	Final draft ECR application and testimony	ES, RR
May 31, 2011	Inv Committee/internal approvals before public mtgs for NGCC construction project	ES
Jun 1, 2011	ECR and CCN filing for MC FGDs, BR landfill, GH SAM mitigation and EGU MACT response	ES, RR

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

March 14, 2011

Jun 1, 2011	Public ROW meetings – gas pipeline (conclude by Jul 18)	ES, RR
Jun 3, 2011	Decision on selection of final RFP offer(s)	ES
Jun 27, 2011	Final CATR issued	Env, Prj Eng, Gen Plan
July 1, 2010	Air permit application for NGCC project	ES, Env
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Jul 29, 2011	Finalize agreements with RFP finalist(s)	ES
Sep 1, 2011	File CCN for CR replacement	ES, RR
Oct-Dec, 2011	Prepare Transmission CCN for CR replacement	Trans, RR
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls, SCRs (if any result from revised CATR allowance allocation)	Prj Eng, Gen Plan, RR
Nov 28, 2011	ECR Order due from KPSC	RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	Prj Eng

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory

From: Schram, Chuck
To: Wilson, Stuart
Sent: 3/24/2011 5:02:15 PM
Subject: Fw: EPA Regs Schedule 20110312.docx
Attachments: EPA Regs Schedule 20110312.docx

----- Original Message -----
From: Voyles, John
Sent: Tuesday, March 15, 2011 10:47 AM
To: Schram, Chuck; Straight, Scott
Subject: EPA Regs Schedule 20110312.docx

Here's the latest draft schedule with both of your comments include that I will share at Paul's staff meeting today.

Thanks,

JV

March 14, 2011

Key 2011 Dates for EPA Regulations Actions

Date	**Item**	**Input/Review**
Jan 14, 2011	Complete review of EPA's two alternate CATR allowance allocation methods	Env, Gen Planning
Jan 28, 2011	RFP responses for CR replacement capacity due	ES
Jan 31, 2011	Finalize content and timing of ECR filing	ES, RR
Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 14-18, 2011	EPA releases EGU MACT and 316(b) draft of proposed rules	Env, ES
Mar 18, 2011	Evaluation of capacity RFP responses complete	Gen Plan
Mar 31, 2011	Complete initial engineering assessments for fleet ESPs and MC FGD options	PE
Apr 8, 2011	ECR project engineering studies and 3rd party cost estimates for all plants submitted for review to ES and RR	PE
Apr 15, 2011	ECR project least cost analysis for ES review	Gen Plan
Apr 18, 2011	Finalize CATR control plan based on potential NOx/ SO_2 allocations	PE, Gen Plan, Env
April 18, 2011	RR submits draft testimony questions for Gen. Plan, PE and Env review.	RR
Apr 22, 2011	Final ECR PVRR and Bill Impact analyses	RR
May 1, 2011	File NOI for ECR filing for MC FGDs, BR Landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	PE, Gen Plan, RR
May 15, 2011	Final draft ECR application and testimony	ES, RR
May 31, 2011	Inv Committee/internal approvals before public mtgs for NGCC construction project	ES

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory; PE+ Project Engineering

March 14, 2011

Jun 1, 2011	ECR and CCN filing for MC FGDs, BR landfill, GH SAM mitigation and EGU MACT response	ES, RR
Jun 1, 2011	Public ROW meetings – gas pipeline (conclude by Jul 18)	ES, RR
Jun 3, 2011	Decision on selection of final RFP offer(s)	ES
Jun 27, 2011	Final CATR issued for evaluation and impact confirmation	Env, ES
July 1, 2010	Air permit application for NGCC project	ES, Env
July 15, 2011	Draft CCN filing for CR Replacement	ES
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Jul 29, 2011	Finalize agreements with RFP finalist(s)	ES
Sep 1, 2011	File CCN for CR replacement	ES, RR
Oct-Dec, 2011	Prepare Transmission CCN for CR replacement	Trans, RR
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls (if not included in June 1 filing), SCRs (if any result from revised CATR allowance allocation)	PE, Gen Plan, RR
Nov 28, 2011	ECR Order due from KPSC	RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	PE

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory; PE+ Project Engineering

From: Saunders, Eileen
To: Karavayev, Louanne; Wilson, Stuart
CC: Ritchey, Stacy
Sent: 3/22/2011 2:36:18 PM
Subject: FW: Scenario Comparison
Attachments: Environmental Summary Breakdown 2-28-11 R6.xlsx; Environmental Summary Breakdown 10-4-10 R1.xlsx

Lou Anne and Stuart,

Please see the documents below. I hope they help. If you have any questions, please give me a call on 627-2431 in the morning.

Thanks,

Eileen

From: Ritchey, Stacy
Sent: Tuesday, March 22, 2011 2:35 PM
To: Saunders, Eileen
Subject: Scenario Comparison

Eileen,

Here is what was included in the MTP:

Here is the file with the SCRs removed (Except Ghent 2) and the turndowns added:

Stacy Ritchey
Sr Budget Analyst
Project Engineering
BOC Phone: (502) 627-4388
EW Brown Phone (859) 748-4455
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	A	C	D	E	F	G	H	I	J	K	L	M	P
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**												
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), Excluding all SCR except Ghent 2**												
3	$ in thousands												
4	**Estimated**	**In-Servi**	Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**												
6	**Brown**												
7	Brown 1 - Baghouse	5/31/2014	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	5/31/2014	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	5/31/2014	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1		**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11													
12	Brown 2 - Baghouse	11/30/2015	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	11/30/2015	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	11/30/2013	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2		**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16													
17	**Brown 1 & 2 - SAM Mitigation**												
18													
19	Brown 3 - Baghouse	5/31/2016	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	5/31/2016	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3		**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22													
23	**Total Brown**		**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24													
25	**Ghent**												
26	Ghent 1 - Baghouse	5/31/2016	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	5/31/2016	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	12/31/2011	$7,751	$189	$4,012	$3,550							
29	Ghent 1 - SCR Turn-Down	10/1/2014	$7,000				$600	$6,400					
30	Total Ghent 1		**$186,142**	**$189**	**$4,012**	**$3,550**	**$5,175**	**$63,126**	**$83,047**	**$27,043**	**$0**		
31													
32	Ghent 2 - SCR	4/30/2014	$262,878		$12,217	$76,235	$105,712	$68,713	$0	$0	$0		
33	Ghent 2 - Baghouse	4/30/2016	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
34	Ghent 2 - PAC Injection	4/30/2016	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
35	Ghent 2 - SAM Mitigation	12/31/2011	$7,750	$26	$4,012	$3,712							
36	Total Ghent 2		**$427,787**	**$26**	**$16,229**	**$79,947**	**$111,301**	**$120,778**	**$76,195**	**$23,311**	**$0**		
37													
38	Ghent 3 - Baghouse	10/31/2015	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
39	Ghent 3 - PAC Injection	10/31/2015	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
40	Ghent 3 - SAM Mitigation	12/31/2012	$8,570	$84	$4,012	$4,475							
41	Ghent 3 - SCR Turn-Down	11/15/2013	$7,000			$300	$6,700						
42	Total Ghent 3		**$193,404**	**$84**	**$4,012**	**$4,775**	**$25,980**	**$62,219**	**$87,298**	**$9,036**	**$0**		
43													
44	Ghent 4 - Baghouse	12/31/2015	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
45	Ghent 4 - PAC Injection	12/31/2015	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
46	Ghent 4 - SAM Mitigation	12/31/2012	$8,570	$153	$4,012	$4,405							
47	Ghent 4 - SCR Turn-Down	3/1/2014	$7,000				$2,400	$4,600					
48	Total Ghent 4		**$167,770**	**$153**	**$4,012**	**$4,405**	**$16,022**	**$57,942**	**$77,575**	**$7,661**	**$0**		
49													
50	**Total Ghent**		**$975,103**	**$452**	**$28,265**	**$92,676**	**$158,477**	**$304,065**	**$324,115**	**$67,052**	**$0**		

	A	C	D	E	F	G	H	I	J	K	L	M	P
51													
52	**Mill Creek**												
53	Mill Creek 1 - FGD Upgrade	11/30/2014	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
54	Mill Creek 1 - Baghouse	11/30/2014	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		
55	Mill Creek 1 - PAC Injection	11/30/2014	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
56	Mill Creek 1 - SAM Mitigation	11/30/2016	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
57	Total Mill Creek 1		**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
58													
59	Mill Creek 2 - FGD Upgrade	11/30/2013	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
60	Mill Creek 2 - Baghouse	11/30/2013	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
61	Mill Creek 2 - Electrostatic Precipitator	11/30/2013	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
62	Mill Creek 2 - PAC Injection	11/30/2013	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
63	Mill Creek 2 - SAM Mitigation	11/30/2015	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
64	Total Mill Creek 2		**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
65													
66	Mill Creek 3 - FGD (U4 update and tie in)	4/30/2015	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
67	Mill Creek 3 - FGD (Unit 3 Removal)		$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
68	Mill Creek 3 - Baghouse	4/30/2015	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
69	Mill Creek 3 - PAC Injection	4/30/2015	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
70	Mill Creek 3 - SCR Turn-Down	4/15/2013	$7,000			$2,200	$4,800						
71	Total Mill Creek 3		**$249,388**	**$0**	**$0**	**$4,655**	**$43,097**	**$116,061**	**$85,575**	**$0**	**$0**		
72													
73	Mill Creek 4 - FGD	5/31/2014	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
74	Mill Creek 4 - SCR Upgrade	5/31/2012	$5,696		$1,175	$4,521	$0	$0	$0	$0	$0		
75	Mill Creek 4 - Baghouse	5/31/2014	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
76	Mill Creek 4 - PAC Injection	5/31/2014	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
77	Mill Creek 4 - Ammonia	5/31/2012	$11,528		$5,651	$5,877	$0	$0	$0	$0			
78	Mill Creek 4 - SCR Turn-Down	3/14/2014	$7,000				$2,400	$4,600					
79	Total Mill Creek 4		**$455,671**	**$0**	**$33,115**	**$154,417**	**$171,220**	**$96,919**	**$0**	**$0**	**$0**		
80													
81	**Total Mill Creek**		**$1,058,205**	**$0**	**$45,832**	**$226,880**	**$365,038**	**$312,971**	**$101,241**	**$5,705**	**$539**		
82			$1,038,320										
83	**Trimble**												
84	Trimble 1 - Baghouse	10/31/2015	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
85	Trimble 1 - PAC Injection	10/31/2015	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
86	Total Trimble 1		**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
87													
88	**Total Trimble**		**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
89													
90	**Environmental Air Studies**												
91	Environmental Air Studies		$2,250	$798	$1,452	$0	$0	$0	$0	$0	$0		
92	Total Environmental Air Studies		**$2,250**	**$798**	**$1,452**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
93													
94													
95	**Total Environmental Compliance - Air**		**$2,379,099**	**$1,250**	**$77,810**	**$337,534**	**$573,612**	**$727,331**	**$565,256**	**$95,766**	**$539**		
96													
97	$7m for each of five SCR's (three KU and two LG&E) has been added back in (above) for turn-down capabilities.												

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	A	D	E	F	G	H	I	J	K	L	M	N
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**											
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO), No SCR**											
3	$ in thousands											
4		Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**											
6	**Brown**											
7	Brown 1 - Baghouse	$39,218		$1,830	$13,322	$15,834	$8,233					
8	Brown 1 - PAC Injection	$1,899		$0	$0	$931	$968					
9	Brown 1 - SAM Mitigation	$4,632		$215	$1,343	$1,863	$1,211					
10	Total Brown 1	**$45,750**	**$0**	**$2,045**	**$14,665**	**$18,627**	**$10,412**	**$0**	**$0**	**$0**		
11												
12	Brown 2 - Baghouse	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
13	Brown 2 - PAC Injection	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
14	Brown 2 - SAM Mitigation	$4,568		$215	$1,791	$2,561	$0	$0	$0			
15	Total Brown 2	**$48,805**	**$0**	**$215**	**$3,314**	**$14,437**	**$14,673**	**$14,831**	**$1,336**	**$0**		
16												
17	**Brown 1 & 2 - SAM Mitigation**											
18												
19	Brown 3 - Baghouse	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
20	Brown 3 - PAC Injection	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
21	Total Brown 3	**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
22												
23	**Total Brown**	**$177,455**	**$0**	**$2,260**	**$17,978**	**$35,194**	**$52,146**	**$55,248**	**$14,628**	**$0**		
24												
25	**Ghent**											
26	Ghent 1 - Baghouse	$163,356				$4,575	$55,515	$77,531	$25,734			
27	Ghent 1 - PAC Injection	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
28	Ghent 1 - SAM Mitigation	$7,750	$375	$7,375								
29	Total Ghent 1	**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
30												
31	Ghent 2 - Baghouse	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
32	Ghent 2 - PAC Injection	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
33	Ghent 2 - SAM Mitigation	$7,750	$375	$7,375								
34	Total Ghent 2	**$164,909**	**$375**	**$7,375**	**$0**	**$5,588**	**$52,065**	**$76,195**	**$23,311**	**$0**		
35												
36	Ghent 3 - Baghouse	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
37	Ghent 3 - PAC Injection	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
38	Ghent 3 - SAM Mitigation	$8,570	$250	$650	$7,670							
39	Total Ghent 3	**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
40												
41	Ghent 4 - Baghouse	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
42	Ghent 4 - PAC Injection	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
43	Ghent 4 - SAM Mitigation	$8,570	$250	$650	$7,670							
44	Total Ghent 4	**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
45												
46	**Total Ghent**	**$691,224**	**$1,250**	**$16,050**	**$15,340**	**$43,065**	**$224,352**	**$324,115**	**$67,052**	**$0**		
47												
48	**Mill Creek**											
49	Mill Creek 1 - FGD Upgrade	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
50	Mill Creek 1 - Baghouse	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		

	A	D	E	F	G	H	I	J	K	L	M	N
51	Mill Creek 1 - PAC Injection	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
52	Mill Creek 1 - SAM Mitigation	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
53	Total Mill Creek 1	**$160,821**	**$0**	**$0**	**$9,531**	**$47,160**	**$87,725**	**$10,680**	**$5,186**	**$539**		
54												
55	Mill Creek 2 - FGD Upgrade	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
56	Mill Creek 2 - Baghouse	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
57	Mill Creek 2 - Electrostatic Precipitator	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
58	Mill Creek 2 - PAC Injection	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
59	Mill Creek 2 - SAM Mitigation	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
60	Total Mill Creek 2	**$192,325**	**$0**	**$12,717**	**$58,276**	**$103,560**	**$12,267**	**$4,987**	**$519**	**$0**		
61												
62	Mill Creek 3 - FGD (U4 update and tie in)	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
63	Mill Creek 3 - FGD (Unit 3 Removal)	$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
64	Mill Creek 3 - Baghouse	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
65	Mill Creek 3 - PAC Injection	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
66	Total Mill Creek 3	**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
67												
68	Mill Creek 4 - FGD	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
69	Mill Creek 4 - SCR Upgrade	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
70	Mill Creek 4 - Baghouse	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
71	Mill Creek 4 - PAC Injection	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
72	Mill Creek 4 - Ammonia	$11,528		$5,651	$5,877	$0	$0	$0	$0			
73	Total Mill Creek 4	**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
74												
75	**Total Mill Creek**	**$1,044,205**	**$0**	**$49,177**	**$221,334**	**$357,838**	**$308,371**	**$101,241**	**$5,705**	**$539**		
76												
77	**Trimble**											
78	Trimble 1 - Baghouse	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
79	Trimble 1 - PAC Injection	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
80	Total Trimble 1	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
81												
82	**Total Trimble**	**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
83												
84	**Environmental Air Studies**											
85	Environmental Air Studies	$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
86	Total Environmental Air Studies	**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
87												
88												
89	**Total Environmental Compliance - Air**	**$2,080,970**	**$2,500**	**$68,238**	**$254,653**	**$450,999**	**$643,018**	**$565,256**	**$95,766**	**$539**		
90												
91	Variance to MTP (No SCR Amounts)	($641,631)	$0	($25,295)	($120,429)	($201,581)	($160,276)	($81,855)	($49,553)	($2,643)		
92	LGE Variance to MTP (No SCR Amounts)	($226,458)	$0	$0	$3,742	($28,016)	($68,134)	($81,855)	($49,553)	($2,643)		
93	KU Variance to MTP (No SCR Amounts)	($415,174)	$0	($25,295)	($124,171)	($173,565)	($92,142)	$0	$0	$0		
94												
95	$7m for each of five SCR's (three KU and two LG&E) has been added back in (above) for turn-down capabilities (1/2 in 2012 and 1/2 in 2013).											
96	LG&E (two Mill Creek units)				$7,000	$7,000						
97	KU (three Ghent units)				$10,500	$10,500						
98	Total w/turn-down	$2,115,970	$2,500	$68,238	$272,153	$468,499	$643,018	$565,256	$95,766	$539		

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	A	C	D	E	F	G	H	I	J	K	L	M	P
1	**2.) Environmental Air - CATR by January 2015, NAAQS by January 2016, HAPs by January 2017**												
2	**Capital Cost - Investment Accrual Basis (Includes Removal/ARO)**												
3	$ in thousands												
4	**Estimated**	**In-Servi**	Total	2010	2011	2012	2013	2014	2015	2016	2017		
5	**Cash Flow By Year**												
6	**Brown**												
7	Brown 1 - SCR	5/31/2014	$68,325		$3,175	$19,814	$27,476	$17,859					
8	Brown 1 - Baghouse	5/31/2014	$39,218		$1,830	$13,322	$15,834	$8,233					
9	Brown 1 - PAC Injection	5/31/2014	$1,899		$0	$0	$931	$968					
10	Brown 1 - SAM Mitigation	5/31/2014	$4,632		$215	$1,343	$1,863	$1,211					
11	Total Brown 1		**$114,075**	**$0**	**$5,221**	**$34,479**	**$46,103**	**$28,272**	**$0**	**$0**	**$0**		
12													
13	Brown 2 - SCR	11/30/2013	$104,971		$9,903	$38,621	$50,877	$5,570	$0	$0	$0		
14	Brown 2 - Baghouse	11/30/2015	$41,179		$0	$1,522	$11,875	$13,174	$13,272	$1,336	$0		
15	Brown 2 - PAC Injection	11/30/2015	$3,058		$0	$0	$0	$1,499	$1,559	$0	$0		
16	Brown 2 - SAM Mitigation	11/30/2013	$4,568		$215	$1,791	$2,561	$0	$0	$0			
17	Total Brown 2		**$153,776**	**$0**	**$10,118**	**$41,935**	**$65,314**	**$20,242**	**$14,831**	**$1,336**	**$0**		
18													
19	**Brown 1 & 2 - SAM Mitigation**												
20													
21	Brown 3 - Baghouse	5/31/2016	$76,066		$0	$0	$2,131	$25,851	$36,102	$11,983	$0		
22	Brown 3 - PAC Injection	5/31/2016	$6,835		$0	$0	$0	$1,211	$4,314	$1,310	$0		
23	Total Brown 3		**$82,901**	**$0**	**$0**	**$0**	**$2,131**	**$27,061**	**$40,416**	**$13,292**	**$0**		
24													
25	**Total Brown**		**$350,751**	**$0**	**$15,339**	**$76,414**	**$113,547**	**$75,575**	**$55,248**	**$14,628**	**$0**		
26													
27	**Ghent**												
28	Ghent 1 - Baghouse	5/31/2016	$163,356				$4,575	$55,515	$77,531	$25,734			
29	Ghent 1 - PAC Injection	5/31/2016	$8,036		$0	$0	$0	$1,211	$5,515	$1,310	$0		
30	Ghent 1 - SAM Mitigation	12/31/2011	$7,750	$375	$7,375								
31	Total Ghent 1		**$179,142**	**$375**	**$7,375**	**$0**	**$4,575**	**$56,726**	**$83,047**	**$27,043**	**$0**		
32													
33	Ghent 2 - SCR	4/30/2014	$262,878		$12,217	$76,235	$105,712	$68,713	$0	$0	$0		
34	Ghent 2 - Baghouse	4/30/2016	$149,464		$0	$0	$5,588	$50,854	$71,021	$22,001			
35	Ghent 2 - PAC Injection	4/30/2016	$7,695		$0	$0	$0	$1,211	$5,174	$1,310			
36	Ghent 2 - SAM Mitigation	12/31/2011	$7,750	$375	$7,375								
37	Total Ghent 2		**$427,787**	**$375**	**$19,592**	**$76,235**	**$111,301**	**$120,778**	**$76,195**	**$23,311**	**$0**		
38													
39	Ghent 3 - Baghouse	10/31/2015	$170,210		$0	$0	$19,280	$58,482	$83,412	$9,036	$0		
40	Ghent 3 - PAC Injection	10/31/2015	$7,624		$0	$0	$0	$3,737	$3,887	$0	$0		
41	Ghent 3 - SAM Mitigation	12/31/2012	$8,570	$250	$650	$7,670							
42	Total Ghent 3		**$186,403**	**$250**	**$650**	**$7,670**	**$19,280**	**$62,219**	**$87,298**	**$9,036**	**$0**		
43													
44	Ghent 4 - Baghouse	12/31/2015	$144,530		$0	$0	$13,622	$49,582	$73,665	$7,661	$0		
45	Ghent 4 - PAC Injection	12/31/2015	$7,669		$0	$0	$0	$3,760	$3,910	$0	$0		
46	Ghent 4 - SAM Mitigation	12/31/2012	$8,570	$250	$650	$7,670							
47	Total Ghent 4		**$160,770**	**$250**	**$650**	**$7,670**	**$13,622**	**$53,342**	**$77,575**	**$7,661**	**$0**		
48													
49	**Total Ghent**		**$954,101**	**$1,250**	**$28,267**	**$91,575**	**$148,777**	**$293,065**	**$324,115**	**$67,052**	**$0**		
50													

	A	C	D	E	F	G	H	I	J	K	L	M	P
51	**Mill Creek**												
52	Mill Creek 1 - FGD Upgrade	11/30/2014	$49,565		$0	$0	$12,006	$34,962	$2,597	$0	$0		
53	Mill Creek 1 - SCR	11/30/2016	$122,586		$0	$0	$3,389	$32,892	$36,651	$47,011	$2,643		
54	Mill Creek 1 - Baghouse	11/30/2014	$96,033		$0	$9,051	$32,945	$48,947	$5,090	$0	$0		
55	Mill Creek 1 - PAC Injection	11/30/2014	$5,085		$0	$480	$1,748	$2,857	$0	$0	$0		
56	Mill Creek 1 - SAM Mitigation	11/30/2016	$10,137		$0	$0	$461	$959	$2,992	$5,186	$539		
57	Total Mill Creek 1		**$283,407**	**$0**	**$0**	**$9,531**	**$50,549**	**$120,617**	**$47,331**	**$52,197**	**$3,182**		
58													
59	Mill Creek 2 - FGD Upgrade	11/30/2013	$47,659		$0	$11,544	$33,617	$2,497	$0	$0	$0		
60	Mill Creek 2 - SCR	11/30/2015	$117,872		$0	$3,258	$31,627	$35,242	$45,203	$2,541	$0		
61	Mill Creek 2 - Baghouse	11/30/2013	$92,339		$8,703	$31,678	$47,064	$4,895	$0	$0	$0		
62	Mill Creek 2 - Electrostatic Precipitator	11/30/2013	$37,690		$3,552	$12,930	$19,210	$1,998	$0	$0	$0		
63	Mill Creek 2 - PAC Injection	11/30/2013	$4,890		$462	$1,681	$2,747	$0	$0	$0	$0		
64	Mill Creek 2 - SAM Mitigation	11/30/2015	$9,747		$0	$443	$922	$2,877	$4,987	$519	$0		
65	Total Mill Creek 2		**$310,196**	**$0**	**$12,717**	**$61,534**	**$135,188**	**$47,508**	**$50,190**	**$3,060**	**$0**		
66													
67	Mill Creek 3 - FGD (U4 update and tie in)	4/30/2015	$84,262		$0	$0	$0	$59,235	$25,027	$0	$0		
68	Mill Creek 3 - FGD (Unit 3 Removal)		$25,500		$0	$0	$0	$6,375	$19,125	$0	$0		
69	Mill Creek 3 - Baghouse	4/30/2015	$125,943		$0	$2,331	$36,368	$47,908	$39,335	$0	$0		
70	Mill Creek 3 - PAC Injection	4/30/2015	$6,683		$0	$124	$1,930	$2,542	$2,087	$0	$0		
71	Total Mill Creek 3		**$242,388**	**$0**	**$0**	**$2,455**	**$38,297**	**$116,061**	**$85,575**	**$0**	**$0**		
72													
73	Mill Creek 4 - FGD	5/31/2014	$271,994		$20,344	$89,920	$104,519	$57,210	$0	$0	$0		
74	Mill Creek 4 - SCR Upgrade	5/31/2012	$5,696		$4,521	$1,175	$0	$0	$0	$0	$0		
75	Mill Creek 4 - Baghouse	5/31/2014	$151,571		$5,651	$51,425	$61,122	$33,373	$0	$0			
76	Mill Creek 4 - PAC Injection	5/31/2014	$7,882		$294	$2,674	$3,178	$1,735	$0	$0			
77	Mill Creek 4 - Ammonia	5/31/2012	$11,528		$5,651	$5,877	$0	$0	$0	$0			
78	Total Mill Creek 4		**$448,671**	**$0**	**$36,461**	**$151,072**	**$168,820**	**$92,319**	**$0**	**$0**	**$0**		
79													
80	**Total Mill Creek**		**$1,284,663**	**$0**	**$49,177**	**$224,592**	**$392,854**	**$376,505**	**$183,095**	**$55,257**	**$3,182**		
81													
82	**Trimble**												
83	Trimble 1 - Baghouse	10/31/2015	$158,119	$0	$0	$0	$14,902	$54,244	$80,591	$8,381	$0		
84	Trimble 1 - PAC Injection	10/31/2015	$7,967	$0	$0	$0	$0	$3,905	$4,062	$0	$0		
85	Total Trimble 1		**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
86													
87	**Total Trimble**		**$166,086**	**$0**	**$0**	**$0**	**$14,902**	**$58,149**	**$84,653**	**$8,381**	**$0**		
88													
89	**Environmental Air Studies**												
90	Environmental Air Studies		$2,000	$1,250	$750	$0	$0	$0	$0	$0	$0		
91	Total Environmental Air Studies		**$2,000**	**$1,250**	**$750**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**		
92													
93													
94	**Total Environmental Compliance - Air**		**$2,757,601**	**$2,500**	**$93,533**	**$392,581**	**$670,080**	**$803,294**	**$647,111**	**$145,319**	**$3,182**		

From:	Schram, Chuck
To:	Jefferson, Tangila
Sent:	3/28/2011 8:23:34 AM
Subject:	RE: Project List
Attachments:	Project List 20110328.docx

From: Jefferson, Tangila
Sent: Monday, March 28, 2011 8:06 AM
To: Schram, Chuck
Subject: Project List

Please send me the approved Project List

Tangila Jefferson
LG&E/KU
Senior Secretary/Chuck Schram
Energy Planning, Forecasting & Analysis
(502) 627-3621
(502) 217-2330 fax

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Generation Planning and Analysis

Project	Status	Schedule
PowerSimm Implementation	• Major issues moving forward are speed and getting our system up and running smoothly. Ascend is addressing the speed issue. Working with Ascend and our IT group to get our system up and running smoothly.	• Planning to use PowerSimm to evaluate top RFP responses. Particular focus will be on the evaluation of ancillary services.
Determine least-cost strategy for complying with NOX and SO2 environmental regulations	• Met with senior managers on November 22 to review recommendation. • Reviewed follow-up items and further analysis with senior managers on December 10.	Will update analysis when additional information regarding CATR allocations becomes available (in March?). For now, analysis is complete.
Integrated Resource Plan	• 1st draft of IRP submitted for internal review on March 1. • Received Astrape Consulting's DRAFT optimal reserve margin report on February 28.	• Second draft of IRP due for Sr. Manager review on March 18.
Evaluate responses to RFP	• Completed Phase I and Phase II screening of RFP responses.	• Analysis to be completed by March 18. [Next steps]
Finalize unit ratings for 2011 ratings sheet	• Ratings have been finalized for 2011 IRP. An updated ratings sheet will be developed that is consistent with these ratings. Notable ratings changes include the Brown CTs and the Ghent units.	Moving forward (this summer), we will continue to monitor the Brown and Trimble CT ratings as well as the Ghent ratings. The significance of the Ghent degradation issue appears to be waning.
2011 ECR filing	Majority of analysis for this filing has been completed.	Key to-do items moving forward include: • Conduct revenue requirement analysis for Brown landfill project. • Develop ECR testimony.
Evaluate decision to modify LG&E's ANNSTLF model to forecast net load (versus gross load)	Draft recommendation/presentation being reviewed by Regulated Trading/Dispatch	Will move forward when we receive feedback from Regulated Trading/Dispatch.

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Project	Status	Schedule
Develop list of standard inputs for evaluating CCP projects	First draft complete and ready to be reviewed by S. Wilson.	Q2 2011
Evaluate Sterling Materials' offer to dispose of CCP at Ghent	• Completed initial evaluation and summary report. • Discussions with SM are underway to better define contract terms.	Will support analysis as needed.
Develop SDG Presentation	• Held first two workshops.	• A third workshop will be scheduled for the end of April.[scheduled?]
On-going Generation Planning study topics	• Min gen issues. With additional SCRs, to what extent do we have min gen issues and on what units do we need additional turn-down capacity? • CT maintenance costs. What is the best way to model CT maintenance costs?	As time permits
Evaluate CCCT operating characteristics and impact of CCCT on other units	Comparing CCCT operation with MTP operating constraints to unconstrained CCCT operation	Will be completed alongside optimal expansion plan study.
Losses Project	Mike Sebourn is leading a team to validate the calculation and uses of losses data within the company.	Final presentation will be delivered to senior management in April.

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Economic Analysis

Project	**Status**	**Schedule**
EEI disposition project: strategy and valuation	No change (awaiting next phase of project, if any)	
Strategy for dealing with atypical rate requests	Commented on potential guidelines for future tariffs.	Comments due by 2/18
Aurora power market model implementation – mid-term market pricing analysis	Benchmarking against other data sources continues. (No change)	Ongoing
Aurora power market model implementation – long-term scenario planning	EPA impact analysis: using AURORA model to determine economic solution to retrofit vs retirement decision for coal-fired plant (for compliance with proposed EPA regulations)	Will refine view through May 2011 in preparation for planning activities.
EPA CATR emissions allowance balances	Comparison of emissions allowance allocations vs expected consumption – for Kentucky as a whole, and by company within the state	Completed; see item above.
Coal inventory optimization model	Developing modeling approach combining economic optimization guidelines with predefined reliability targets.	In progress
'Extreme green' capacity expansion scenario for IRP (?)	Assessment of the volume (and cost) of wind/solar capacity necessary to meet 100% of native load energy and peak load requirements	First-cut spreadsheet model completed 2/11; optional for IRP
LG&E/KU environmental retrofit rate impact, by company and rate class	Update completed using 2011 Plan capital profile; 2016 revenue requirements allocated between rate classes on revenue-share basis	Provisional estimate to J Voyles 1/21.
Forthcoming EPA regulation – economic impact assessment (higher electricity prices)	Final report received from Paul Coomes 12/22	Final edits/questions in process.
Review of (State) HB 239 (promoting renewables and energy efficiency)	Updating earlier assessment (last year's review of HB 408) of potential utility rate impacts of RPS and energy efficiency measures. Current bill has similar impact through 2020 – but no further escalation thereafter	High level assessment complete; similar to 2010 impact.
2011 IRP	Preparing contribution for Section 6 – Significant Changes	Complete
Review of bi-weekly Trading	Combined with Fcast mtg	

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Meeting objectives, participation and content		
Legislation monitoring (EPA regulation, RPS, energy efficiency initiatives)	Summary of current bills (Federal and State)	Ongoing
Regular analyses/deliverables	Commodities Markets Update; Trading Group meeting presentations Month-end OSS review (CinHub and PJM-W price forecast variance)	Monthly

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Operational Analysis

Project	Status	Schedule
Generation Fleet - Coal Unit Variable O&M Costs Project	Historical analysis and scenarios complete. The MTP $ and data has been checked and incorrect or incomplete has been obtained. Finalized the detailed calculation steps and procedure documents. Added new CT "start-up" adder calculation for consideration. Meetings are scheduled with key staff to obtain input for coal fleet and CT cost adder recommendations.	March 2011 Update?
Development of a dashboard to provide a near real time snapshot view of large industrial customer usage.	Data looks good, however it is not in "dashboard" usable format. Also, and this is a big positive - data is now available weekly (on Wednesdays) although our goal is to have it near real-time. Evaluating plans and objectives based on recent accomplishments.	Business Case presentation to mgmt 1st week of April
WKEC Unwind activities • WKEC/BREC IT Service Agreement	• Ongoing activities, prepare monthly punch list for Paul Thompson • Sent 13 tapes via UPS to BREC and obtained executed turnover documents.. • Due to an error in the non-FAC PPA, the Company is due a small refund from Century; the exact amount is being determined by the Parties. • The final piece of equipment in BREC data center will be relocated to the City by 3/11. • BREC submitted an invoice for 75% of its HMPL arbitration proceeding costs; a response was sent to BREC indicating that such payment is not provided for in the Indemnification Agreement. Legal has now decided that payments are covered;	Ongoing

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

	however, certain billed items were not applicable – we are awaiting a corrected invoice. •	
• Power Supply System Agreement (PSSA) Operating Committee • Transmission Coordination Agreement (TCA) Coordinating Committee	• Ongoing quarterly and semi-annual meetings • Drafted the December 10th meeting minutes and the 2010 periodic company reports for committee review.	Ongoing
New Project – CT Fleet Optimal Dispatch Project	• Draft Project outline/scope - completed • Discuss plan and resources • Complete analysis work • Prepare summary report	• TBD
New Project - Firm Gas for CTs Analysis Project Complete analysis that categorizes firm day ahead natural gas purchases, actual purchases vs. burn and seek to determine reasons for variances and suggest optimal strategies.	• Drafted project outline/scope • Compiled data on gas purchases and CT usage. • Preliminary data assembled and reviewed. • Documenting budget and categorizing optimal conditions. • Prepare report and schedule meeting to review with management.	• March 2011
Unbilled Processes/ Methodology/Losses	• Work with Rates and Revenue Accounting	• 2011
Electric Energy, Inc. (EEI) Quarterly Review	• 1st Quarter 2011 Review	April 2011
BTF Analysis Financial Impact	• Will schedule a meeting with applicable groups to obtain understanding of BTF work and current initiatives.	TBD
Regular analyses/deliverables Notes: New end-of-month analysis of Unsold Native Load Variance (Feb 2011).	OSS and Native Load Report Month-end OSS Review OSS Forecast Update KPI s OSS Activity / MTP Support / PEPs Energy Services Audit Report	Daily Monthly Monthly Monthly Ongoing/As needed Monthly

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Sales Analysis & Forecasting

Project	Status	Schedule
Load Research	Continually extracting monthly data. Updated the recorder map for the census class and in the process of validating the representation of the sample classes. Next, recorders will be installed to the appropriate customers. KU and ODP mapping complete.	Completing LG&E mapping for recorders. Completion in May 2011.
2011 IRP • Update tables with 2010 data • Complete write-up of load forecasting sections	In process. Tables and commentary in the process of being updated and developed. Sections 5, 6, & 7 almost complete. Technical appendix to complete.	In review stage.
Weather Normalization Coefficients for 2011 MTP	In progress	Complete
2012 MTP Forecasts	Preparation of historical data	Feb 2011 Complete
Populate CCS with NAICS data for Commercial and Industrial customers	Have developed a 3-digit NAICS code. Revenue and Major Accounts are in agreement to the level of detail. Next is to update the BP Industry field in CCS for all C&I customers that do not have a BP Industry value.	The BP Industry field in CCS was found to be incomplete and/or inaccurate. This project is on hold for now.
Substation demand forecast	Confirming that no changes are needed.	Complete
Commercial End-Use Survey	Survey complete. Data still to be analyzed and incorporated into the SAE model.	Having some issues with the dataset and incorporating into SAS. End of March completion.
ODP rate case support	Began downloading MV90 data for rate case filing (test year Jan-Dec 2010)	Class data due from SAF on Feb 12011; filing scheduled for Apr 2011 Complete.
ODP fuel adjustment filing	Routine filing takes place in Q1 2011	Complete

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Project	Status	Schedule
KU Jurisdictional Study	Routine filing takes place in Q1 2011	Complete
Reviewing approaches to economic sensitivities for commercial and industrial sales forecasts	IHS Global Insight information was used to put assumptions around economic forecasts for industrial and commercial class rates. Oil price impact on GDP being studied to estimate impact on balance-of-year load.	March 21
Opportunities and challenges associated with growing PHEV penetration In utility service territory	Updated earlier analysis by Chris Heiniger to take account of data on (existing) hybrid vehicle registrations obtained from RL Polk	Write-up complete. Adding additional language around quality and summary of Polk data.

From: Jefferson, Tangila
To: Schram, Chuck
Sent: 3/29/2011 4:21:59 PM
Subject: FW: Project List
Attachments: Project List 3 29 2011 lipp.docx

Hey Chuck,
Just want to let you know that the Project has now went on to Stuart and he should have both now.

-----Original Message-----
From: Jefferson, Tangila
Sent: Tue 3/29/2011 12:27 PM
To: Lawson, Gregory
Subject: Project List

<<Project List 3 29 2011 lipp.docx>>

Tangila Jefferson
LG&E/KU
Senior Secretary/Chuck Schram
Energy Planning, Forecasting & Analysis
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(502) 217-2330 fax

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Generation Planning and Analysis

Project	**Status**	**Schedule**
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Energy Planning, Analysis & Forecasting Projects

March 28, 2011

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Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Economic Analysis

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Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Meeting objectives, participation and content		
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Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Operational Analysis

Project	**Status**	**Schedule**
Generation Fleet - Coal Unit Variable O&M Costs Project	Historical analysis and scenarios complete. The MTP $ and data has been checked and incorrect or incomplete has been obtained. Phase 1 - Finalized the detailed calculation steps and procedure documents. Updated CT "start-up" adder calculation, 2010 operational data and 2011 major capital costs. Phase 2 - Schedule meetings with key staff to finalize coal fleet and CT cost adder recommendations. • Obtain final approval from B. Brunner/D. Schrader. Note: C. Martin had to cancel last Friday; he is out on vacation for two weeks. • Review with R. Hudson and Rates.	Phase 1 - March 2011-complete Phase 2 - June 2011
Development of a dashboard to provide a near real time snapshot view of large industrial customer usage.	Data looks good, however it is not in "dashboard" usable format.Data is now available weekly (on Wednesdays). \ Phase 1 - Evaluation of options for adding customers for remote read complete. Recommended alternative "#3" to team members and management. Phase 2 - Obtain approvals for recommended alternative; discuss how to move forward with the groups that would be responsible for recorder installation and subsequent data management.	Phase 1 - Business Case presentation to mgmt 1st week of April – complete Phase 2 - TBD
WKEC Unwind activities • WKEC/BREC IT Service Agreement	• Ongoing activities, prepare monthly punch list for Paul Thompson • The City of Henderson has paid the FYE 2009 settlement; still negotiating the FYE 2010 settlement.	Ongoing

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

• Power Supply System Agreement (PSSA) Operating Committee • Transmission Coordination Agreement (TCA) Coordinating Committee	• Ongoing quarterly and semi-annual meetings • Drafted the December 10th meeting minutes and the 2010 periodic company reports for committee review.	Ongoing
New Project – CT Fleet Optimal Dispatch Project	• Draft Project outline/scope - completed • Discuss plan and resources • Complete analysis work • Prepare summary report	• TBD
New Project - Firm Gas for CTs Analysis Project Complete analysis that categorizes firm day ahead natural gas purchases, actual purchases vs. burn and seek to determine reasons for variances and suggest optimal strategies.	• Drafted project outline/scope • Compiled data on gas purchases and CT usage. • Preliminary data assembled and reviewed. • Documenting budget and categorizing optimal conditions. • Prepare report and schedule meeting to review with management. Note: Delayed one week to complete higher priority ANR natural gas transportation service rate analysis.	• April 2011
Unbilled Processes/ Methodology/Losses	• Work with Rates and Revenue Accounting	• 2011
Electric Energy, Inc. (EEI) Quarterly Review	• 1st Quarter 2011 Review	April 2011
BTF Analysis Financial Impact	• Drafted project plan. • Discussed project with Fred Jackson. • Will schedule meetings with Generation Services to obtain understanding of BTF work and current initiatives.	TBD
ANR Natural Gas Transportation Service Analysis for CCG, LLC Proposal Note: This is a high priority request related to the RFP analysis.	• Review ANR pipeline tariff. • Document applicable rates/fees. • Estimate natural gas transportation costs for transportation via ANR. • Review with C. Balmer.	March 31, 2011
Regular analyses/deliverables Notes: New end-of-month analysis of Unsold Native Load Variance	OSS and Native Load Report Month-end OSS Review OSS Forecast Update	Daily Monthly Monthly

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

(Feb 2011). Note: Jeff provided Regulated Trading a brief outline of the MISO RSG Redesign impact to Trading that becomes effective April 1st.	KPI s OSS Activity / MTP Support / PEPs Energy Services Audit Report	Monthly Ongoing/As needed Monthly

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Sales Analysis & Forecasting

Project	Status	Schedule
Load Research	Continually extracting monthly data. Updated the recorder map for the census class and in the process of validating the representation of the sample classes. Next, recorders will be installed to the appropriate customers. KU and ODP mapping complete.	Completing LG&E mapping for recorders. Completion in May 2011.
2011 IRP • Update tables with 2010 data • Complete write-up of load forecasting sections	In process. Tables and commentary in the process of being updated and developed. Sections 5, 6, & 7 almost complete. Technical appendix to complete.	In review stage.
Weather Normalization Coefficients for 2011 MTP	In progress	Complete
2012 MTP Forecasts	Preparation of historical data	Feb 2011 Complete
Populate CCS with NAICS data for Commercial and Industrial customers	Have developed a 3-digit NAICS code. Revenue and Major Accounts are in agreement to the level of detail. Next is to update the BP Industry field in CCS for all C&I customers that do not have a BP Industry value.	The BP Industry field in CCS was found to be incomplete and/or inaccurate. This project is on hold for now.
Substation demand forecast	Confirming that no changes are needed.	Complete
Commercial End-Use Survey	Survey complete. Data still to be analyzed and incorporated into the SAE model.	Having some issues with the dataset and incorporating into SAS. End of March completion.
ODP rate case support	Began downloading MV90 data for rate case filing (test year Jan-Dec 2010)	Class data due from SAF on Feb 12011; filing scheduled for Apr 2011 Complete.
ODP fuel adjustment filing	Routine filing takes place in Q1 2011	Complete

Energy Planning, Analysis & Forecasting Projects

March 28, 2011

Project	Status	Schedule
KU Jurisdictional Study	Routine filing takes place in Q1 2011	Complete
Reviewing approaches to economic sensitivities for commercial and industrial sales forecasts	IHS Global Insight information was used to put assumptions around economic forecasts for industrial and commercial class rates. Oil price impact on GDP being studied to estimate impact on balance-of-year load.	March 21
Opportunities and challenges associated with growing PHEV penetration In utility service territory	Updated earlier analysis by Chris Heiniger to take account of data on (existing) hybrid vehicle registrations obtained from RL Polk	Write-up complete. Adding additional language around quality and summary of Polk data.

From: Voyles, John
To: Schram, Chuck
CC: Thompson, Paul
Sent: 4/12/2011 9:26:00 AM
Subject: Timelines
Attachments: EPA Regs Schedule 20110312.docx

Chuck,

Here's the soft copy of the previous EPA Regs timeline. It has some of the RFP and CCGT dates included. Just need to re-confirm and put on chart(s).

JV

<<...>>

Please note that my e-mail address has changed from john.voyles@eon-us.com to john.voyles@lge-ku.com. Please take this opportunity to update my address in your address book and delete the old e-mail address immediately. The old e-mail address will soon expire, and I will no longer be able to receive e-mails at that address.

March 14, 2011

Key 2011 Dates for EPA Regulations Actions

Date	**Item**	**Input/Review**
Jan 14, 2011	Complete review of EPA's two alternate CATR allowance allocation methods	Env, Gen Planning
Jan 28, 2011	RFP responses for CR replacement capacity due	ES
Jan 31, 2011	Finalize content and timing of ECR filing	ES, RR
Mar 11, 2011	Review ECR filing draft	ES, RR
Mar 14-18, 2011	EPA releases EGU MACT and 316(b) draft of proposed rules	Env, ES
Mar 18, 2011	Evaluation of capacity RFP responses complete	Gen Plan
Mar 31, 2011	Complete initial engineering assessments for fleet ESPs and MC FGD options	PE
Apr 8, 2011	ECR project engineering studies and 3rd party cost estimates for all plants submitted for review to ES and RR	PE
Apr 15, 2011	ECR project least cost analysis for ES review	Gen Plan
Apr 18, 2011	Finalize CATR control plan based on potential NOx/ SO_2 allocations	PE, Gen Plan, Env
April 18, 2011	RR submits draft testimony questions for Gen. Plan, PE and Env review.	RR
Apr 22, 2011	Final ECR PVRR and Bill Impact analyses	RR
May 1, 2011	File NOI for ECR filing for MC FGDs, BR Landfill, GH SAM Mitigation; (bag houses and GH2 SCR TBD)	PE, Gen Plan, RR
May 15, 2011	Final draft ECR application and testimony	ES, RR
May 31, 2011	Inv Committee/internal approvals before public mtgs for NGCC construction project	ES

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory; PE+ Project Engineering

March 14, 2011

Jun 1, 2011	ECR and CCN filing for MC FGDs, BR landfill, GH SAM mitigation and EGU MACT response	ES, RR
Jun 1, 2011	Public ROW meetings – gas pipeline (conclude by Jul 18)	ES, RR
Jun 3, 2011	Decision on selection of final RFP offer(s)	ES
Jun 27, 2011	Final CATR issued for evaluation and impact confirmation	Env, ES
July 1, 2010	Air permit application for NGCC project	ES, Env
July 15, 2011	Draft CCN filing for CR Replacement	ES
Jul 26, 2011	EPA releases proposed GHG regs	Env, ES
Jul 29, 2011	Finalize agreements with RFP finalist(s)	ES
Sep 1, 2011	File CCN for CR replacement	ES, RR
Oct-Dec, 2011	Prepare Transmission CCN for CR replacement	Trans, RR
Nov 19, 2011	Potential ECR filing for MACT/HAPS controls (if not included in June 1 filing), SCRs (if any result from revised CATR allowance allocation)	PE, Gen Plan, RR
Nov 28, 2011	ECR Order due from KPSC	RR
Nov 30, 2011	Receive final MACT/HAPS rule	Env, ES
Dec 30, 2011	Review MACT/HAPS control plan based on final rule	PE

Input/Review: Env = Environmental; ES= Energy Services; RR = Rates and Regulatory; PE+ Project Engineering

From: Schram, Chuck
To: Voyles, John
Sent: 4/12/2011 3:58:18 PM
Subject: Project Calendar
Attachments: Prj Calendar 20110412.xlsx

John,
Please see attached for a summary calendar for ECR, RFP, and 2016 CCCT. I'll need to get some key dates from Doug for the 2018 unit.

Chuck

	A	E	F	G	H	I	J	K	L	M
1		**2011**								
2		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
3	**ECR**									
4	Complete analysis	15-Apr								
5	Draft testimony for review	18-Apr								
6	Finalize bill impacts	22-Apr								
7	File KPSC notice		2-May							
8	Submit newspaper notices		11-May							
9	Final draft ECR appl and testimony		16-May							
10	File ECR/CCN applications			1-Jun						
11	Final CATR issued			27-Jun						
12	EPA releases proposed GHG regs				26-Jul					
13	ECR order due from KPSC								28-Nov	
14	Receive final MACT/HAPS rule								30-Nov	
15	Complete review of MACT/HAPS control plan based on final rule									30-Dec
16										
17	**RFP**									
18	Bidders deadline for best offer	11-Apr								
19	Decision on selection of final RFP offer(s)			3-Jun						
20	Finalize agreement(s) with RFP finalist(s)				29-Jul					
21	File KPSC notice/CCN						1-Sep			
22										
23	**CCCT (2016 unit)**									
24	Inv Comm/internal approvals		31-May							
25	Public ROW mtgs for gas pipeline			1-Jun						
26	Air permit application				1-Jul					
27	Draft CCN filing				15-Jul					
28	File CCN						1-Sep			
29	Prepare Transmission CCN							1-Oct		16-Dec

From: Schram, Chuck
To: Wilson, Stuart
Sent: 4/12/2011 6:03:21 PM
Subject: FW: Project Calendar
Attachments: Prj Calendar 20110412.xlsx

fyi

From: Schram, Chuck
Sent: Tuesday, April 12, 2011 3:58 PM
To: Voyles, John
Subject: Project Calendar

John,
Please see attached for a summary calendar for ECR, RFP, and 2016 CCCT. I'll need to get some key dates from Doug for the 2018 unit.

Chuck

	A	E	F	G	H	I	J	K	L	M
1		**2011**								
2		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
3	**ECR**									
4	Complete analysis	15-Apr								
5	Draft testimony for review	18-Apr								
6	Finalize bill impacts	22-Apr								
7	File KPSC notice		2-May							
8	Submit newspaper notices		11-May							
9	Final draft ECR appl and testimony		16-May							
10	File ECR/CCN applications			1-Jun						
11	Final CATR issued			27-Jun						
12	EPA releases proposed GHG regs				26-Jul					
13	ECR order due from KPSC								28-Nov	
14	Receive final MACT/HAPS rule								30-Nov	
15	Complete review of MACT/HAPS control plan based on final rule									30-Dec
16										
17	**RFP**									
18	Bidders deadline for best offer	11-Apr								
19	Decision on selection of final RFP offer(s)			3-Jun						
20	Finalize agreement(s) with RFP finalist(s)				29-Jul					
21	File KPSC notice/CCN						1-Sep			
22										
23	**CCCT (2016 unit)**									
24	Inv Comm/internal approvals		31-May							
25	Public ROW mtgs for gas pipeline			1-Jun						
26	Air permit application				1-Jul					
27	Draft CCN filing				15-Jul					
28	File CCN						1-Sep			
29	Prepare Transmission CCN							1-Oct		16-Dec

From: Schram, Chuck
To: Schetzel, Doug
Sent: 4/13/2011 12:13:10 PM
Subject: RE: 2018 NGCC Development Schedule.xlsx
Attachments: Prj Calendar 20110413.pdf

Thanks Doug...I used a few dates for the summary calendar. John and I aren't sure how much detail Paul wants at this point.

<<...>>

Chuck

From: Schetzel, Doug
Sent: Wednesday, April 13, 2011 10:56 AM
To: Schram, Chuck
Subject: 2018 NGCC Development Schedule.xlsx

Chuck

Per your request is the development schedule for the June 2018 NGCC. It is likely more detail than needed, so feel free to pick only the items you need. This schedule reflects the timing we are currently seeing. Extended procurement times for equipment are not included. If the industry is in a gas building boom when procurement is occurring, the schedule could lengthen.

<< File: 2018 NGCC Development Schedule.xlsx >>

Key Dates

April 13, 2011

	2011									2012	2013	2014
	Apr	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**			
ECR												
Complete analysis	15-Apr											
Draft testimony for review	18-Apr											
Finalize bill impacts	22-Apr											
File KPSC notice		2-May										
Submit newspaper notices		11-May										
Final draft ECR appl and testimony		16-May										
File ECR/CCN applications			1-Jun									
Final CATR issued			27-Jun									
EPA releases proposed GHG regs				26-Jul								
ECR order due from KPSC								28-Nov				
Receive final MACT/HAPS rule								30-Nov				
Complete review of MACT/HAPS control plan based on final rule									30-Dec			
RFP												
Bidders deadline for best offer	11-Apr											
Decision on selection of final RFP offer(s)			3-Jun									
Finalize agreement(s) with RFP finalist(s)				29-Jul								
File KPSC notice/CCN						1-Sep						
CCCT (2016 unit)												
Inv Comm/internal approvals		31-May										
Public ROW mtgs for gas pipeline			1-Jun									
Air permit application				1-Jul								
Draft CCN filing				15-Jul								
File CCN						1-Sep						
Prepare Transmission CCN							1-Oct		16-Dec			
Receive CCN and air permit										Q3		
Award eqpt and EPC contract										Q4		
EPC full notice to proceed											Q1	
Eminent domain filings for ROW (if needed)											Q2	
CCCT (2018 unit)												
Identify site acquisition needs										Q4		
Complete plant concept											Q1	
File CCN application												Q3

From:	Schram, Chuck
To:	Wilson, Stuart
Sent:	4/13/2011 2:04:27 PM
Subject:	Prj Calendar
Attachments:	Prj Calendar 20110413.xlsx

	A	E	F	G	H	I	J	K	L	M	N	O	P
1		2011									2012	2013	2014
2		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec			
3	**ECR**												
4	Complete analysis	15-Apr											
5	Draft testimony for review	18-Apr											
6	Finalize bill impacts	22-Apr											
7	File KPSC notice		2-May										
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9	Final draft ECR appl and testimony		16-May										
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13	ECR order due from KPSC								28-Nov				
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15	Complete review of MACT/HAPS control plan based on final rule									30-Dec			
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19	Decision on selection of final RFP offer(s)			3-Jun									
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22													
23	**CCCT (2016 unit)**												
24	Inv Comm/internal approvals		31-May										
25	Public ROW mtgs for gas pipeline			1-Jun									
26	Air permit application				1-Jul								
27	Draft CCN filing				15-Jul								
28	File CCN						1-Sep						
29	Prepare Transmission CCN							1-Oct		16-Dec			
30	Receive CCN and air permit										Q3		
31	Award eqpt and EPC contract										Q4		
32	EPC full notice to proceed											Q1	
33	Eminent domain filings for ROW (if needed)											Q2	
34													
35	**CCCT (2018 unit)**												
36	Identify site acquisition needs										Q4		
37	Complete plant concept											Q1	
38	File CCN application												Q3

From:	Sturgeon, Allyson </O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=N093308>
Sent:	4/19/2011 2:54:43 PM
To:	Schroeder, Andrea <Andrea.Schroeder@lge-ku.com>; Schram, Chuck <Chuck.Schram@lge-ku.com>; Conroy, Robert <Robert.Conroy@lge-ku.com>; 'Kendrick Riggs' <kendrick.riggs@skofirm.com>; Bellar, Lonnie <Lonnie.Bellar@lge-ku.com>; Charnas, Shannon <Shannon.Charnas@lge-ku.com>; Revlett, Gary <Gary.Revlett@lge-ku.com>; Voyles, John <John.Voyles@lge-ku.com>; Straight, Scott <Scott.Straight@lge-ku.com>; Saunders, Eileen <Eileen.Saunders@lge-ku.com>; Wilson, Stuart <Stuart.Wilson@lge-ku.com>; Winkler, Michael <Michael.Winkler@lge-ku.com>; Ehrler, Bob <Bob.Ehrler@lge-ku.com>; Sturgeon, Allyson <Allyson.Sturgeon@lge-ku.com>
Subject:	Copy: General Comments/Discussion on First Draft of ECR Applications and Testimony
Location:	LGEC12 North 2 (Cap 15)
Start:	Tue 4/26/2011 9:00:00 AM
End:	Tue 4/26/2011 10:00:00 AM
Recurrence:	(none)
Meeting Status:	Not yet responded
Required Attendees:	Schroeder, Andrea; Schram, Chuck; Conroy, Robert; 'Kendrick Riggs'; Bellar, Lonnie; Charnas, Shannon; Revlett, Gary; Voyles, John; Straight, Scott; Saunders, Eileen; Wilson, Stuart; Winkler, Michael; Ehrler, Bob; Sturgeon, Allyson

When: Tuesday, April 26, 2011 9:00 AM-10:00 AM (GMT-05:00) Eastern Time (US & Canada).
Where: LGEC12 North 2 (Cap 15)

Note: The GMT offset above does not reflect daylight saving time adjustments.

~~*~*~*~*~*~*~*~*

I realize that not everyone is available, but if you can make it, please try to do so. Thanks.

From: Schram, Chuck
To: Sturgeon, Allyson
Sent: 4/19/2011 3:15:36 PM
Subject: Accepted: General Comments/Discussion on First Draft of ECR Applications and Testimony

---

From:	Walters, Kim
To:	'Riggs, Kendrick R.'; Conroy, Robert; Schroeder, Andrea; Bellar, Lonnie; Schram, Chuck; Wilson, Stuart; LGEC12 West 1201 (Cap 20)
Sent:	4/20/2011 7:47:02 AM
Subject:	ECR Testimony Review-Chuck Schram-Stuart Wilson

When: Monday, May 09, 2011 10:00 AM-11:30 AM (UTC-05:00) Eastern Time (US & Canada).

Where: LGEC 1201

Note: The GMT offset above does not reflect daylight saving time adjustments.

~~*~*~*~*~*~*~*~*

From: Schram, Chuck
To: Sturgeon, Allyson
Sent: 4/20/2011 7:58:03 AM
Subject: Accepted: ECR Testimony Review-Chuck Schram-Stuart Wilson

From: Schram, Chuck
To: Voyles, John; Conroy, Robert
CC: Bellar, Lonnie; Wilson, Stuart
Sent: 4/21/2011 9:44:06 AM
Subject: RE: ECR update mtg

All,

Updates on analytics to be discussed:
Bag houses: All work done except remaining discussions on issues around installation on TC1 (or not).
FGDs: Complete for filing purposes, but still working on break-even analyses.
Brown landfill: Rev requirements not ready. Will be complete next week.

Chuck

-----Original Message-----
From: Voyles, John
Sent: Wednesday, April 20, 2011 7:19 PM
To: Conroy, Robert
Cc: Schram, Chuck; Bellar, Lonnie
Subject: Re: ECR update mtg

Thanks Robert.

----- Original Message -----
From: Conroy, Robert
Sent: Wednesday, April 20, 2011 07:15 PM
To: Voyles, John
Cc: Schram, Chuck; Bellar, Lonnie
Subject: Re: ECR update mtg

I can update on 1) testimony, 2) bill impact, and 3) KPSC letter request. We are waiting on three items from Scott on contracting dates, cancellation $s, and actual breaking ground dates for Kendrick to finish legal memo on CPCN risk. I met with Chris W earlier this week to give her all the info needed for communication plan.

Robert

Sent from my iPhone

On Apr 20, 2011, at 6:44 PM, "Voyles, John" <John.Voyles@lge-ku.com> wrote:

> I have not thought about this update mtg or materials to speak from.
>
> Chuck - Will you have updates on the analytics?
>
> Robert - progress or go forward plan for rate calcs?
>
> Is there missing data I need to pursue?
>
> Will double check with you guys in the a.m.
>
> We've asked chip & c. Whelan to try to join us for communication planning.
>
>
> Thanks
>
> JV

From:	Sturgeon, Allyson </O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=N093308>
Sent:	5/5/2011 1:52:37 PM
To:	Sturgeon, Allyson <Allyson.Sturgeon@lge-ku.com>; 'Riggs, Kendrick R.' <kendrick.riggs@skofirm.com>; Conroy, Robert <Robert.Conroy@lge-ku.com>; Schroeder, Andrea <Andrea.Schroeder@lge-ku.com>; Bellar, Lonnie <Lonnie.Bellar@lge-ku.com>; Schram, Chuck <Chuck.Schram@lge-ku.com>; Wilson, Stuart <Stuart.Wilson@lge-ku.com>
Subject:	Copy: ECR Testimony Review-Chuck Schram-Stuart Wilson
Location:	LGEC12 North 1 (Cap 15)
Start:	Mon 5/9/2011 3:00:00 PM
End:	Mon 5/9/2011 4:30:00 PM
Recurrence:	(none)
Meeting Status:	Not yet responded
Required Attendees:	Sturgeon, Allyson; 'Riggs, Kendrick R.'; Conroy, Robert; Schroeder, Andrea; Bellar, Lonnie; Schram, Chuck; Wilson, Stuart

From:	Sturgeon, Allyson
To:	'Riggs, Kendrick R.'; Conroy, Robert; Schroeder, Andrea; Bellar, Lonnie; Schram, Chuck; Wilson, Stuart
Sent:	5/5/2011 1:52:37 PM
Subject:	ECR Testimony Review-Chuck Schram-Stuart Wilson

When: Monday, May 09, 2011 3:00 PM-4:30 PM (GMT-05:00) Eastern Time (US & Canada).
Where: LGEC12 North 1 (Cap 15)

Note: The GMT offset above does not reflect daylight saving time adjustments.

~~*~*~*~*~*~*~*~*

From: Schram, Chuck
To: Sturgeon, Allyson
Sent: 5/5/2011 2:05:23 PM
Subject: Accepted: ECR Testimony Review-Chuck Schram-Stuart Wilson

From:	Schram, Chuck
To:	Sturgeon, Allyson
Sent:	5/9/2011 3:08:07 PM
Subject:	Accepted: Final ECR Application and Testimony Review

From:	Schram, Chuck
To:	Wilson, Stuart
Sent:	5/10/2011 7:43:36 AM
Subject:	ECR bkgrd 20110509.docx
Attachments:	ECR bkgrd 20110509.docx

May 10, 2011

NAAQS

The NAAQS regulations restrict SO2 and NOx emissions for those areas declared in "non-attainment". The Louisville area is a non-attainment area. Therefore, both the Mill Creek and Cane Run stations are subject to NAAQS restrictions. NAAQS is a one-hour standard, so the rate of SO2 and NOx emissions is the governing factor.

Mill Creek's NOx emissions are within the NAAQS one-hour standard. However, the station's SO2 emissions are higher than NAAQS limits. Under NAAQS, the Mill Creek units cannot operate without reductions in SO2 emissions. Project Engineering engaged external consultant Black and Veatch to review FGD alternatives for reducing SO2 to comply with NAAQS regulations. The most cost effective FGD control configuration, consisting of total capital investment of $ million, includes the following:

1. Removing the existing FGD controls on Unit 1 and Unit 2.
2. Constructing a new FGD to serve Unit 1 and Unit 2.
3. Attaching Unit 3 to the existing FGD serving Unit 4.
4. Constructing a new FGD to serve Unit 4.

Cane Run Units 4, 5, and 6 have first generation FGDs built in the 1970s. The Cane Run units are not equipped with SCRs. Cane Run will require extensive FGD improvements and new SCR controls to meet NAAQS regulations. Black and Veatch estimates that these controls will require capital investment of $xxx million for FGDs and $xxx for SCRs.

[Also cover GR and TY]

CATR

The CATR regulates SO2 and NOx emissions. While CATR is designed as a cap-and-trade program with annual emissions caps, the EPA has indicated that interstate allowance trading will be limited. Therefore, the Companies have assumed that physical compliance on a systemwide basis is required. The NOx and SO2 emissions of the Companies' system was modeled and compared to the EPA's proposed emissions allocations.

The Companies analysis indicates that NOx emissions fall just under the EPA's NOx allowance proposal through 2015 as seen in Figure xx. Therefore, the construction of additional SCRs at Mill Creek Units 1-2, Ghent Unit 2, and Brown Units 1-2 is not recommended.

Estimated SO2 emissions exceed the EPA's SO2 allowance proposal. As a result, construction of new FGDs and/or improvements to the FGD systems at Mill Creek, Cane Run, Green River and Tyrone were evaluated. These units will face operational limitations under CATR without the construction of additional SO2 controls.

May 10, 2011

The Mill Creek FGD program to comply with NAAQS regulations will also support the CATR requirements. Emissions will be reduced by xxx tons of SO2 by 2015. No additional FGD related expenditures are required at Mill Creek as a result of CATR.

Cane Run's control requirements for NAAQS will also contribute toward the Companies system wide CATR compliance. The controls will support reductions of xx tons of SO2 and xx tons of NOx by 20xx. No further controls at Cane Run are required for CATR compliance.

[Also address GR, TY]

EGU MACT/HAPS

The EPA's proposal for EGU MACT/HAPS was released in March 2011. The Companies engaged Black and Veatch to study compliance options. After reviewing potential precipitator ugrades and fabric filter bag houses, constructing bag houses on all generating units is recommended as the most cost effective approach if this regulation is met through construction of controls.

The EGU MACT/HAPS regulations govern acid aerosols, including SO3. SO3 is sometimes produced during the high temperatures associated with full load operations of units equipped with SCR controls. The Companies have reviewed approaches to manage potential SO3 emissions at SCR equipped units and recommend improvements to manage the operating temperature ranges of SCRs at Ghent and Mill Creek. These improvements involve economizer modifications which will lower the high temperatures associated with full load operation of the SCRs. The Companies believe that the EPA will be vigilant in enforcing SO3 limitations and strive to avoid potential SO3 violations at its SCR equipped units. In addition, the SCR improvements will enable operation of the SCRs at lower load levels. This will contribute to lower NOx emissions at low loads and further ensure NOx compliance with CATR during the years where NOx emissions are projected to approach emission limits.

[Need summary chart with costs for above by reg/by unit]

[Discussion of each unit for build controls vs. retire]

From:	Walters, Kim </O=LGE/OU=LOUISVILLE/CN=RECIPIENTS/CN=E010358>
Sent:	5/18/2011 7:58:08 AM
To:	Sturgeon, Allyson <Allyson.Sturgeon@lge-ku.com>; Voyles, John <John.Voyles@lge-ku.com>; Schram, Chuck <Chuck.Schram@lge-ku.com>; Charnas, Shannon <Shannon.Charnas@lge-ku.com>; Bellar, Lonnie <Lonnie.Bellar@lge-ku.com>; Conroy, Robert <Robert.Conroy@lge-ku.com>; Revlett, Gary <Gary.Revlett@lge-ku.com>; Straight, Scott <Scott.Straight@lge-ku.com>; Wilson, Stuart <Stuart.Wilson@lge-ku.com>; Saunders, Eileen <Eileen.Saunders@lge-ku.com>; Schroeder, Andrea <Andrea.Schroeder@lge-ku.com>; 'Riggs, Kendrick R.' <kendrick.riggs@skofirm.com>; 'Crosby, W. Duncan' <duncan.crosby@skofirm.com>; LGEC12 West 1202 (Cap 35) <EONUSC12WEST1202@lge-ku.com>
Subject:	Copy: Final ECR Application and Testimony Review (Updated with new location)
Location:	LGEC 1202
Start:	Wed 5/18/2011 1:00:00 PM
End:	Wed 5/18/2011 3:00:00 PM
Recurrence:	(none)
Meeting Status:	Not yet responded
Required Attendees:	Sturgeon, Allyson; Voyles, John; Schram, Chuck; Charnas, Shannon; Bellar, Lonnie; Conroy, Robert; Revlett, Gary; Straight, Scott; Wilson, Stuart; Saunders, Eileen; Schroeder, Andrea; 'Riggs, Kendrick R.'; 'Crosby, W. Duncan'; LGEC12 West 1202 (Cap 35)

From:	Schram, Chuck
To:	Sturgeon, Allyson
Sent:	5/18/2011 7:59:10 AM
Subject:	Accepted: Final ECR Application and Testimony Review (Updated with new location)

From: Schroeder, Andrea
To: Schram, Chuck
CC: Williams, Cheryl; Sebourn, Michael
Sent: 5/24/2011 9:18:45 AM
Subject: ECR filing - confidential information

Chuck,

Please make sure any confidential data included in your testimony and/or exhibits is clearly identified in yellow highlight. I will create a redacted version based on the data you identify as confidential.

Thanks,
Andrea

Andrea Schroeder
LG&E and KU
State Regulation and Rates
502-627-3651
502-627-3213 (fax)

From: Schram, Chuck
To: Wilson, Stuart
Sent: 5/24/2011 9:20:03 AM
Subject: FW: ECR filing - confidential information

We need to talk about this for CRS-1.

From: Schroeder, Andrea
Sent: Tuesday, May 24, 2011 9:19 AM
To: Schram, Chuck
Cc: Williams, Cheryl; Sebourn, Michael
Subject: ECR filing - confidential information
Importance: High

Chuck,

Please make sure any confidential data included in your testimony and/or exhibits is clearly identified in yellow highlight. I will create a redacted version based on the data you identify as confidential.

Thanks,
Andrea

Andrea Schroeder
LG&E and KU
State Regulation and Rates
502-627-3651
502-627-3213 (fax)

From: Wilson, Stuart
To: Schram, Chuck
Sent: 5/24/2011 9:20:45 AM
Subject: RE: ECR filing - confidential information

OK. Almost finished with exhibit 2...

From: Schram, Chuck
Sent: Tuesday, May 24, 2011 9:20 AM
To: Wilson, Stuart
Subject: FW: ECR filing - confidential information
Importance: High

We need to talk about this for CRS-1.

From: Schroeder, Andrea
Sent: Tuesday, May 24, 2011 9:19 AM
To: Schram, Chuck
Cc: Williams, Cheryl; Sebourn, Michael
Subject: ECR filing - confidential information
Importance: High

Chuck,

Please make sure any confidential data included in your testimony and/or exhibits is clearly identified in yellow highlight. I will create a redacted version based on the data you identify as confidential.

Thanks,

Andrea

Andrea Schroeder
LG&E and KU
State Regulation and Rates
502-627-3651
502-627-3213 (fax)

From: Jefferson, Tangila
To: Schram, Chuck
Sent: 5/25/2011 9:41:47 AM
Subject: ECR Filing

Hey Chuck,
Andrea Schroeder just stopped by. She needs to know if your Testimony final? If so, which version? If not, when can she get it?

Is your Exhibits final? If so, which version? If not, when can she get it?

Tangila Jefferson
LG&E/KU
Senior Secretary/Chuck Schram
Energy Planning, Forecasting & Analysis
(502) 627-3621
(502) 217-2330 fax

From: Schram, Chuck
To: Schroeder, Andrea
CC: 'thesabbath4@sbcglobal.net'
Sent: 5/25/2011 9:49:51 AM
Subject: Re: ECR Filing

Andrea,
No further changes to the 4 red line docs I sent to you yesterday. Can you accept the changes to make final?
I am off site at an Energy Svcs mtg.
thx
Chuck

From: Jefferson, Tangila
Sent: Wednesday, May 25, 2011 09:41 AM
To: Schram, Chuck
Subject: ECR Filing

Hey Chuck,

Andrea Schroeder just stopped by. She needs to know if your Testimony final? If so, which version? If not, when can she get it?

Is your Exhibits final? If so, which version? If not, when can she get it?

Tangila Jefferson

LG&E/KU

Senior Secretary/Chuck Schram

Energy Planning, Forecasting & Analysis

(502) 627-3621

(502) 217-2330 fax

From: Schroeder, Andrea
To: Conroy, Robert
Sent: 12/9/2010 9:29:38 AM
Subject: 2011 ECR Plan Work Plan DRAFT
Attachments: Work Plan 11052010 - 2011 Plan.docx

Robert,

Attached is the DRAFT 2011 ECR Work Plan document. As we discussed, the format of the project descriptions has been revised to include bullet-points instead of narratives for each project. Please review and provide comments to finalize the document. The document is currently saved in my ECR\2011 ECR Plan folder if you with to edit the source document directly.

Also, please remember to speak with John Voyles to determine who will serve as his support team for projects and environmental.

Thanks,
Andrea

Andrea Schroeder
LG&E and KU
State Regulation and Rates
502-627-3651
502-627-3213 (fax)

2011 Amended ECR Plan / CCN Filing

Kentucky Utilities Company (KU) and Louisville Gas & Electric Company (LG&E) plan to file an application to amend their respective ECR plans by April 1, 2011. Simultaneously KU will file an application (one ECR/CCN application) for Certificates of Public Convenience and Necessity (CCN) for the construction of Air Compliance projects at Brown and Ghent and modification of the Brown Ash Pond to a Landfill. LG&E will also simultaneously file an application (one ECR/CCN application) for CCNs for the construction of Air Compliance projects at Mill Creek and Trimble County.

ECR Projects included in 2011 Amended Plan

KU

Project 34 - Brown Station – Air Compliance

- Required to comply with NAAQS and proposed CATR and HAPS regulations
- Baghouse with PAC Injection – shared between Units 1 and 2
- Baghouse with PAC Injection – Unit 3
- SAM Mitigation – Units 1 and 2
- Project cost forecast is $177.46M and will have associated O&M
- Baghouses will require a CCN

Project 35 – Ghent Station – Air Compliance

- Required to comply with NAAQS and proposed CATR and HAPS regulations
- Baghouse with PAC Injection – all four units
- SAM Mitigation – all four units
- Project cost forecast is $691.22M and will have associated O&M
- Baghouses will require a CCN

Amended Project 29 – Brown Station Landfill

As part of the approved 2009 ECR Plan, Project 29 included Phase II of the Main Pond and Aux Pond Expansion. With the 2011 ECR Plan filing, we recommend amending Project 29 to include dry storage instead of the approved wet storage.

- Required to comply with proposed Coal Combustion Residuals regulations
- Multi-phase project will maximize future vertical expansion opportunities and reduce final landfill height by using original Ash Pond footprint
- Phase I anticipated in-service by January 2014
- Phase I project cost forecast is $57.12M; total project cost forecast is $154.94M, and will have associated O&M
- Landfill does not require a CCN

LG&E

Project 26 – Mill Creek Station – FGDs

- Required to comply with NAAQS and proposed CATR regulations
- FGD Upgrades – Units 1 and 2
- New FGD – Unit 4
- Update and tie-in existing Unit 4 FGD to Unit 3
- Project cost forecast is 478.98M and will have associated O&M
- FGDs will require a CCN

Project 27 – Mill Creek Station – Air Compliance

- Required to comply with NAAQS, proposed CATR and HAPS regulations, and Jefferson County Non-Attainment
- Baghouse with PAC Injection – all four units
- Electrostatic Precipitator – Unit 2
- Ammonia – Unit 4
- SCR Upgrade – Unit 4
- Project cost forecast is $545.34M and will have associated O&M
- Baghouses will require a CCN

Project 28 – Trimble County Unit 1 – Air Compliance

- Required to comply with proposed CATR and HAPS regulations
- Baghouse with PAC Injection – all four units
- SAM Mitigation – all four units
- Project cost forecast is $691.22M and will have associated O&M
- Baghouses require CCN

Work Plan Key Dates

Identify Eligible ECR Projects	December 6, 2010
Kick-off meeting with Witnesses and Support	December 15, 2010
Begin drafting application and testimony	January 1, 2011
Exhibits supporting application and testimony due to Rates	January 29, 2011
Least cost analysis / Cost justification	January 29, 2011
Finalize Revenue Requirements/Bill Impact Analysis of eligible projects	February 15, 2011
1st Draft of Application and Testimony due to Rates	March 1, 2011
File a "Notice of Intent" with KPSC	March 1, 2011

Submit KU and LG&E newspaper notice of proposed tariff changes and estimated bill impact	March 11, 2011
2nd Draft of Application and Testimony due to Rates	March 15, 2011
Final Draft of Application and Testimony circulated for review	March 17, 2011
Final Reviews	March 22, 2011
File KU CCN/ECR Application and LG&E CCN/ ECR Application with the KPSC	April 1, 2011

Witness Listing and Subject Matter

Witness: Lonnie E. Bellar

- Support/Contact: Andrea Schroeder
- Subject Matter: CCN and ECR
    - Overview of the applications
    - Introduction of Company witnesses & testimony
    - Reasons for requesting CCN
    - Reasons for ECR projects
    - Requested Rate of Return (10.63% in accordance with Rate Case assumption)
    - Project financing

Witness: John Voyles

- Support/Contact: Fred Jackson (Projects); Mike Winkler and Gary Revlett (Environmental)
- Subject Matter: CCN and ECR
    - Engineering studies supporting the cost and construction for the environmental projects
    - Overview of the projects contained in the ECR Plan
    - Detailed discussion of each project contained in the ECR Plan
        - Any O&M savings associated with projects
        - Any incremental O&M cost to be recovered
        - Why the projects are needed
    - NOV Consent Decree (SAM Mitigation) ???
    - Discussion of environmental regulation requiring additional compliance measures including the Clean Air Act Amendments (CAAA) and Clean Water Act

    - Specific Environmental laws and/or regulations that require each of the Projects included in the ECR filing
    - Status of environmental permits/requirements for each project, as necessary

Witness: Chuck Schram

- Support/Contact: Stuart Wilson

- Subject Matter: CCN and ECR

    - Least cost analyses for environmental compliance
    - Project cost justification
    - Cost support as needed for each project contained in the ECR Plan
        - Accuracy/confidence of cost estimates

Witness: Shannon Charnas

- Support/Contact: Eric Raible

- Subject Matter: ECR Only

    - Explanation of the Company's reporting and accounting of the O&M expenses associated with the projects contained in the plan
    - Discussion of the level of expenditures already included in existing rates

Witness: Robert M. Conroy

- Support/Contact: Andrea Schroeder

- Subject Matter: ECR Only

    - Modification to each Company's ES Tariff
    - Discussion of Customer bill impact
        - Increase due to ECR projects
    - Presentation of forms for ECR filings

Overall Risks/Issues associated with the Filing

- ECR Legislation under KRS 278.183

- Significant cost overruns for project construction of prior approved projects

- Consent decree (SAM Mitigation) ???

- Lack of final regulations adds uncertainty to the need for and scope of the projects

- Commission could grant a CCN and deny ECR recovery until a future compliance plan or rate case

- Previous compliance plan results

- New Commission and PSC staff turnover

From: Schroeder, Andrea
To: Charnas, Shannon
Sent: 1/6/2011 10:17:25 PM
Subject: RE: ECR 6 month review

Sounds good. The explanation of the O&M expenses does not impact any other responses and is not addressed in testimony. Thanks for letting me know about the other responses. Don't work too late.....

From: Charnas, Shannon
Sent: Thursday, January 06, 2011 10:16 PM
To: Schroeder, Andrea
Subject: FW: ECR 6 month review

Andrea -

Attached are the tax files. I am also OK with #1 and #5 that Jenny already provided. I am still waiting on one, which I should have soon. I'll get it to you as soon as I can.

Thanks,

Shannon Charna.
Director, Utility Accounting & Reporting
LG&E and KU
(502) 627-4978

From: Williams, Scott
Sent: Wednesday, December 29, 2010 4:34 PM
To: Charnas, Shannon; Skaggs, Jennifer
Subject: ECR 6 month review

Shannon/Jenny,
I will be out tomorrow so I went ahead and updated the tax information for the ECR response to give you a chance to look over. On project 21 for KU I have to follow up on tax depreciation for Apr and May, it may be correct, I just need to check further but wanted to get you everything.
Thanks
Scott

<< File: ECR 6mo KU 8 10.xls >> << File: ECR 6mo LGE 8 10.xls >>

From: Saunders, Eileen
To: Schroeder, Andrea
Sent: 2/1/2011 12:58:21 PM
Subject: FW: 168908.41.0803 110120 Brown Validation Meeting Presentation
Attachments: Brown Validation Presentation.pdf; LG&EKU Brown Validation Report.pdf

Andrea,

This email will be the first of three that includes the **preliminary** conceptual layouts and equipment for each plant/unit. Also, I have included copies of the presentations as well. These are living documents that may change once we get the draft final reports.

Thanks,

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Thursday, January 20, 2011 5:30 PM
To: Saunders, Eileen
Cc: 168908 E.ON-AQC; Jackson, Audrey; Wehrly, M. R.; Hintz, Monty E.; Lucas, Kyle J.; Mehta, Pratik D.; Mahabaleshwarkar, Anand; Goodlet, Roger F.
Subject: 168908.41.0803 110120 Brown Validation Meeting Presentation

Eileen,

Please find attached a PDF of the Brown Validation Meeting Presentation. We plan to bring color copy handouts as well as the electronic PowerPoint to the meeting on January 25th. I assume you can provide the PC projector again.

Best regards,

TIM HILLMAN | Project Manager, Energy
Black & Veatch Corporation | 11401 Lamar Ave., Overland Park, KS 66211
+ 1 913-458-7928 P |HillmanTM@BV.com
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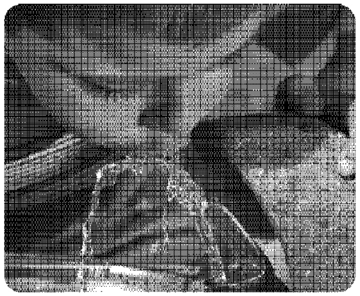
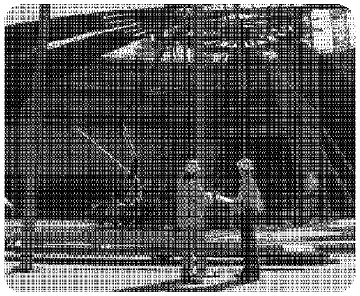
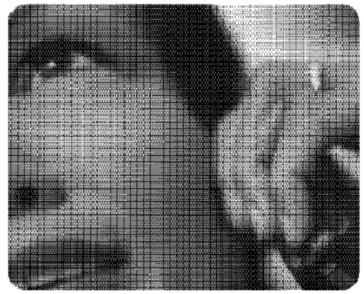
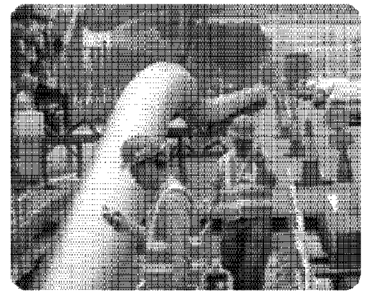
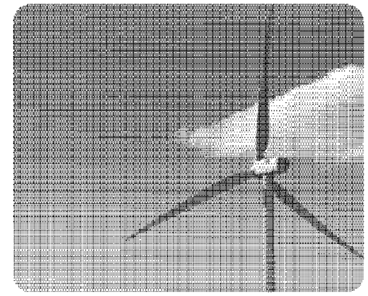

Phase II AQC Study
E.W. Brown Validation

LG&E KU
PPL companies

Black & Veatch

January 2011

Agenda

- Units 1, 2 and 3 AQC equipment train
- AQC equipment layout validation
  - Conceptual sketches
  - 3-D models
- Summary / wrap-up and discussions

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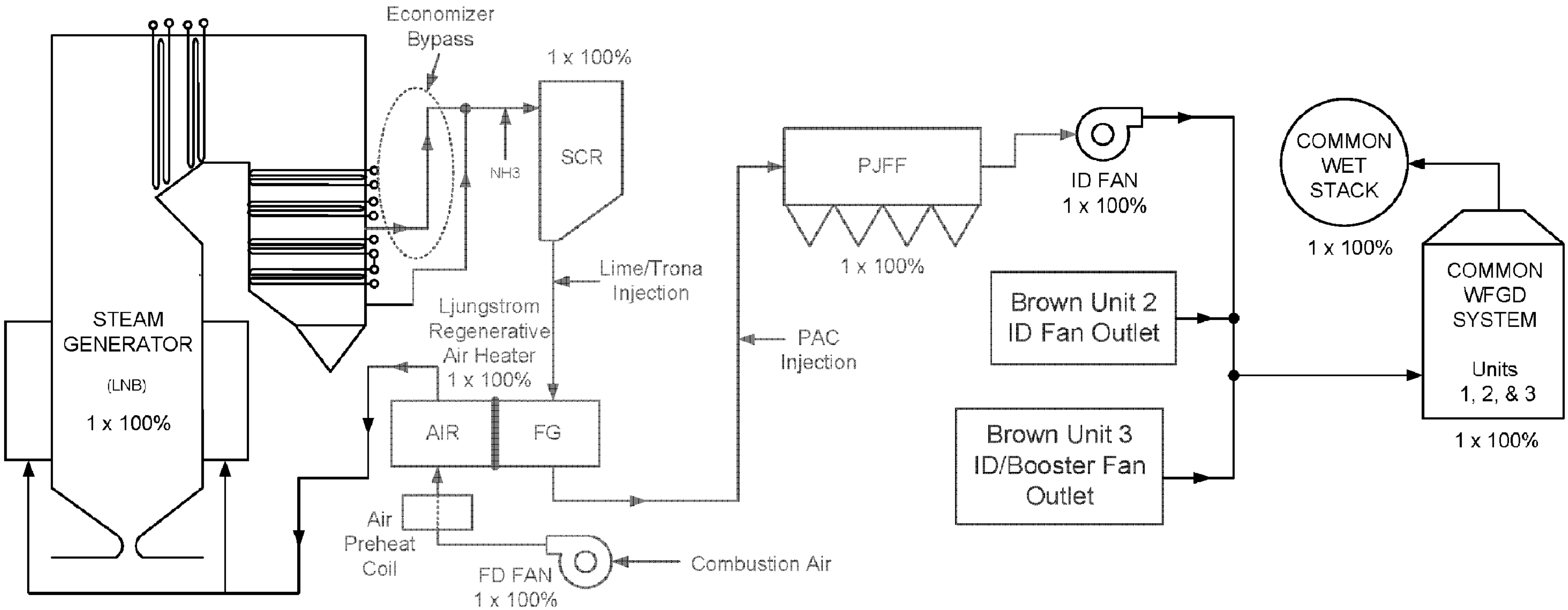
AQC Equipment Train
E.W. Brown Units 1, 2 and 3

E.W. Brown Unit 1 AQC process flow diagram

- Add new SCR
- Add new air heater
- Add new FD fan
- Add new PJFF
- Add new PAC injection system
- Add new sorbent injection system



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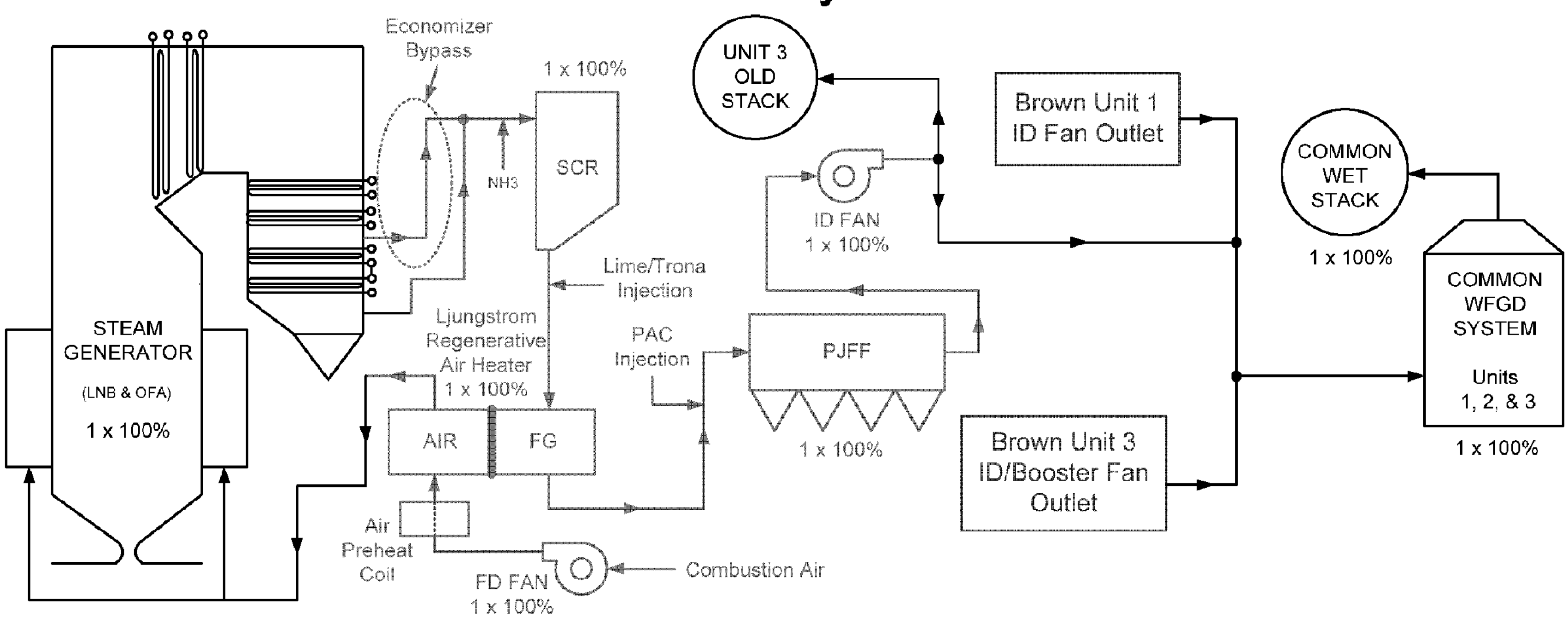
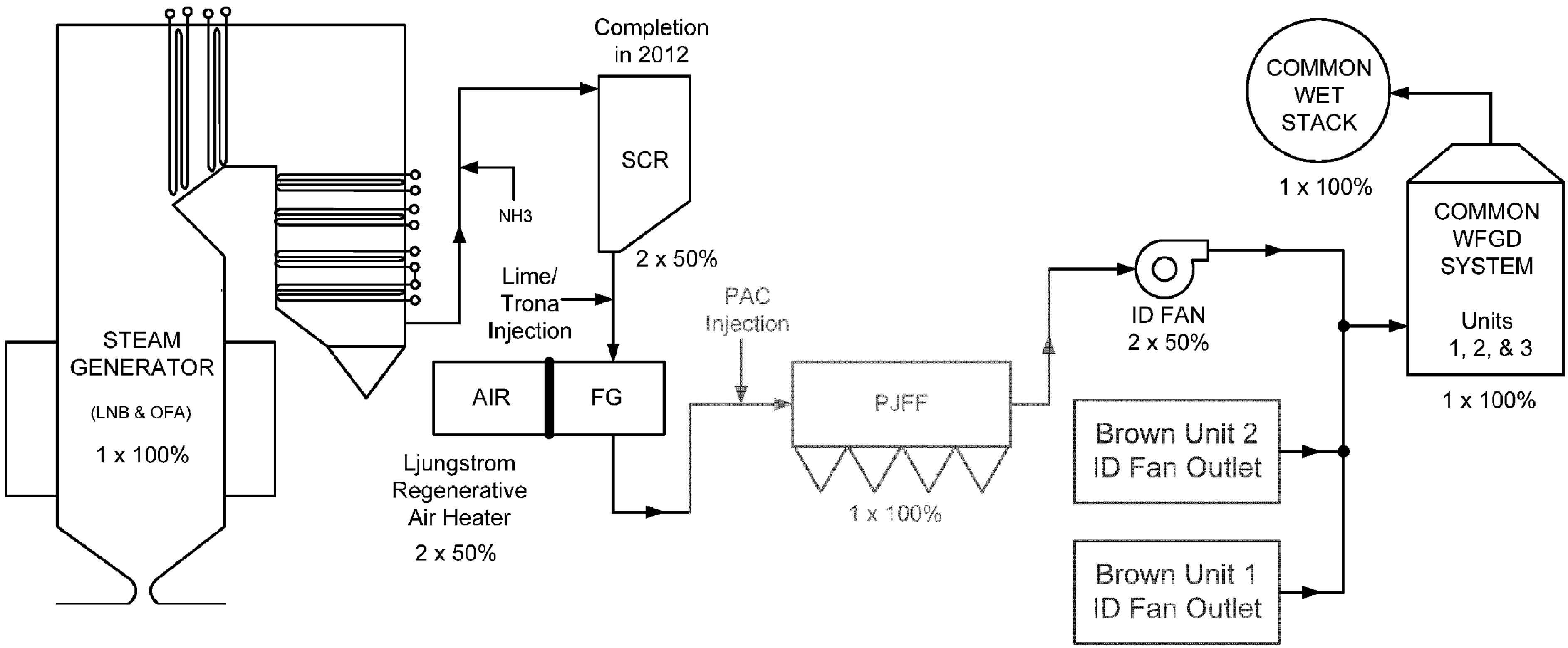
E.W. Brown Unit 2 AQC process flow diagram

- Add new SCR
- Add new air heater
- Add new FD fan
- Add new ID fan
- Add new PJFF
- Add new PAC injection system
- Add new sorbent injection system



E.W. Brown Unit 3 AQC process flow diagram

- Add new PJFF
- Add new PAC injection system
- Future new SCR
- Future new sorbent injection system



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AQC Equipment Layout Validation

AQC validation

- Validation report determined no fatal flaws for the selected AQC equipment
- AQC equipment can meet identified emission targets

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Unit 1 and Unit 2 Conceptual Sketch Base Case

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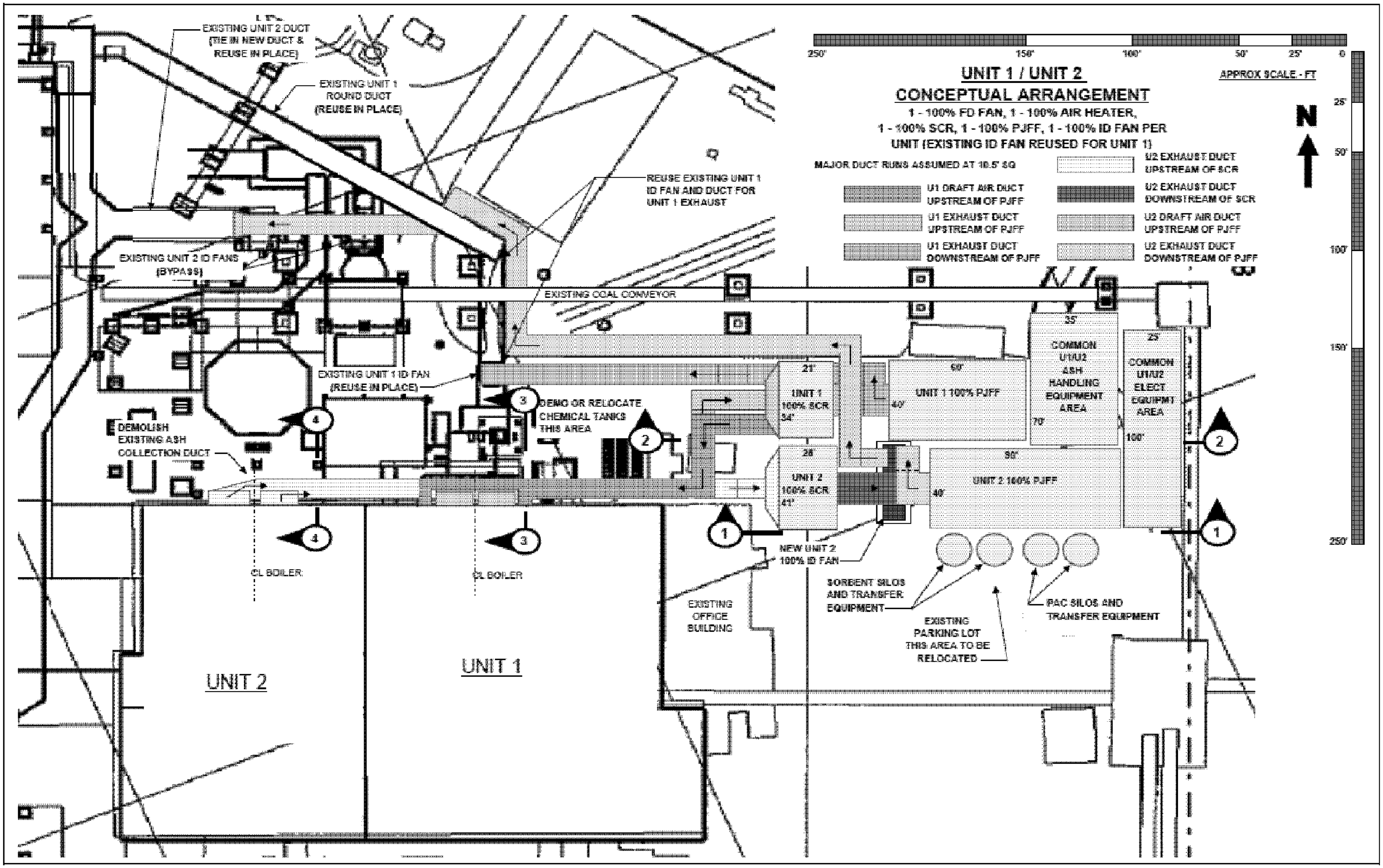
E.W. Brown Unit 1 and Unit 2 arrangement (Base)



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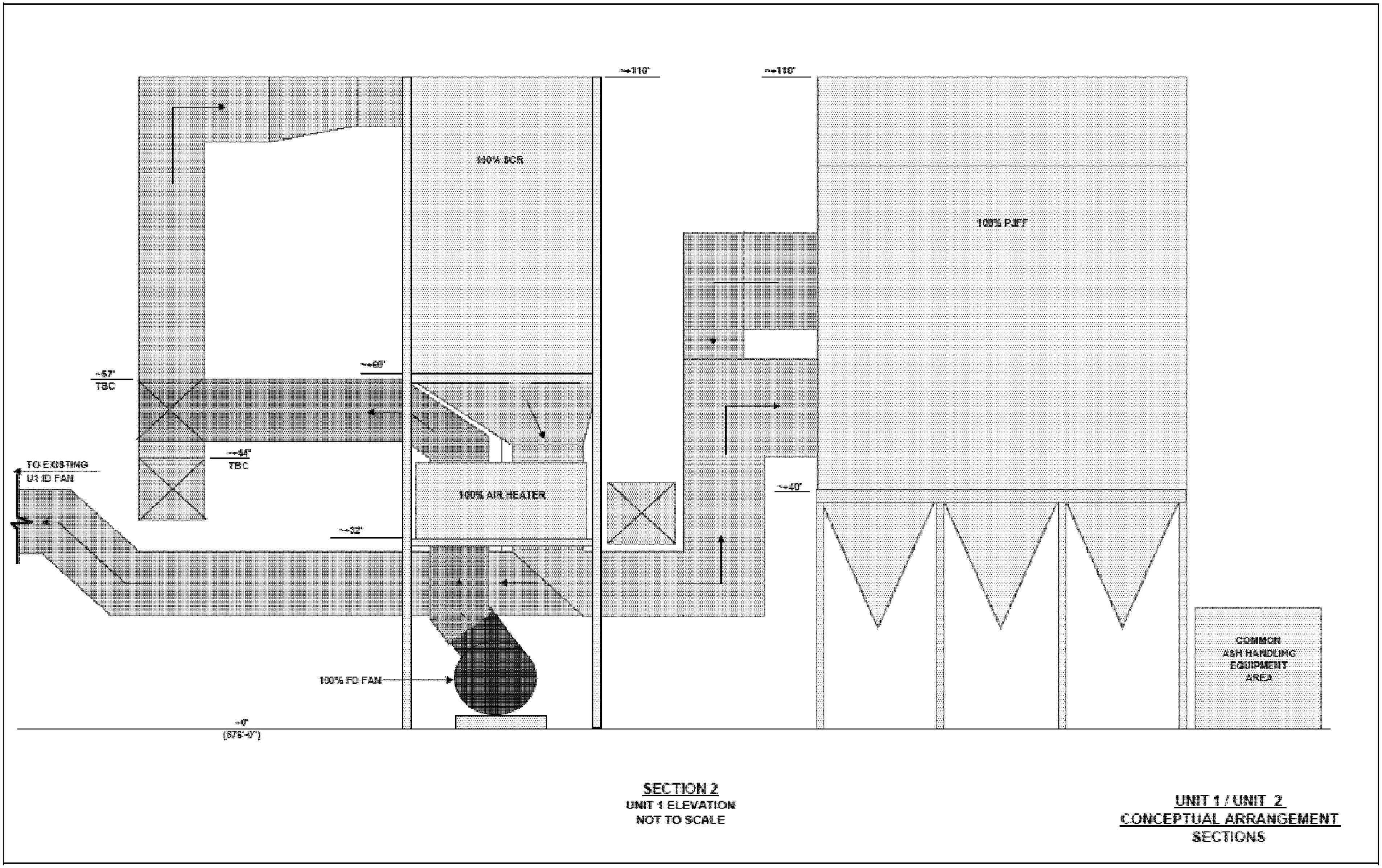
E.W. Brown Unit 1 arrangement (Base)



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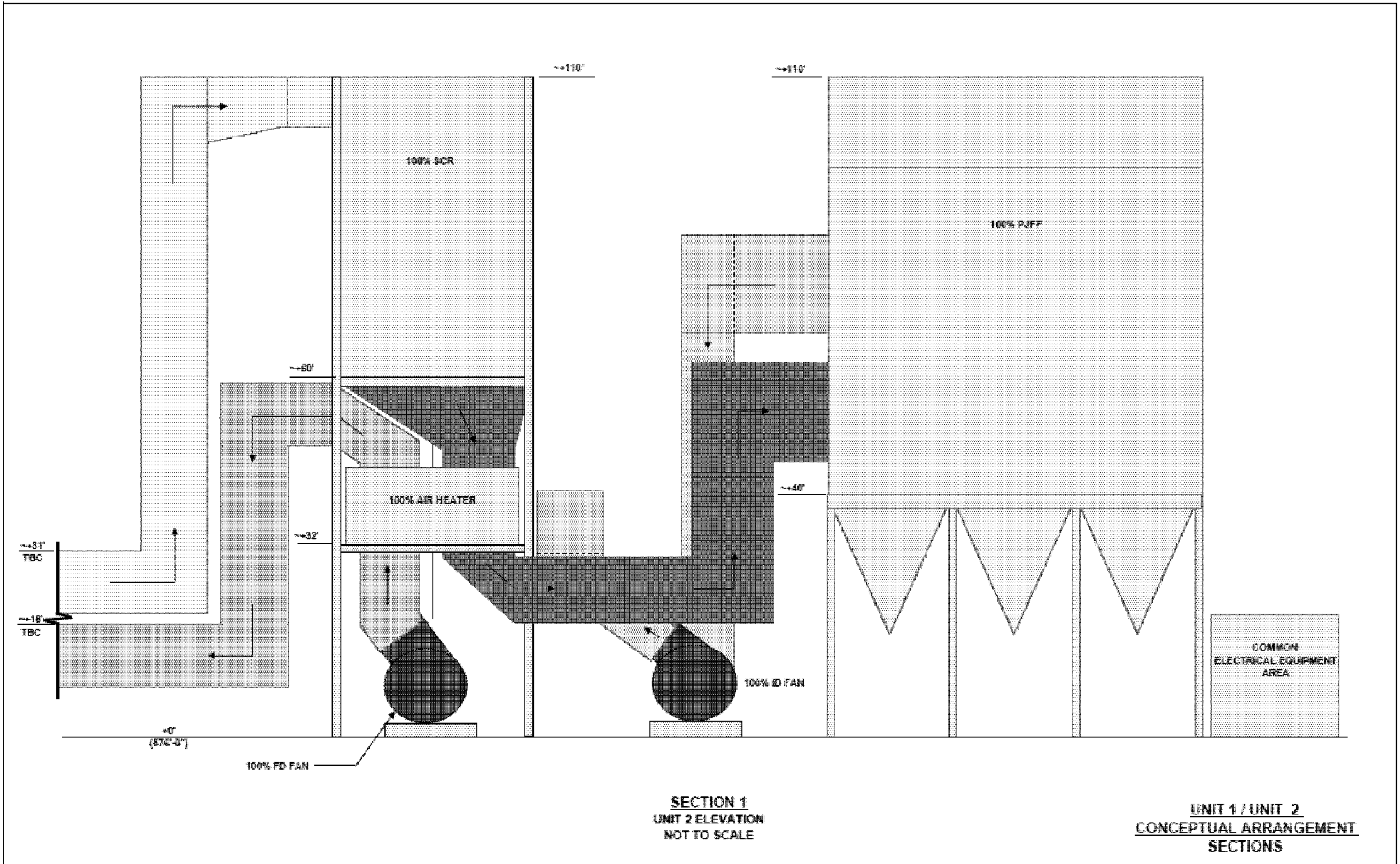
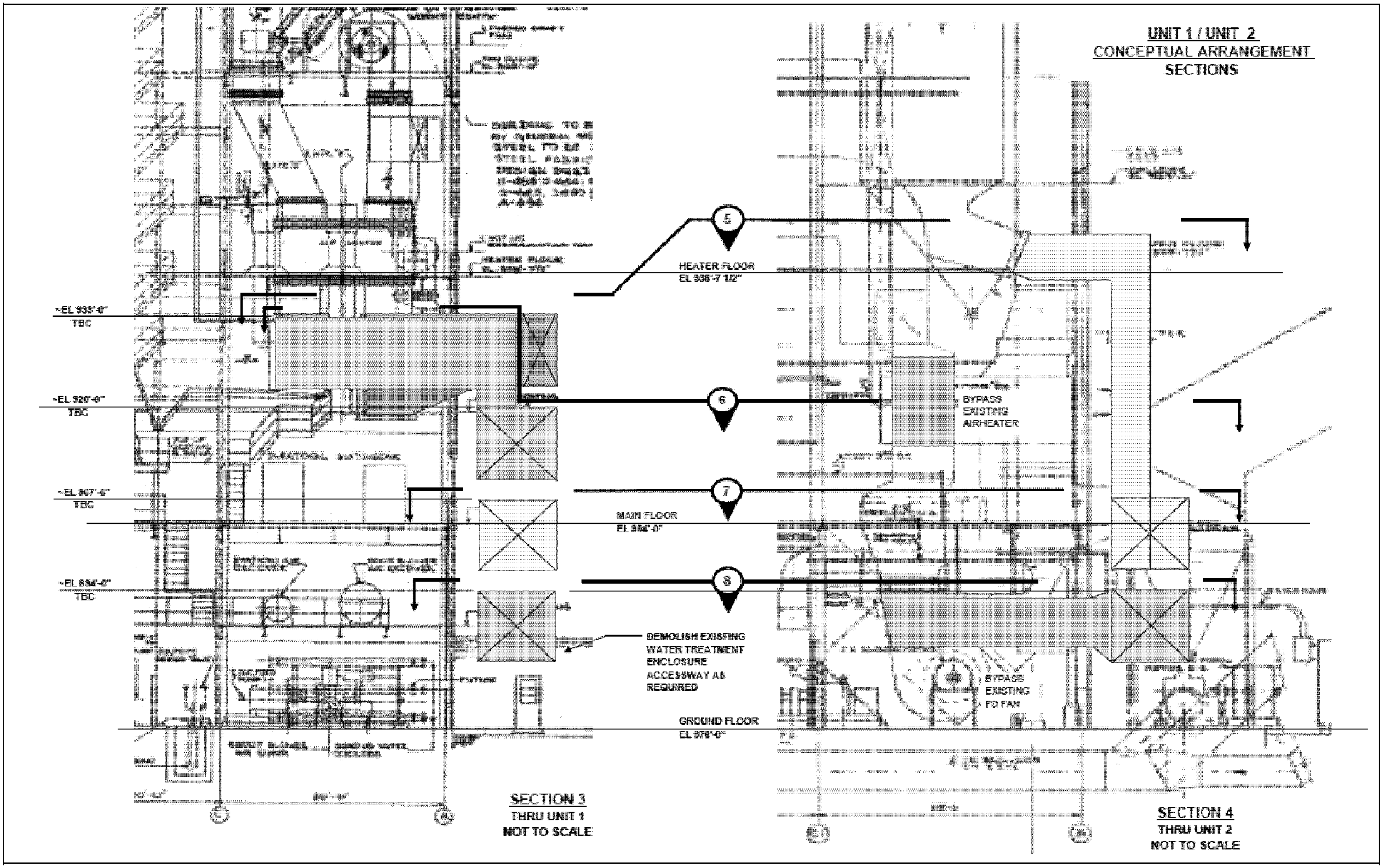
E.W. Brown Unit 2 arrangement (Base)



E.W. Brown Unit 1 and Unit 2 duct tie-in (Base)



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Unit 1 and Unit 2 Conceptual Sketch Alternate 1 (No SCRs)

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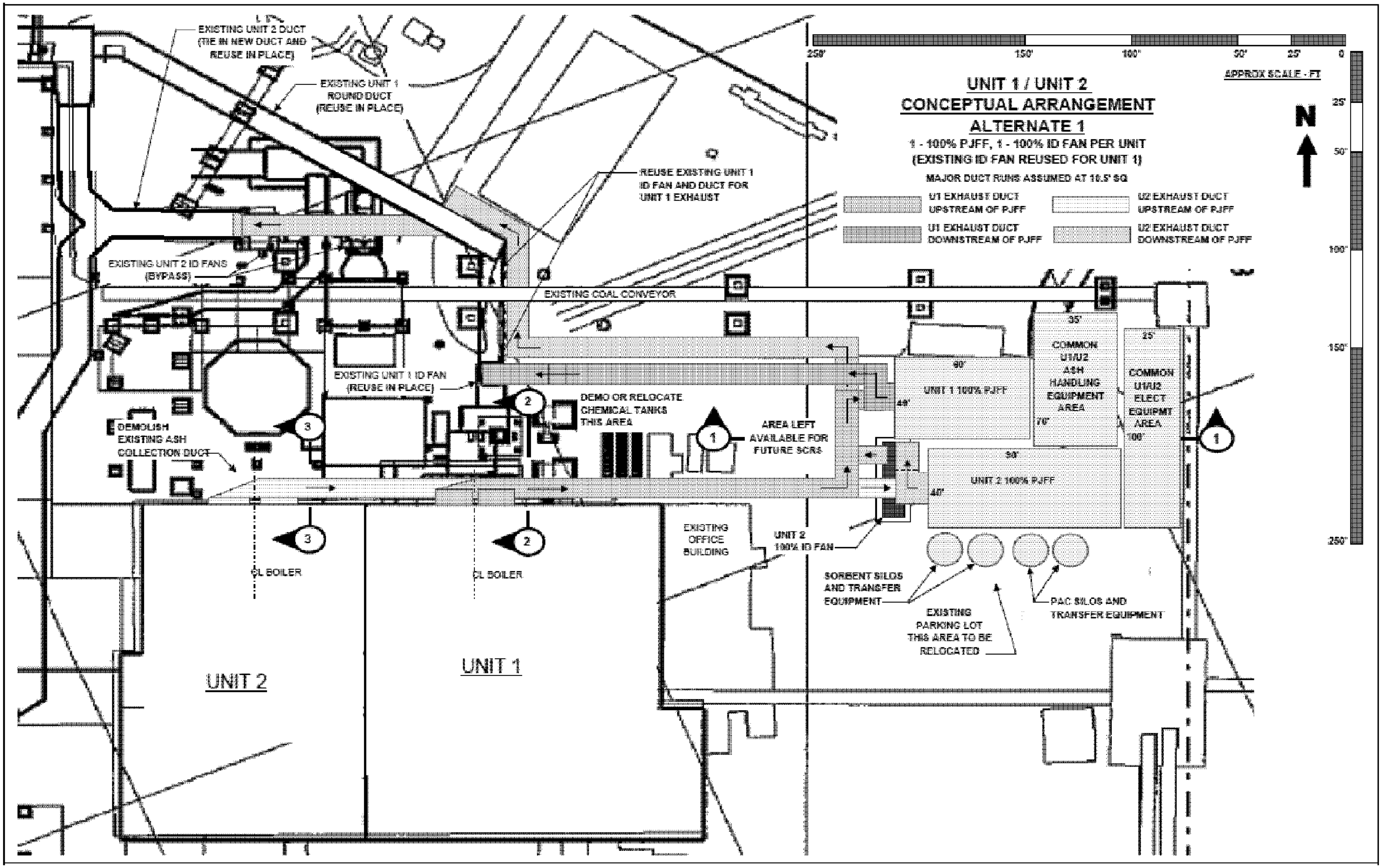
E.W. Brown Unit 1 and Unit 2 arrangement (Alt. 1)



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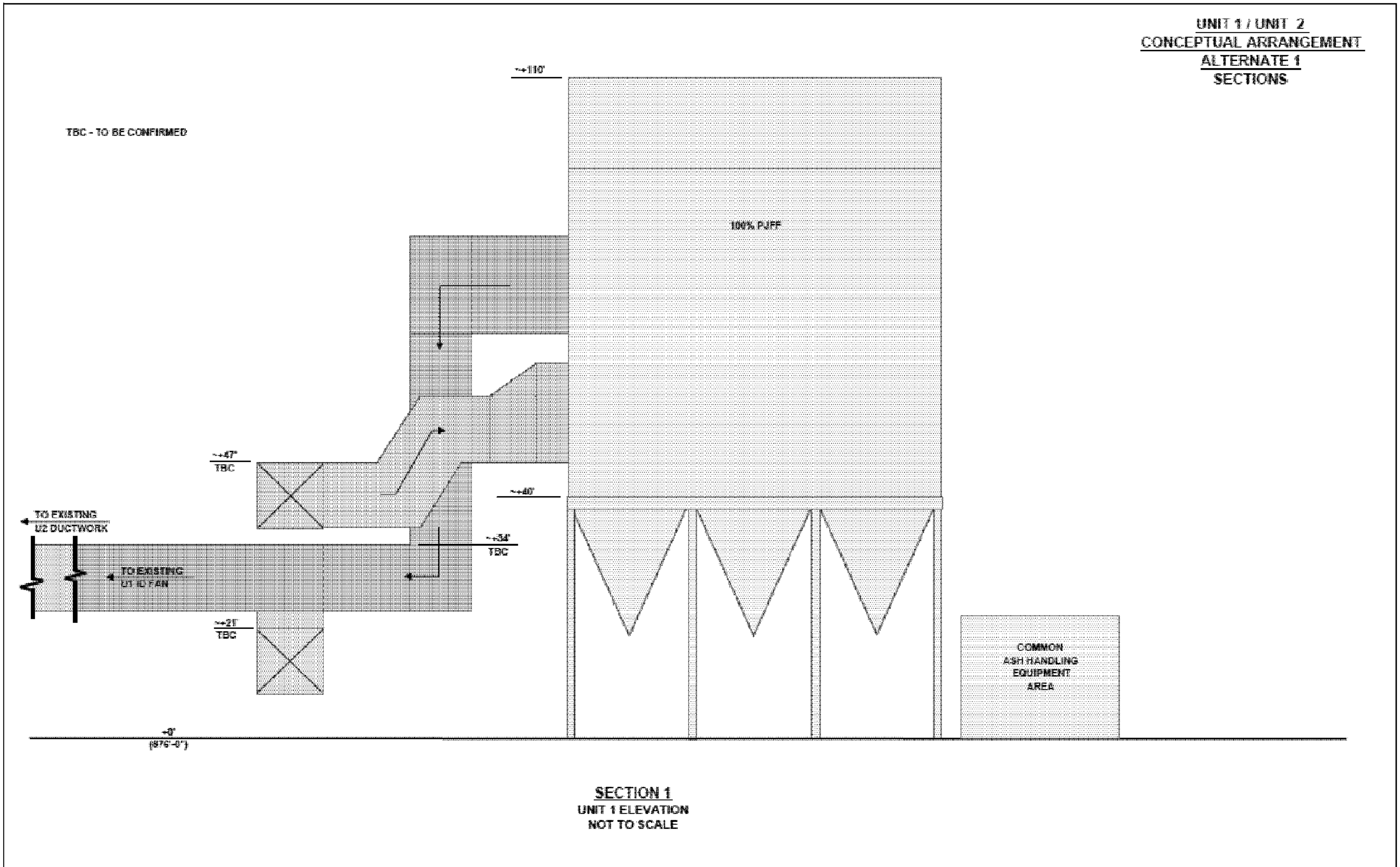
E.W. Brown Unit 1 arrangement (Alt. 1)



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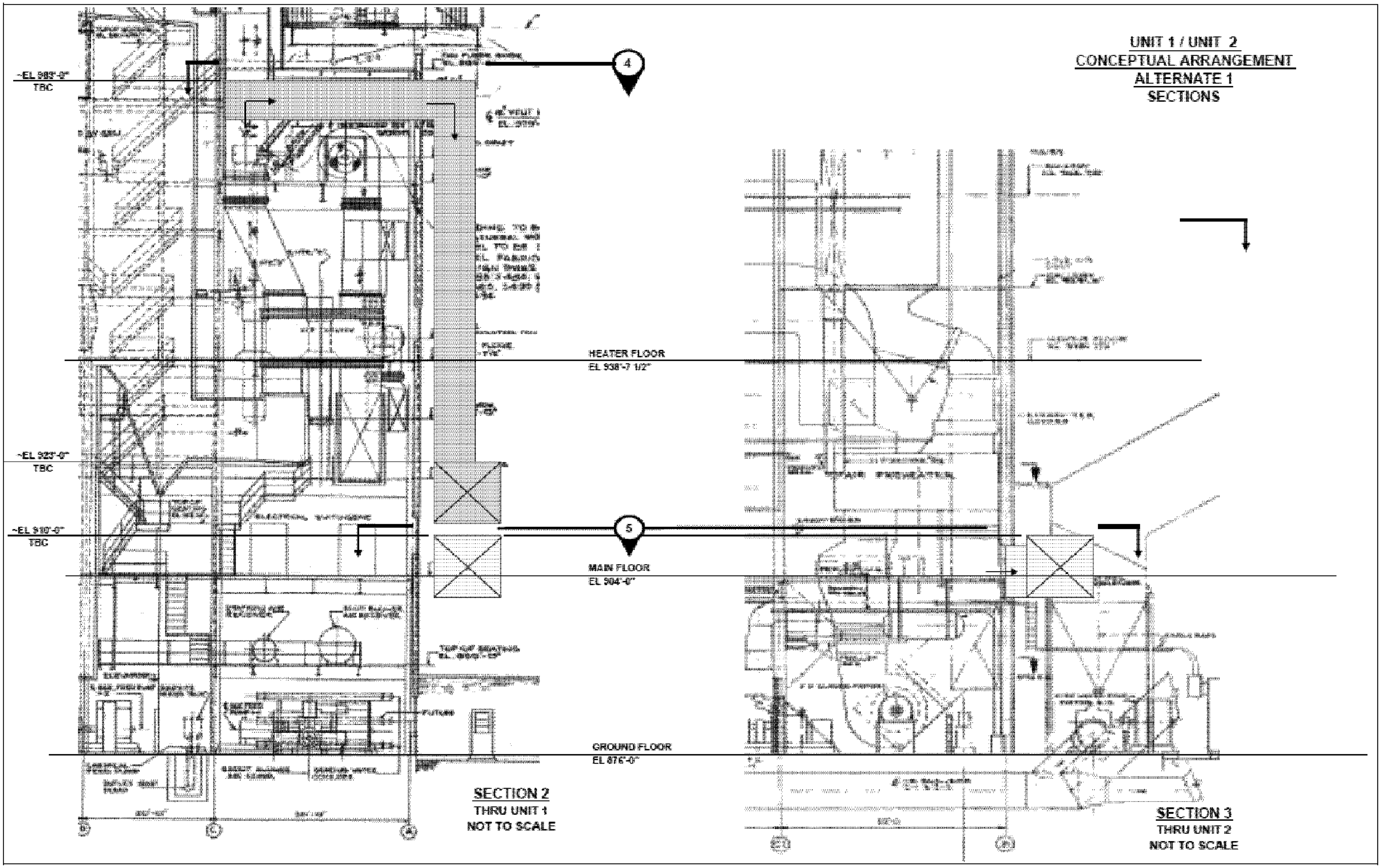
E.W. Brown Unit 1 and Unit 2 duct tie-in (Alt. 1)



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Unit 1 and Unit 2 Conceptual Sketch Alternate 2 (No U2 AH)

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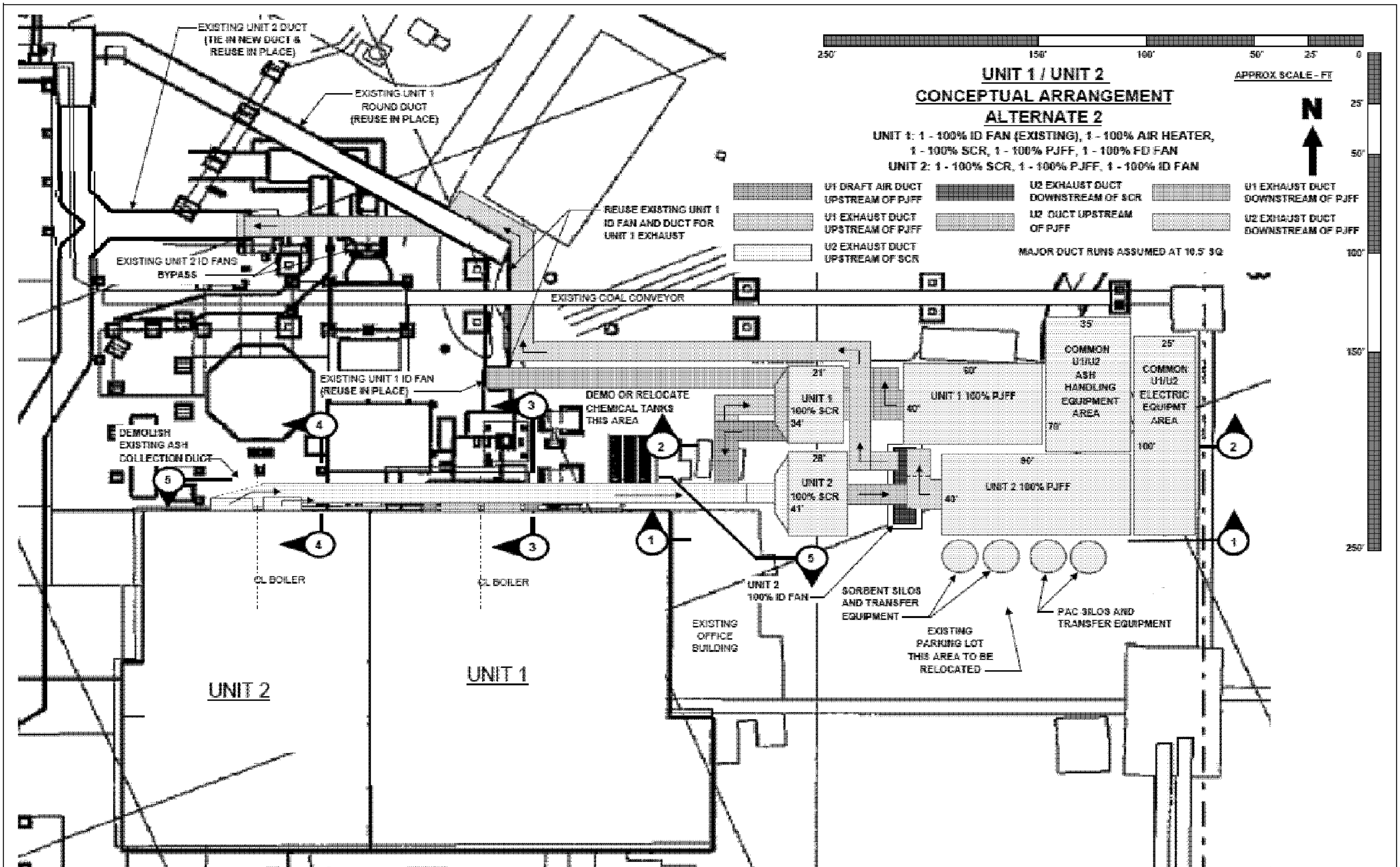
E.W. Brown Unit 1 and Unit 2 arrangement (Alt. 2)



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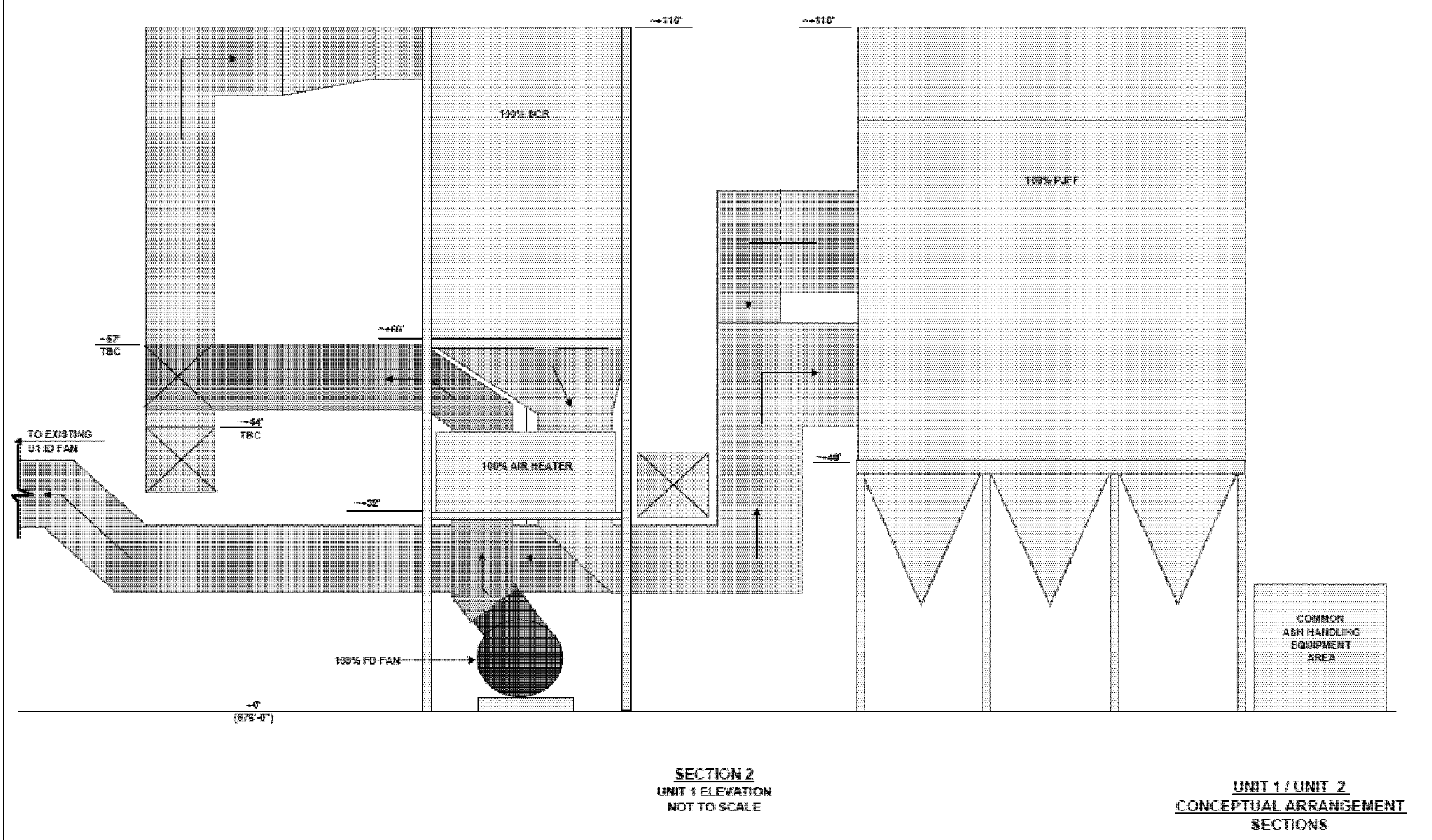
E.W. Brown Unit 1 arrangement (Alt. 2)



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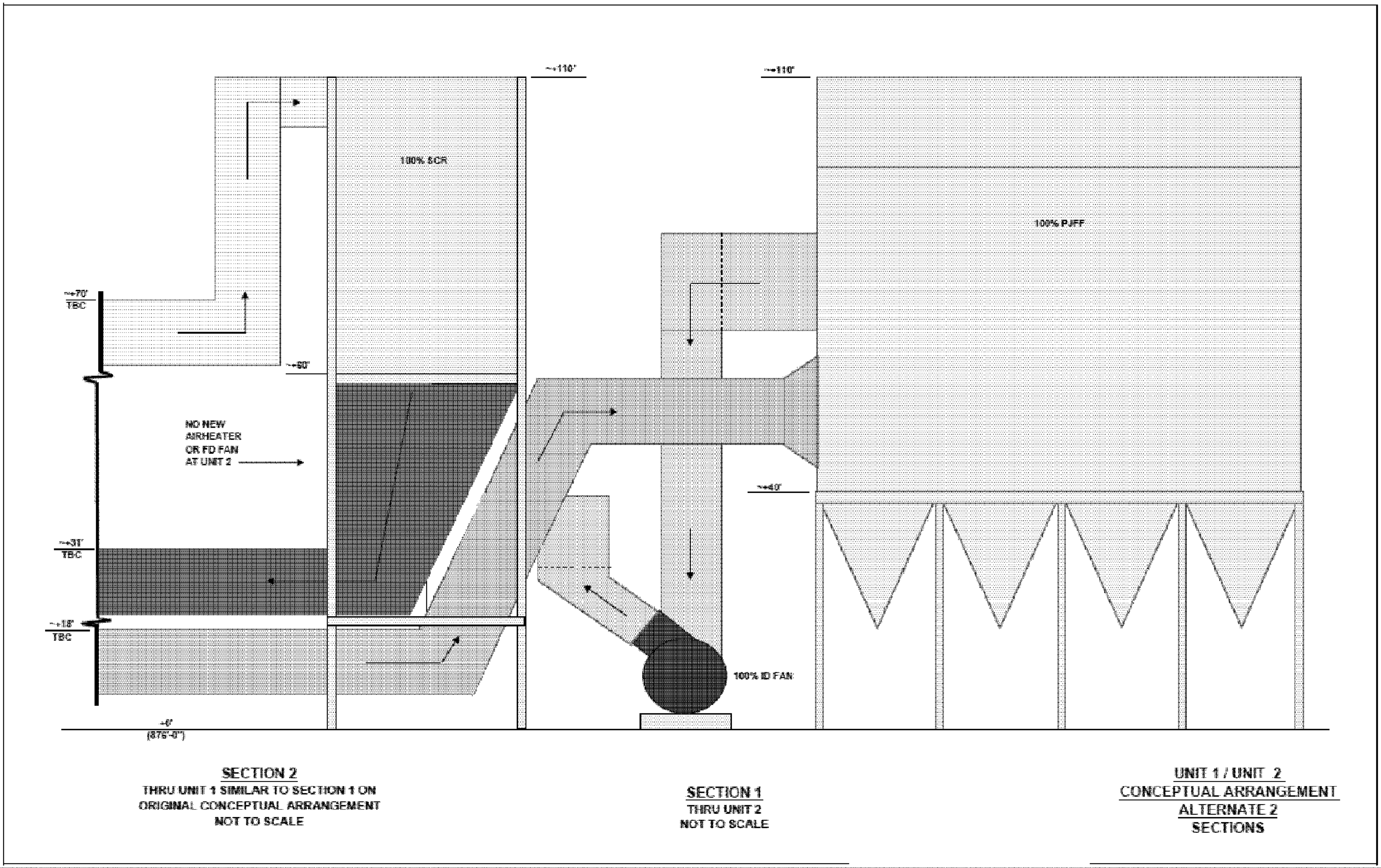
E.W. Brown Unit 2 arrangement (Alt. 2)



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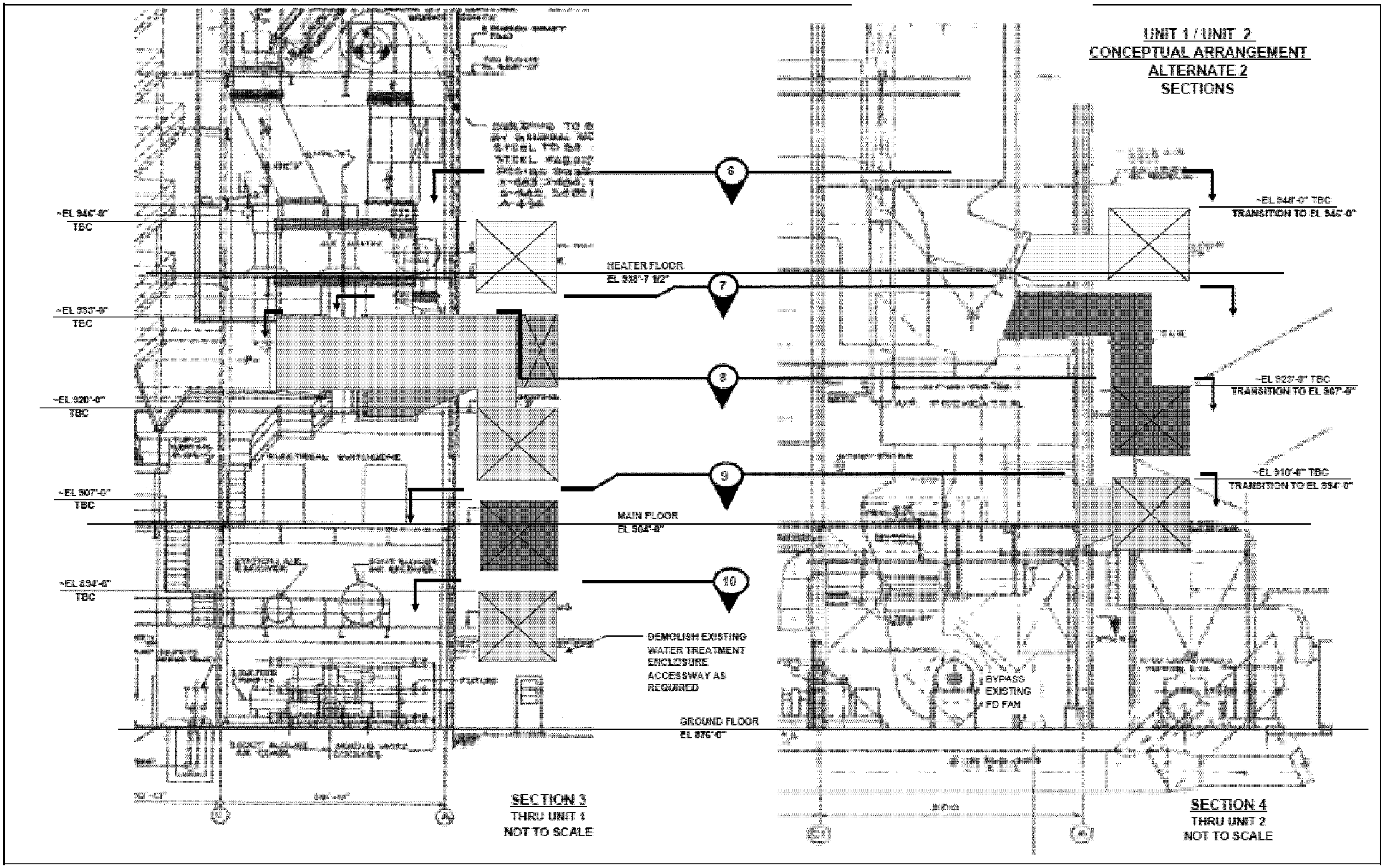
E.W. Brown Unit 1 and Unit 2 duct tie-in (Alt. 2)



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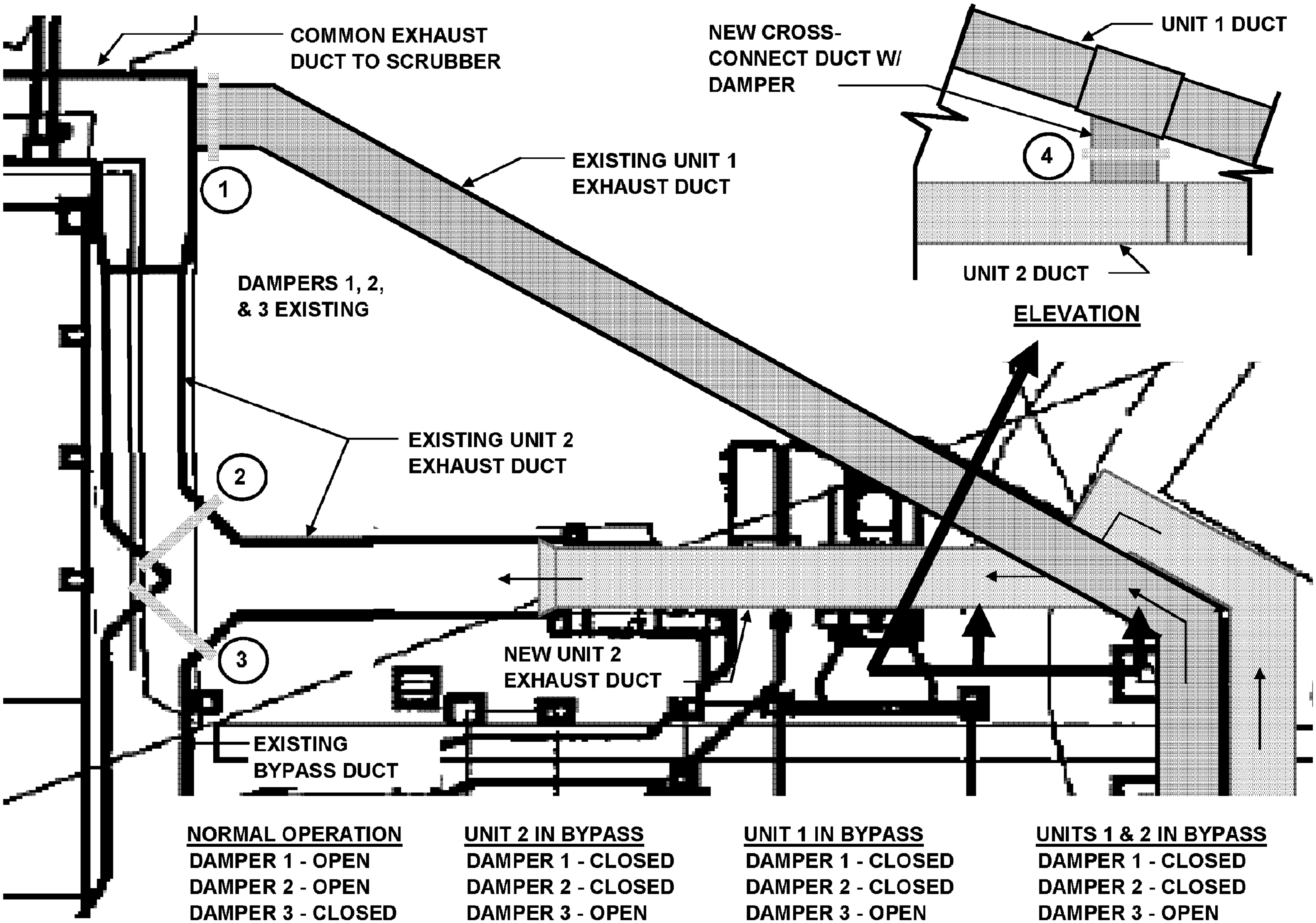
Unit 1 and 2 Bypass Conceptual Sketch



NORMAL OPERATION	UNIT 2 IN BYPASS	UNIT 1 IN BYPASS	UNITS 1 & 2 IN BYPASS
DAMPER 1 - OPEN	DAMPER 1 - CLOSED	DAMPER 1 - CLOSED	DAMPER 1 - CLOSED
DAMPER 2 - OPEN	DAMPER 2 - CLOSED	DAMPER 2 - CLOSED	DAMPER 2 - CLOSED
DAMPER 3 - CLOSED	DAMPER 3 - OPEN	DAMPER 3 - OPEN	DAMPER 3 - OPEN
DAMPER 4 - CLOSED	DAMPER 4 - CLOSED	DAMPER 4 - OPEN	DAMPER 4 - OPEN

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Unit 3
Conceptual Sketch

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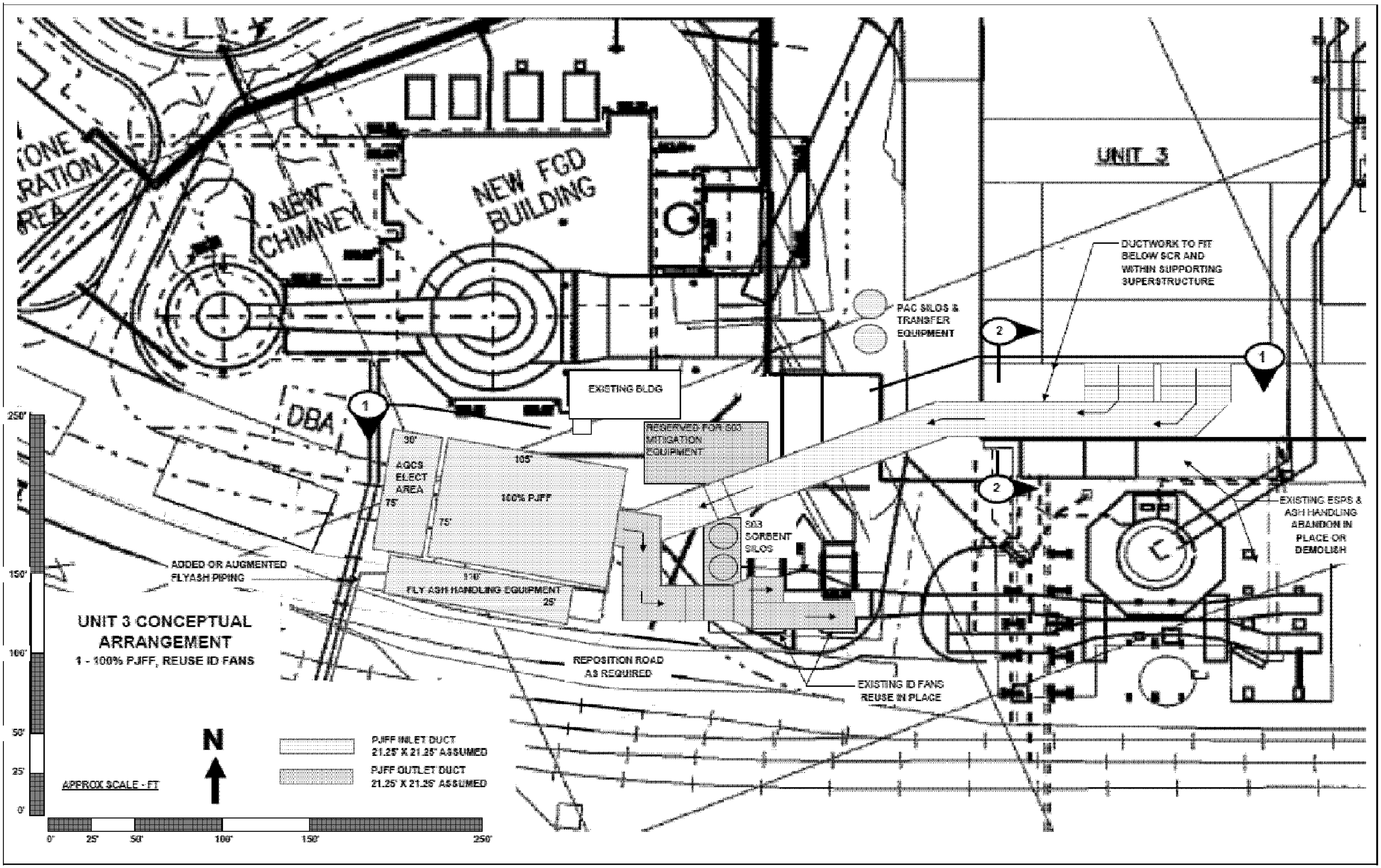
E.W. Brown Unit 3 arrangement



January 25, 2011

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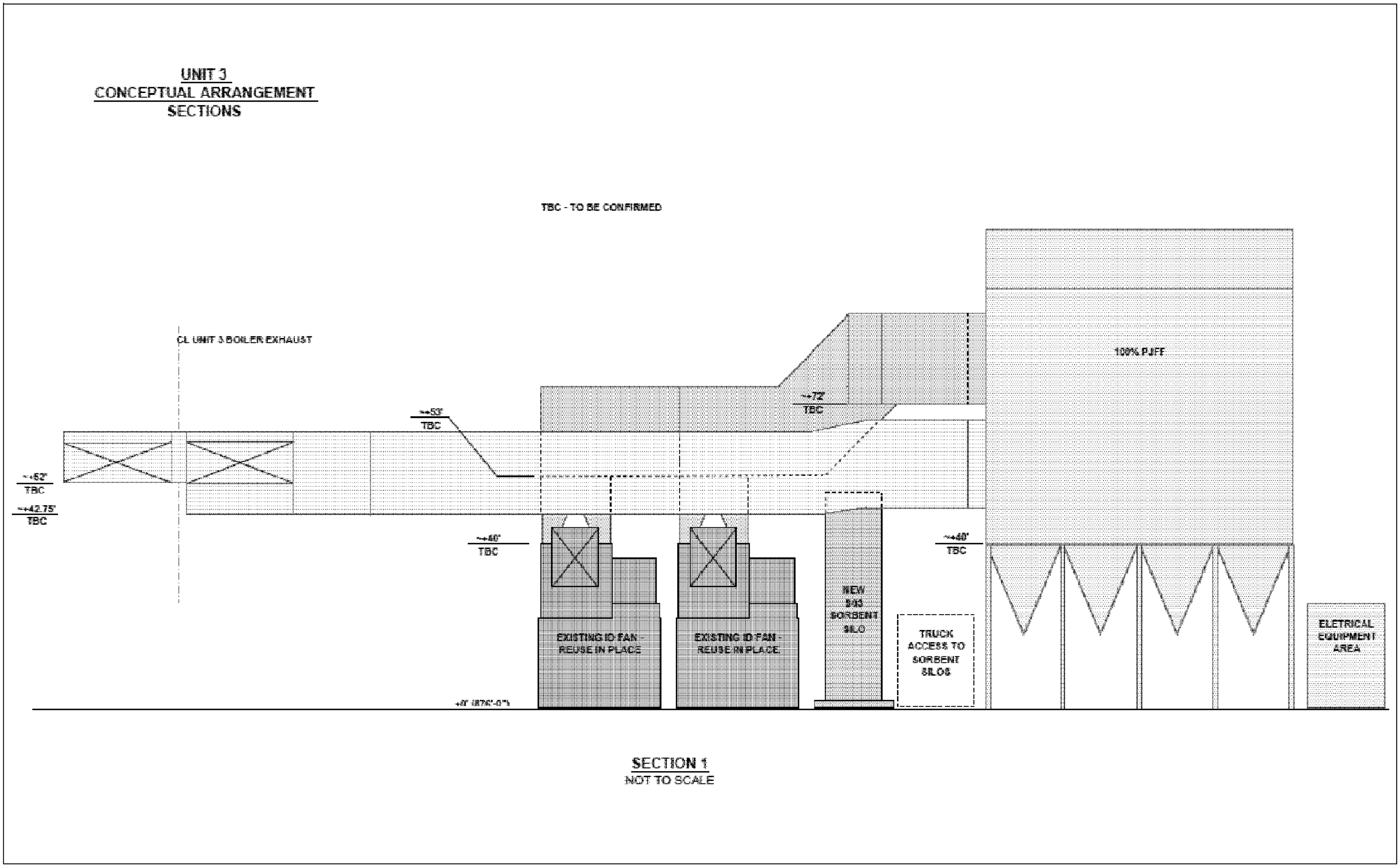
E.W. Brown Unit 3 – PJFF arrangement



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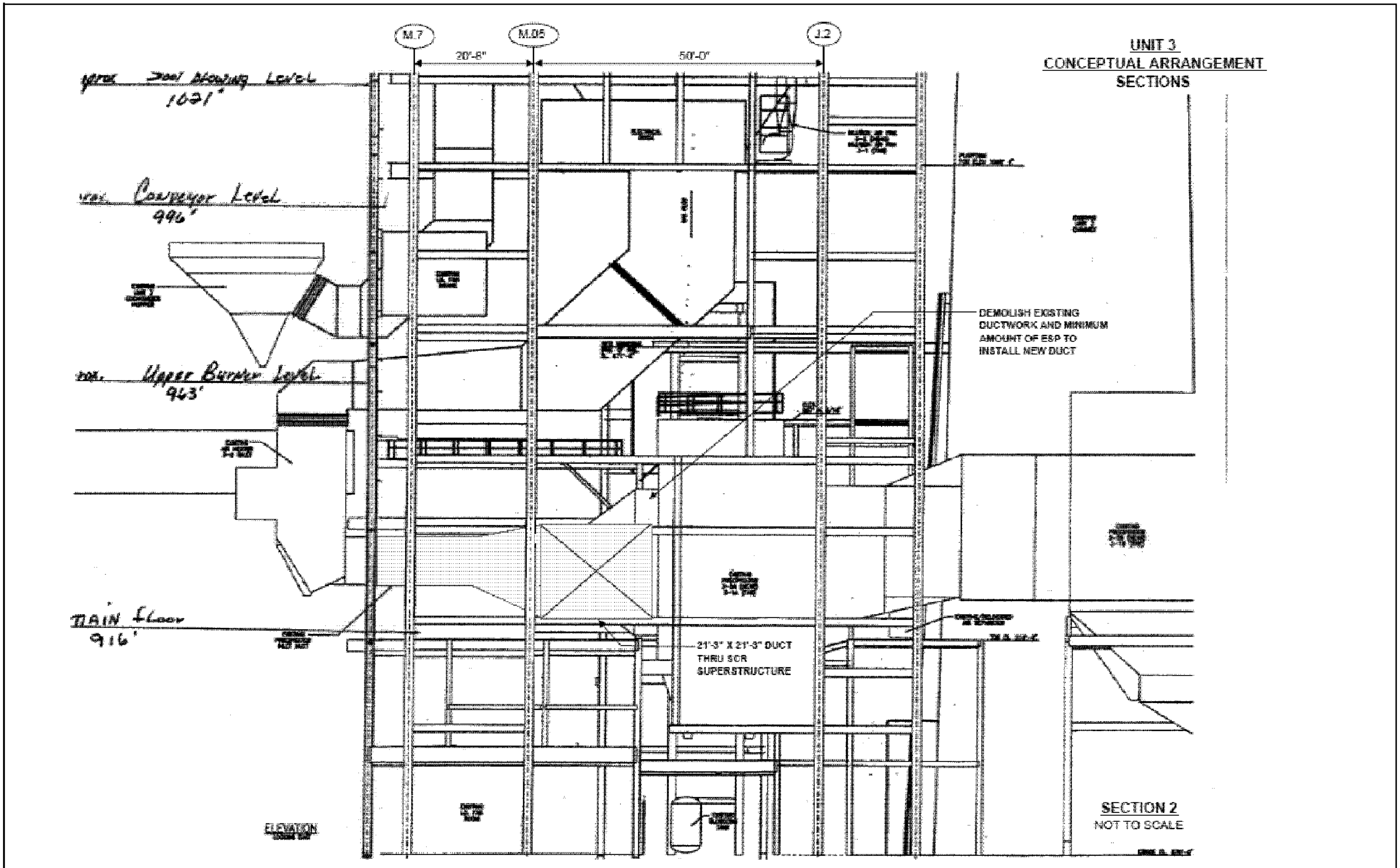
E.W. Brown Unit 3 duct tie-in



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Constructability and Coordination Issues at Unit 3 SCR

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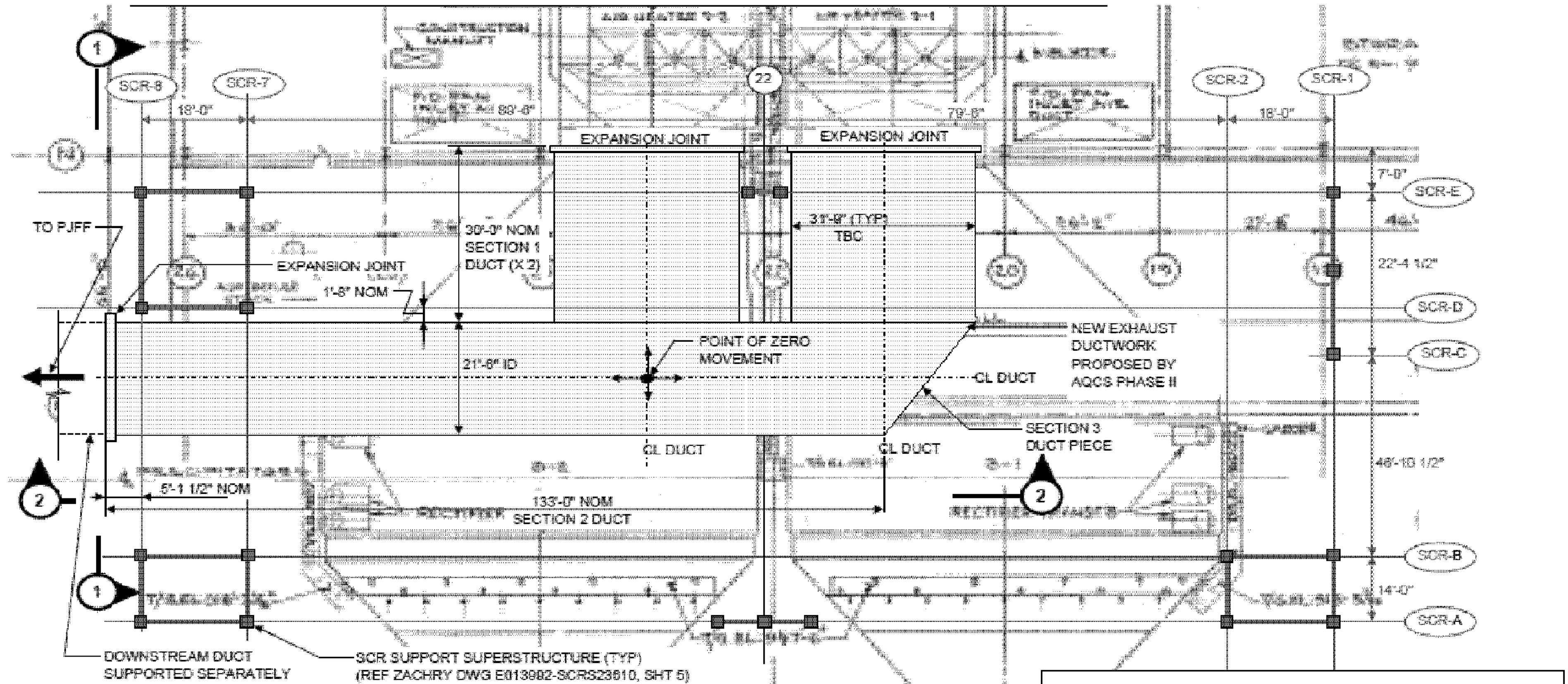
Unit 3 – PJFF Ductwork/SCR interface – Plan



NOTES:

1. THIS DRAWING IS INTENDED TO PROVIDE AN APPROXIMATE ARRANGEMENT AND THE RELATIONSHIP BETWEEN NEW PROPOSED DUCTWORK AND THE SUPPORT SUPERSTRUCTURE CARRYING THE UNIT 3 SCR.
2. THE LOAD SUMMARY APPRXOXIMATES THE GRAVITY LOADS THAT WOULD RESULT ON A STRUCTURE SUPPORTING THE DUCT, BOTH ON A TOTAL AND PER LINEAR FOOT OF LENGTH BASIS.

APPENDIX A

CONCEPTUAL SKETCH 1

DUCTWORK/SCR INTERFACE - PLAN VIEW

LOAD SUMMARY	K PER LF	K TOTAL
SECTION 1 (TYP OF 2)		
DEAD LOAD INCLUDING INSULATION	10.1	305
LIVE/SNOW LOAD	0.6	19
ASH ALLOWANCE LOAD	3.2	95
SECTION 2		
DEAD LOAD INCLUDING INSULATION	18.5	2429
LIVE/SNOW LOAD	0.4	57
ASH ALLOWANCE LOAD	2.2	286
SECTION 3		
DEAD LOAD INCLUDING INSULATION	N/A	45
LIVE/SNOW LOAD	N/A	3
ASH ALLOWANCE LOAD	N/A	17

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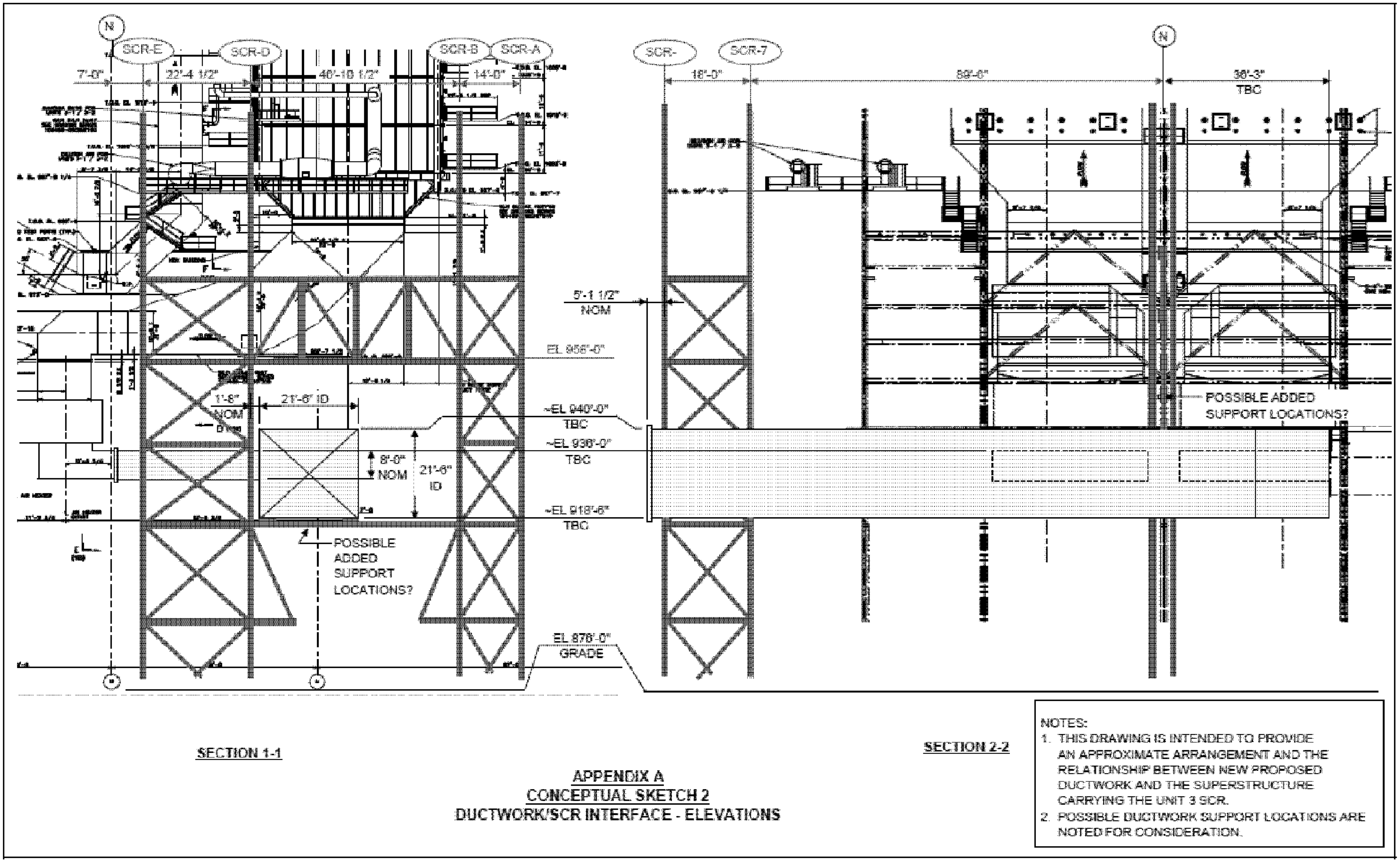
Unit 3 – PJFF Ductwork/SCR interface – Elevation



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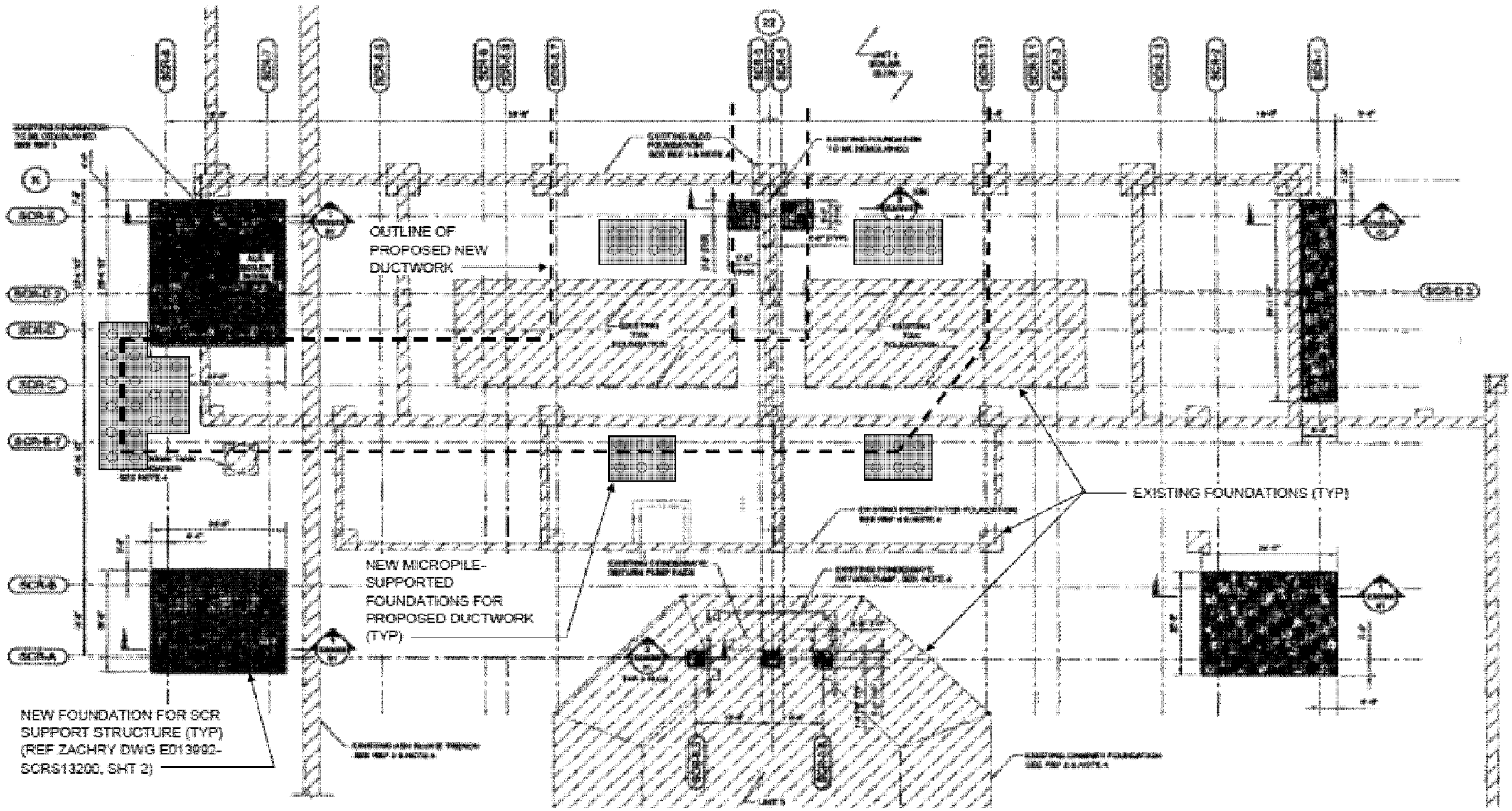
Unit 3 –PJFF Ductwork/SCR interface–Foundations



APPENDIX A
CONCEPTUAL SKETCH 3
DUCTWORK/SCR INTERFACE - FOUNDATIONS

NOTES:
1. THIS DRAWING IS INTENDED TO ILLUSTRATE A CONCEPTUAL RELATIONSHIP BETWEEN EXISTING, SCR, AND DUCTWORK FOUNDATIONS SHOULD THE DUCTWORK NOT BE SUPPORTED BY THE SCR SUPPORT STRUCTURE.

Unit 3 – PJFF Ductwork/SCR interface

- Exhaust ductwork from the Unit 3 air heaters to the new PJFF may be successfully routed beneath the planned SCR and through the supporting structure beneath
- Existing ESP immediately south of the Unit 3 Boiler Building will have to be demolished before the ductwork can be installed.
- Supporting the new ductwork from the structure planned for supporting the SCR will require further investigation.
- Basis for cost estimate will be separate support systems for PJFF ductwork.

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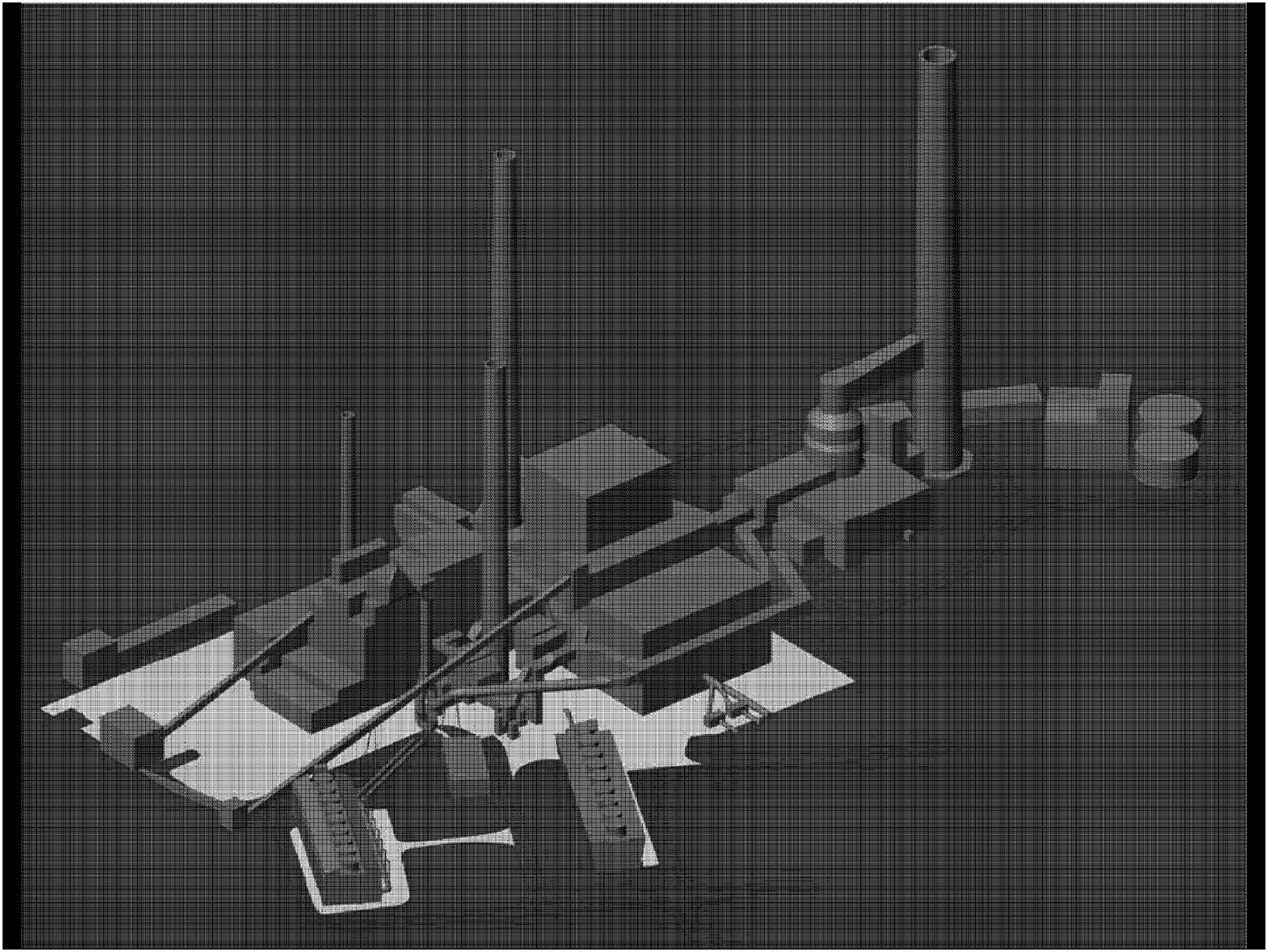
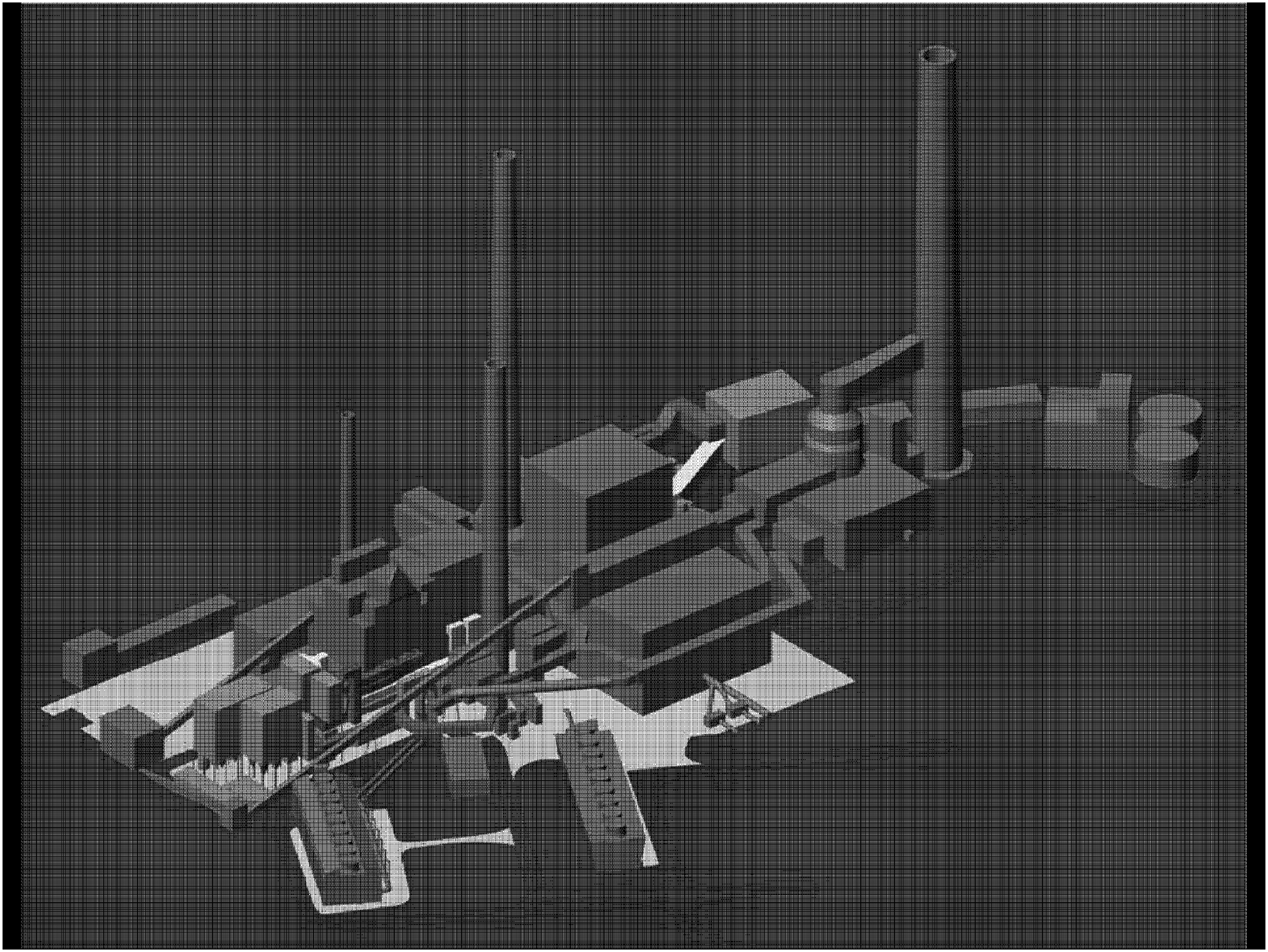
3-D Models Overview: Before and After





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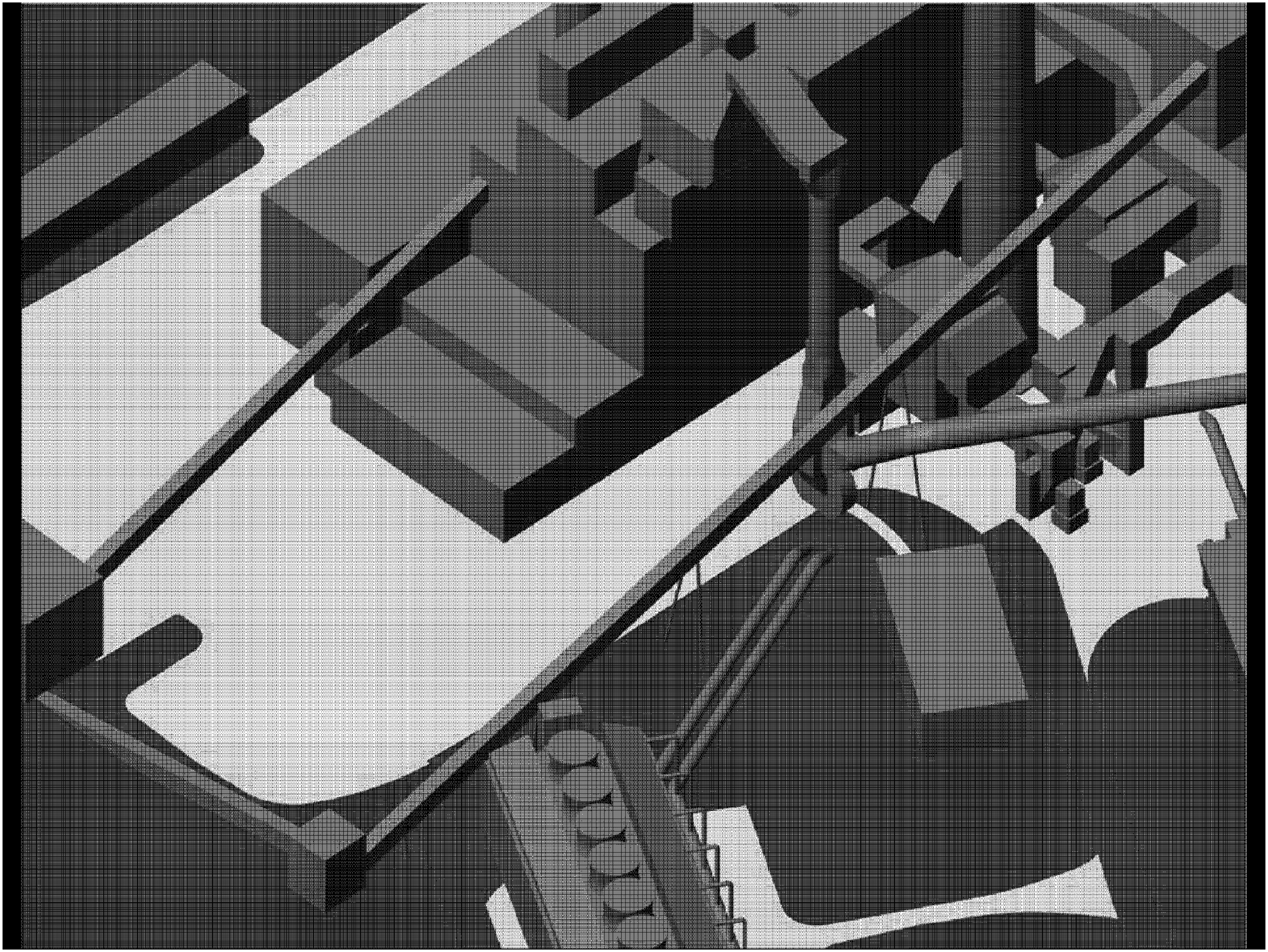
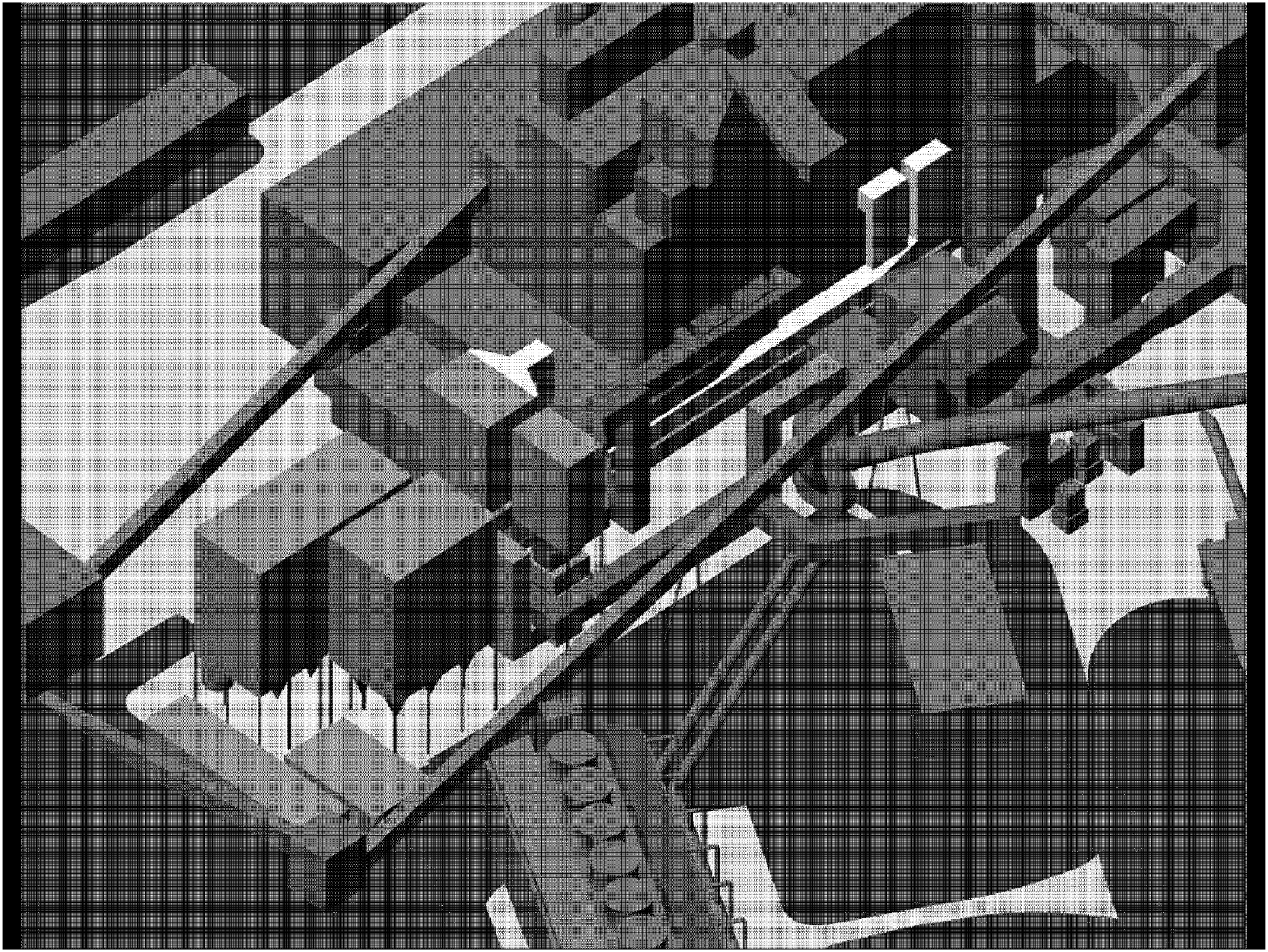
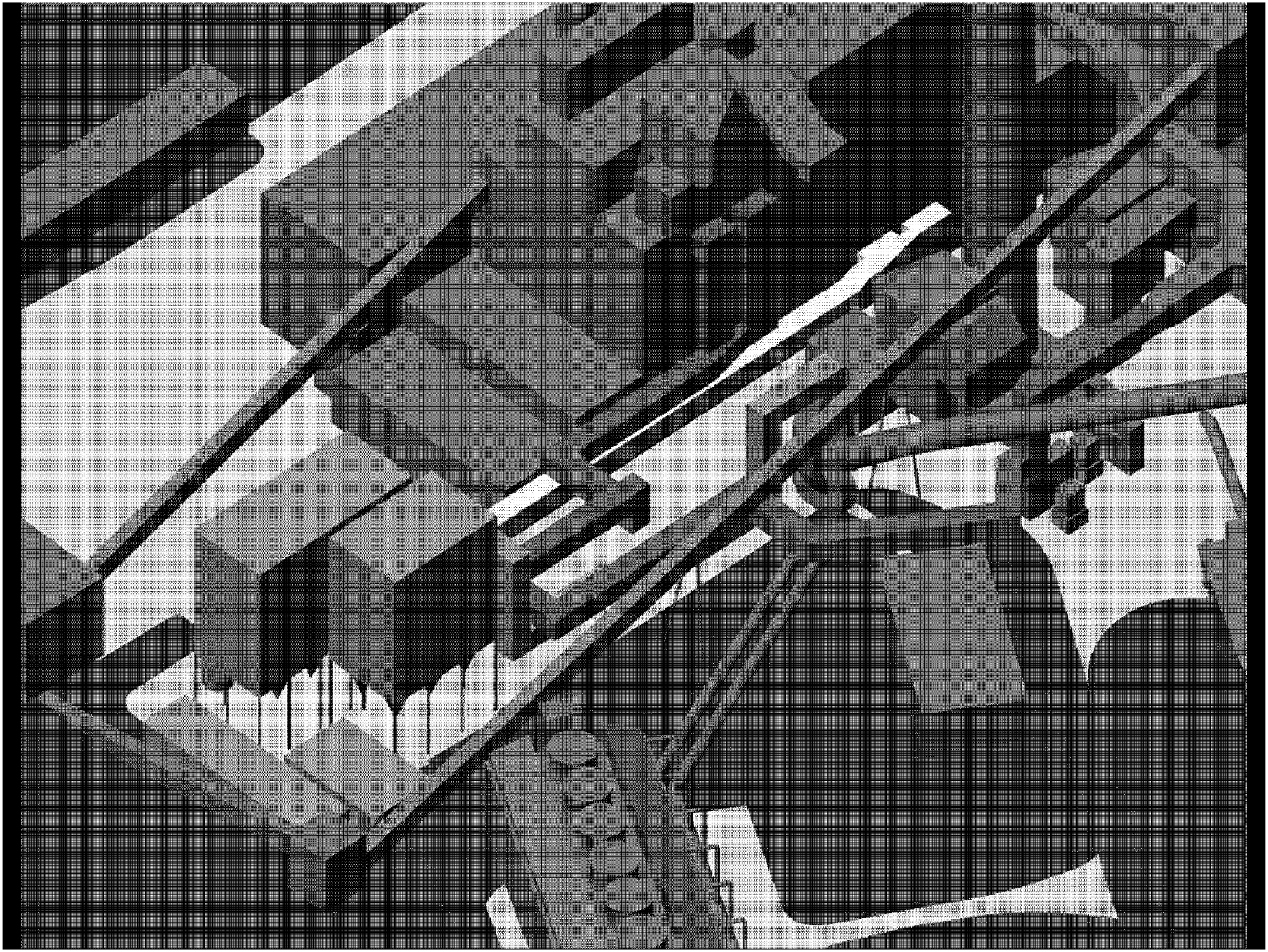
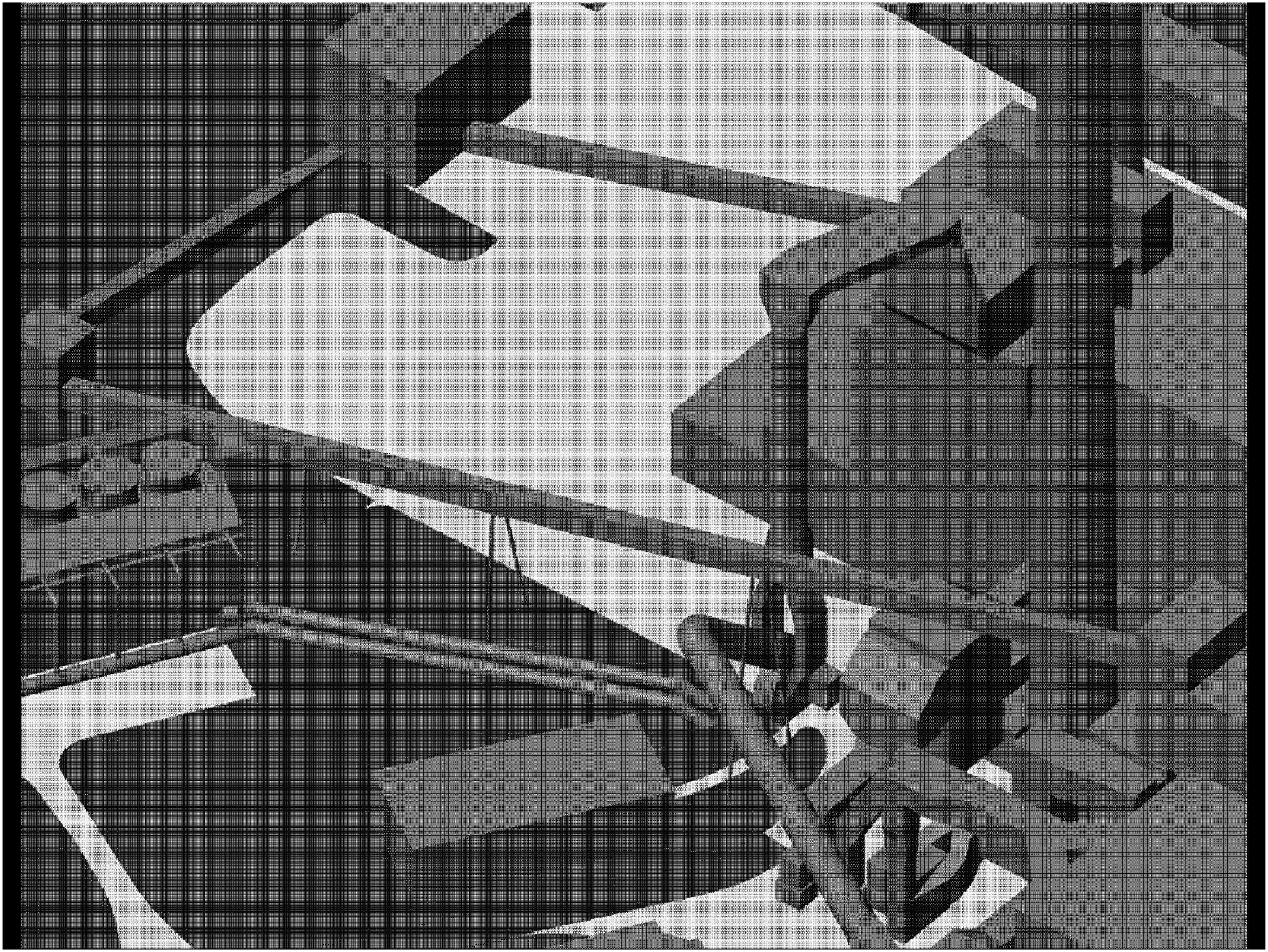
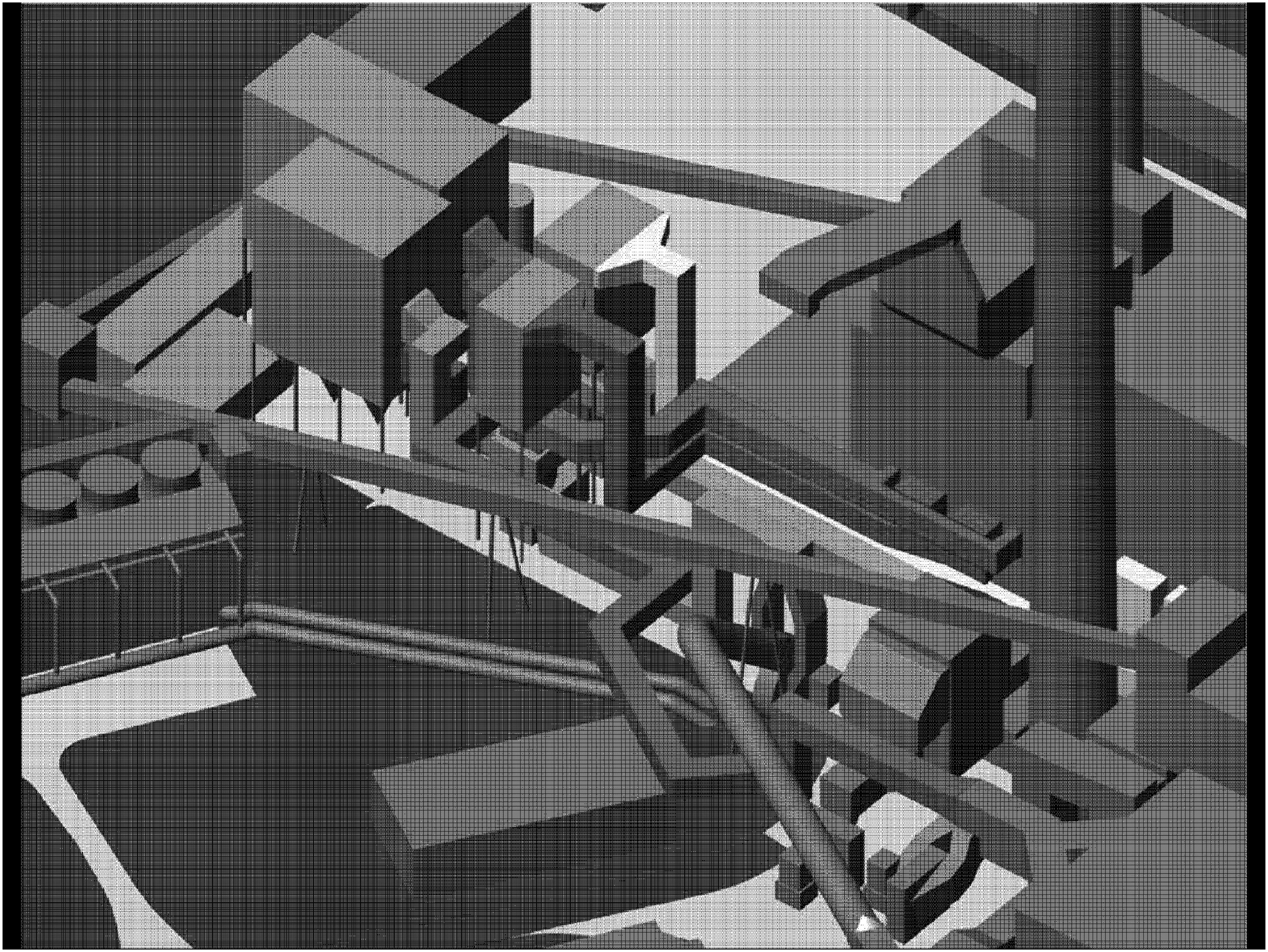
Units 1 and 2
3-D Model

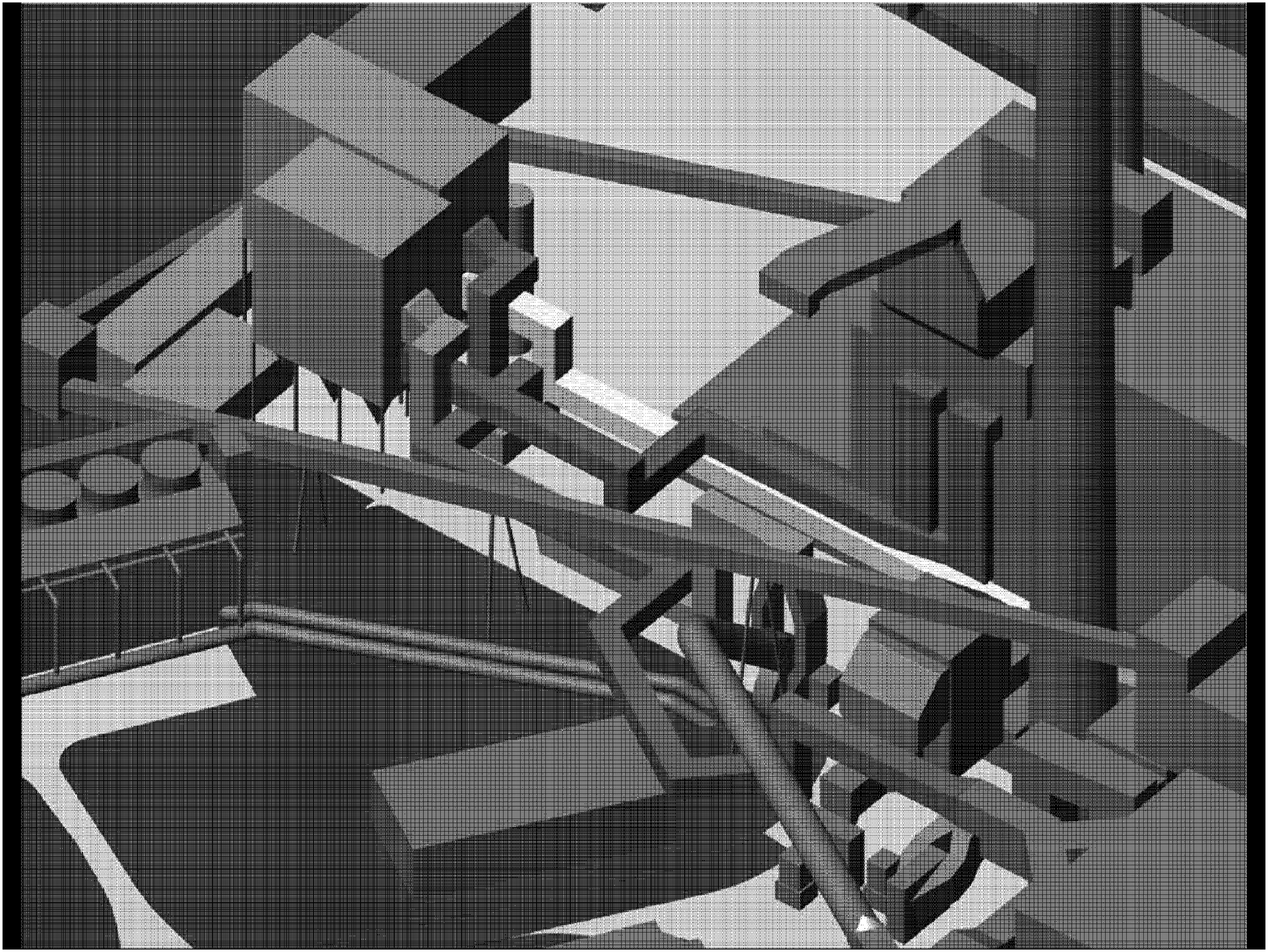


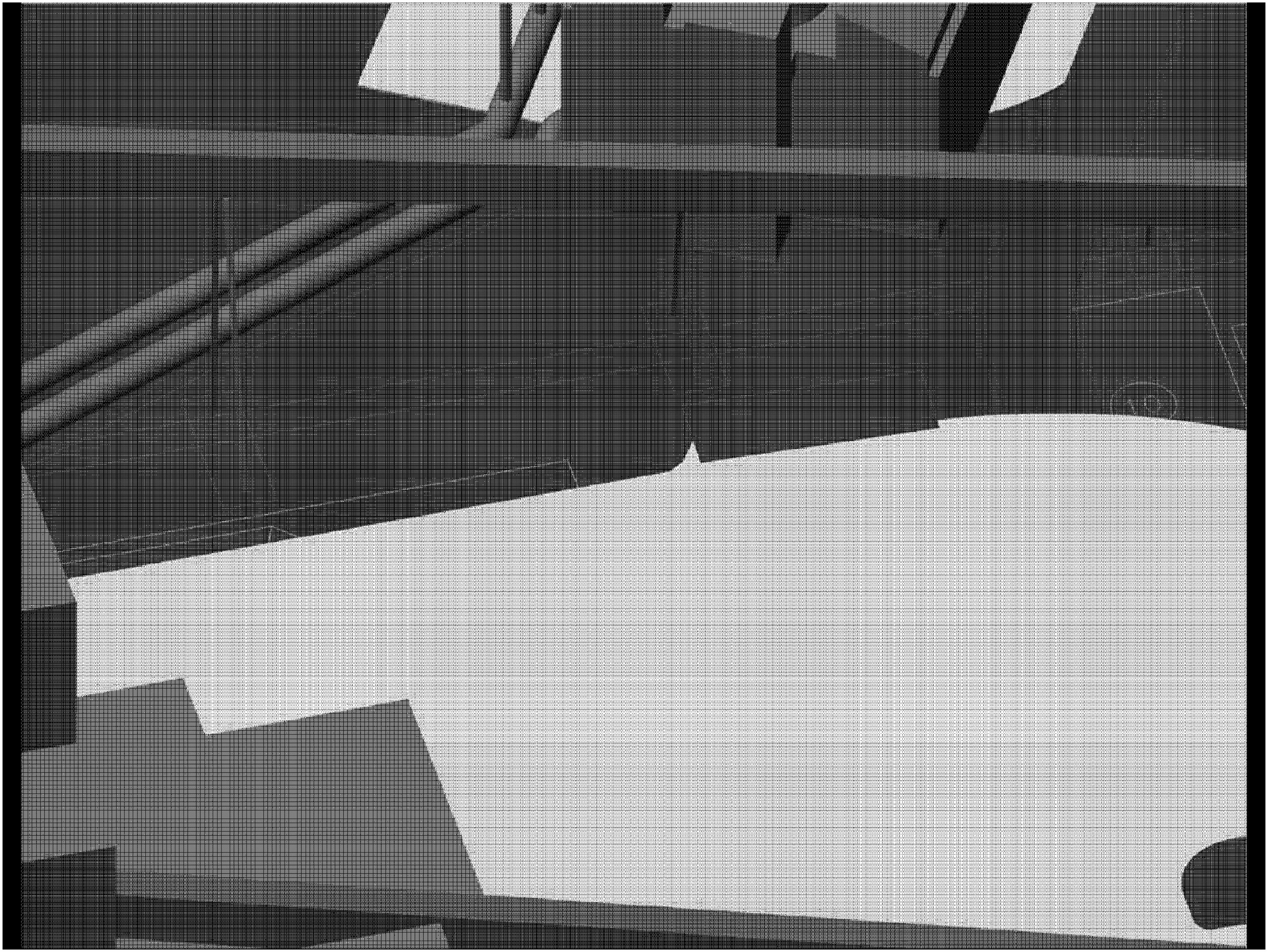


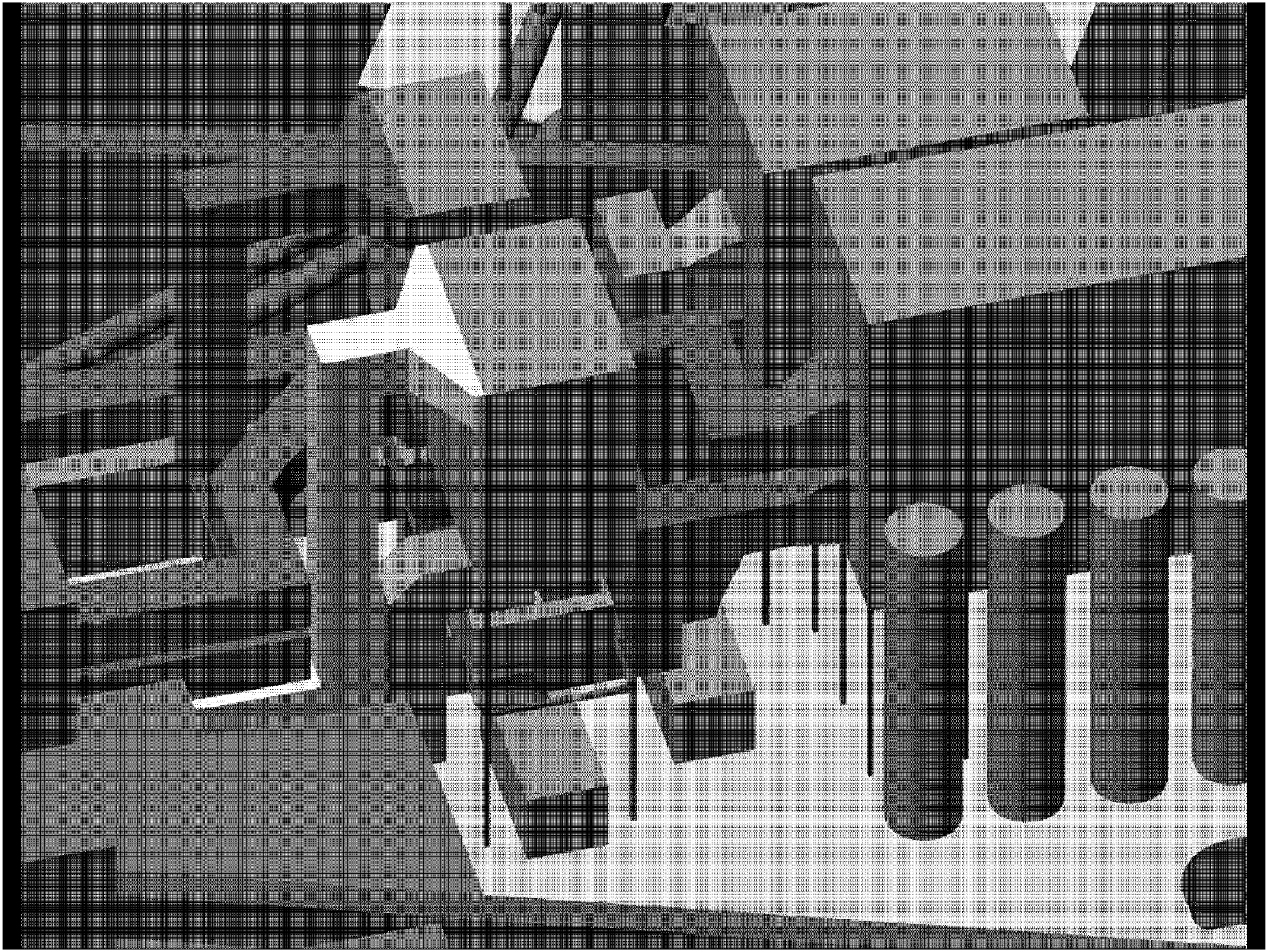


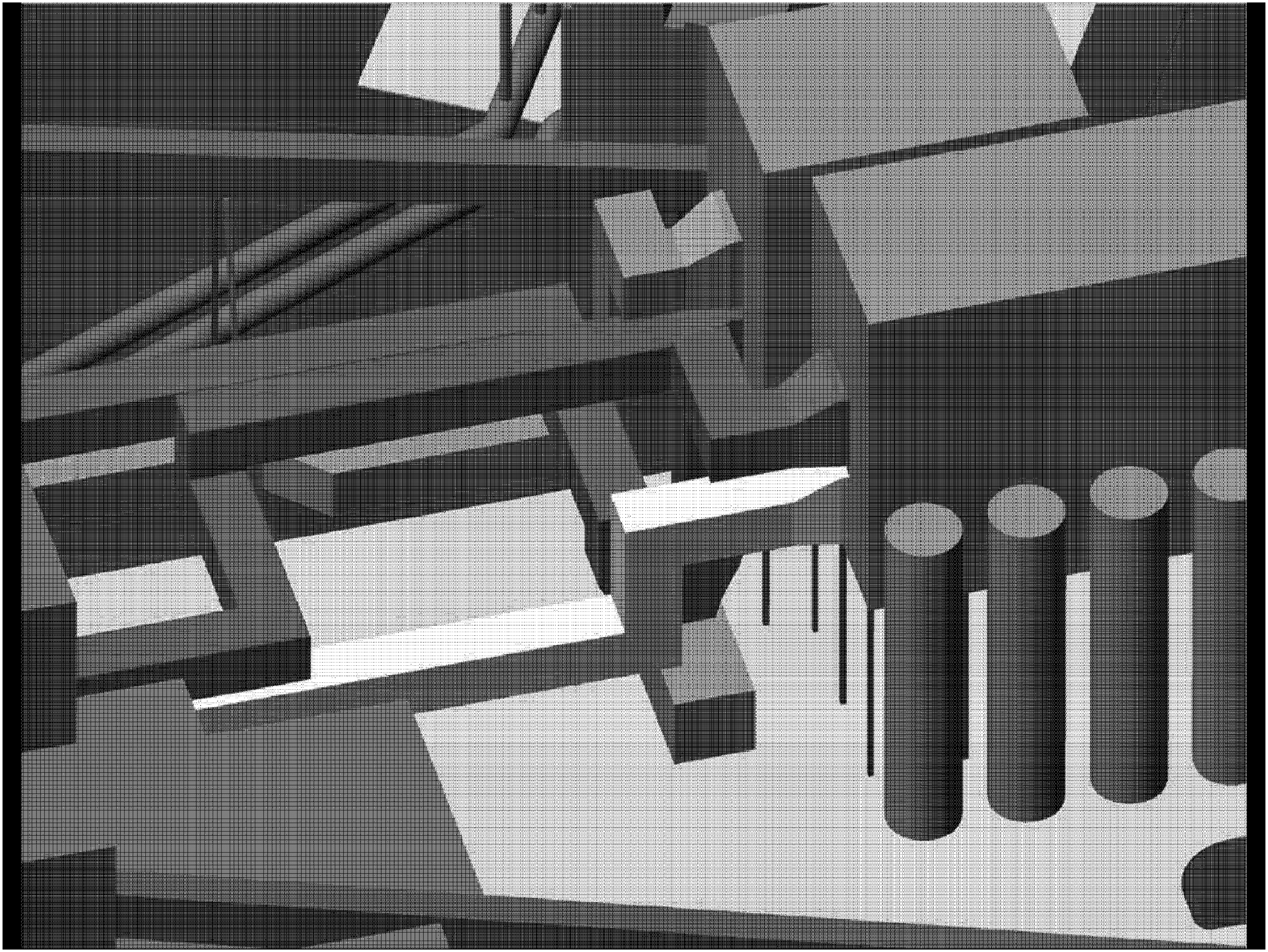












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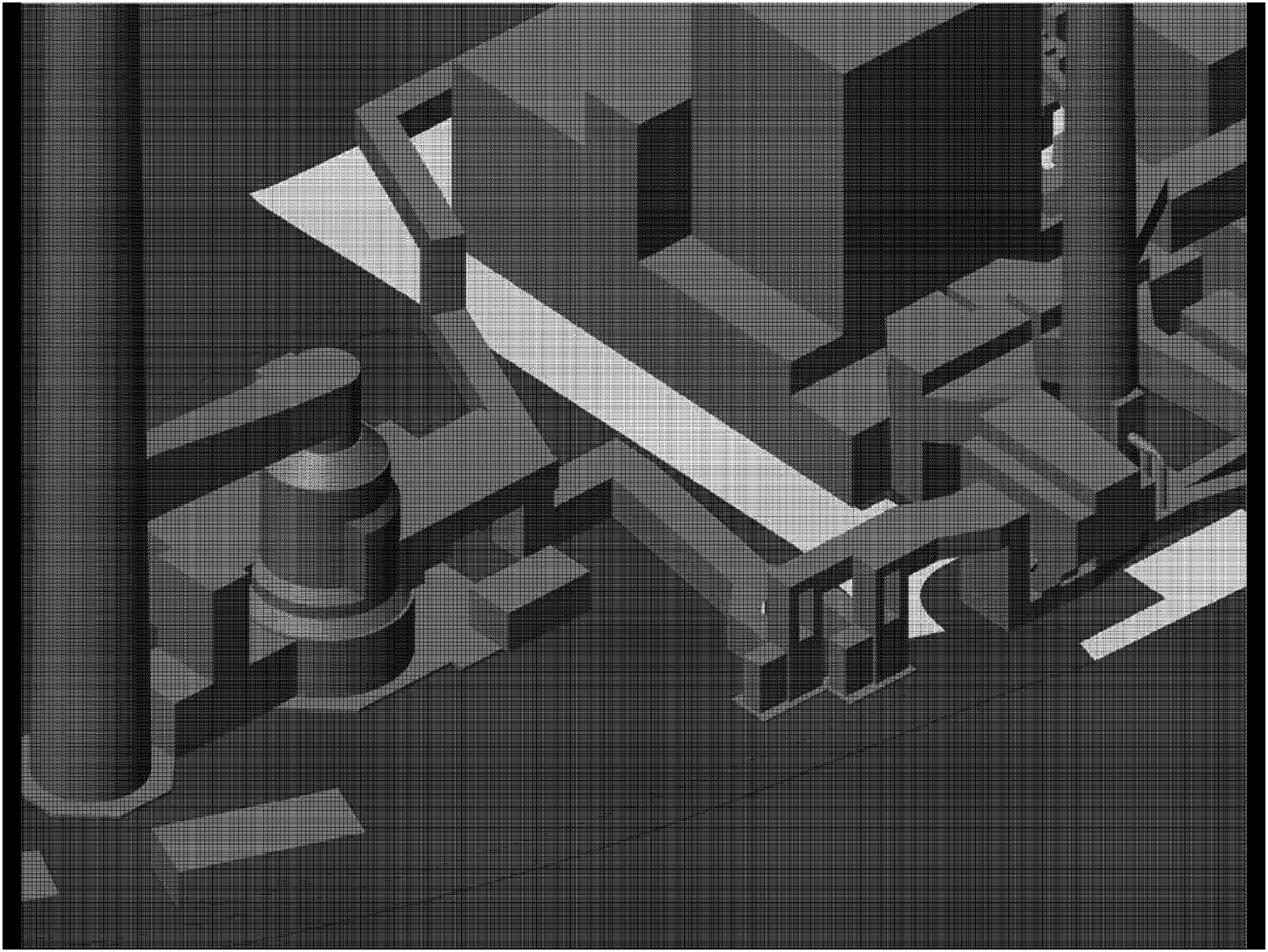
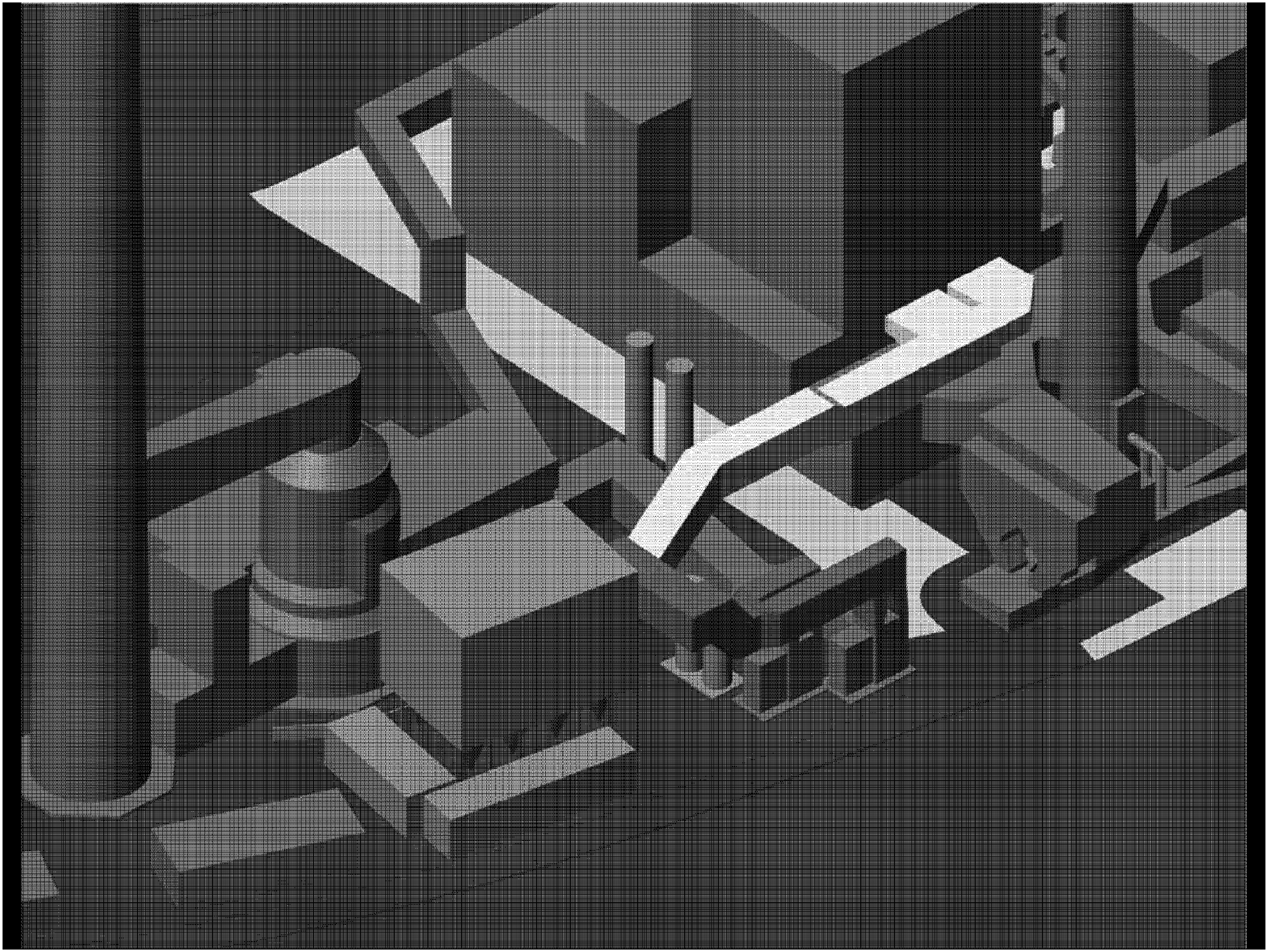
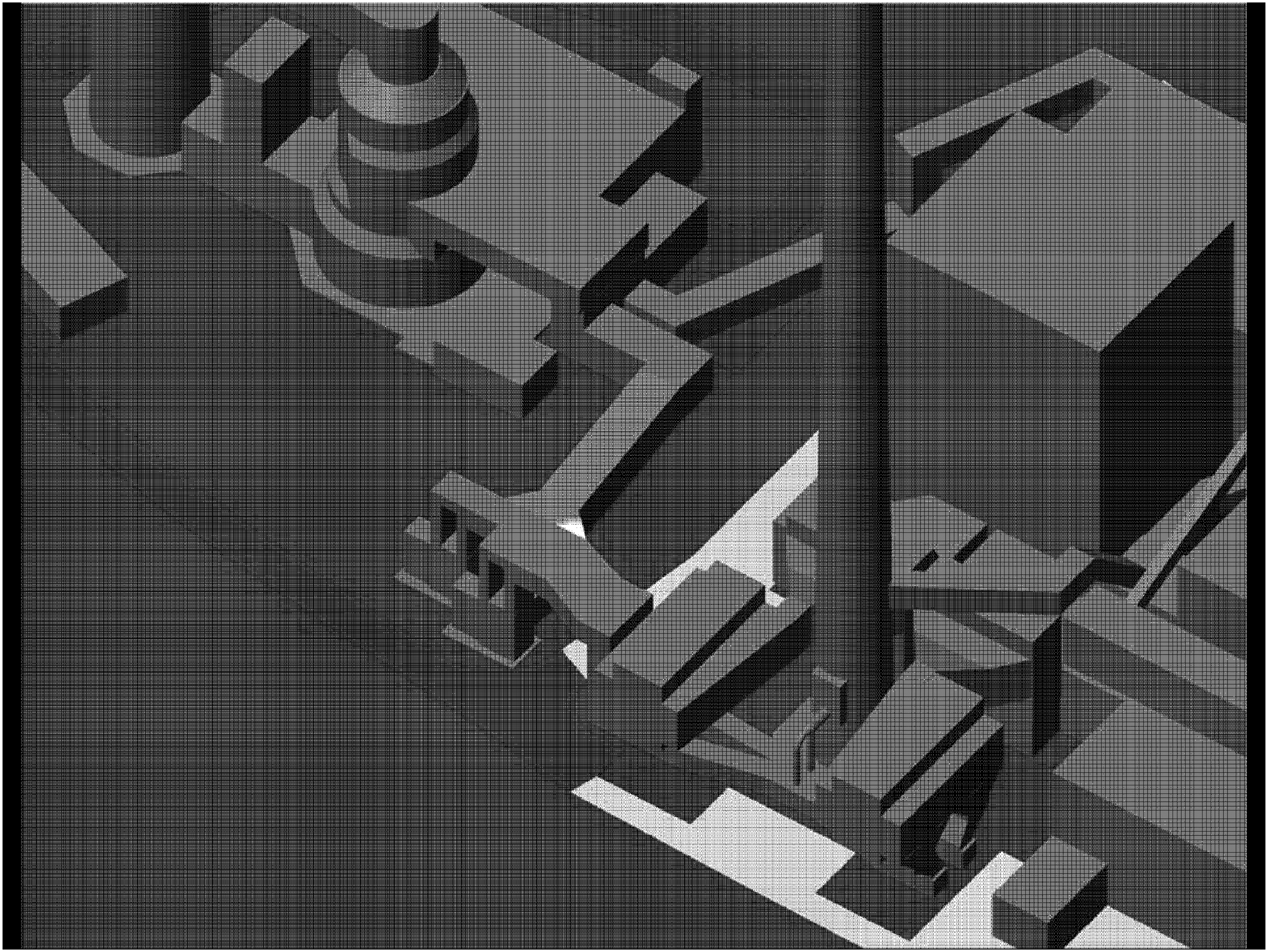
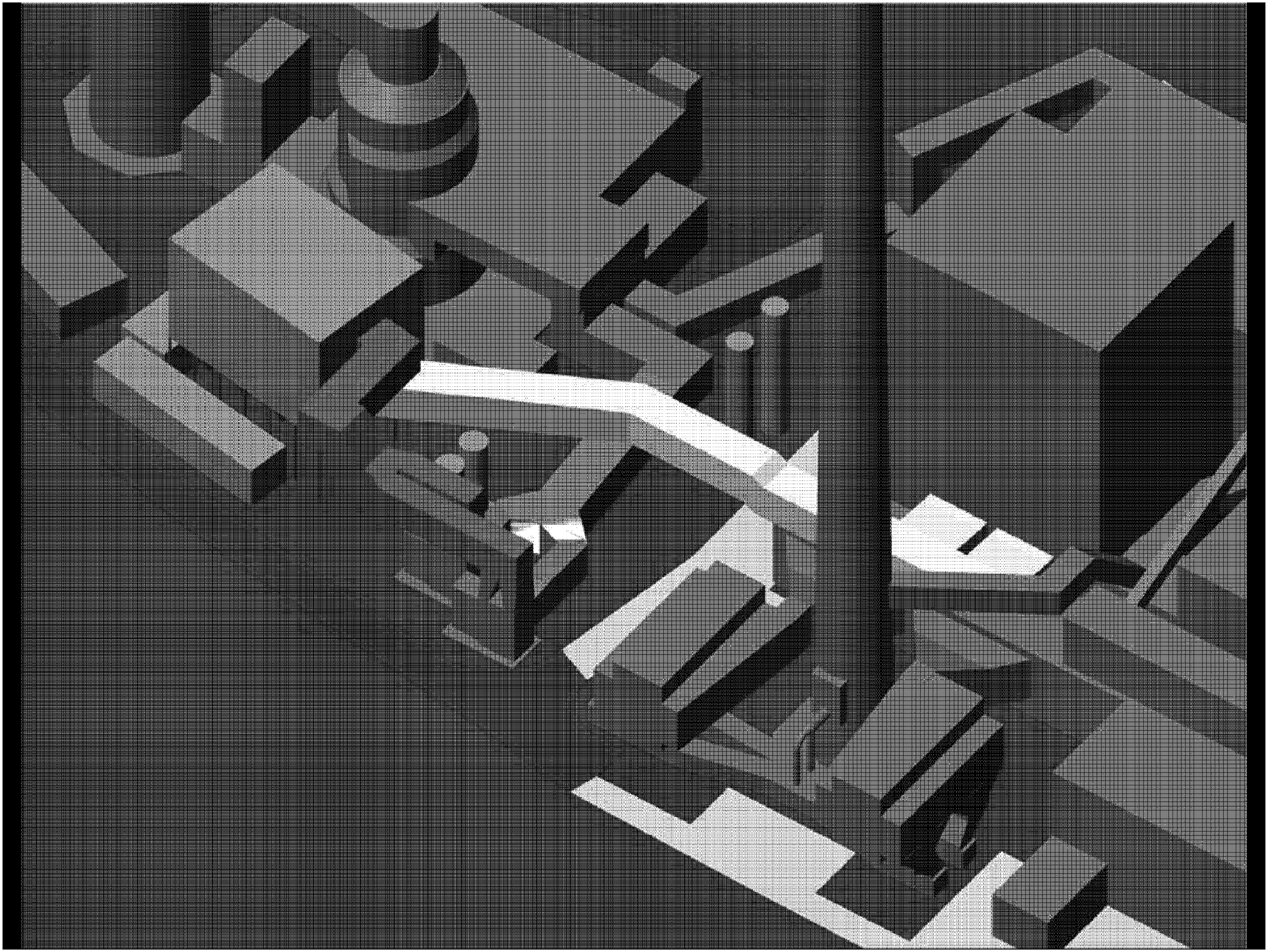
Unit 3
3-D Model









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Summary / Wrap-up and Discussions

LG&E/KU – E.W. Brown Station

Phase II Air Quality Control Study

Air Quality Control Validation Report

January 19, 2011
Revision B – Issued For Client Review

B&V File Number 41.0803

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Acronym List

AQC	Air Quality Control
As	Arsenic
Be	Beryllium
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
Cd	Cadmium
Co	Cobalt
Cr	Chromium
CS-DESP	Cold-side Dry Electrostatic Precipitator
CS-ESP	Cold-side Electrostatic Precipitator
DCS	Distributed Control System
DOE	Department of Energy
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FA	Fly Ash
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
Hg	Mercury
ID	Induced Draft
inw	Inch of Water
LNB	Low NO_x Burners
LOI	Loss On Ignition
LV	Low Voltage
MACT	Maximum Achievable Control Technology
MBtu	Million British Thermal Unit
MCC	Motor Control Center
Mn	Manganese
MSW	Municipal Solid Waste
MV	Medium Voltage
MWC	Medical Waste Combustors
NAAQS	National Ambient Air Quality Standard
NFPA	National Fire Protection Association
Ni	Nickel
NN	Neural Network

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NO_x	Nitrogen Oxides
OFA	Overfire Air
PAC	Powdered Activated Carbon
Pb	Lead
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
RAT	Reserve Auxiliary Transformer
RGFF	Reverse Gas Fabric Filters
SAM	Sulfuric Acid Mist
Sb	Antimony
SBS	Sodium Bisulfite
SCR	Selective Catalytic Reduction
Se	Selenium
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
UAT	Unit Auxiliary Transformer
USS	Unit Secondary Substation
WFGD	Wet Flue Gas Desulfurization

1.0 Introduction

Following the submittal of the Phase I report on July 8, 2010, Black & Veatch developed scope to further define facility technology options based on the Phase I report. The purpose of this Phase II air quality control (AQC) validation study is to build upon the previous fleet-wide, high-level air quality technology review and cost assessment conducted for six LG&E/KU facilities (Phase I) in order to develop a facility-specific project definition consisting of a conceptual design and a budgetary cost estimate for selected AQC technologies (Phase II) for the E.W. Brown Generating Station (Brown). The following AQC technology options have been assessed in this report:

- PJFF on Units 1-3.
- Sorbent injection (trona/lime/SBS) injection on Units 1-2.
- SCR on Unit 1 and 2.
- Powdered activated carbon (PAC) injection on Units 1-3.
- Feasibility of neural network (NN) on Units 1-3.

This validation study confirms the feasibility of installing the aforementioned AQC equipment at Brown, and presents the supporting considerations, arrangements, and preliminary validating analyses of the AQC equipment that will be built upon in the next step of this project to complete the conceptual design and budgetary cost estimate.

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2.0 Facility Description

2.1 Brown - Units 1, 2, and 3

The E.W. Brown Station is located on Herrington Lake in Mercer County, Kentucky, between Shakertown and Burgin, off of Hwy 33. The station was constructed on the west side of Herrington Lake, the impoundment behind Dix Dam. The plant began commercial operation in 1957. The station includes three pulverized coal fired electric generating units with a total nameplate capacity of 747 MW gross. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems.

The plant site also includes seven simple cycle combustion turbines located on the northwest side of the site.

All three steam generators (boilers) fire high sulfur bituminous coal. Unit 1 has a gross capacity of 110 MW and is equipped with old generation Low NO_x Burners (LNBs) and Cold-side Dry Electrostatic Precipitator (CS-DESP) for nitrogen oxide (NO_x) and particulate matter (PM) control, respectively. Unit 2 has a gross capacity of 180 MW and is equipped with LNBs, Overfire Air (OFA), and CS-DESP for NO_x and PM control. Unit 3 has a gross capacity of 457 MW and is equipped with LNBs, OFA, and CS-DESP for NO_x and PM control. LG&E/KU is in the process of installing a Selective Catalytic Reduction (SCR) module (in-service date, 2012) on Unit 3 to control NO_x. LG&E/KU recently installed a common Wet Flue Gas Desulfurization (WFGD) for sulfur dioxide (SO_2) control for Units 1, 2, and 3. Unit 2 is also equipped with a WFGD bypass system which directs flue gas to the Unit 3 chimney. Lower sulfur coal will be fired in Unit 2 during bypass operation.

Gypsum, a scrubber by-product, produced at Brown is stored in the on-site landfill. Fly ash and bottom ash is sluiced to on-site storage pond. All three units are cooled using mechanical draft cooling towers. Arrangements developed for the Unit 3 SCR will be taken into account during the Phase II Air Quality Control Study.

Figures 2-1 and 2-2 illustrate the plant location and Table 2-1 summarizes the plant's existing facilities.

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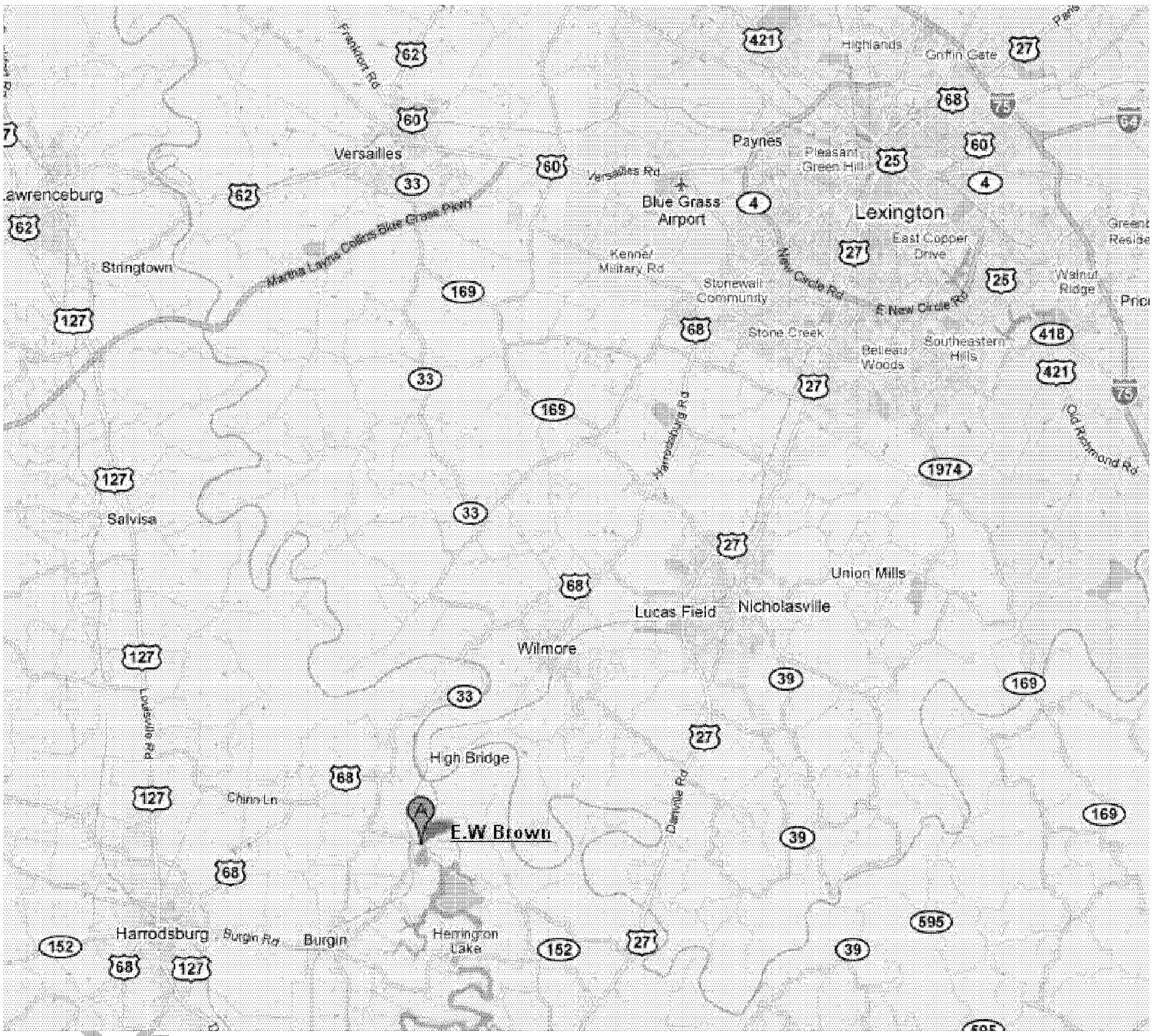
NORTH

SOUTH

Figure 2-1. Brown Power Plant Site

NORTH



SOUTH

Figure 2-2. Brown and Surrounding Area Map

Table 2-1. Existing Brown Plant Facilities	
Existing On Site Generation Units:	• Unit 1 - 110 gross MW (in-service date 1957) • Unit 2 - 180 gross MW (in-service date 1963) • Unit 3 - 457 gross MW (in-service date 1969)
Existing AQC Equipment:	• Unit 1 - LNBs, CS-DESP, Common WFGD with Units 2 and 3 • Unit 2 - LNBs, OFA System, CS-DESP, Common WFGD with Units 1 and 3 • Unit 3 - LNBs, OFA, CS-DESP, Common WFGD with Units 1 and 2, and Future SCR (in-service date, 2012)

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3.0 Emission Target Basis

LG&E/KU provided a matrix of estimated requirements under current and future environmental regulations, as well as a summary implementation schedule of regulatory programs. Table 3-1 summarizes the future pollution emission targets provided by LG&E/KU for each unit.

The current regulatory drivers include the NO_2 and SO_2 National Ambient Air Quality Standard (NAAQS). On January 22, 2010, the Environmental Protection Agency (EPA) announced a new 1-hour NO_2 NAAQS of 100 ppb. The final rule for the new hourly NAAQS was published in the Federal Register on February 9, 2010, and the standard became effective on April 12, 2010. Likewise, on June 2, 2010, EPA strengthened the primary SO_2 NAAQS. EPA established a new 1-hour standard at a level of 75 ppb and revoked the existing 24-hour and annual standards.

The potential impact of future regulations is the primary driver for both the timing and extent of environmental controls planned at the LG&E/KU plants. Among the regulatory drivers are the Utility Maximum Achievable Control Technology (MACT), and the Clean Air Transport Rule (CATR) -- Clean Air Interstate Rule (CAIR) replacement to be proposed by the United States EPA by spring 2011 and summer 2011, respectively.

From this information, LG&E/KU developed specific pollutant emission limit targets with the intent that the limits would be applied to each unit individually to assess current compliance and the potential for additional AQC equipment. These regulatory drivers and their associated emission levels serve as the primary basis used by Black & Veatch to develop unit-by-unit AQC technology recommendations. For the purposes of this study, compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) were not considered.

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Table 3-1. Primary Design Emission Targets

Pollutant	Unit 1	Unit 2	Unit 3
NO_x	0.156 lb/MBtu[c]	0.156 lb/MBtu[c]	N/A[b]
SO_2	N/A[b]	N/A[b]	N/A[b]
Sulfuric Acid Mist (SAM)	2-10 ppm[a] TBD	2-10 ppm[a] TBD	2-10 ppm[a] TBD
Mercury (Hg)	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh
Hydrogen Chloride (HCl)	0.002 lb/MBtu	0.002 lb/MBtu	0.002 lb/MBtu
PM[c],[d]	0.03[c] lb/MBtu	0.03[c] lb/MBtu	0.03[c] lb/MBtu
Arsenic (As) [e]	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu
CO	0.10 lb/MBtu	0.10 lb/MBtu	0.10 lb/MBtu
Dioxin/Furan	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu

Data from LG&E/KU E.W Brown Station kickoff meeting November 10, 2010 (Gary Revlett handouts and meeting notes) unless noted otherwise.

(a) Units provided in ppmvd at 3% O_2 Control of sulfuric acid (H_2SO_4) emission from the installation of new Unit 1 and 2 SCRs and the Unit 3 SCR currently in design.

(b) Not applicable for this Phase II study.

(c) Emission rate target is higher than what can typically be achieved with chosen technology; a lower emission target may be possible.

(d) Particulate matter control limits for $PM_{2.5}$ or $PM_{condensable}$ have not been determined for this project.

(e) Particulate matter assumed to be the surrogate for emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)).

(f) Arsenic assumed to be the surrogate for non-mercury metallic HAP (i.e., As, chromium (Cr), and selenium (Se)).

4.0 Site Visit Summary

The following section describes the existing site conditions and site visit observations for the Brown Generating Station.

4.1 Site Visit Observations and AQC

The following observations are from the November 10-11 2010 site visit and summarize the site and equipment constraints. The following excerpts are from the site visit meeting minutes and focus specifically on the installation of specified AQC equipment.

- For the purpose of the Phase II cost estimate, B&V should assume that SCRs are required on Units 1 and 2.
- B&V to consider re-using the recently installed induced draft (ID) fan on Unit 1.
- The sulfur trioxide (SO_3) mitigation silos are currently planned to be located in the same general area as the proposed future Unit 3 PJFF. B&V to take the drawings from the SO_3 mitigation project into consideration.
- Air heater temperature control and leakage are current issues at Unit 1.
- LG&E/KU wants to keep the ability to bypass the WFGD on Unit 2, and add the same capability for a Unit 1 bypass with the future AQC retrofit if reasonably possible.
- Units 1 and 2:
  - The existing Unit 1 economizer and air heater arrangement are not suitable for adding a new SCR due to tie-in duct connection challenges. Also, since the existing ESPs will not be used, adding a new single air heater at the bottom of a new SCR would ease the construction and reduce the extended flue gas ductwork and supporting structural steel. A new single FD fan would be added and the combustion air ductwork would be tied back to existing wind boxes plenum. The economizer outlet duct would be extended north out of the boiler building by cutting the east-west wind box ductwork section and then connected to SCR located at east of Unit 1. The new air heater gas side outlet will then be connected to a new Unit 1 PJFF and a new single ID fan. The new ID fan discharge will then be connected to the Unit 1 existing round ductwork connecting further downstream to existing new WFGD. The Unit 1 and Unit 2 PJFF will be co-located east-west

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with ID fans on the west side. Similar to Unit 1, the SCR and new air heater for Unit 2 will be co-located with Unit 1 in the same general area. A new FD fan for Unit 2 will be added and the combustion air duct will be connected back to Unit 2 wind box plenum. A set of four ducts, including flue gas and combustion air duct for Unit 1 and Unit 2, will be stacked and paired in the alley between the boiler building and the Unit 1 ID fan structure.

– SCRs for both Unit 1 and Unit 2 are located to the east of the existing Unit 1 ID fan area, with individual unit PJFFs shown downstream of the SCRs. Individual ID fans (either new or possibly reused existing fans) are located downstream of the PJFFs to forward the clean exhaust gas to the WFGD and to control unit operating pressures.
– Due to the extreme congestion at the air heater in Unit 1, a new air heater would be located below the new SCR and the existing air heater abandoned or removed. A new FD fan would provide draft air through the new air heater and back to the Unit 1 windbox. Ductwork would connect the economizer outlet to the SCR and the cold-side air heater outlet to the windbox. This would minimize the required work inside Unit 1 and in the congested area to the north.
– The ductwork in and out of the existing air heater at Unit 2 is less congested, and the Unit 2 air heater and FD fans can remain in place. However, should it be advantageous, a new Unit 2 air heater and FD fan could be installed under the SCR as with Unit 1. The ductwork serving the Unit 2 SCR (and new air heater and fan, if so determined) would be stacked with the new Unit 1 ductwork in the area immediately north of the existing building.
– The "remote" location of the SCRs is suggested due to the lack of available room in the area north of the building and the extremely poor construction access to the area that does exist. With only ductwork being located immediately north of the building, it is expected that the existing chimney would not require demolition and modification of the existing duct support tower upstream of the Unit 1 ID fan could be avoided. The ash capture duct and the existing (but not in service) demin equipment room would have to be demolished to make room for the ductwork.

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- The new Unit 1 and 2 PJFFs are proposed to be located in the parking lot, and not in the common ductwork near the WFGD, to avoid the ash dropout and high ash loading in the long run of existing horizontal duct upstream of the common WFGD.
- The arrangement is intended to allow the reuse of major sections of the existing new Unit 1 ductwork. The ductwork will be evaluated to determine whether the new current Unit 1 duct work can handle exhaust flow from both Units 1 and 2 from the PJFFs, minimizing new construction.
- Neither arrangement currently impacts the office building, but both will displace significant areas of the existing parking lot.
- Unit 1 and Unit 2 combined PJFF can be located near the new WFGD absorber if Unit 1 and Unit 2 can survive without new SCRs. However, due to space limitation on site and the complexities of installation of this equipment as noted above, it may be advantageous for the arrangement for Units 1 and 2 (with and without SCRs) to be the same in spacing and orientation in order to allow for the future installation of SCRs should it be required.

- Unit 3:
  - The new Unit 3 PJFF will be located west of existing ID fans and south of the new WFGD absorber. The existing series of ESPs on side A and side B will be bypassed and retired in place. At the inlet of the existing primary ESPs, a new ductwork will be added blocking the flow to the existing ESP inlet nozzle. The new ductwork will be designed in such a way that the new SCR structure will not pose any obstructions. However, it may be advantageous if the new SCR structure can be used to support the new PJFF ductwork connection. The new SCR structure, as well as foundation loading modification request, would need to be communicated to Riley Power if this is a possibility. The new PJFF ductwork will then be connected to the new PJFF on east side and the PJFF outlet duct will then be routed back to the existing ID fans on the same side as the inlet. Bypassing the existing ESPs will potentially allow the reuse of existing ID fans if found capable. It is estimated that the bypassing the existing ESPs and connected ductwork could save about 4-5" of w.g.

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- The PJFF would be located in the area west of the Unit 3 ID fans and south of the FGD scrubber. A common duct would be routed from the air heater outlet duct just outside the Unit 3 Boiler Building, turn immediately west before the ESPs, and routed over the Unit 3 exhaust duct to the PJFF inlet. The PJFF outlet duct would be routed to the existing ID fan inlets to allow re-use of the fans in their current location, if practical. Duct downstream of the ID fans would not be modified. The PJFF and its ductwork would be arranged to allow installation of the planned SO_3 mitigation equipment beneath.
- The PJFF can be constructed high enough to allow vehicle traffic underneath if acceptable traffic patterns around the superstructure cannot be established.
- If the ductwork can be successfully routed to avoid the ESPs, the ESPs can be abandoned in place or demolished after the fact as desired by LG&E/KU. However, whether or not the exhaust duct can be routed around the new SCR and its supporting superstructure is the greater concern.

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5.0 Selected Air Quality Control Technology

The following sections present a general description of the AQC technologies considered for Brown, as well as a unit by unit discussion of the key attributes of the technologies and special considerations for their application and arrangement at the affected units. Table 5-1 presents the selected AQC technologies that were considered in the validation process.

Table 5-1. AQC Technologies

	Unit 1	Unit 2	Unit 3
NO_x Control	New SCR	New SCR	Future[(a)] SCR
SO_2 Control	Existing WFGD	Existing WFGD	Existing WFGD
PM Control	New PJFF	New PJFF	New PJFF
HCl Control	Existing WFGD and New Sorbent Injection	Existing WFGD and New Sorbent Injection	Existing WFGD and Future[(a)] Sorbent Injection
CO Control	New NN	New NN	New NN
SO_3 Control	New Sorbent Injection	New Sorbent Injection	Future[(a)] Sorbent Injection
Hg Control	New PAC Injection	New PAC Injection	New PAC Injection
Dioxin/Furan Control	New PAC Injection	New PAC Injection	New PAC Injection
Fly Ash Sales	None	None	None

[(a)]Planned in-service date of 2012.

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5.1 Technology Descriptions

The following sections provide a brief general description of the proposed AQC technologies.

5.1.1 Selective Catalytic Reduction System

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_x into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_x-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_x levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_x available for removal. Essentially, as NO_x is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature are costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure 5-1 shows a schematic diagram of SCR.

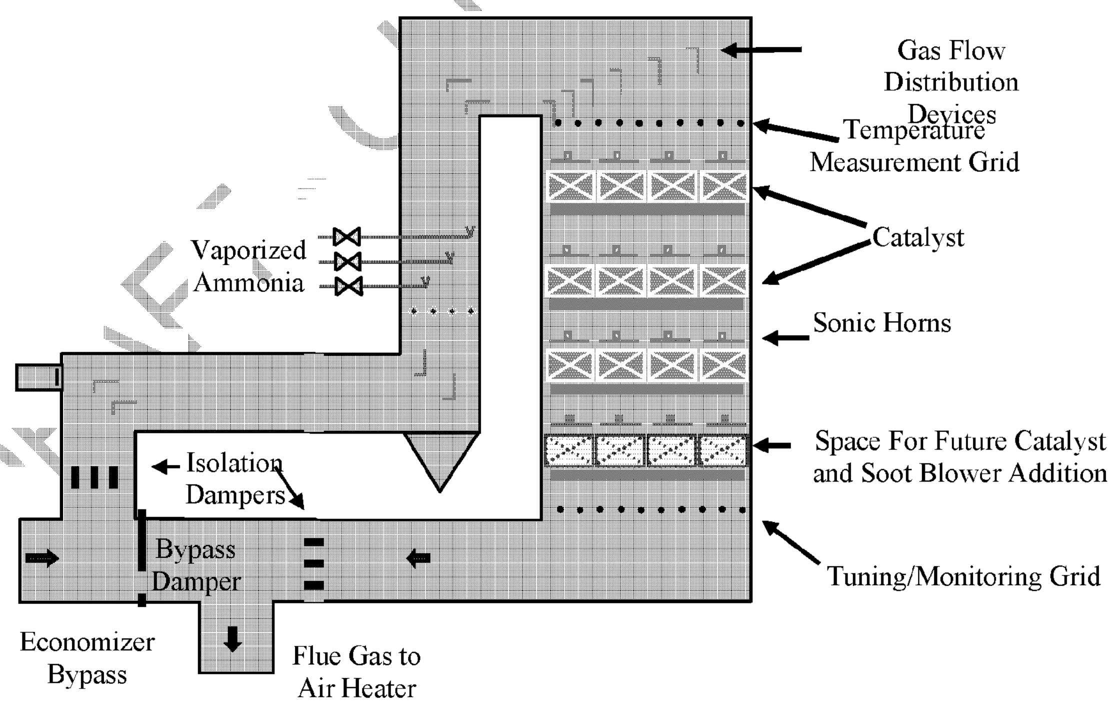

Figure 5-1. Schematic Diagram of a Typical SCR Reactor

5.1.2 Pulse Jet Fabric Filter

Pulse jet fabric filters (PJFFs) have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the PJFF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the PJFF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementation. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each PJFF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure 5-2.

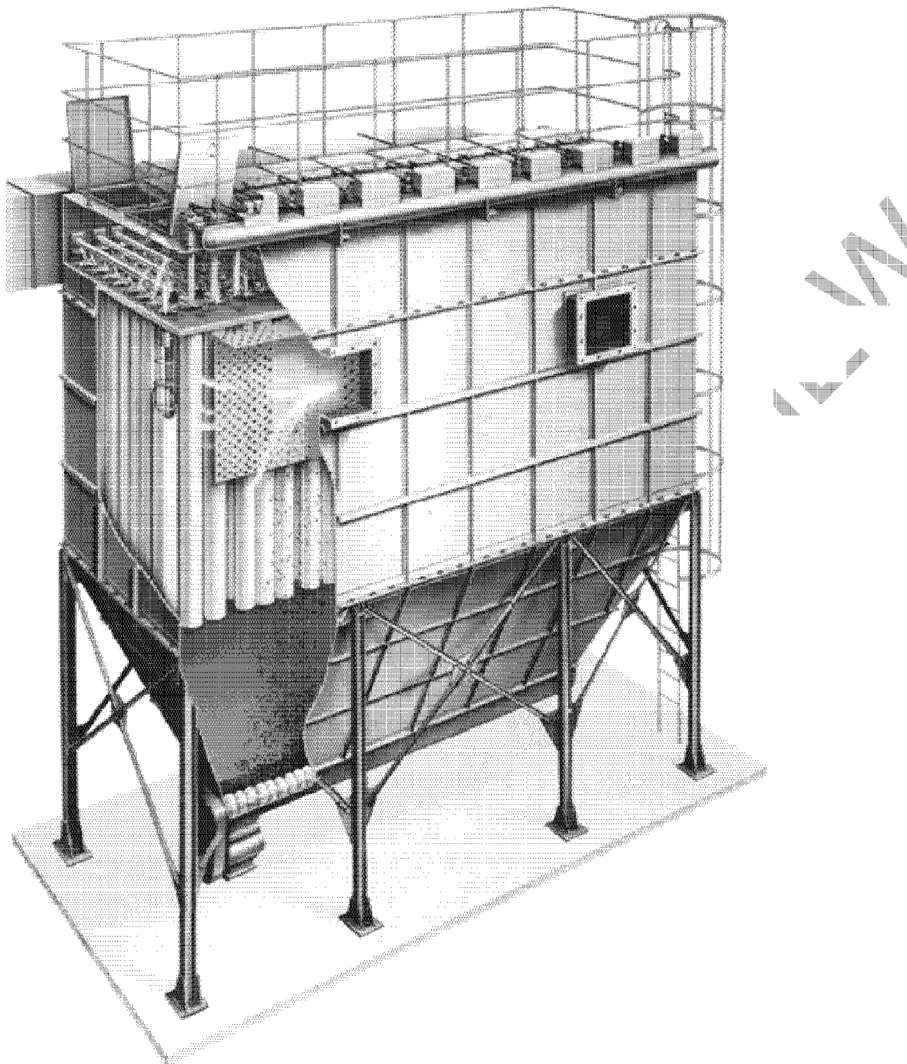

Figure 5-2. Pulse Jet Fabric Filter Compartment

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

5.1.3 Powdered Activated Carbon Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of Energy (DOE), EPA, Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure 5-3. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

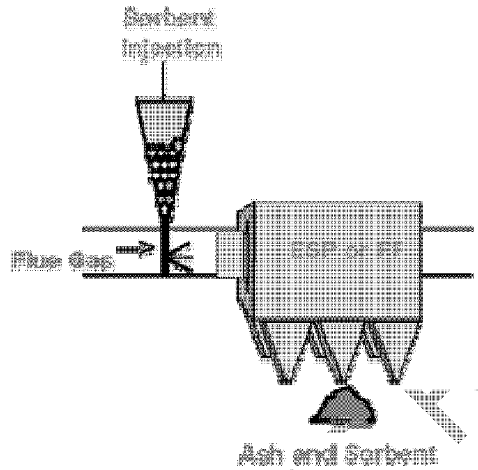

Figure 5-3. Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of an ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a cold-side electrostatic precipitator (CS-ESP) can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of CS-ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a CS-ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC (approximately $5.00/lb of iodine, $1.00/lb of bromine, and $0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

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5.1.4 Sorbent Injection

Injection of finely divided alkalis into the flue gas has been demonstrated for the removal of SO_3 from flue gases. Most commercial experience is from units firing high sulfur oil where trace metals, mainly vanadium, increase SO_2 oxidation. Magnesium-based compounds have been used successfully for decades to capture SO_3 in oil fired units. As coal fired units burning high sulfur bituminous coals have been retrofitted with SCR systems, interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Sorbents such as SBS, trona, and hydrated lime have recently been used on large coal fired units, with reported results showing the achievement of high control efficiencies of SO_3 in high sulfur applications.

5.1.5 CO Reduction Technologies

Control of CO is divided into two basic categories, good combustion controls and neural networks.

5.1.5.1 Good Combustion Controls. As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits. Good combustion controls are an option to aid in reduction of CO but are assumed to currently be optimized. No further study of this option was considered in this report.

5.1.5.2 Neural Networks. Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions

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of NO_x, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation.

At this point, there are no proven and feasible post combustion AQC technologies for the control of CO emissions from coal-fired boilers of this size. DCS based computer furnace combustion monitoring systems, such as neural networks, may help reduce CO emissions by improving plant heat rate and optimizing the various combustion parameters responsible for the formation of CO. Improvising the coal mills and coal feed injection/air management and or burner modifications including the detuning of any existing NO_x combustion controls devices will help reduce the CO in combustion or pre-combustion stage. There are no arrangement fatal flaws or constraints associated with the installation of a NN at Brown, although it cannot be validated at this point whether or not a NN can achieve the required CO target emission rate.

5.2 Unit by Unit Summary of AQC Selection

The following AQC control technologies comprise the selected technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the selected technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the AQC validation process, as well as information provided by LG&E/KU.

5.2.1 Brown Unit 1

Table 5-2 identifies the selected AQC technologies for Brown Unit 1. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-2. Unit 1– AQC Selection	
AQC Equipment	**Pollutant**
New SCR	NO_x
New Sorbent Injection	SO_3, HCl
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF	PM

New SCR

- SCR can consistently achieve NO_x emissions of lower than 0.156 lb/MBtu on a continuous basis. Therefore, SCR is the most feasible and expandable control technology considered for NO_x reduction including future NO_x reduction requirements.
- The SCR system would increase the pressure drop of the draft system requiring the draft system to be investigated for available capacity. Additional auxiliary power would be required as a result of the increase in pressure drop.
- Due to the proposed bypass and abandonment of the existing air heaters, a new air heater would be required. The gas side would be placed downstream of the SCR system.
- Due to the proposed abandonment of the existing FD fans, the combustion air system needs to be investigated and a new FD fan and air preheat system would be required. Additional auxiliary power and steam cycle heat balance requirements would need to be considered for the new FD fan and air preheat system.
- Ammonia consumption increases with the addition of SCR. Detailed investigation or study will be required to confirm if a new ammonia storage facility is required or if the existing ammonia storage facility can be upgraded to accommodate the Unit 1 ammonia supply.
- The use of ammonia will slightly increase the truck traffic at the plant.
- An SO_3 mitigation system like alkali injection and PJFF will be required.
- A new SCR can be located downstream of the existing economizer and upstream of the new air heater.
- A new SCR will be arranged as 1 x 100% reactor.
- The SCR will be located on the east side of the existing Unit 1 AQC equipment area.

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New SO_3 Control System (Sorbent Injection)

A sorbent injection system that injects trona, lime or SBS into the flue gas to remove SO_3 would be necessary.

- A PJFF is recommended in conjunction with a sorbent injection system.
- Trona/lime/SBS would be injected downstream of the SCR but upstream of the air heater.
- Sorbent injection can reduce the sulfuric acid emissions on a continuous basis and mitigate the visible blue plume formation from the chimney which is often associated when burning high sulfur coal.
- The use of sorbent system will slightly increase the truck traffic at the plant. A sorbent receiving and storage system common to both Units 1 and 2 will limit the areas subject to the increased traffic as well as minimize the infrastructure required.

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the air heater but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries. A PAC receiving and storage system common to both Units 1 and 2 will limit the areas subject to the increased traffic as well as minimize the infrastructure required.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.

- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the draft system. Preliminary investigation has determined that the existing 100 percent capacity ID fan possesses sufficient margin to accommodate the increased pressure drop. Accordingly, the existing ID fan would be incorporated in the draft system downstream of the PJFF and no new ID fan would be required. Any additional auxiliary power required due to the increased load on the existing fan would need to be considered.
- The existing ESP will be bypassed and abandoned in place.
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the new air heater and upstream of the existing ID fan and can possibly be installed as suggested in the high level layout drawings as shown in Appendix A.
- The PJFF for Unit 1 will be located on the east side of the existing Unit 1 AQC equipment area and south of the existing coal conveyor.
- A major portion of the existing parking lot needs to be relocated.

5.2.2 Brown Unit 2

Table 5-3 identifies the selected AQC technologies for Brown Unit 2. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-3. Unit 2– AQC Selection

AQC Equipment	Pollutant
New SCR	NO_x
New Sorbent Injection	SO_3, HCl
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF	PM

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New SCR

- SCR can consistently achieve NO_x emissions of lower than 0.156 lb/MBtu on a continuous basis. Therefore, SCR is the most feasible and expandable control technology considered for NO_x reduction including future NO_x reduction requirements.
- The SCR will increase pressure drop of the draft system, so the draft system needs to be investigated and a new ID fan would likely be required. Additional auxiliary power requirements would need to be considered for a new ID fan.
- Due to the possible bypass and abandonment of the existing air heaters, a new air heater may be required. The gas side would be placed downstream of the SCR system.
- Due to the possible abandonment of the existing FD fans, the combustion air system needs to be investigated and a new FD fan and air preheat system may be required. Additional auxiliary power and steam cycle heat balance requirements would need to be considered for new FD fan(s).
- Ammonia consumption increases with the addition of SCR. Detailed investigation or study will be required to confirm if a new ammonia storage facility is required or if the existing ammonia storage facility can be upgraded to accommodate the Unit 2 ammonia supply.
- The use of ammonia will slightly increase the truck traffic at the plant.
- An SO_3 mitigation system like alkali injection and PJFF will be required.
- A new SCR can be located downstream of the existing economizer and upstream of the new air heater.
- A new SCR will be arranged as 1 x 100% reactor.
- The SCR will be located on the east side of the existing Unit 1 AQC equipment area.

New SO_3 Control System (Sorbent Injection)

A sorbent injection system that injects trona, lime or SBS into the flue gas to remove SO_3 would be necessary.

- A PJFF is recommended in conjunction with a sorbent injection system.
- Trona/lime/SBS would be injected downstream of the SCR but upstream of the air heater.

- Sorbent injection can reduce the sulfuric acid emissions on a continuous basis and mitigate the visible blue plume formation from the chimney which is often associated when burning high sulfur coal.
- The use of sorbent system will slightly increase the truck traffic at the plant. A sorbent receiving and storage system common to both Units 1 and 2 will limit the areas subject to the increased traffic as well as minimize the infrastructure required.

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the air heater but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries. A PAC receiving and storage system common to both Units 1 and 2 will limit the areas subject to the increased traffic as well as minimize the infrastructure required.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the draft system. As such, the draft system needs to be investigated and a new ID fan would likely be required. Additional auxiliary power requirements would need to be considered for a new ID fan.

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- The existing ESP will be bypassed and abandoned in place.
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the new air heater and upstream of the new ID fans and can possibly be installed as suggested in the high level layout drawings as shown in Appendix A.
- The PJFF for Unit 2 will be located on the east side of the existing Unit 1 AQC equipment area adjacent to the Unit 1 PJFF.
- A major portion of the existing parking lot needs to be relocated.

5.2.3 Brown Unit 3

Table 5-4 identifies the selected AQC technologies for Brown Unit 3. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-4. Units 3 – AQC Technology Selection

AQC Equipment	Pollutant
New Sorbent Injection	SO_3, HCl
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF	PM

Future SO_3 Control System (Sorbent Injection)

A sorbent injection system that injects trona, lime or SBS into the flue gas to remove SO_3 is currently being planned in the area of the Unit 3 ID fans. It is expected this system will not require modification as part of Phase II work.

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the existing air heater but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the draft system. However, preliminary investigation has determined that the two existing 50 percent capacity ID fans possess sufficient margin to accommodate the increased pressure drop of the PJFF as well as the SCR system. Accordingly, the existing ID fans would be incorporated into the draft system downstream of the new PJFF. Any additional auxiliary power required due to the increased load on the existing fans would need to be considered.
- The existing ESPs will be bypassed and abandoned in place, except as required to be removed for installation of new ductwork to the PJFF.
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the existing air heater and upstream of the existing ID fans and can possibly be installed as suggested in the high level layout drawings as shown in Appendix A.
- The PJFF for Unit 3 will be located on the west side of the existing Unit 3 ID fans and south side of the combined common WFGD absorber module.
- Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

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6.0 Validation Analyses

The following sections describe the analyses of various balance of plant systems necessary to validate the selected AQC equipment.

6.1 Draft System Analysis

As a part of the draft system analysis of the AQC validation process for Brown, the flue gas draft fans need to be evaluated to determine if modifications, replacements, or additions to the existing fans will be required. This is due to the installation of additional draft system equipment to control certain flue gas emissions. For Units 1 and 2, the modifications and additions to the draft system being considered include new SCR systems for removing NO_x emissions and new PJFF systems that will replace the existing electrostatic precipitators (ESP) in the removal of particulate. For Unit 3 the draft system modifications and additions being considered include a new PJFF system. For more detail on the AQC equipment modifications, additions, etc. for each Brown unit refer to Section 5.0.

For the sizing of any new fans for the Brown site, the standard Black & Veatch fan sizing philosophy for developing Test Block conditions as additional margin on MCR conditions is recommended. This philosophy includes the application of the following items to the required MCR conditions for new or modified fans:

- 10 percent margin on flue gas flow exiting the boiler.
- 50 percent margin on leakages throughout the draft system.
- 50 percent margin on air heater differential pressure.
- 25°F temperature increase at the fan inlet.
- Adjustments of draft system pressure drops to correspond with increased Test Block flow rates.
- 1.0 inch of water (inw) control allowance.

The application of these items typically results in flow margins in the range of 20 to 30 percent and pressure margins in the range of 35 to 45 percent. If the flow and/or pressure margins for the Test Block conditions fall outside of these ranges the items listed above are typically adjusted appropriately.

Additionally, following the preliminary analyses of the Brown draft systems, there will be a discussion on draft system stiffening, or transient design pressure, requirements per NFPA 85.

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6.1.1 Unit 1

Based on the additions to the Unit 1 draft system previously discussed, the flue gas flow through the draft system would change as follows. At the outlet of the existing boiler it is expected that the flue gas would bypass the existing air heaters and travel to the new SCR system before entering a new 100 percent capacity air heater. It is expected that the existing air heaters would not be reused and abandoned in place. This is due to the congestion in their current location that would result in significant construction difficulties if they were to be reused. Once the flue gas is through the new air heater it would travel directly to the new PJFF. The existing cold-side ESP would not be used and abandoned in place. The existing ID fan would then draw the flue gas through the PJFF and new ductwork and then send it to the common WFGD system through existing ductwork. Along with the previously mentioned new air heater, a new FD fan and air preheat system must be considered as well to accommodate the relocation of the air heater. Lastly, it expected that an economizer bypass system of some type will be required to maintain flue gas temperatures entering the SCR system above a minimum reaction temperature. An illustration of the Unit 1 future draft system based on these changes (in red) is shown in Figure 6-1.

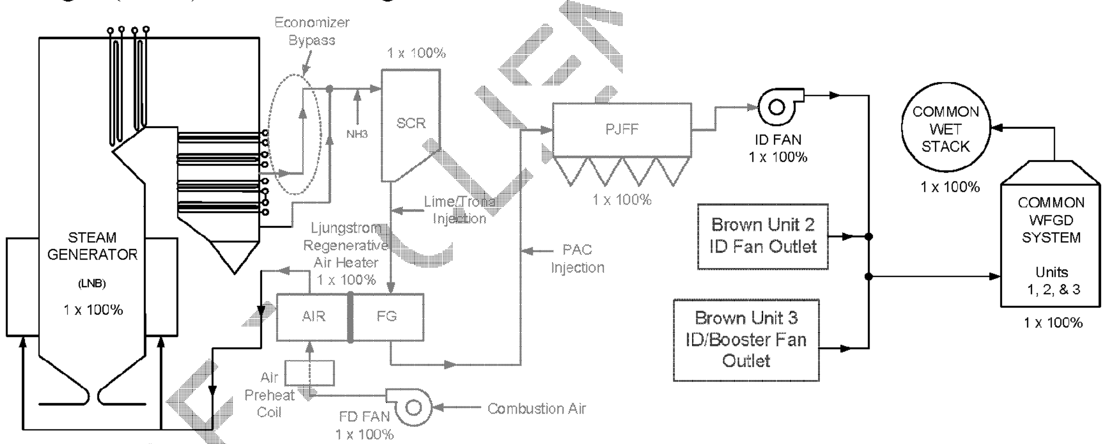

Figure 6-1. Unit 1 Future Draft System

Also, Unit 1 currently does not have the ability to bypass the common WFGD and the desire for this has recently been discussed. B&V has determined that adding this capability may be feasible with the assumption that the common WFGD would always be offline when bypassing. Existing Unit 1 exhaust duct could be interconnected with appropriate dampers to existing Unit 2 exhaust duct to allow Unit 1 exhaust to be directed to the old Unit 3 chimney, bypassing the WFGD. Since exhaust flow from Unit 1 is less than that from Unit 2, which currently can be bypassed, minimal problems are expected from the ductwork flow if Unit 1 is bypassed instead of Unit 2. However, if exhaust flows from both Unit 1 and Unit 2 are intended to be directed to the Unit 3 chimney simultaneously, the impact of the combined flow characteristics through existing duct must be investigated. In either case, the air permit regulatory requirements of the bypass scenario would need to be investigated. B&V is open to future discussions regarding adding this capability.

Typically SCR systems are installed between the existing boiler outlet and existing air heater gas inlet. However, in this case with Unit 1 there is the potential for construction difficulties next to the Unit 1 boiler building. Therefore, one of the arrangement options that Black & Veatch is considering includes the installation of a new 100 percent capacity air heater and a new 100 percent capacity FD fan, as shown in Figure 6-1. This will minimize the construction activities next to the Unit 1 boiler building. In addition, air heaters typically require major modifications with the installation of SCR systems and the installation of a new air heater will simplify that process. A single train of equipment is being considered to minimize capital costs to this relatively small unit and due to the new single ID fan that will be reused. The existing 50 percent capacity air heaters and FD fans would be bypassed and abandoned.

With the expected addition of an SCR system and a PJFF system to the existing draft system, the pressure demand on the draft fan system will be significantly higher than what the existing ID fan is currently experiencing. However, due to the selected capacity of the newly installed existing ID fan, it is expected that enough capacity is available to compensate for the AQC additions and still allow for adequate margins. The existing ID fan is expected to be reused as shown in Figure 6-1.

Future Draft System Characteristics

The major performance characteristics of the Unit 1 boiler and future draft system at MCR are as follows in Tables 6-1 and 6-2. Note that the items in bold in Table 6-2 are new.

Table 6-1. Unit 1 Boiler Characteristics at MCR

Boiler total heat input	1,000 MBtu/hr (based on net plant output of 102,000 kW and heat rate of 9,802 Btu/kWh)
Boiler excess air	34.3% (5.0% oxygen, wet basis)
Loss On Ignition (LOI)	2.0% (estimated)
Ambient conditions	
Dry bulb temperature	74° F
Relative humidity	60%
Barometric pressure	28.97 inHg

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Table 6-2. Unit 1 Future Draft System Characteristics at MCR	
SCR system leakage	**2.0%**
Air heater leakage	**6.0%**
PJFF system leakage	**3.0%**
Flue gas temperatures	
Boiler outlet	650° F
SCR outlet	**650° F**
Air heater outlet	350° F
ESP outlet	**(Abandoned)**
PJFF outlet	**350° F**
ID fan outlet	~375° F (calculated)
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	7.5 inw
SCR	**10.0 inw**
Air heater	**6.0 inw**
ESP	**(Abandoned)**
PJFF	**6.0 inw**
Duct to WFGD	2.0 inw
WFGD	10.0 inw
Stack	1.0 inw

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Based on the layout of the future draft system in Figure 6-1 and the future draft system characteristics in Table 6-1, the estimated performance requirements of the existing ID fan at MCR are shown in Figure 6-2 as the MCR Point. Also in Figure 6-2 is the Maximum Fan Runout illustrating the maximum capability of the existing ID fan in the future draft system. Note the estimated flow and pressure margins of 13 and 27 percent, respectively. These margins are below the typical ranges of the Black & Veatch recommended margins. However, they are adequate enough to warrant the reuse of the newly installed Unit 1 ID fan to limit the capital costs of the AQC upgrades being considered. Black & Veatch recommends the continued use of the existing Unit 1 ID fan in support of the proposed AQC upgrades.

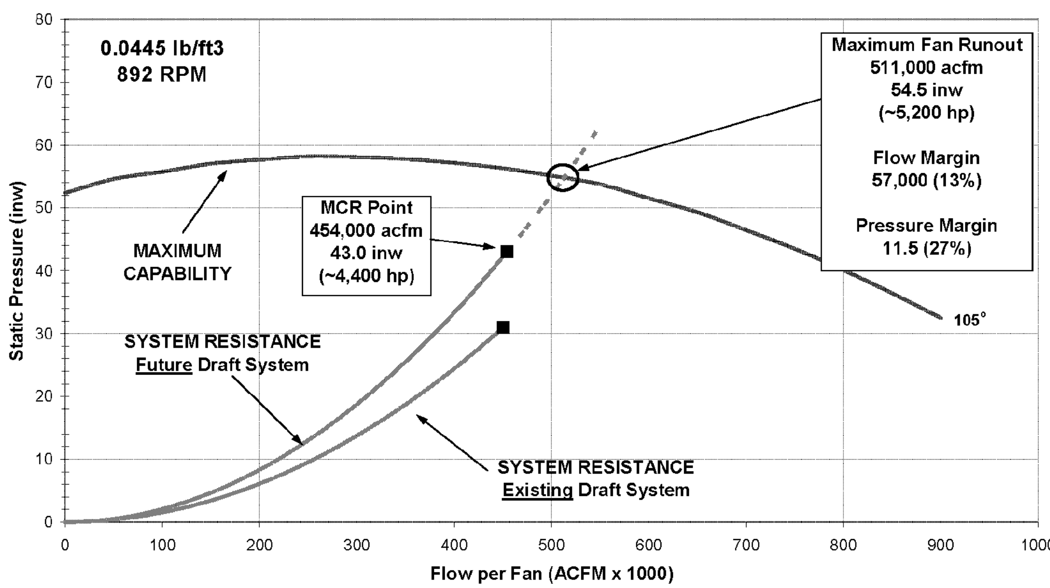

Figure 6-2. Unit 1 Existing ID Fan Performance

For the sizing of the new air heater, the performance of the existing equipment will be matched. For this validation stage, the single air heater will be of the Ljungtrom bisector regenerative type in a vertical shaft orientation.

Similarly, for the sizing of the new FD fans, the performance of the existing equipment will be approximately matched. For this validation stage, the single FD fan will be of the centrifugal type with the estimated MCR performance requirements listed in Table 6-3. Also in Table 6-3 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 19 and 50 percent, respectively. Various means of flow control can be discussed and analyzed in the future, however, for now it will be assumed that inlet vanes will be used in a single speed application.

In contrast, the sizing of the new air preheat system will be different than the existing equipment. The existing air preheat system on Unit 1 uses a hot air recirculation fan. With this system, a fan intakes hot air at the air heater air outlet and forces it back into the air heater air inlet to control air heater gas outlet temperatures. For the purposes of conducting this study B&V is proposing the installation of a more traditional preheat system through the use of a hot water air preheat system with a coil at the air heater air inlet that would operate similar to the system on Unit 2. However, B&V is open to further discussions in the future on the appropriate type of preheat system to install on Unit 1.

Table 6-3. Unit 1 New FD Fan MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	85	110
Inlet Density (lb/ft^3)	0.0704	0.0673
Flow per Fan (acfm) *	255,000	303,000
Inlet Pressure (inwg)	-1.0	-1.3
Outlet Pressure (inwg)	11.0	16.7
Static Pressure Rise (inw)	12.0	18.0
Shaft Power Required (HP) **	700	1,000
Efficiency (%) **	70	85
Number of Fans	1	1
Flow Margin (%)	--	19
Pressure Margin (%)	--	50

* Per fan basis with both fans in operation.
** Estimated – assumes single speed damper flow control.

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6.1.2 Unit 2

Based on the additions to the Unit 2 draft system previously discussed, the flue gas flow through the draft system would change as follows. At the outlet of the existing boiler it is expected that the flue gas would bypass the existing air heaters and travel to the new SCR system before entering a new 100 percent capacity air heater. It is expected that the existing air heaters would not be reused and abandoned in place. This is due to the congestion in their current location that would lead to significant construction difficulties. Once the flue gas is through the new air heater it would travel directly to the new PJFF. The existing cold-side ESPs would not be used and abandoned in place. A new 100 percent capacity ID fan would then draw the flue gas through the PJFF and send it to the common WFGD system. New ductwork would be constructed to interface with the ductwork currently in place that allows Unit 2 to either send flue gas to the common WFGD system or bypass it. Along with the previously mentioned new air heater, a new FD fan and air preheat coil must be considered as well to accommodate the relocation of the air heater. Lastly, an economizer bypass system of some type may be required to maintain flue gas temperatures entering the SCR system above a minimum reaction temperature. An illustration of the Unit 2 future draft system based on these changes (in red) is shown in Figure 6-3.

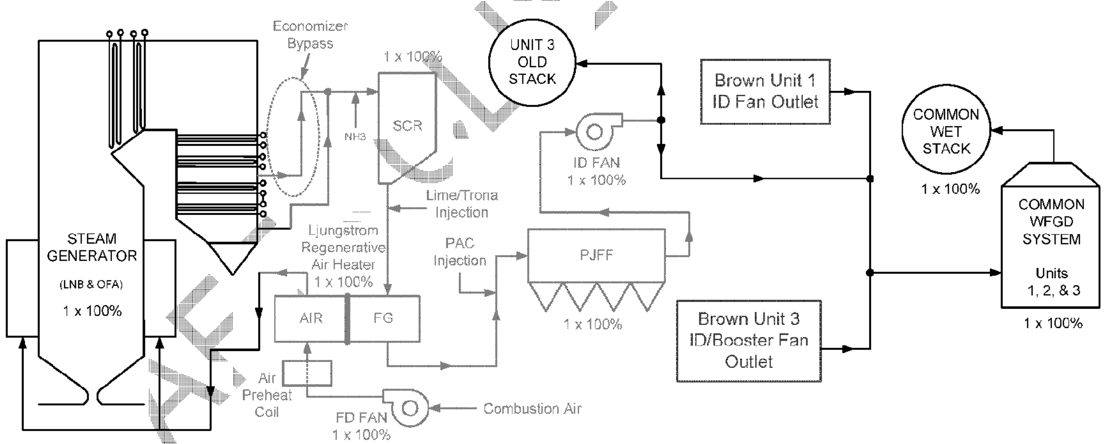

Figure 6-3. Unit 2 Future Draft System

Typically SCR systems are installed between the existing boiler outlet and existing air heater gas inlet. However, in this case with Unit 2 there is the potential for construction difficulties next to the Unit 2 boiler building as with Unit 1. Therefore, one of the arrangement options that Black & Veatch is considering includes the installation of a new 100 percent capacity air heater and a new 100 percent capacity FD fan, as shown in Figure 6-3, due to similar reasons discussed for Unit 1. The existing 50 percent capacity air heaters and FD fans would be bypassed and abandoned. Other arrangement options involve the continued use of the existing air heaters and FD fans, however, these options are not shown or discussed in this section.

With the expected addition of an SCR system and a PJFF system to the existing draft system, the pressure demand on the draft fan system will be significantly higher than what the existing ID fans currently experience. It is expected that the Unit 2 ID fans will not have the available capacity to overcome these AQC equipment additions and that a new ID fan system will be required. Therefore, a new 100 percent capacity ID fan has been shown in Figure 6-3.

Future Draft System Characteristics

The major performance characteristics of the Unit 2 boiler and future draft system at MCR are as follows in Tables 6-4 and 6-5. Note that the items in bold in Table 6-5 are new.

Table 6-4. Unit 2 Boiler Characteristics at MCR

Boiler total heat input	1,665 MBtu/hr (based on net plant output of 169,000 kW and heat rate of 9,855 Btu/kWh)
Boiler excess air	18.2% (3.0% oxygen, wet basis)
LOI	2.0% (estimated)
Ambient conditions	
Dry bulb temperature	74° F
Relative humidity	60%
Barometric pressure	28.97 inHg

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Table 6-5. Unit 2 Future Draft System Characteristics at MCR

SCR system leakage	**2.0%**
Air heater leakage	**6.0%**
PJFF system leakage	**3.0%**
Flue gas temperatures	
Boiler outlet	730° F
SCR outlet	**730° F**
Air heater outlet	330° F
ESP outlet	**(Abandoned)**
PJFF outlet	**330° F**
ID fan outlet	**~350° F (calculated)**
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	3.2 inw
SCR	**10.0 inw**
Air heater	**6.0 inw**
ESP	**(Abandoned)**
PJFF	**6.0 inw**
Duct to WFGD	2.0 inw
WFGD	10.0 inw
Stack	1.0 inw
Stack	1.0 inw

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Based on the layout of the future draft system in Figure 6-3 and the future draft system characteristics in Table 6-5, the estimated performance requirements of the existing ID fans is shown in Figure 6-4 as the MCR Point. As expected, the performance requirements of the future Unit 2 draft system are beyond the capabilities of the existing ID fans. The existing ID fans will either need to be upgraded or replaced. For the purposes of conducting this initial validation process B&V has decided to replace the existing ID fans with a new 100 percent capacity ID fan since the existing ESPs will not be used, to minimize construction activities near the Unit 2 boiler building, and to maintain similarity to Unit 1. Operational preferences of Brown station personnel and/or future analyses of the Unit 2 draft system may reveal a different arrangement at a later time.

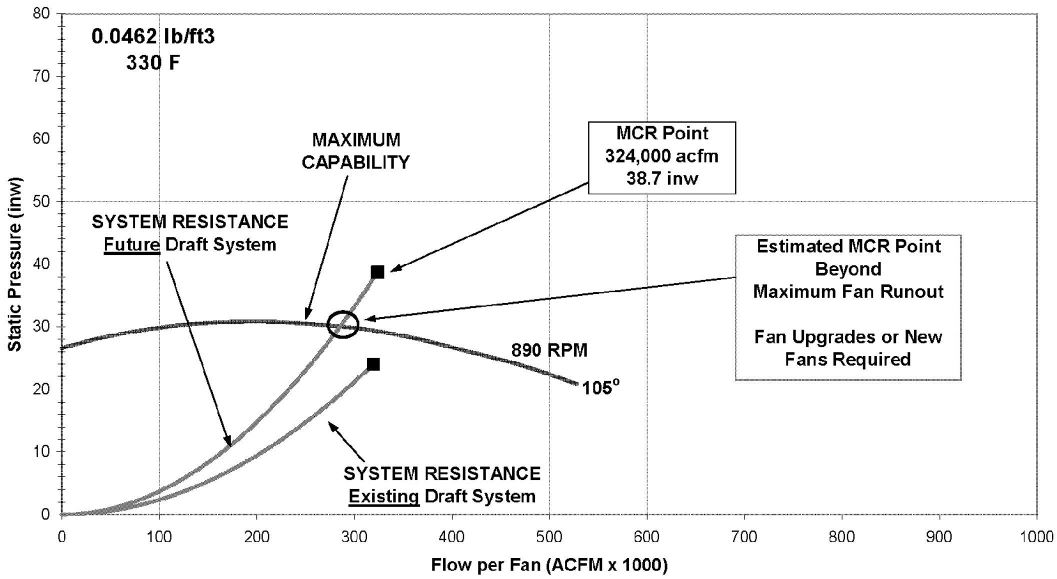

Figure 6-4. Unit 2 Existing ID Fan Performance

Based on the future draft system characteristics in Table 6-5, the estimated performance requirements of the new ID fan at MCR is shown in Table 6-6. Also in Table 6-6 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 23 and 40 percent, respectively.

Table 6-6. Unit 2 New ID Fan MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	330	355
Inlet Density (lb/ft^3)	0.0463	0.0437
Flow per Fan (acfm) *	647,000	795,000
Inlet Pressure (inwg)	-25.7	-35.6
Outlet Pressure (inwg)	13.0	18.5
Static Pressure Rise (inw)	38.7	54.1
Shaft Power Required (HP) **	5,600	8,000
Efficiency (%) **	70	85
Number of Fans	2	2
Flow Margin (%)	--	23
Pressure Margin (%)	--	40

* Per fan basis with both fans in operation.
** Estimated – assumes single speed damper flow control.

For the sizing of the new air heater and hot water air preheat coil, the performance of the existing equipment will be matched. For this validation stage, the single air heater will be of the Ljungtrom bisector regenerative type in a vertical shaft orientation. The air preheat coil will require that condensate lines to and from the existing support equipment be routed to the new location near the new air heater. It is recommended that the existing hot water air preheat support equipment be evaluated to confirm that the additional pipe lengths can be accommodated.

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In contrast, the sizing of the new FD fans will be different that the existing equipment due to the lower capacity required now that Unit 2 is a balanced draft unit. The existing two FD fans are carryover equipment from when Unit 2 operated as a forced draft unit with approximately 2,800 horsepower combined. The current balanced draft capacity will be matched with a single centrifugal FD fan with the estimated MCR performance requirements listed in Table 6-7. Also in Table 6-7 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 15 and 38 percent, respectively. Various means of flow control can be discussed and analyzed in the future, however, for now it will be assumed that inlet vanes will be used in a single speed application.

Table 6-7. Unit 2 New FD Fan MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	85	110
Inlet Density (lb/ft^3)	0.0704	0.0673
Flow per Fan (acfm) *	351,000	404,000
Inlet Pressure (inwg)	-1.0	-1.2
Outlet Pressure (inwg)	13.0	18.2
Static Pressure Rise (inw)	14.0	19.4
Shaft Power Required (HP) **	1,100	1,500
Efficiency (%) **	70	85
Number of Fans	1	1
Flow Margin (%)	--	15
Pressure Margin (%)	--	38

* Per fan basis with both fans in operation.
** Estimated – assumes single speed damper flow control.

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6.1.3 Unit 3

Based on the additions to the Unit 3 draft system previously discussed, the flue gas flow through the draft system would change as follows. At the outlet of the existing air heaters the flue gas would bypass both sets of the existing cold-side ESPs and travel through new ductwork directly to the new PJFF. The existing cold-side ESPs would not be used and abandoned in place. The newly installed existing 50 percent capacity ID fans would then draw the flue gas through the PJFF and new ductwork and then send it to the common WFGD system. An illustration of the Unit 2 future draft system based on these changes (in red) is shown in Figure 6-5.

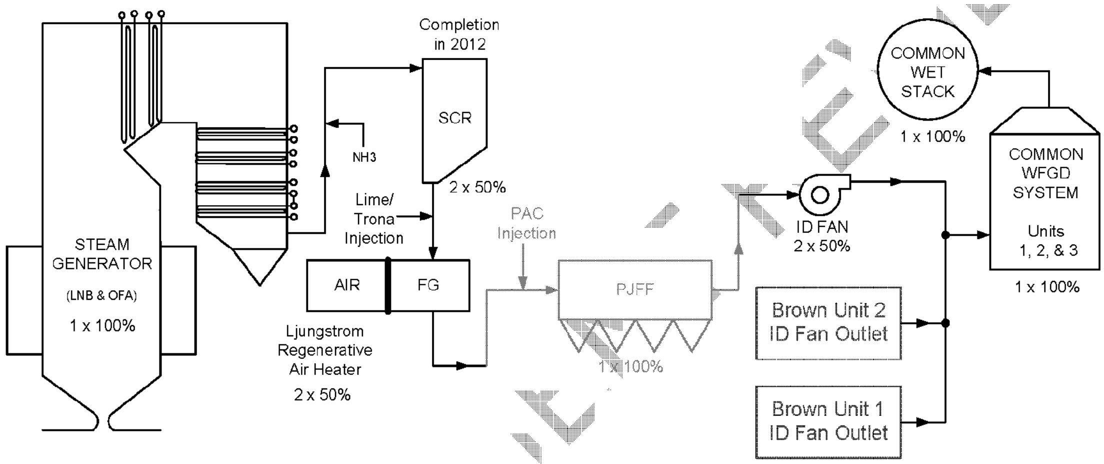

Figure 6-5. Unit 3 Future Draft System

With the expected addition of a PJFF system to the existing draft system, the pressure demand on the draft fan system will be higher than what the existing ID fans are currently experiencing. However, due to the selected capacity of the newly installed existing ID fans, it is expected that enough capacity is available to compensate for the PJFF addition and still allow for adequate margins. The existing ID fans are expected to be reused as shown in Figure 6-5.

Future Draft System Characteristics

The major performance characteristics of the Unit 3 boiler and future draft system at MCR are as follows in Tables 6-8 and 6-9. Note that the items in bold in Table 6-9 are new.

Table 6-8. Unit 3 Boiler Characteristics at MCR

Boiler total heat input	4,120 MBtu/hr (based on net plant output of 433,000 kW and heat rate of 9,516 Btu/kWh)
Boiler excess air	16.8% (2.8% oxygen, wet basis)
LOI	2.0% (estimated)
Ambient conditions	
Dry bulb temperature	74° F
Relative humidity	60%
Barometric pressure	28.97 inHg

Based on the layout of the future draft system in Figure 6-5 and the future draft system characteristics in Table 6-9, the estimated performance requirements of the existing ID fans at MCR are shown in Figure 6-6 as the MCR Point. Also in Figure 6-6 is the Maximum Fan Runout illustrating the maximum capability of the existing ID fans in the future draft system. Note the estimated flow and pressure margins of 15 and 33 percent, respectively. These margins are below the typical ranges of the Black & Veatch recommended margins. However, they are adequate enough to warrant the reuse of the newly installed Unit 3 ID fans to limit the capital costs of the AQC upgrades being considered. Black & Veatch recommends the continued use of the existing Unit 3 ID fans in support of the proposed AQC upgrades.

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Table 6-9. Unit 3 Future Draft System Characteristics at MCR	
SCR system leakage	2.0% (estimated)
Air heater leakage	10.0% (estimated)
PJFF system leakage	**3.0%**
Flue gas temperatures	
Boiler outlet	730° F
SCR outlet	730° F
Air heater outlet	340° F
ESP outlet	**(Abandoned)**
PJFF outlet	**340° F**
ID fan outlet	~370° F (calculated)
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.5 inw
SCR	10.0 inw (estimated)
Air heater	13.0 inw
ESP	**(Abandoned)**
Duct to PJFF	**1.0 inw**
PJFF	**6.0 inw**
Duct to WFGD	1.0 inw
WFGD	10.0 inw
Stack	1.0 inw

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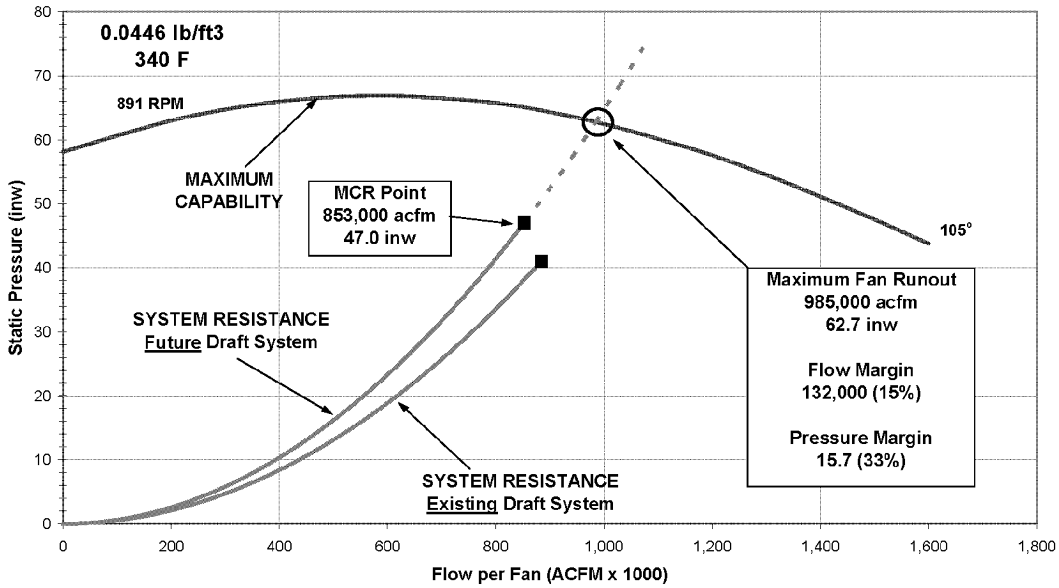

Figure 6-6. Unit 3 Existing ID Fan Performance

6.1.4 Draft System Transient Design Pressures

The AQC equipment additions and changes to all of the Brown units will likely be considered major alterations or extensions to the existing facilities per the National Fire Protection Association (NFPA) 85 code - Section 1.3 (2007 Edition). The code, in this instance, would imply that the boiler and flue gas ductwork from the boiler outlet (economizer outlet) to the ID fan inlet be designed for transient pressures of ± 35 inwg at a minimum per Section 6.5. Further research is needed to determine whether the existing boilers and draft systems of each of the Brown units meets this criteria or if they will require stiffening. Each new piece of AQC equipment, and its associated ductwork, being considered for the Brown units will also be required to meet this NFPA 85 requirement. Additionally, in some sections of the future draft systems, the transient design pressures will need to exceed the ± 35 inwg due to high negative draft pressures.

The Black & Veatch philosophy for calculating the minimum required transient design pressures is based on the draft system being designed to 66 percent of its yield stress for maximum continuous (fan Test Block) operating pressures and 95 percent for short durations, or transient conditions. This results in a 44 percent increase in the allowable stress throughout the draft system for short durations without resulting in permanent deformation or buckling of any structural components. For example, if a section of ductwork is expected to be exposed to negative draft pressures of -30 inwg when the ID fans are operating at Test Block conditions, the calculated negative transient design pressure would be 44 percent higher or -43.2 inwg. The positive transient design pressure would still be +35 inwg. Since NFPA 85 requires that flue gas ductwork between the boiler outlet and the ID fan inlet be designed for transient pressures of ± 35 inwg, calculated transient design pressures below ± 35 inwg are disregarded and the ± 35 inwg is used as the design transient pressure for that draft system component or section of ductwork. For calculated transient design pressures over ± 35 inwg such as in the previous example, the calculated pressure is used.

6.2 Auxiliary Electrical System Analysis

All units main plant auxiliary electrical system 2.4 kV or 4.16 kV auxiliary switchgear buses UA and UB are fed from their own respective two-winding unit auxiliary transformer (UAT) that is powered from their respective generator leads. UAT 1 is rated 10,000 kVA, 13.2 kV-2.4 kV supplying 2.4 kV auxiliary switchgear buses 1A and 1B, UAT 2 is rated 10,000/12,500 kVA, 17.1 kV-2.4 kV supplying 2.4 kV auxiliary switchgear buses 2A and 2B, and UAT 3 is rated 15,100/20,100/25,200 kVA 24 kV-4.25 kV supplying 4.16 kV auxiliary switchgear buses 3A and 3B. Reserve power to Unit 1 and 2 auxiliary switchgear buses is provided from the 138 kV Substation (South) through a two-winding Reserve Auxiliary Transformer (RAT) rated 10,000/12,500 kVA, 138 kV-2.4 kV. Reserve power to Unit 3 auxiliary switchgear buses is provided from the West Cliff Substation 138/69/13.2 kV transformer through a two-winding RAT rated 31,360 kVA FOA, 13.2 kV-4.25/2.45 kV.

Unit 1, 2, and 3 13.2 kV FGD switchgear buses 0AP01E-A and 0AP01E-B are fed respectively from the two-winding UAT-3C that is powered from Unit 3 generator leads. UAT-3C is rated 33,600/44,800/56,000 kVA, 25 kV-13.2 kV. Reserve power to Unit 1, 2, and 3 13.2 kV FGD switchgear buses is provided from the Unit 1 13.2 kV Generator leads through a Clip PME Triggered Current Limiter connected between the Unit 1 Generator Breaker and the Unit 1 Main Transformer 1 low voltage terminals, via 15 kV cable bus consisting of 4-1/C 500KCMIL/PH conductors. Each 13.2 kV FGD switchgear bus feed a 13.2 kV–4.16 kV step down transformer rated 13,400/17,900/22,400 kVA, that provides power to the 4.16 kV FGD switchgear buses 0AP02E-A and 0AP02E-B.

The addition of SCR and PJFF and fly ash (FA) handling equipment on Unit 1 would require the addition of one new 1,000 HP FD Fan motor. The addition of SCR and PJFF and FA Handling equipment on Unit 2 may require the addition of one new 1,500 HP FD Fan motor, and will require one 8,000 HP ID fan motor. The addition of a PJFF and FA Handling equipment on Unit 3 would not require the addition of any new significant loads. The existing Unit 1 and 3 ID fans were determined sufficient size to handle the new SCR and PJFF equipment. The new Unit 3 SCR that is being installed under a separate contract. The new total Units 1, 2, and 3 connected electrical load for the new SCR/PJFF/FA equipment including new fan loads was estimated to be approximately 20,000 kVA. The existing unit auxiliary transformers, reserve auxiliary transformers or existing FGD13.2 kV switchgear buses were determined to have insufficient spare capacity, spare circuit breakers, single speed motor starting and voltage limitations, and short circuit ratings to power all of the total loads of the PJFF, SCR and FA additions. Also, existing units 2.4 kV and 4.16 kV auxiliary switchgear buses are older vintage equipment where new additions and spare parts may be an issue.

Unit 1 and 2 will require new 13.2 kV AQC switchgear buses A and B that will be fed respectively from one two-winding UAT-3D that is powered from Unit 3 generator leads. The new UAT-3D will be rated approximately 16,500/22,000/27,500 kVA, 25 kV-13.2 kV. Reserve power to the new Unit 1, and 2 13.2 kV AQC switchgear buses will be provided existing FGD 13.2 kV switchgear supply, via a new 15 kV cable bus consisting of -1/C 500KCMIL/PH conductors.. Each new Units 1 and 2 13.2 kV AQC switchgear bus will feed a 13.2 kV–4.16 kV step down auxiliary transformer rated approximately 5,000 kVA, that will provide power to the 4.16 kV AQC switchgear buses A and B. The new 13.2 kV AQC switchgear buses A and B will also supply power to each of the new AQC unit secondary substation (USS) transformers that will power the 480V USS for Units 1 and 2 SCR, PJFF, and FA additions

The existing 13.2 kV FGD switchgear buses will supply power to each of the new Unit 3 AQC USS transformers, and most likely power the Unit 3 SCR being installed under a separate contract. Any Unit 3 AQC medium voltage motor loads will be powered from the existing 4.16 kV FGD switchgear buses.

Further electrical studies (short circuit, motor starting, etc.) will be performed during detailed design to determine the final transformer impedance and MVA ratings. Also, further field investigation will be required to determine the best way to connect the new AQC reserve 13.2 kV cable bus to the existing Unit 1 13.2 kV source, and to connect to the existing UAT-3C 25 kV Isolated Phase Bus Duct connection. In addition to verify spare breaker positions are available on the existing FGD switchgear buses, and to verify how Unit 3 SCR will be powered.

The recommended location of the new Units 1 and 2 AQC 13.2 kV reserve power supply that will be connected to the new Unit 1 and 2 13.2 kV AQC switchgear will be at the existing FGD 13.2 kV supply connections . The recommended location of the new AQC UAT-3D will be in close proximity to the existing UAT-3C. Cable bus will be routed during detailed design from the secondary windings of the UAT-3D to the new Unit 1 and 2 AQC electrical building close to the new Unit 1 and 2 AQC major loads. The new Unit 3 AQC electrical equipment will be located in the new Unit 3 AQC electrical building. The new AQC electrical buildings will be located in the vicinity of the PJFF and SCR equipment for each unit as shown in the conceptual sketches in Appendix A. The buildings will contain the new medium voltage (MV) and low voltage (LV) switchgear, motor control centers (MCCs), and distributed control system (DCS) cabinets. A DC and UPS system will also be included in the Unit 1 and 2 AQC electrical building to provide control power to the switchgear and DCS system. Existing DC and UPS power from the existing Unit 3 FGD electrical building will be used for the new Unit 3 AQC Electrical Equipment Building needs. Motor control centers and DCS I/O cabinets may be installed in a small electrical building adjacent to remote AQC equipment to minimize cable lengths for the equipment in this area.

6.3 AQC Mass Balance Analysis

The addition of PJFF equipment will increase the amount of ash removed from the Brown Units.

- **Ash Handling**--Additional new ash handling system will be required for new PJFF. Additional ash handling equipment may include but is not limited to pipes, blowers, valves, etc. There will be approximately 6,200 lb/hr of additional waste (ash) generated for Brown Station.

6.4 Reagent Impact Analysis

- **Anhydrous Ammonia System**--There will be an increase in the amount of ammonia required if SCR systems are implemented on Brown Unit 1 and Unit 2. Additional equipment required for anhydrous ammonia system may include but is not limited to an ammonia storage tank, ammonia feed pumps, dilution air blowers, vaporizers, pipes, valves, instrumentation and control equipments etc. There will be approximately 300 lb/hr of additional anhydrous ammonia required for Brown Unit 1 and Unit 2.
- **PAC Injection System**--A new PAC injection system will be required for mercury and dioxin/furan control. Additional equipment required for PAC injection system may include but is not limited to a PAC storage silo, PAC injection lances, blowers, pipes, valves, instrumentation and control equipments etc. There will be approximately 1,675 lb/hr of PAC required for the Brown Station.

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- **Trona/Lime/SBS Injection System**--A new sorbent (trona/lime/SBS) injection system will be required for SO_3 control for Units 1 and 2. Additional equipment required for sorbent injection system may include but is not limited to a sorbent storage silo, injection lances, blowers, pipes, valves, instrumentation and control equipments etc. There will be approximately 3,183 lb/hr of sorbent (trona) required for the Brown Station

6.5 Chimney Analysis

Based on the recommendations made in Section 5.2, analysis of the chimneys at the Brown Station is not required. The Brown Station Units 1-3 will continue to use the single common chimney downstream of the existing common WFGD. As proposed, the ductwork will also retain the capability to allow exhaust from Unit 2 to bypass the WFGD to the old Unit 3 chimney, as is currently possible. LG&E/KU requested that consideration be given to providing the same bypass potential to Unit 1. Preliminary investigation determined that providing a means to bypass the WFGD and direct exhaust from Unit 1 to the old Unit 3 chimney may be feasible with the addition of interconnecting ductwork between existing Unit 1 and Unit 2 exhaust ductwork. As previously discussed, if operating Unit 1 in bypass instead of or in addition to Unit 2 is acceptable from a air permit regulatory standpoint, further investigation can be made. From a technical perspective, it is expected that the major concern would be whether the existing ductwork to the old Unit 3 chimney is sufficiently sized to carry exhaust from both Units 1 and 2 with an acceptable flow velocity.

6.6 Constructability Analysis

Several major AQC construction projects have been executed at the Brown plant site over the last several years, with at least one additional project (SCR at Unit 3) in the planning stage as of the date of this report. The construction facilities, utilities, and services established to support these projects, such as parking, material laydown, fabrication areas, temporary utilities, and support services are expected to be adequate to support the work scope presented in this study. Several of the close-in staging and final assembly areas used in the previous projects will, however, be occupied by the proposed new construction and some adjustment in laydown, staging areas, and other construction facilities will be required to support unit-specific project execution. These needs will be addressed in the detailed construction execution plan submitted by the installing Contractor.

"Brown-field" construction of major new equipment on the existing Brown plant footprint will present significant challenges in construction due to congestion, obstructions, and the need to keep existing units on line during construction. Each of the three units presents access and construction execution challenges to implementing the selected AQC technologies. Accordingly, a high level constructability analysis was completed as part of this study in order to identify and evaluate potential concerns with the arrangement presented for each unit. Two conceptual arrangement plan sketches (one covering both Units 1 and 2, the other covering Unit 3) with corresponding elevation sketches are attached to this study in Appendix A. Each sketch depicts the current proposed arrangement, including refinements made per site walk down inspections and joint project team discussion. Because of the need to maintain generation capacity to the maximum practical, it is expected that major work requiring a unit outage will be done sequentially by unit and not simultaneously. However, Unit 1 and Unit 2 are enclosed in a common building structure, require similar modifications, and share a portion of the new ductwork support frame. For the purposes of this study, it is assumed a large majority of the non-outage work for Units 1 and 2 will be executed concurrently as a single construction project to minimize staggered remobilization and access concerns. Any work expected to be completed concurrently for Units 1 and 2 will be so noted in the description that follows. The planned construction for Unit 3 is located well away from Units 1 and 2, and will be considered independently.

Following is a generalized discussion of the sequence and concerns identified with the arrangement presented for Units 1 and 2 and for Unit 3.

6.6.1 Unit 1 and Unit 2 Arrangement

As detailed on the conceptual arrangement plan, the AQC technology proposed for both Unit 1 and Unit 2 consists of replacing the existing air heater and FD fan with new equipment "remote" from that existing. Both Units 1 and 2 will each be provided with a new 100 percent capacity SCR and a corresponding 100 percent PJFF. A preliminary check confirmed that the existing Unit 1 ID fan is adequately sized for the new design conditions and will be reused in its current location. The two 50 percent ID fans existing at Unit 2 will be replaced with a single new 100 percent capacity ID fan. PAC and sorbent transfer equipment, associated ductwork, and ancillary electrical and ash handling equipment required for Units 1 and 2 will be provided in facilities common for both units, to the extent practical.

The area directly north of the existing Unit 1 and Unit 2 powerblock structure is extremely congested with ductwork, the Unit 2 chimney, the (mostly inoperative) Water

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Treatment Building, and other equipment. Reclaiming this area for new construction would involve extensive demolition and unacceptably long unit outages.

Accordingly, the major equipment required for Units 1 and 2 is proposed to be located in the parking lot area east of the Unit 1 ID fan. A new structure supporting a new FD fan, new air heater, and new SCR module would be erected for each unit in the area closest to the Unit 1 ID fan. A new PJFF would be erected for each unit immediately east of the SCR/air heater structures. The new Unit 2 ID fan would be located between the Unit 2 SCR/air heater structure and the Unit 2 PJFF. The remainder of the area west and south of the existing coal conveyor would be reserved for ash handling, electrical power and control, and PAC and sorbent facilities common to both Unit 1 and Unit 2.

Exhaust ductwork downstream of the PJFFs would remain unit-dedicated. Unit 1 exhaust ductwork would be routed from the Unit 1 PJFF outlet to the inlet of the existing Unit 1 ID fan, with the new arrangement reusing the fan in its current location. Ductwork downstream of the Unit 1 ID fan outlet would remain unchanged to the extent practical. Unit 2 exhaust ductwork would be routed from the Unit 2 PJFF outlet, through the new Unit 2 ID fan, and parallel as practical to the Unit 1 duct. It would then turn and tie into the existing Unit 2 exhaust ductwork above, and bypassing, the existing Unit 2 ID fans. Separate routing of Unit 1 and 2 exhaust ductwork will allow maximum reuse of existing duct as well as maintain Unit 2's ability to discharge to the old Unit 3 chimney, bypassing the WFGD if required.

Ductwork between Units 1 and 2 and the new air heaters and SCRs would be routed immediately adjacent to the north wall of the powerblock structure. The ductwork would be stacked to minimize its footprint and thus reduce the amount of demolition or relocation of existing equipment north of the powerblock. It is expected, however, that existing chemical storage tanks and pumps in the area will have to be relocated or demolished, and the old Water Treatment Building and the dust collection ductwork and hoppers at Unit 2 will have to be demolished to gain sufficient access along the north building wall to install the ductwork support foundations and structural framing. It is anticipated the foundations will be supported from micropiles due to the limited access available for construction equipment.

The congestion north of the powerblock building, the extensive ductwork in the area, and the coal conveyor greatly complicate crane access for installation of the new ductwork next to the building. It is expected that a common steel structure carrying both Unit 1 and Unit 2 ductwork would be constructed with a crane located to the east of this area. To minimize foundations, the support structure would likely be designed as a series of trussed "bridges" sharing foundations. Each section of ductwork would be swung into the east end of the bridge, drifted horizontally to the west on a rail or roller system, and jacked into its final location within the trusswork. Due to routing limitations, Unit 1 ductwork must be erected first on the top tier of the support frame. However, by simultaneously installing the maximum amount of Unit 1 and Unit 2 ductwork in one operation, the crane will be allowed to "work bottom to top and west to east" as ductwork for both units is completed while maintaining the east end of the trusswork support frame open to land and jack ductwork segments into place. It may be possible to set some sections of the ductwork directly in place on the support frame as the frame is erected if the lifting crane can be positioned to avoid vertical obstructions and maintain a suitable swing radius. This would eliminate jacking of the ductwork, but may complicate the frame design and rigging plans. Main crane access for construction of Unit 1 and Unit 2 would be from the parking lot area to the east, with a secondary crane located between Unit 1 and Unit 2 cooling towers for installation of downstream exhaust duct.

Construction activities must be closely coordinated with plant operations to ensure adequate access is maintained to both Units 1 and 2 ESPs, ID fans, and associated ductwork while construction is ongoing. The congested footprint limits available area to stage material. Major components of ductwork and PJFFs must be modularized for efficient execution of the work scope. It is assumed that the major component modules will be fabricated in remote fabrication areas, transported to the parking lot area east of Unit 1 or between the two cooling towers, and set in place by the main lift cranes located as noted above.

As part of each unit outage, the respective existing air heater and FD fan will need to be bypassed inside the powerblock building. Tie in work will likely begin prior to the outage by modifying the north exterior boiler wall and associated structural wall girts adjacent to each tie in point at Unit 1 and Unit 2. Temporary rigging and support steel will be installed as required to remove existing ductwork and install modified tie-in duct sections. In addition, lagging and insulation will be removed from the ductwork around the tie-in points and new ductwork flat panel sections will be staged in available floor space inside the boiler building. During the outage, existing ductwork will be demolished at the tie-in point(s) and connecting flanges installed to accept the new ductwork section(s). Once the old ductwork sections have been removed, new duct section(s) will be fabricated in place from the flat panel duct pieces previously staged in the boiler building. Post outage work will likely include insulating and lagging the new ductwork, closing the north exterior wall around the duct penetrations, and removing demolished material from the building.

The expected sequence of construction (and estimated timeframe) for installation for the Unit 1 arrangement is as follows and as noted:

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- Demolish/relocate chemical tanks and equipment and portions of the Water Treatment Building necessary to install the ductwork support structure adjacent to the Unit 1/Unit 2 powerblock building. (3 months, non-outage)
- Install foundations and structural steel for the common ductwork support structure to the extent allowed with units on line. Set, slide, and jack sections of Unit 1 and Unit 2 ductwork in and on the common support structure. (4 months, non-outage).
- Construct new foundations and any supporting structural steel superstructure for the Unit 1 and 2 SCRs, air heaters, PJFFs, and dedicated ductwork, plus foundations for common facilities (5 months, non-outage).
- Install new Unit 1 FD fan, air heater, SCR, and PJFF, plus remaining ductwork upstream and downstream to tie-in points (14 months, non-outage, to work concurrently with Unit 2 similar work scope).
- Install new Unit 2 FD fan, air heater, SCR, PJFF and ID fan, plus remaining ductwork upstream and downstream to tie-in points (16 months, non-outage, to work concurrently with Unit 1 similar work scope).
- Install common facilities such as the ash handling equipment, electrical facilities, and PAC and sorbent storage and transfer equipment (6 months, non-outage).
- Demolish required portions of Unit 1 ductwork and equipment to complete tie-in of ductwork to existing Unit 1 ductwork and ID fan (6 weeks, outage).
- Start-up and tune new Unit 1 SCR, air heater, PJFF, FD fans, PAC, sorbent, and ash handling systems (10 weeks, combined outage and non-outage).
- Demolish required portions of Unit 2 ductwork and equipment to complete tie-in of ductwork to existing Unit 2 ductwork (6 weeks, outage).
- Start-up and tune new Unit 2 SCR, air heater, PJFF, FD fans, PAC, sorbent, and ash handling systems (10 weeks, combined outage and non-outage).

The main crane east of Unit 1 will have a limited boom swing due to its close proximity to Unit 1 and the coal conveyor. Detailed rigging and lift plans must be developed for each major component installed. Installation of foundations for the common ductwork support will be problematic due to the existing congestion and the need to maintain unit operation to the extent practical. Micropiles may be required for these foundations. In addition, the following issues will have to be addressed in detail to support construction at Unit 1.

- Above and below grade utility interferences must be identified and relocations may be necessary, especially low overhead obstructions along the north access road.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed and special precautions taken in the area of the semi-exposed Unit 1 and Unit 2 cooling water piping.
- The potential and magnitude of existing equipment relocations needed to support access, crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated. The existing circulating water piping, valves and pumps located at the northeast corner of Unit 1 must be protected from damage during installation of ductwork support frame foundations and structural steel.
- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment.
- Existing plant traffic and plant parking east of Unit 1 interrupted/displaced and must be rerouted. Existing traffic patterns must be re-established prior to start of construction and parking area permanently lost due to new equipment must be relocated.
- Demolition/modification of existing ductwork, especially the ductwork located inside the powerblock building, will require selective dismantling operations in order to work around existing equipment and ancillaries.

In addition to the conceptual arrangement plan for Units 1 and 2, two alternate arrangements were developed and are included in the sketches in Appendix A. Alternate 1 was developed at the request of LG&E/KU and illustrates a conceptual arrangement for when SCRs are not included within the modification scope. However, it should be noted that it is possible that SCRs may ultimately be required at some point, even if not included as part of the modifications being studied. For that reason the new equipment shown on the Alternate 1 arrangements is located to allow installation of SCRs at both Units 1 and 2 at some point in the future.

Ductwork and access at the existing air heaters in Unit 2, although limited and congested, is not as severe as that at Unit 1. It is expected that simplicity, operability, and maintenance considerations would dictate that a new air heater and FD fan be

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installed at both Unit 1 and Unit 2, but consideration may be given to reusing the existing Unit 2 air heaters and FD fans. Accordingly, an Alternate 2 arrangement was developed to illustrate a conceptual arrangement if no new air heater or FD fan was included at Unit 2. It should be noted that this arrangement actually increases the amount of ductwork required in the congested area directly north of the Unit 1/Unit 2 powerblock building.

The two alternate arrangements and supporting details are presented for information. The majority of the constructability analysis developed for the initial conceptual arrangement would remain applicable to either of these alternates, if considered.

6.6.2 Unit 3 Arrangement

The AQC technology proposed for Unit 3 consists primarily of a 100 percent PJFF, PAC silos and transfer equipment; and the associated ductwork and ancillary equipment required to tie this equipment into the exhaust gas air stream. The two existing 50 percent ID fans are expected to be re-used in place and a new SCR and sorbent injection system are expected to be in place and operational prior to installation of the PJFF.

The new PJFF is proposed to be located south of the existing WFGD module and west of the existing ID fans. A relatively significant difference in grade exists between the area to receive the PJFF and that surrounding the WFGD. Grade stabilization and possibly a retaining wall will be required between the WFGD and the PJFF to maintain stability of the PJFF without compromising the foundation at the WFGD.

New ductwork is routed from the Unit 3 air heater outlets just inside the south wall of the Unit 3 powerblock building. The ductwork exits the Unit 3 boiler building under the new SCR facility, then turns west, and crosses over the access road and the existing Unit 3 ductwork downstream of the ID fans to the PJFF inlet. New ductwork is also routed from the PJFF outlet to the inlets of the existing ID fans. No changes are expected to any equipment downstream of the ID fans. Existing ESPs south of Unit 3 will be bypassed and abandoned in place to the extent practical. New ash handling equipment will be located near the PJFF with short access to the existing ash transfer pipelines. New electrical power and control equipment will be located adjacent to the PJFF and a new PAC station and transfer station will be located accessible from the road west of Unit 3. The conceptual arrangement takes into account the currently planned SO_3-control sorbent handling facility west of the ID fans.

A major constructability concern will be installation of new ductwork beneath the SCR south of Unit 3. Routing of the new ductwork must take into account the SCR support structure, the existing ductwork in the area, and the to-be-bypassed ESP. If the

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ductwork is supported from a dedicated structure, foundations for new ductwork supports must be installed in extremely congested locations with the unit on line to avoid extended outages. Special "bridged" duct support framework, similar to that conceived for Units 1 and 2, and independent of the SCR framework, must be installed to allow sections of ductwork to be set from the west side of the SCR area, drifted horizontally to the east on a rail or roller system, and jacked into place on the support framework. A report titled, "Review of Constructability and Coordination Issues at Unit 3 SCR," File 41.0403, compiled separately, recommends designing the new SCR superstructure to support the PJFF ductwork for this project. This document has been included for reference in Appendix B. A combined structure supporting both the SCR and the ductwork is expected to be overall more economical and allow faster and easier installation than two separate support structures.

The expected sequence of construction (and estimated timeframe) for installation for the Unit 3 construction is as follows:

- Demolish and/or relocate existing structures in the way of new construction, i.e.; fire hydrant station and underground utilities, demolished building slab, etc. Complete necessary earthworks and retaining wall, if necessary, to accommodate the existing grade immediately surrounding the WFGD (3 months, non-outage).
- Construct new foundations for the PJFF, ductwork, PAC station, and associated ancillary facilities (4 months, non-outage).
- Install new PJFF and ancillary systems such as PAC, electrical gear, and ash handling, plus ductwork to tie-in points. (16 months, non-outage).
- Complete tie-in of ductwork to existing air heater outlet scrubber and ID fans. This includes selected demolition of the existing ESP units to allow installation of ductwork exiting the building from the air heater outlet. This is assumed to include removal of a section of inlet ductwork from each ESP, modifying structural framing to accommodate the removed section(s), and installation of vertical blanking plates over exposed ends. (8 weeks, outage).
- Start-up new PJFF, booster fans, PAC, and ash handling systems (10 weeks, combined outage and non-outage).

The main crane for PJFF construction will be located in the roadway south of the PJFF, with a second crane for ductwork installation located in the area west of the SCR. Limited amounts of construction material can be staged in these areas, making modularization of major ductwork and PJFF components a necessity. Major component

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modules will be fabricated in remote fabrication areas, transported to the work site via the plant access roads, raised over or around existing obstructions, and set in place by the cranes. At locations overhead access is blocked by existing components, as under the SCR, duct sections will be set on the end of the steel support superstructure, drifted horizontally on a rail or roller system, and jacked into final position. Detailed rigging and lift plans must be developed for each major component installed. Micropiles will likely be required for the ductwork foundations under the SCR. In addition, the following issues will have to be addressed in detail to support construction at Unit 3.

- Above and below grade utility interferences must be identified and relocations may be necessary, especially in the area to receive the PJFF and adjacent structures.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed.
- The potential and magnitude of existing equipment relocations needed to support access, crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated.
- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment.
- Existing plant traffic along the south plant road and road west of Unit 3 will be interrupted and must be rerouted. Existing traffic patterns must be reestablished prior to start of construction.
- Demolition/modification of existing ductwork and necessary portions of the ESP will require selective dismantling operations in order to work around the existing SCR, support structure, and ancillaries.

6.7 Truck/Rail Traffic Analysis

The modifications proposed for the three Brown units will result in additional bulk material required to support the AQC processes. These materials will be delivered from offsite on a regular basis and stored onsite for use. Preliminary estimates of the rate of use of sorbents or reagents required in the proposed AQC processes by unit are listed in Table 6-10. Additional delivery traffic for the site as a whole will be addressed accordingly. A new SCR and a new SO_3 (sorbent injection) system are already being planned for Unit 3 by others, and ammonia and sorbent storage facilities for Unit 3 are included in those plans. Table 6-10 reflects the ammonia and sorbent usage rates for Units 1 and 2 only, as well as the PAC usage rates for all three units.

Table 6-10. Sorbents and Reagents Consumption Rates (lb/hr)				
Material	**Unit 1**	**Unit 2**	**Unit 3**	**Station Total**
PAC	278	394	1,003	1,675
Sorbent (trona)	1,194	1,989	N/A	3,183 additional
Sorbent (lime)	1,237	2,061	N/A	3,298 additional
Anhydrous ammonia	114	184	N/A	298 additional

The table lists both trona and lime as possible sorbents. Either one or the other, not both, would be used in SO_3 control. The usage rate for lime is slightly higher than that for trona and thus more lime than trona would be required for continuous operation. For purposes of delivery and traffic analysis, the usage rate for lime would result in slightly more conservative results. Accordingly, bulk delivery for sorbent will be based on the usage rates for lime, noting that deliveries would be slightly less if trona is ultimately used instead.

Although a rail spur exists at the Brown Station, its use is primarily for coal delivery and no onsite spurs exist to the expected loading and storage areas for the sorbent and reagent bulk materials. Using the existing rail system for periodic delivery of other bulk materials would be expensive in terms of additional facilities required and potentially disruptive to coal delivery. Accordingly, delivery of bulk sorbents and reagents for the proposed AQC systems will be assumed to be via truck on existing roads.

Dry bulk material, such as PAC and sorbent, is normally delivered in fully-enclosed bulk delivery trucks and offloaded using a pneumatic transfer system integral to the truck. A standard over-the-road trailer truck size for these materials is nominally 20 tons per load. Anhydrous ammonia is usually transported in a pressurized tank truck with a nominal capacity of 10,000 gallons. Based on the consumption rates in the Table 6-9 above and the nominal truck sizes, the additional truck deliveries to the Brown site can be summarized as follows.

- PAC — 7 loads per week
- Sorbent — 14 loads per week additional
- Anhydrous ammonia — 1 load per week additional

Therefore, the total additional truck deliveries estimated to provide sorbents or reagents is approximately 22 loads per week. Assuming delivery operations are limited to five days a week and an 8-hour day, the maximum additional truck deliveries to site would be approximately 4.4 per day or 1 every 110 minutes over and above the current deliveries planned or already being made. Existing roads onsite should be able to accommodate the additional deliveries.

Bins or silos are often provided for each material at each unit to minimize the size and length of distribution systems. However, since the AQCS systems proposed for Units 1 and 2 are located adjacently, a single unloading and storage location is recommended to minimize unloading time and extended truck travel onsite. The arrangements as proposed combine the silos for Units 1 and 2 to minimize the new construction as well as decrease congestion. To ensure continuous operation in case one silo is out of service, two PAC storage silos and two sorbent storage silos are proposed near Units 1 and 2, each able to serve both units. Another set of four silos will be located near Unit 3; two for PAC as proposed by Phase II and two for sorbent as planned by others. Each silo is sized to store 3.5 days' usage of material to ensure 7 days total storage onsite. Estimated silo sizes, including area for transfer equipment beneath, are as follows.

- Unit 1 and 2 PAC Storage Silo – 2 x 14 foot diameter x 60 feet high
- Unit 1 and 2 Sorbent Storage Silo – 2 x 14 foot diameter x 70 feet high
- Unit 3 PAC Storage Silo – 2 x 14 foot diameter x 85 feet high
- Unit 3 Sorbent Storage Silo – (By Others)

An ammonia storage tank facility is currently being planned as part of the Unit 3 SCR addition, to be located west of the Unit 3 cooling towers. Because of the hazardous nature of stored ammonia, concentration of all ammonia storage facilities in one location is often preferred over multiple storage locations. Accordingly, it is recommended that LG&E/KU consider expansion of the planned ammonia storage facility to include storage for the ammonia to be used at Units 1 and 2. The additional volume required to store seven days' usage for Units 1 and 2 would be approximately 10,000 gallons. Placing all ammonia unloading and storage at one location has the added benefit of reducing truck traffic in other areas of the plant.

The PJFF system added at each unit will capture additional particulate that will need to be landfilled. The total expected additional fly ash removed from the exhaust streams of the three units is estimated at 6,200 lb/hr, or approximately 74 tons per day of operation of all three units. This increased volume will require additional operating time for the existing (and augmented) ash transfer systems to deliver the ash to the ash handling area. Current ash disposal activities will have to increase accordingly.

The modifications proposed include no changes to the existing common WFGD scrubber. Therefore limestone consumption and gypsum or scrubber byproduct production are not expected to change appreciably. No modifications to the existing limestone or scrubber byproduct bulk materials handling systems are expected to be required.

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7.0 Conclusion

(Later: To be completed based on the outcomes and decisions of the technology validation meeting.)

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Appendix A
Conceptual Sketches

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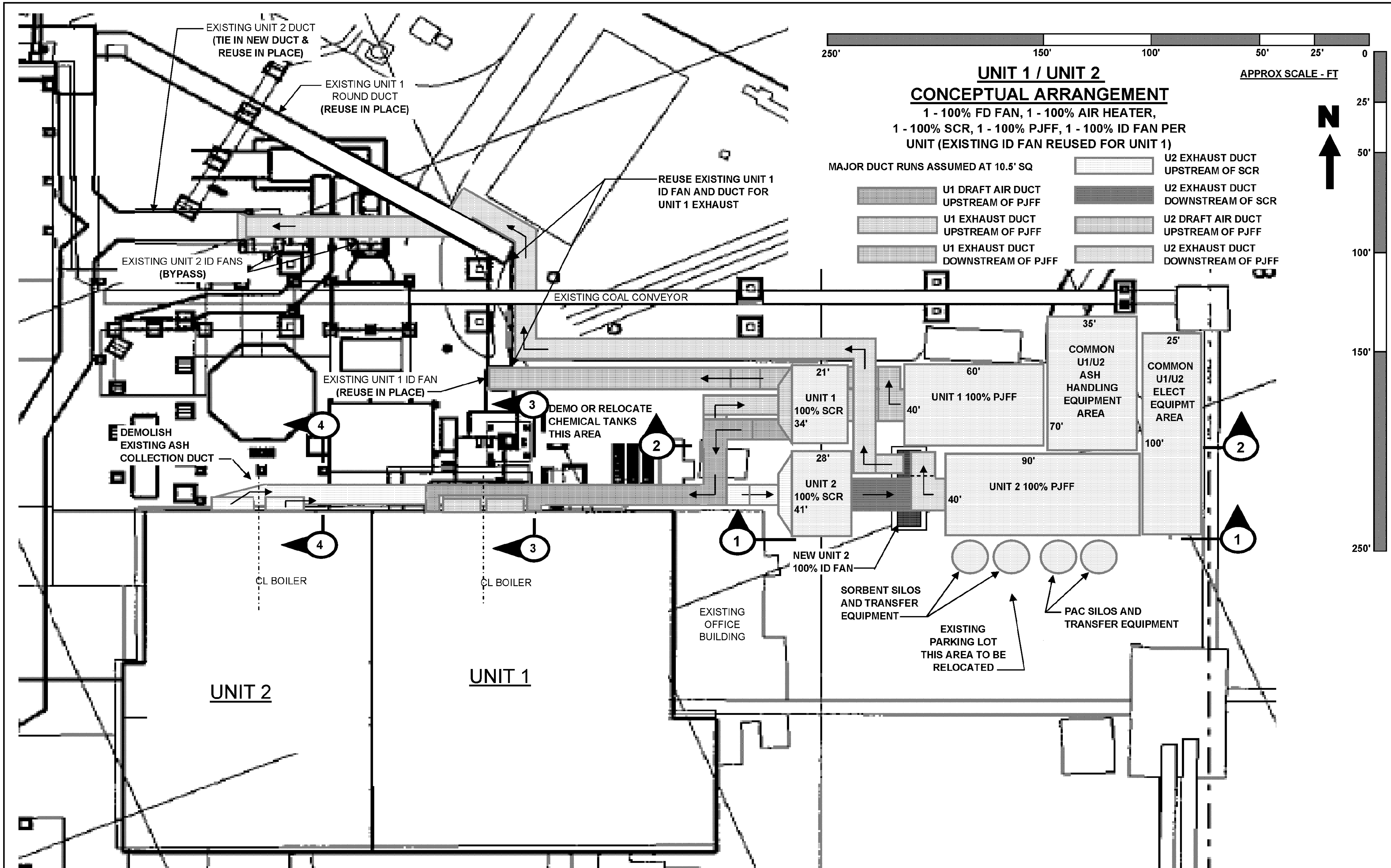
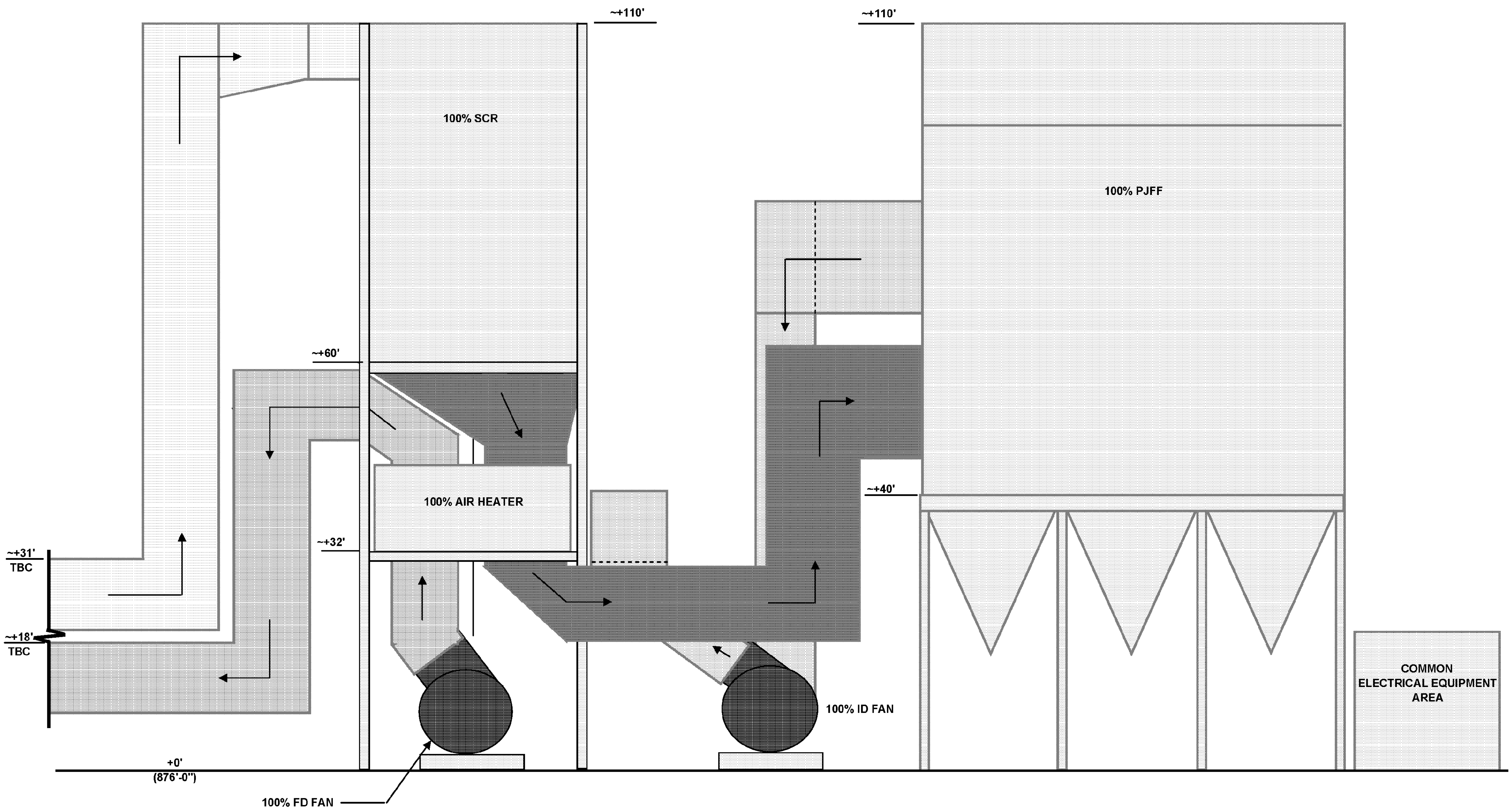
Unit 1 & 2 Arrangements with SCR, New Air Heater, and FD Fan

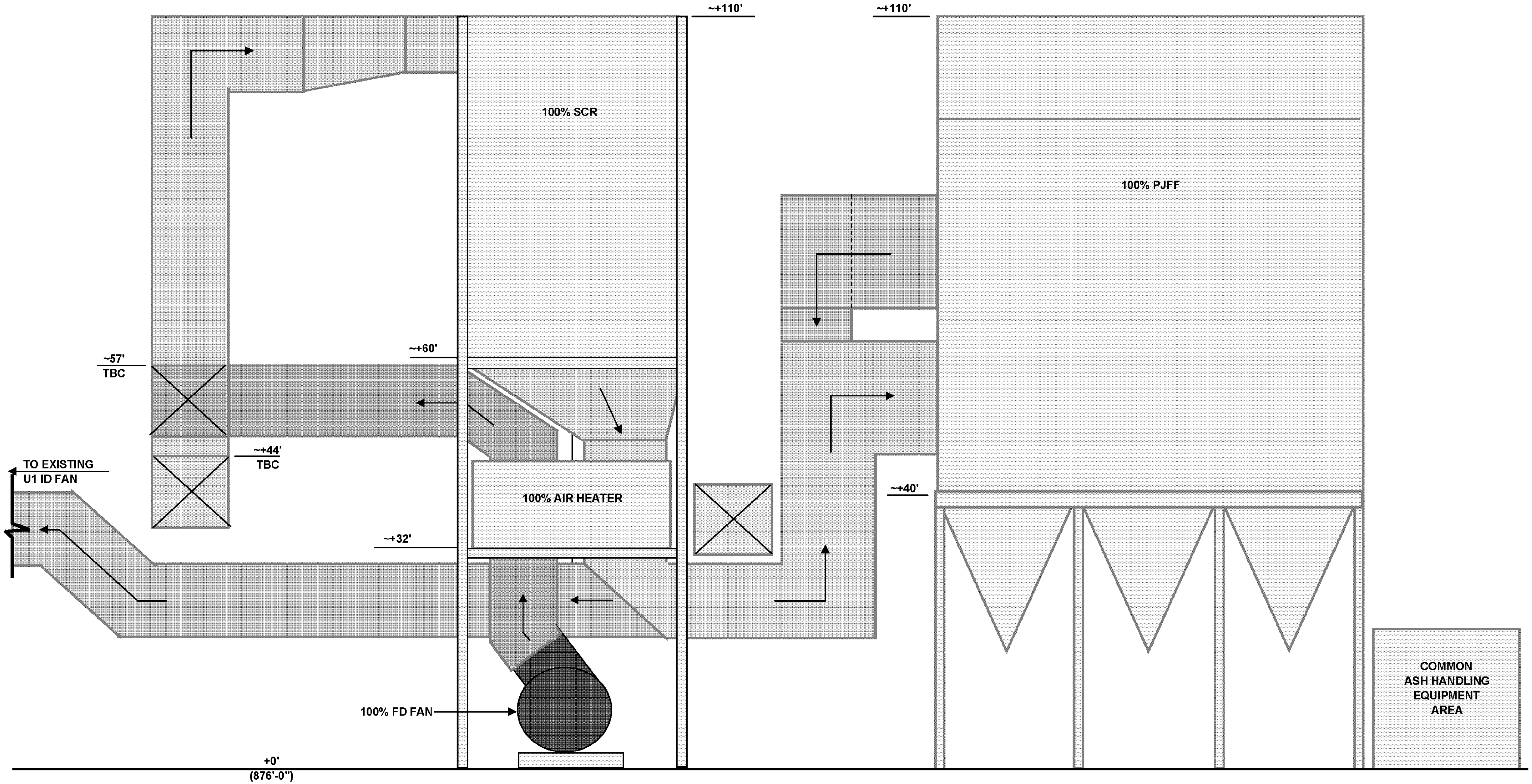


UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
1 - 100% FD FAN, 1 - 100% AIR HEATER,
1 - 100% SCR, 1 - 100% PJFF, 1 - 100% ID FAN PER
UNIT (EXISTING ID FAN REUSED FOR UNIT 1)
APPROX SCALE - FT
250' 150' 100' 50' 25' 0
N
MAJOR DUCT RUNS ASSUMED AT 10.5' SQ
U1 DRAFT AIR DUCT UPSTREAM OF PJFF
U1 EXHAUST DUCT UPSTREAM OF PJFF
U1 EXHAUST DUCT DOWNSTREAM OF PJFF
U2 EXHAUST DUCT UPSTREAM OF SCR
U2 EXHAUST DUCT DOWNSTREAM OF SCR
U2 DRAFT AIR DUCT UPSTREAM OF PJFF
U2 EXHAUST DUCT DOWNSTREAM OF PJFF
EXISTING UNIT 2 DUCT (TIE IN NEW DUCT & REUSE IN PLACE)
EXISTING UNIT 1 ROUND DUCT (REUSE IN PLACE)
REUSE EXISTING UNIT 1 ID FAN AND DUCT FOR UNIT 1 EXHAUST
EXISTING UNIT 2 ID FANS (BYPASS)
EXISTING COAL CONVEYOR
EXISTING UNIT 1 ID FAN (REUSE IN PLACE)
DEMO OR RELOCATE CHEMICAL TANKS THIS AREA
DEMOLISH EXISTING ASH COLLECTION DUCT
UNIT 1 100% SCR
21' 34'
UNIT 2 100% SCR
28' 41'
UNIT 1 100% PJFF
60' 40'
UNIT 2 100% PJFF
90' 40'
COMMON U1/U2 ASH HANDLING EQUIPMENT AREA
35' 70'
COMMON U1/U2 ELECT EQUIPMT AREA
25' 100'
NEW UNIT 2 100% ID FAN
SORBENT SILOS AND TRANSFER EQUIPMENT
PAC SILOS AND TRANSFER EQUIPMENT
EXISTING PARKING LOT THIS AREA TO BE RELOCATED
EXISTING OFFICE BUILDING
CL BOILER
CL BOILER
UNIT 2
UNIT 1
1 2 3 4



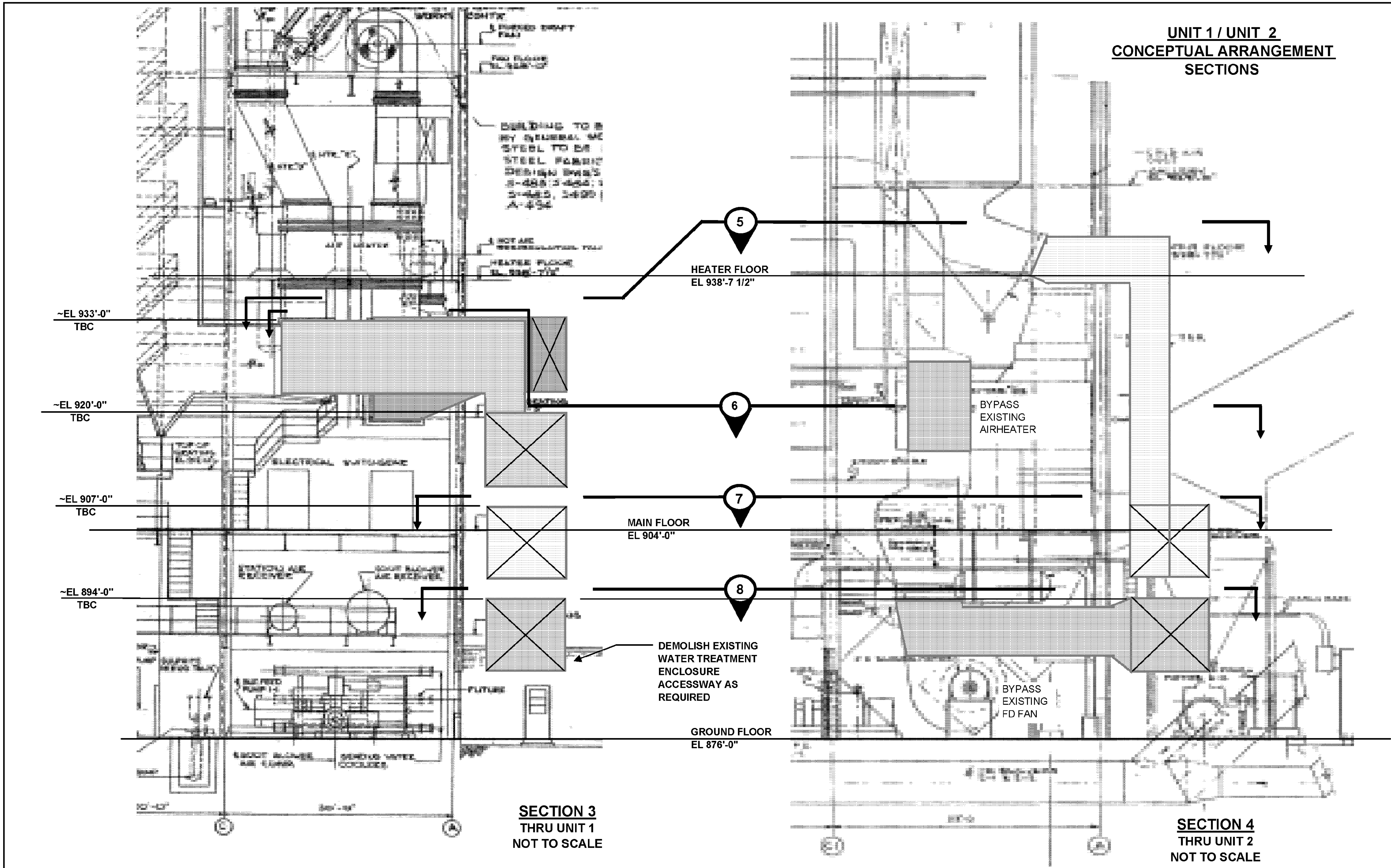
SECTION 1
UNIT 2 ELEVATION
NOT TO SCALE

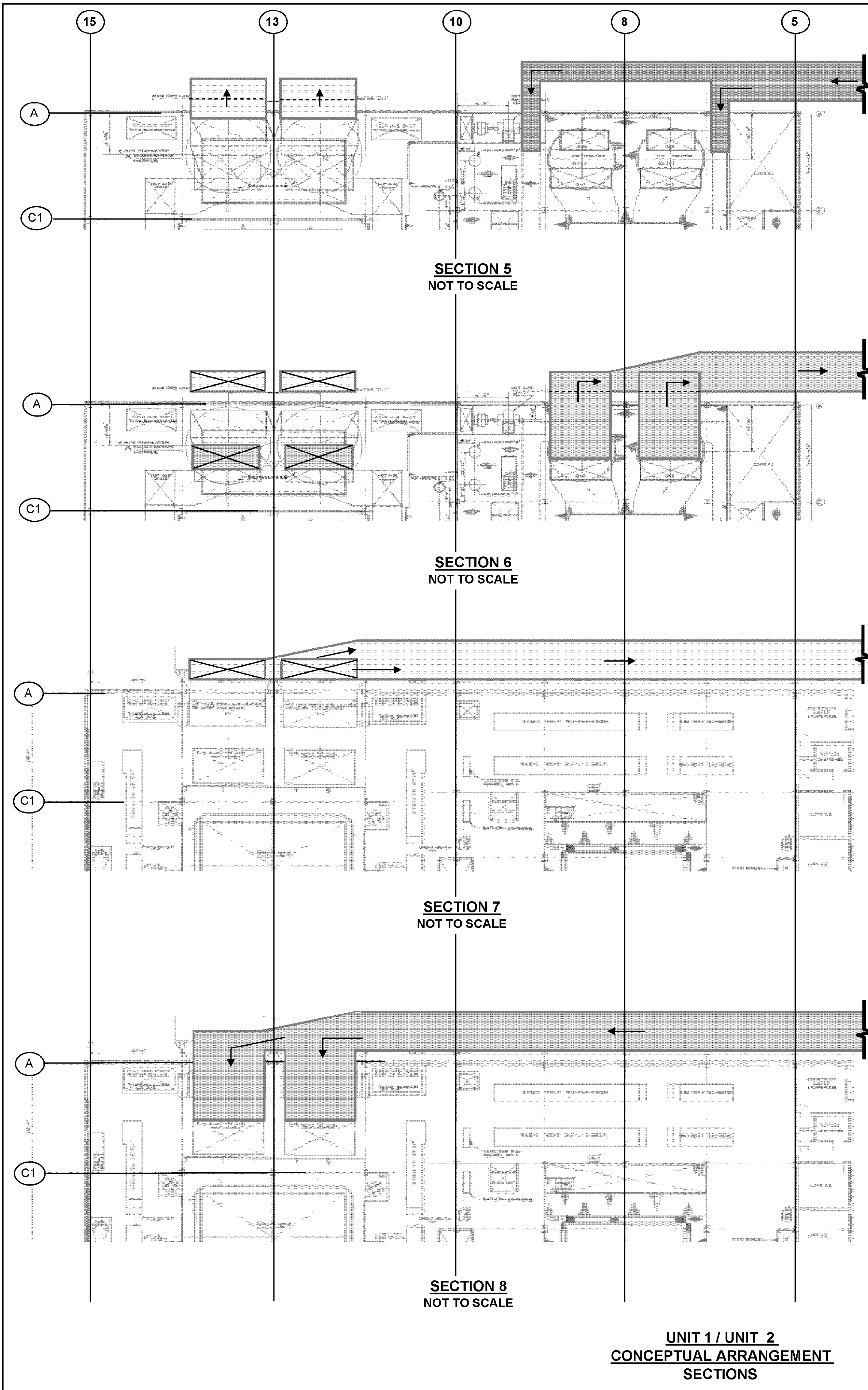
UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
SECTIONS



SECTION 2
UNIT 1 ELEVATION
NOT TO SCALE

UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
SECTIONS


UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
SECTIONS
~EL 933'-0"
TBC
~EL 920'-0"
TBC
~EL 907'-0"
TBC
~EL 894'-0"
TBC
5
HEATER FLOOR
EL 938'-7 1/2"
6
BYPASS
EXISTING
AIRHEATER
7
MAIN FLOOR
EL 904'-0"
8
DEMOLISH EXISTING
WATER TREATMENT
ENCLOSURE
ACCESSWAY AS
REQUIRED
BYPASS
EXISTING
FD FAN
GROUND FLOOR
EL 876'-0"
SECTION 3
THRU UNIT 1
NOT TO SCALE
SECTION 4
THRU UNIT 2
NOT TO SCALE


15
13
10
8
5
A
C1
SECTION 5
NOT TO SCALE
SECTION 6
NOT TO SCALE
SECTION 7
NOT TO SCALE
SECTION 8
NOT TO SCALE
UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
SECTIONS

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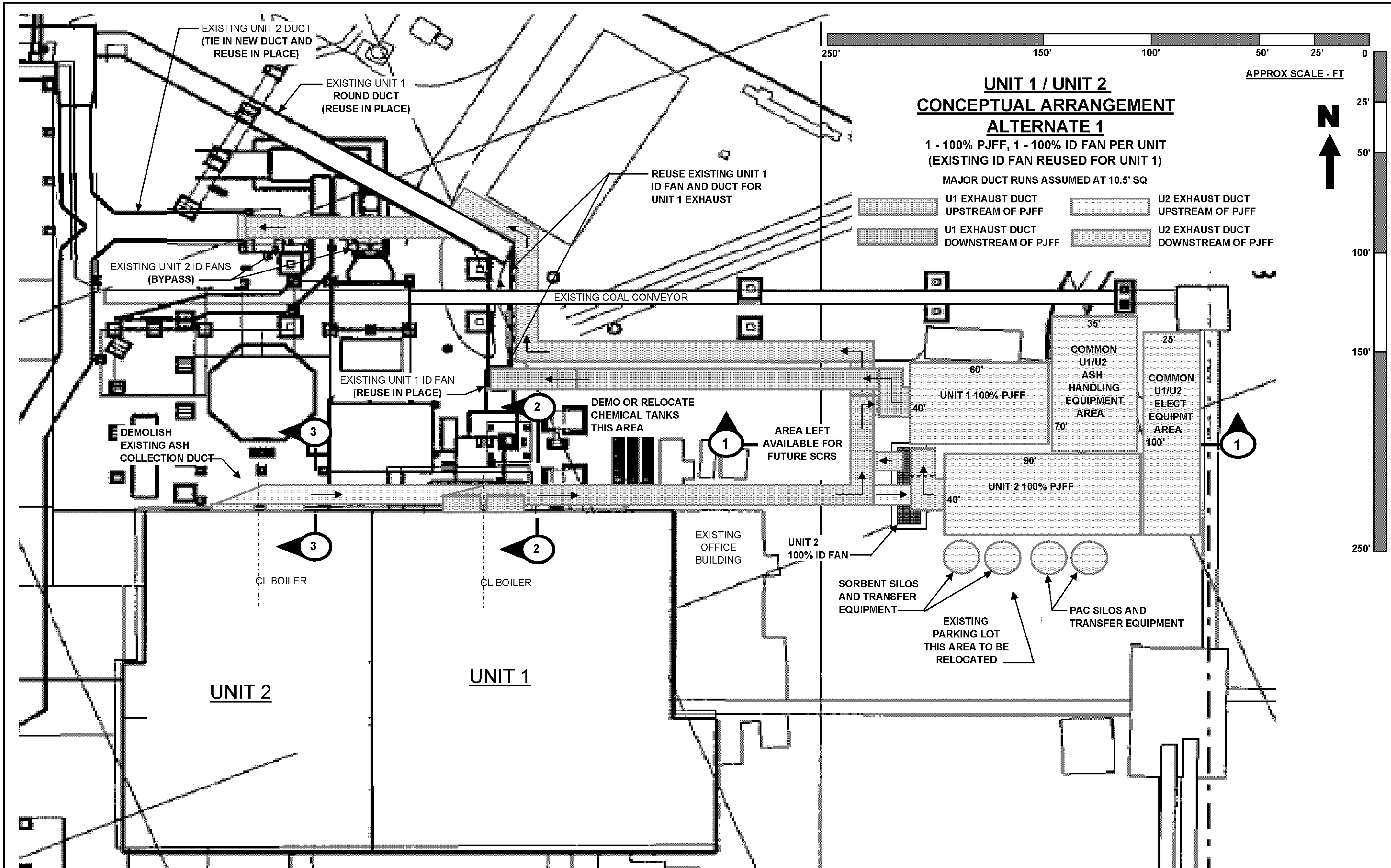
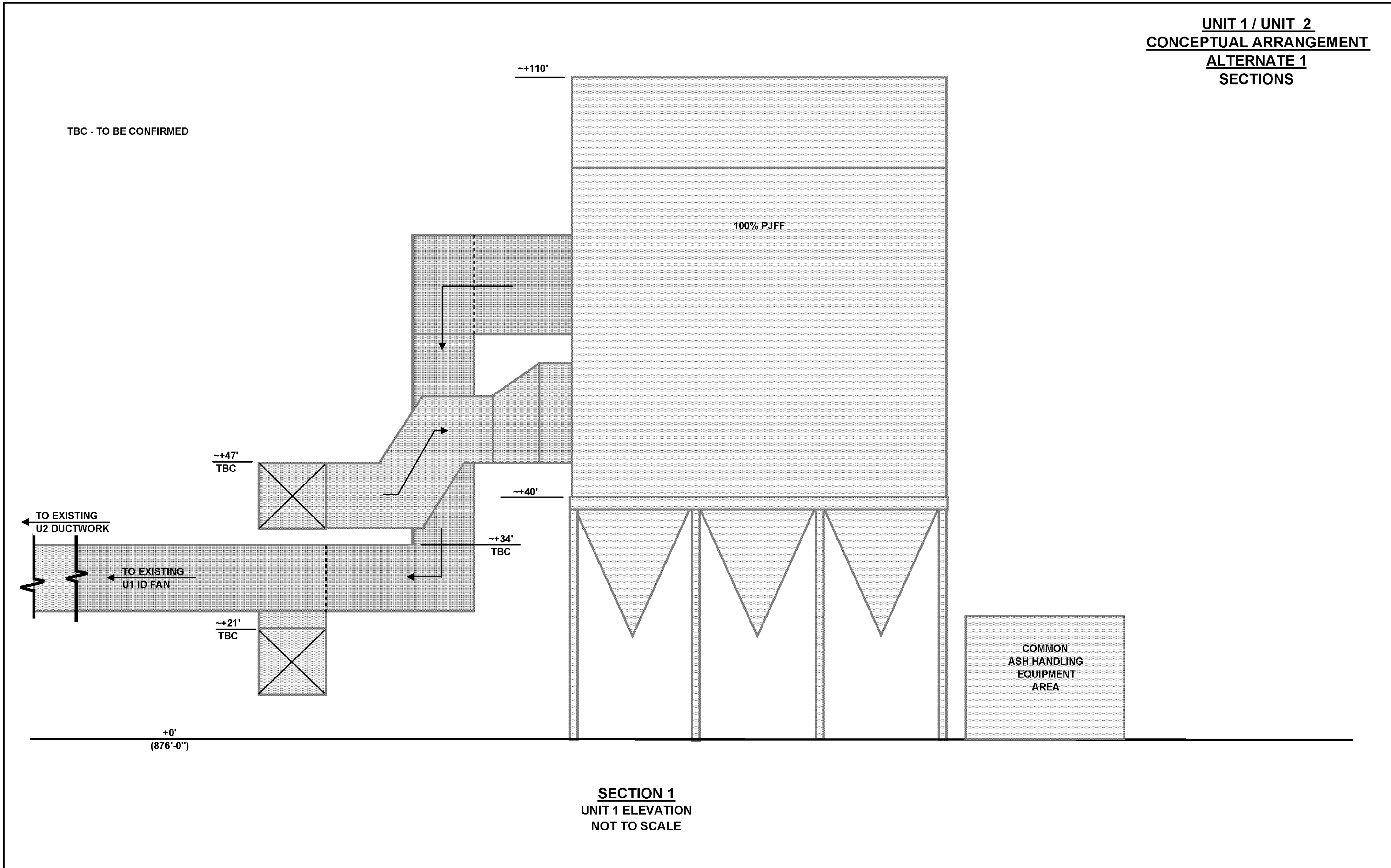
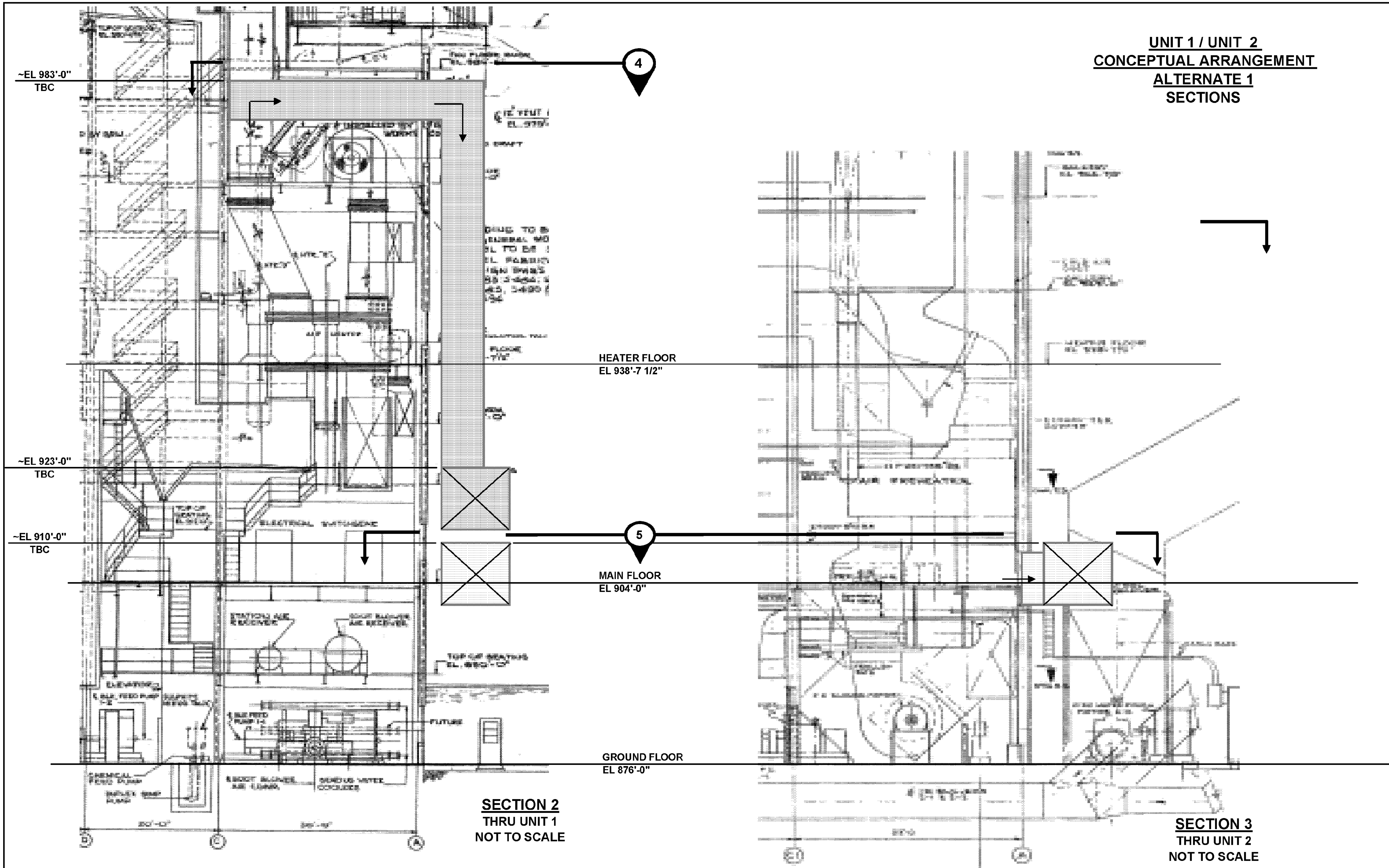
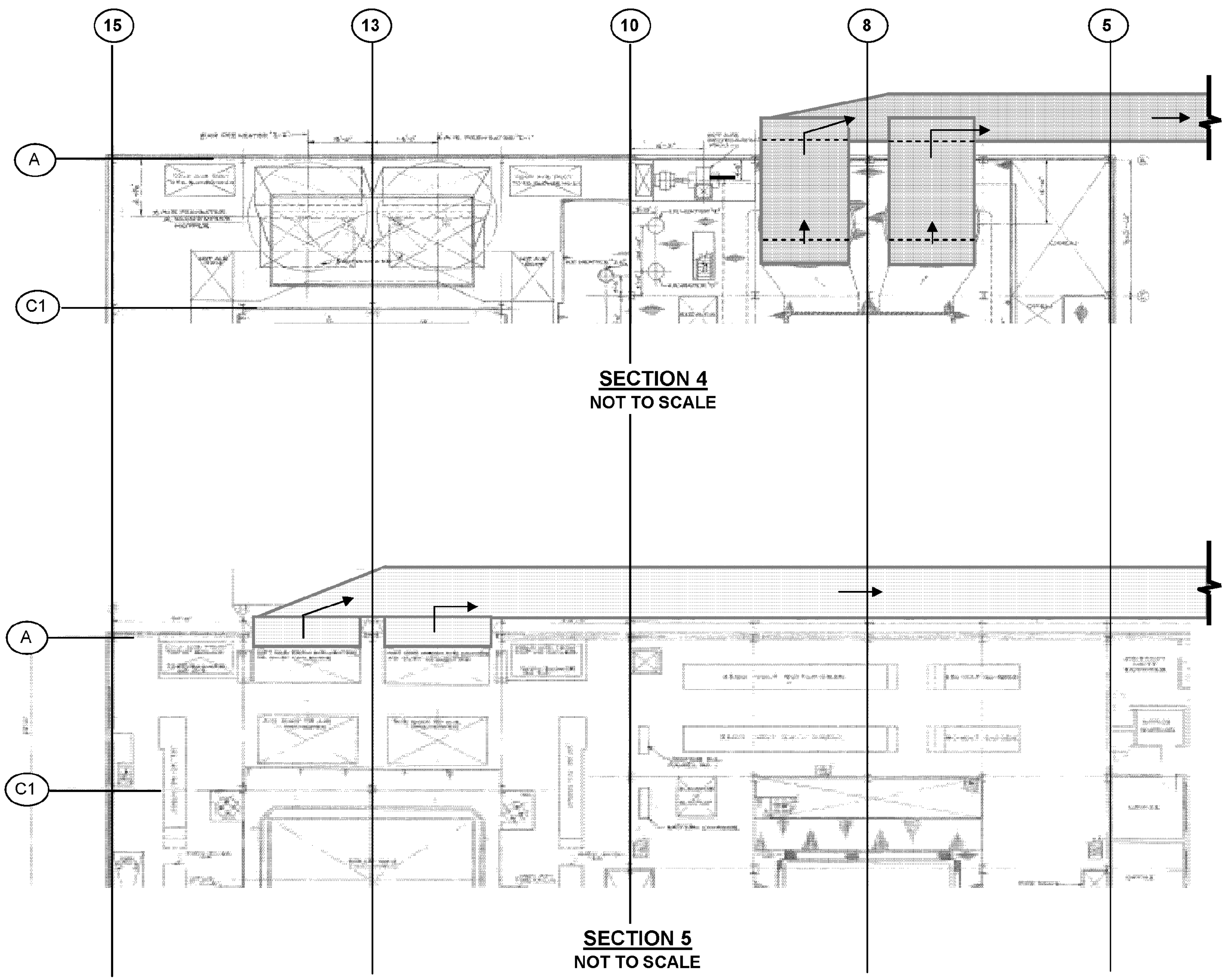
Unit 1 & 2 Arrangements without SCR, New Air Heater, and FD Fan


UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 1
1 - 100% PJFF, 1 - 100% ID FAN PER UNIT
(EXISTING ID FAN REUSED FOR UNIT 1)
MAJOR DUCT RUNS ASSUMED AT 10.5' SQ
U1 EXHAUST DUCT UPSTREAM OF PJFF
U2 EXHAUST DUCT UPSTREAM OF PJFF
U1 EXHAUST DUCT DOWNSTREAM OF PJFF
U2 EXHAUST DUCT DOWNSTREAM OF PJFF
APPROX SCALE - FT
250' 150' 100' 50' 25' 0
25' 50' 100' 150' 250'
N
EXISTING UNIT 2 DUCT (TIE IN NEW DUCT AND REUSE IN PLACE)
EXISTING UNIT 1 ROUND DUCT (REUSE IN PLACE)
REUSE EXISTING UNIT 1 ID FAN AND DUCT FOR UNIT 1 EXHAUST
EXISTING UNIT 2 ID FANS (BYPASS)
EXISTING COAL CONVEYOR
EXISTING UNIT 1 ID FAN (REUSE IN PLACE)
DEMO OR RELOCATE CHEMICAL TANKS THIS AREA
AREA LEFT AVAILABLE FOR FUTURE SCRS
DEMOLISH EXISTING ASH COLLECTION DUCT
35'
COMMON U1/U2 ASH HANDLING EQUIPMENT AREA
70'
25'
COMMON U1/U2 ELECT EQUIPMT AREA
100'
60'
UNIT 1 100% PJFF
40'
90'
UNIT 2 100% PJFF
40'
1
2
3
CL BOILER
CL BOILER
EXISTING OFFICE BUILDING
UNIT 2 100% ID FAN
SORBENT SILOS AND TRANSFER EQUIPMENT
EXISTING PARKING LOT THIS AREA TO BE RELOCATED
PAC SILOS AND TRANSFER EQUIPMENT
UNIT 2
UNIT 1


UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 1
SECTIONS
TBC - TO BE CONFIRMED
~+110'
100% PJFF
~+47'
TBC
~+40'
TO EXISTING
U2 DUCTWORK
~+34'
TBC
TO EXISTING
U1 ID FAN
~+21'
TBC
COMMON
ASH HANDLING
EQUIPMENT
AREA
+0'
(876'-0")
SECTION 1
UNIT 1 ELEVATION
NOT TO SCALE


UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 1
SECTIONS
~EL 983'-0"
TBC
4
HEATER FLOOR
EL 938'-7 1/2"
~EL 923'-0"
TBC
~EL 910'-0"
TBC
5
MAIN FLOOR
EL 904'-0"
GROUND FLOOR
EL 876'-0"
SECTION 2
THRU UNIT 1
NOT TO SCALE
SECTION 3
THRU UNIT 2
NOT TO SCALE



UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 1
SECTIONS

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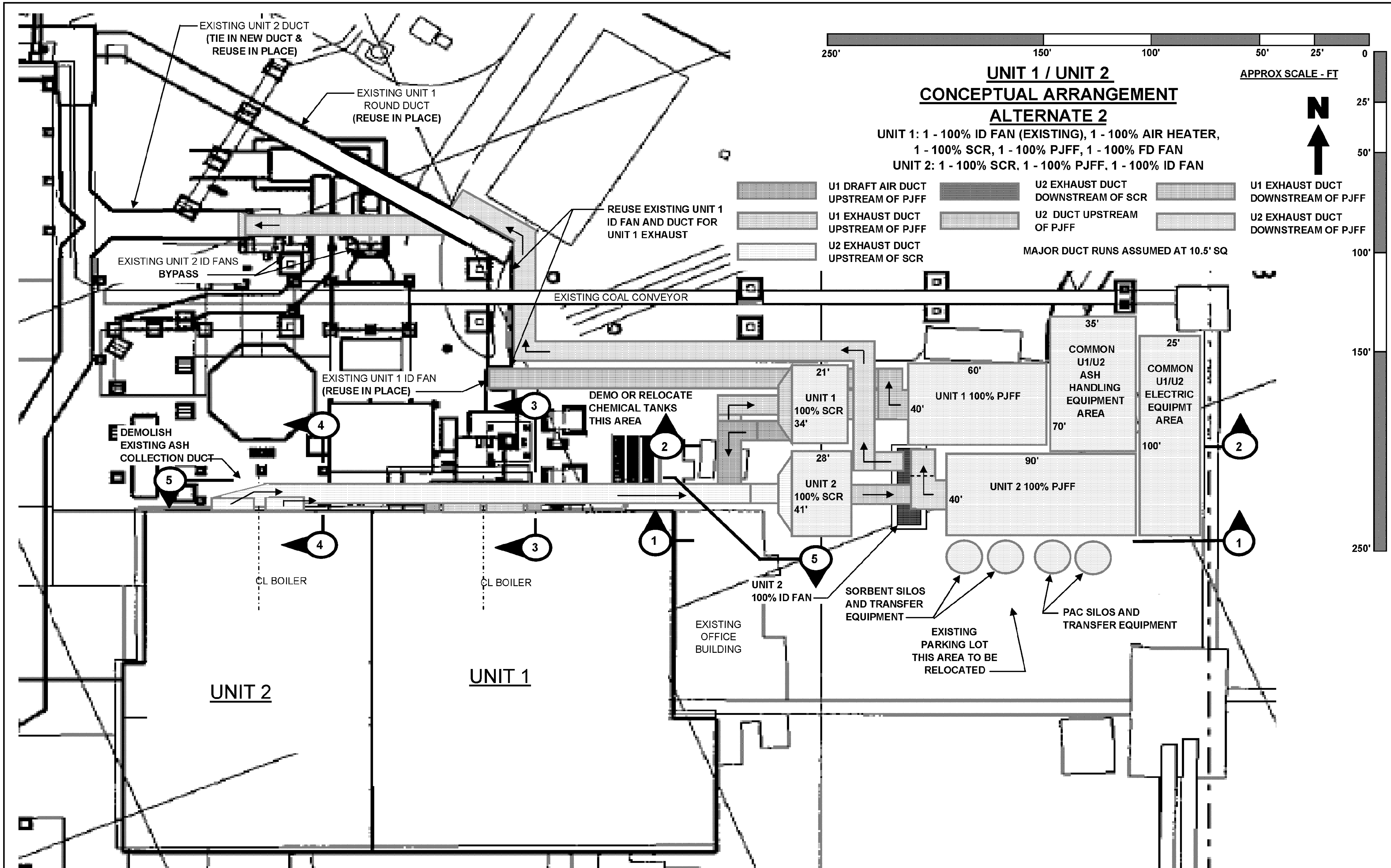
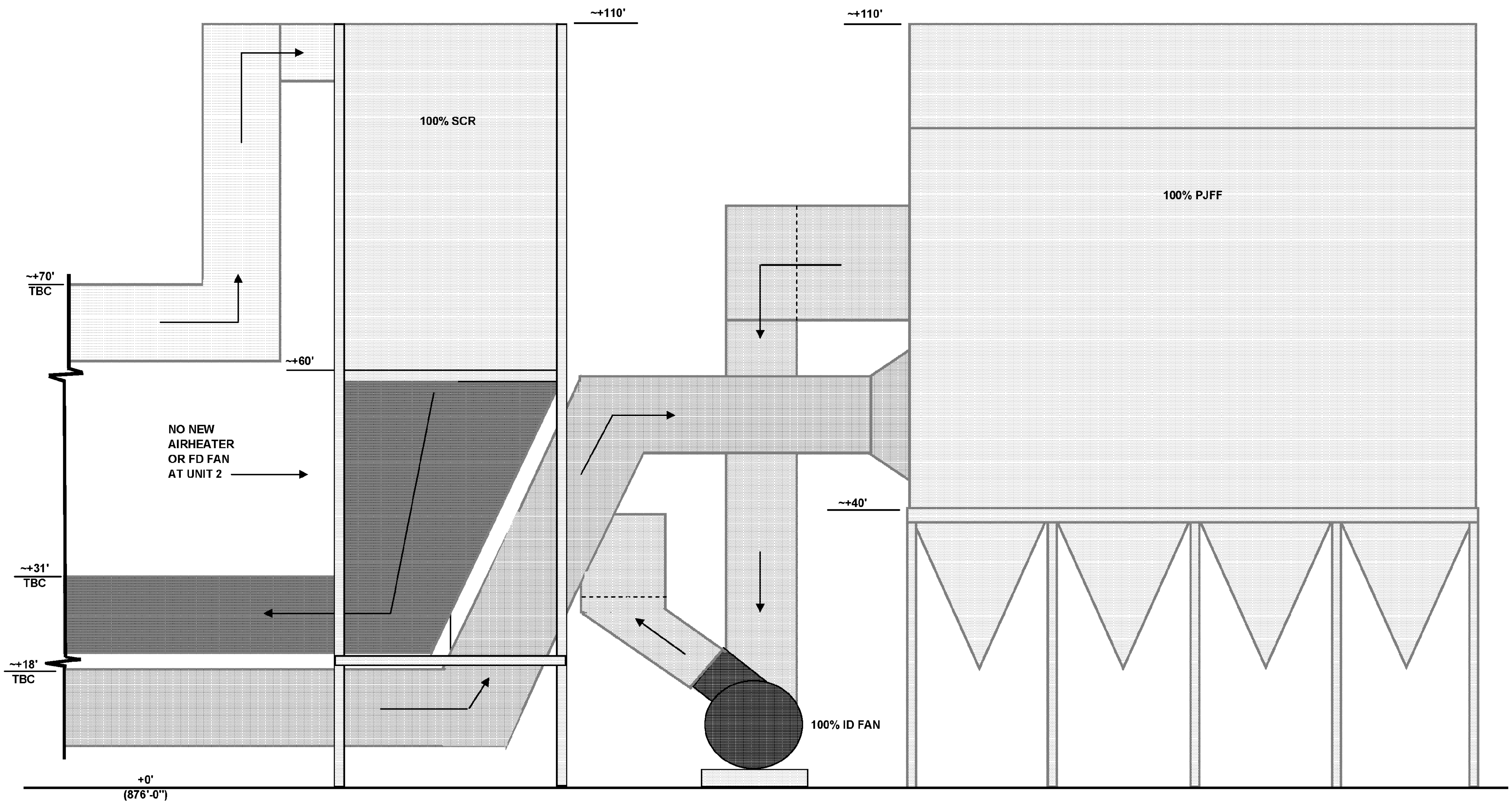
Unit 1 and 2 Arrangements with SCR at Both Units, and New Air Heater and FD Fan at Unit 1 Only

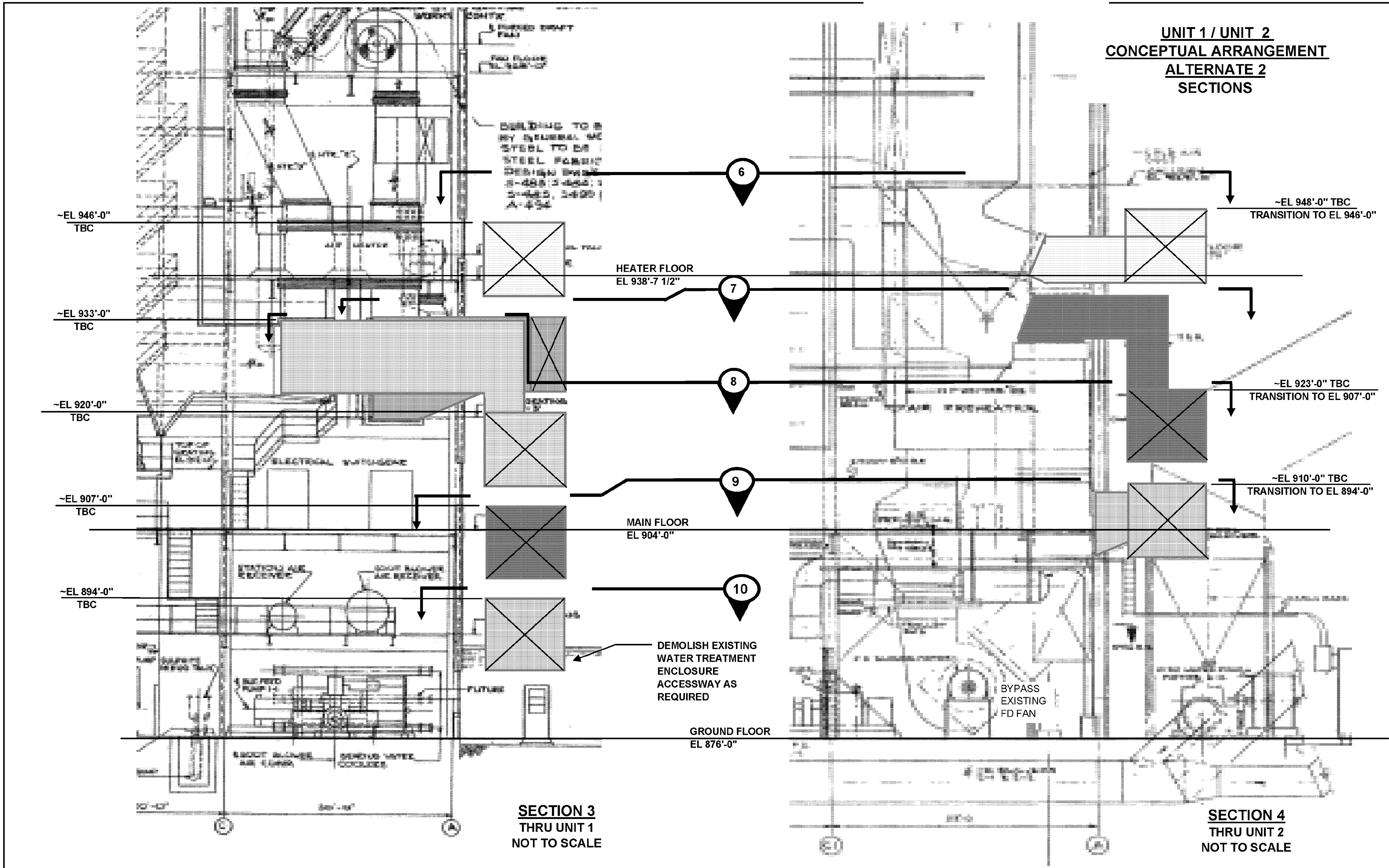

UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 2
UNIT 1: 1 - 100% ID FAN (EXISTING), 1 - 100% AIR HEATER,
1 - 100% SCR, 1 - 100% PJFF, 1 - 100% FD FAN
UNIT 2: 1 - 100% SCR, 1 - 100% PJFF, 1 - 100% ID FAN
APPROX SCALE - FT
250'
150'
100'
50'
25'
0
N
U1 DRAFT AIR DUCT UPSTREAM OF PJFF
U1 EXHAUST DUCT UPSTREAM OF PJFF
U2 EXHAUST DUCT UPSTREAM OF SCR
U2 EXHAUST DUCT DOWNSTREAM OF SCR
U2 DUCT UPSTREAM OF PJFF
U1 EXHAUST DUCT DOWNSTREAM OF PJFF
U2 EXHAUST DUCT DOWNSTREAM OF PJFF
MAJOR DUCT RUNS ASSUMED AT 10.5' SQ
EXISTING UNIT 2 DUCT (TIE IN NEW DUCT & REUSE IN PLACE)
EXISTING UNIT 1 ROUND DUCT (REUSE IN PLACE)
REUSE EXISTING UNIT 1 ID FAN AND DUCT FOR UNIT 1 EXHAUST
EXISTING UNIT 2 ID FANS BYPASS
EXISTING COAL CONVEYOR
EXISTING UNIT 1 ID FAN (REUSE IN PLACE)
DEMO OR RELOCATE CHEMICAL TANKS THIS AREA
DEMOLISH EXISTING ASH COLLECTION DUCT
21'
UNIT 1 100% SCR
34'
28'
UNIT 2 100% SCR
41'
60'
UNIT 1 100% PJFF
40'
90'
UNIT 2 100% PJFF
40'
35'
COMMON U1/U2 ASH HANDLING EQUIPMENT AREA
70'
25'
COMMON U1/U2 ELECTRIC EQUIPMT AREA
100'
CL BOILER
CL BOILER
UNIT 2 100% ID FAN
SORBENT SILOS AND TRANSFER EQUIPMENT
EXISTING PARKING LOT THIS AREA TO BE RELOCATED
PAC SILOS AND TRANSFER EQUIPMENT
EXISTING OFFICE BUILDING
UNIT 2
UNIT 1
1
2
3
4
5

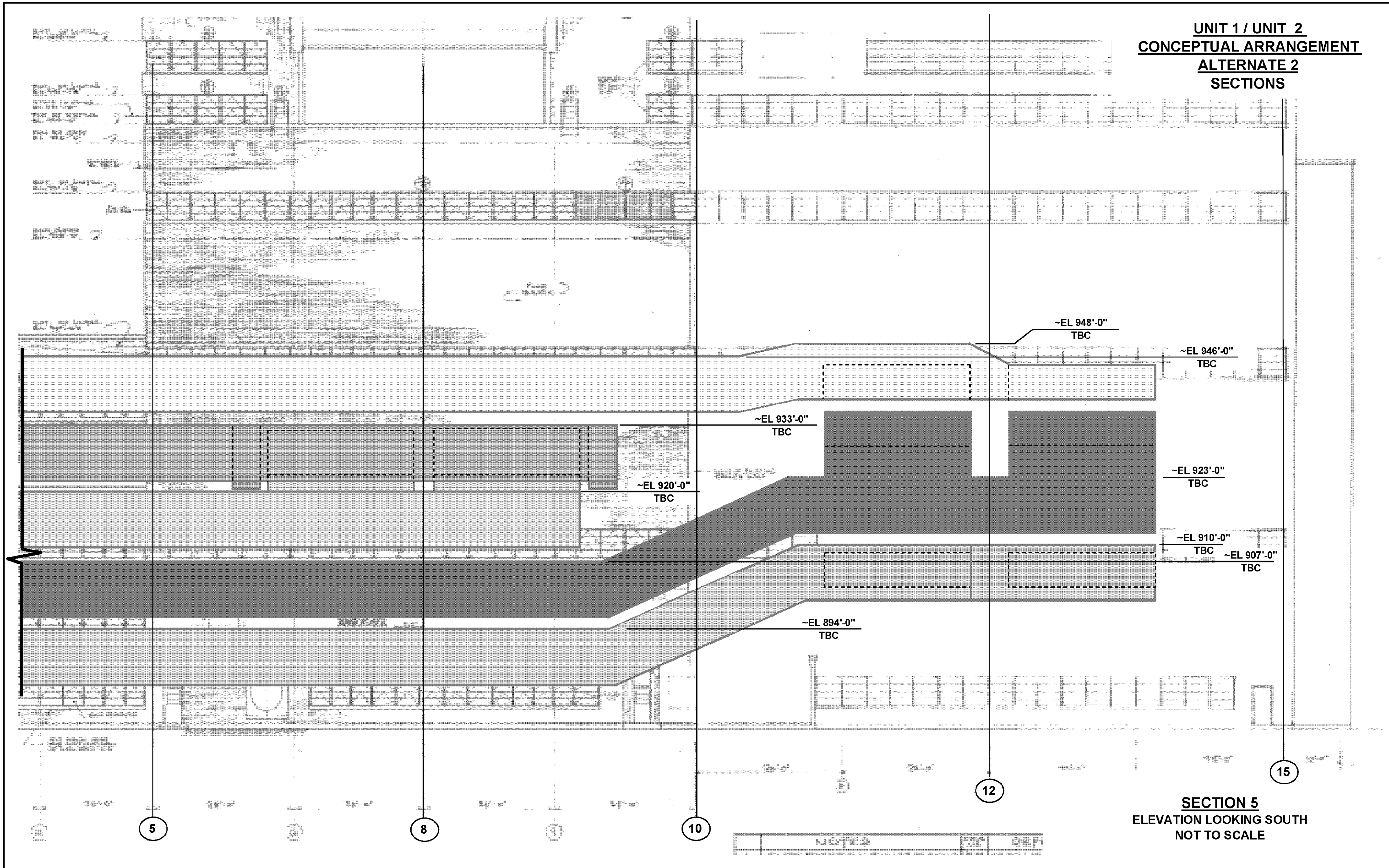


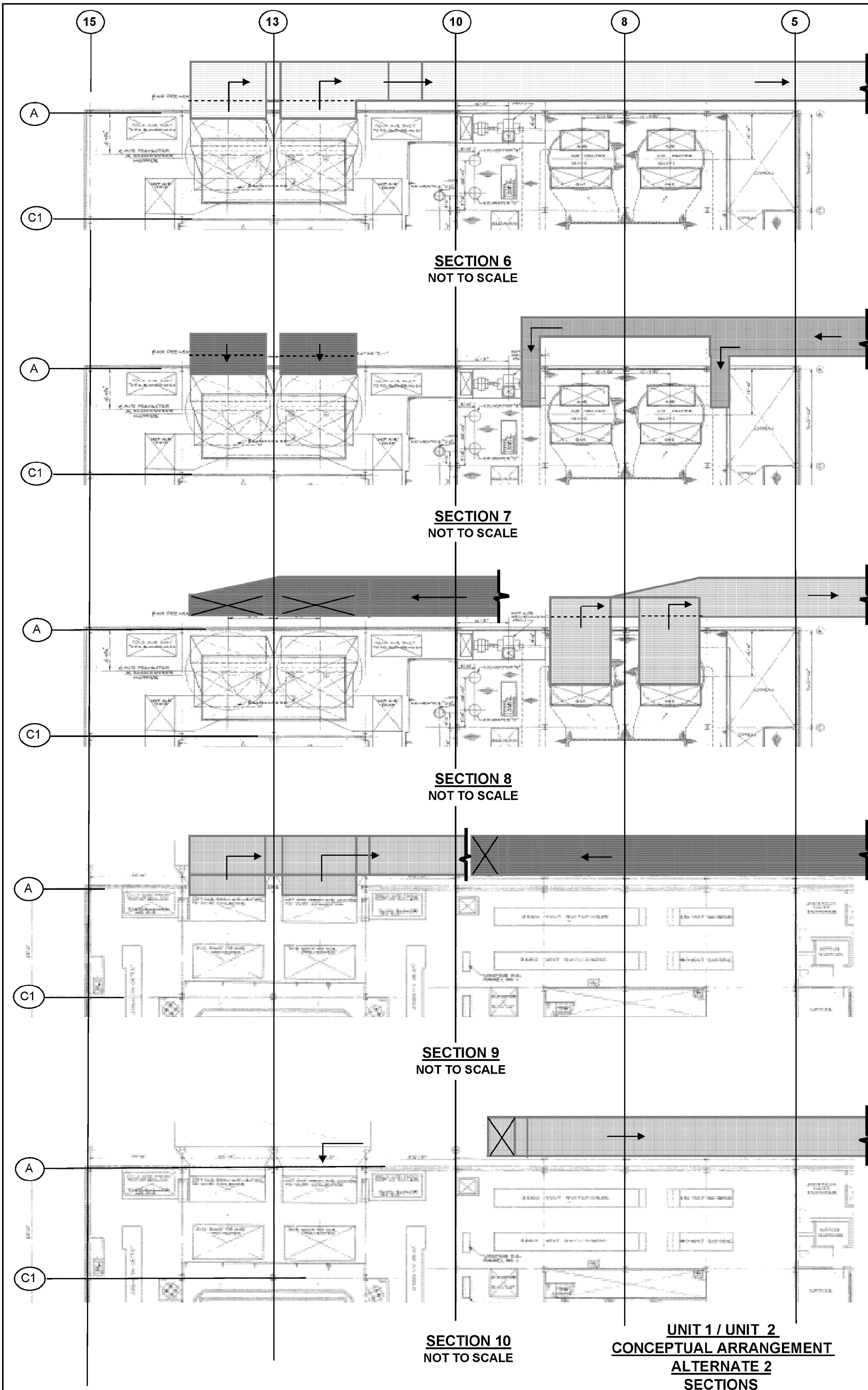
SECTION 2
THRU UNIT 1 SIMILAR TO SECTION 1 ON
ORIGINAL CONCEPTUAL ARRANGEMENT
NOT TO SCALE

SECTION 1
THRU UNIT 2
NOT TO SCALE

UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 2
SECTIONS

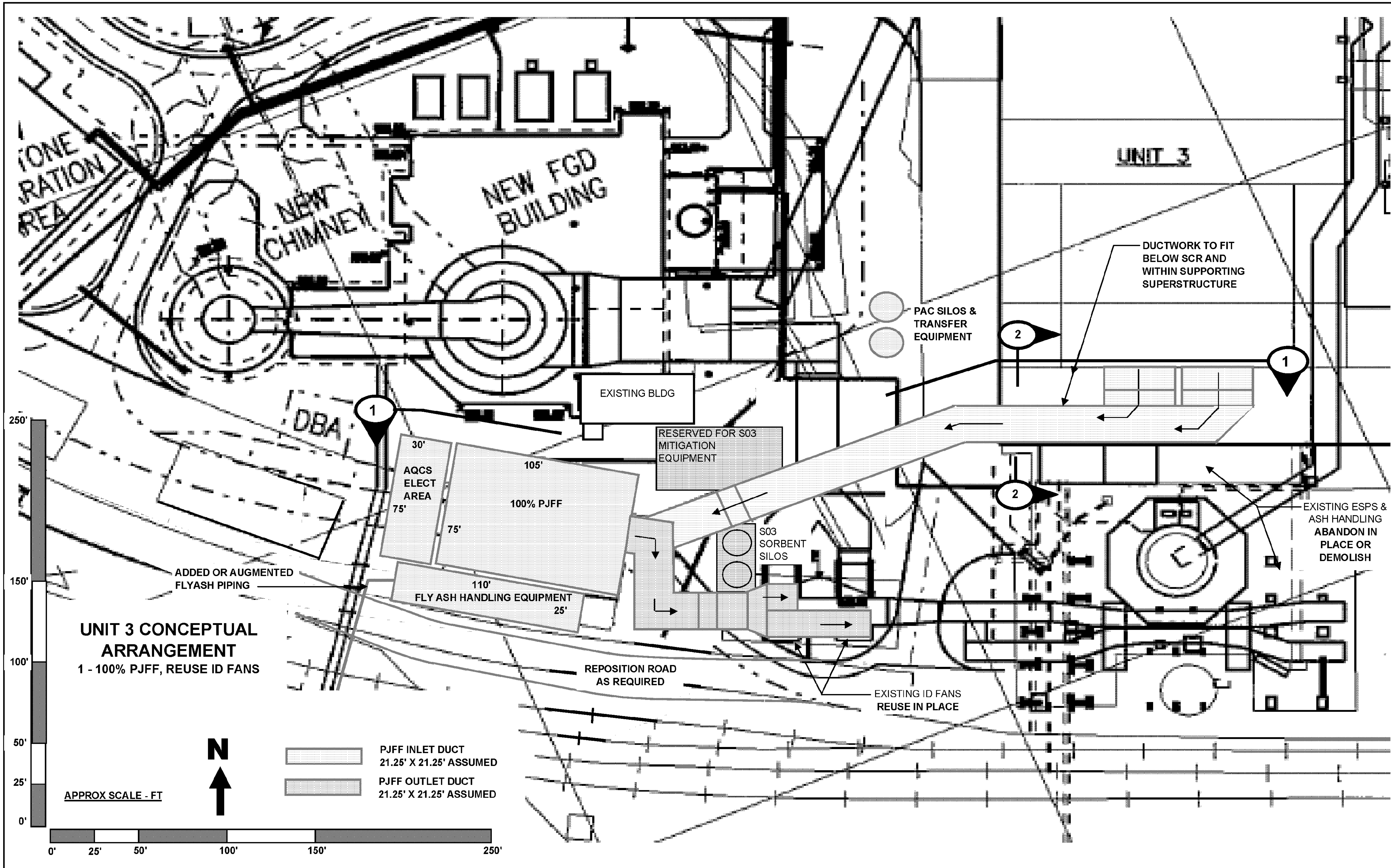

UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 2
SECTIONS
~EL 946'-0" TBC
~EL 933'-0" TBC
~EL 920'-0" TBC
~EL 907'-0" TBC
~EL 894'-0" TBC
HEATER FLOOR EL 938'-7 1/2"
MAIN FLOOR EL 904'-0"
GROUND FLOOR EL 876'-0"
6
7
8
9
10
DEMOLISH EXISTING WATER TREATMENT ENCLOSURE ACCESSWAY AS REQUIRED
~EL 948'-0" TBC TRANSITION TO EL 946'-0"
~EL 923'-0" TBC TRANSITION TO EL 907'-0"
~EL 910'-0" TBC TRANSITION TO EL 894'-0"
BYPASS EXISTING FD FAN
SECTION 3
THRU UNIT 1
NOT TO SCALE
SECTION 4
THRU UNIT 2
NOT TO SCALE

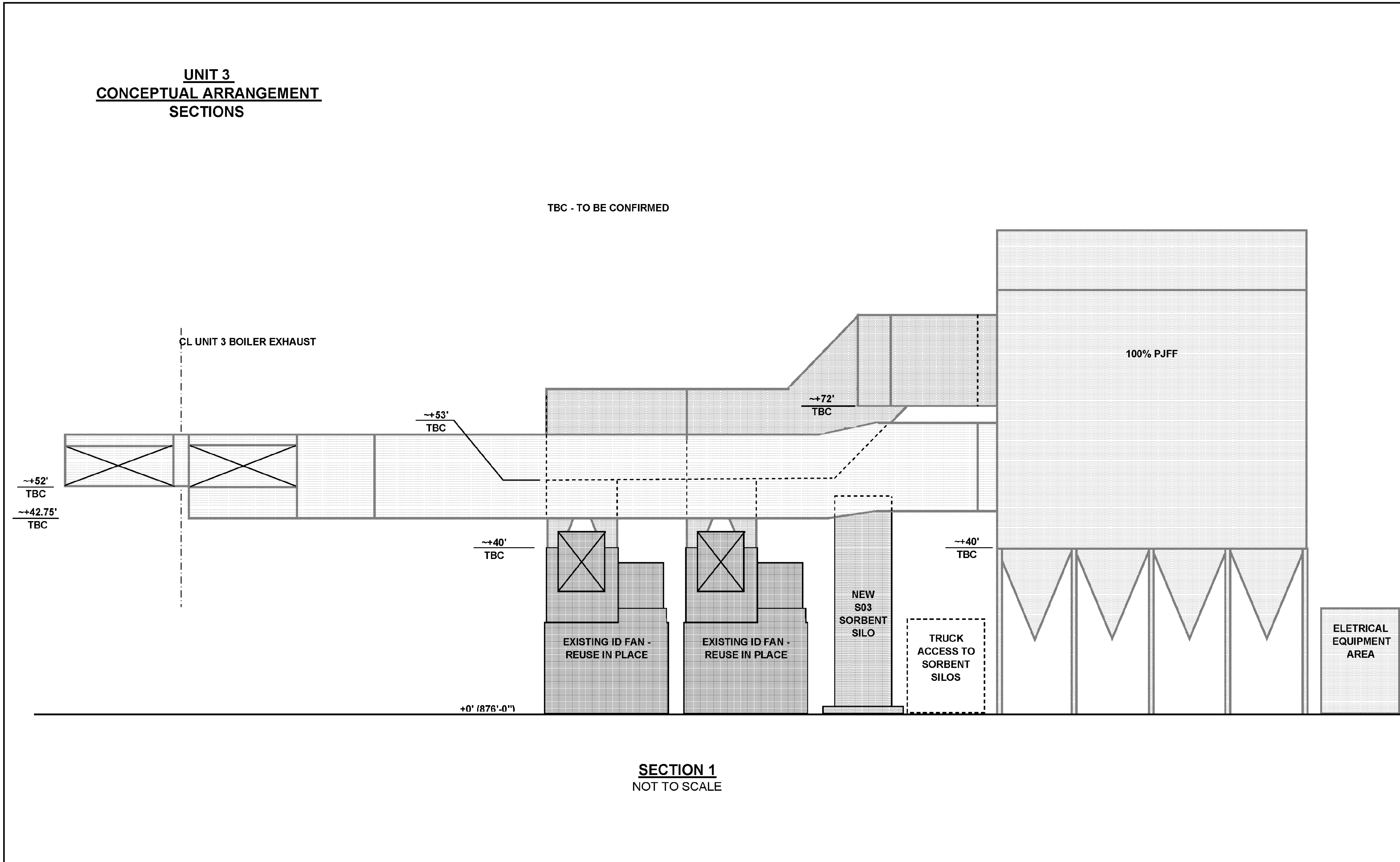

UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 2
SECTIONS
~EL 948'-0"
TBC
~EL 946'-0"
TBC
~EL 933'-0"
TBC
~EL 923'-0"
TBC
~EL 920'-0"
TBC
~EL 910'-0"
TBC
~EL 907'-0"
TBC
~EL 894'-0"
TBC
5
8
10
12
15
SECTION 5
ELEVATION LOOKING SOUTH
NOT TO SCALE

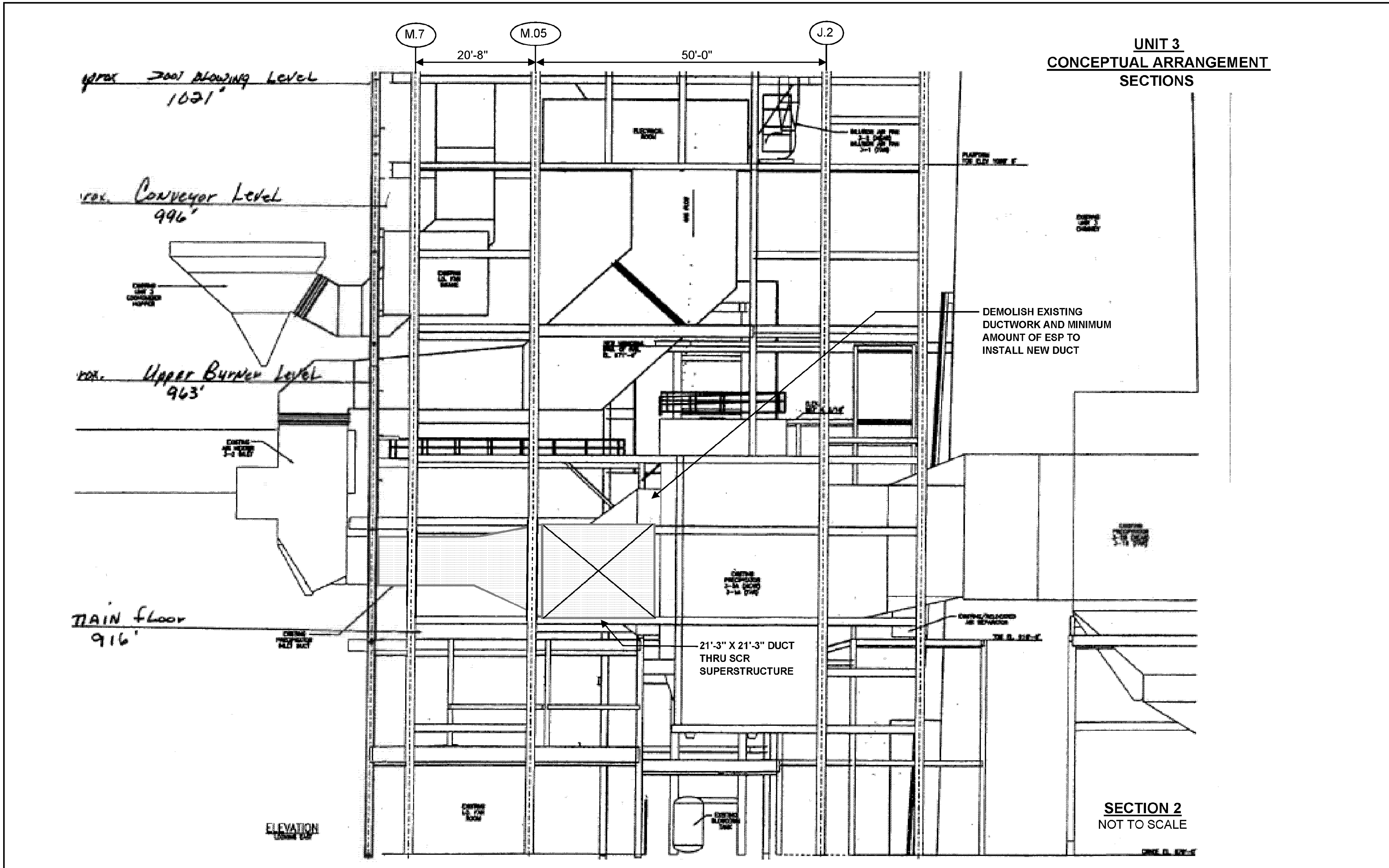

15
13
10
8
5
A
C1
SECTION 6
NOT TO SCALE
SECTION 7
NOT TO SCALE
SECTION 8
NOT TO SCALE
SECTION 9
NOT TO SCALE
SECTION 10
NOT TO SCALE
UNIT 1 / UNIT 2
CONCEPTUAL ARRANGEMENT
ALTERNATE 2
SECTIONS

DRAFT CLIENT REVIEW

Unit 3 Arrangement


NEW FGD BUILDING
NEW CHIMNEY
UNIT 3
DUCTWORK TO FIT BELOW SCR AND WITHIN SUPPORTING SUPERSTRUCTURE
PAC SILOS & TRANSFER EQUIPMENT
EXISTING BLDG
DBA
RESERVED FOR S03 MITIGATION EQUIPMENT
30'
AQCS ELECT AREA
105'
100% PJFF
75'
75'
S03 SORBENT SILOS
110'
FLY ASH HANDLING EQUIPMENT
25'
ADDED OR AUGMENTED FLYASH PIPING
EXISTING ESPS & ASH HANDLING
ABANDON IN PLACE OR DEMOLISH
REPOSITION ROAD AS REQUIRED
EXISTING ID FANS
REUSE IN PLACE
UNIT 3 CONCEPTUAL ARRANGEMENT
1 - 100% PJFF, REUSE ID FANS
N
PJFF INLET DUCT 21.25' X 21.25' ASSUMED
PJFF OUTLET DUCT 21.25' X 21.25' ASSUMED
APPROX SCALE - FT
250'
150'
100'
50'
25'
0'
0'
25'
50'
100'
150'
250'
1
2


UNIT 3
CONCEPTUAL ARRANGEMENT
SECTIONS
TBC - TO BE CONFIRMED
CL UNIT 3 BOILER EXHAUST
100% PJFF
~+72'
TBC
~+53'
TBC
~+52'
TBC
~+42.75'
TBC
~+40'
TBC
~+40'
TBC
NEW
S03
SORBENT
SILO
TRUCK
ACCESS TO
SORBENT
SILOS
ELETRICAL
EQUIPMENT
AREA
EXISTING ID FAN -
REUSE IN PLACE
EXISTING ID FAN -
REUSE IN PLACE
+0' (876'-0")
SECTION 1
NOT TO SCALE


M.7
M.05
J.2
20'-8"
50'-0"
UNIT 3
CONCEPTUAL ARRANGEMENT
SECTIONS
Conveyor Level
996'
Upper Burner Level
963'
MAIN floor
916'
DEMOLISH EXISTING
DUCTWORK AND MINIMUM
AMOUNT OF ESP TO
INSTALL NEW DUCT
21'-3" X 21'-3" DUCT
THRU SCR
SUPERSTRUCTURE
ELEVATION
SECTION 2
NOT TO SCALE

Appendix B
Review of Constructability and Coordination Issues at Unit 3 SCR

LG&E/KU – E. W. Brown Station

Phase II Air Quality Control Study

Review of Constructability and Coordination Issues at Unit 3 SCR

DRAFT CLIENT REVIEW

January 5, 2011
Revision B – Issued For Client Review

B&V File Number 41.0803

LG&E KU

BLACK & VEATCH
Building a world of difference.

Table of Contents

DRAFT - CLIENT REVIEW

1.0 Introduction

As part of the Phase II Air Quality Control System (AQCS) modification at the E. W. Brown Station, a pulse jet fabric filter (PJFF) is proposed to be added at Unit 3. Ductwork would be routed from the existing air heaters located in the Unit 3 Boiler Building to the new PJFF, with the ductwork starting near the south side of the building and turning to the west.

In the same area south of the Unit 3 Boiler Building, LG&E/KU is currently planning to construct a selective catalyst reduction (SCR) system. The SCR is supported some distance above the ductwork proposed for the PJFF, but the ductwork would have to coexist with the structural steel supporting the SCR above.

The area beneath both the planned SCR and the proposed ductwork to the PJFF is already extremely congested, making new construction difficult. Further, only limited pre-demolition of existing obstacles is possible to avoid extended outages while the SCR and the PJFF are being constructed.

Design of the SCR and its support steel has already been initiated and somewhat detailed conceptual information and arrangements already exist. The purpose of this study is to review at a high overview level the conceptual information already developed for the SCR and supporting superstructure and confirm the compatibility of the ductwork routing proposed to the PJFF with the SCR structures. Further, this study is to develop high-level estimated loads resulting from the proposed ductwork to allow consideration of their inclusion in the SCR support steel design.

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2.0 Arrangement Comparison

A conceptual design and preliminary arrangement for the SCR and its supporting structure have previously been developed by others. LG&E/KU has provided this arrangement information to allow coordination of the conceptual SCR arrangements with the ductwork routing to be considered for the Phase II Air Quality Control Study. B&V has reviewed the information and reflected it in the proposed ductwork arrangement described below.

2.1 List of SCR Information Reviewed

The following drawings containing the conceptual arrangement of the SCR and its support structure were reviewed as part of this study.

SCR General Arrangement – Riley Power Inc. Drawings

- 100468-092675100-01 – SCR General Arrangement, Plan View
- 100468-092675101-01 – SCR General Arrangement, Side Elevation View A-A
- 100468-092675102-01 – SCR General Arrangement, Elevation View B-B
- 100468-092675104-01 – SCR General Arrangement, Elevation View D-D
- 100468-092675105-01 – SCR General Arrangement, Front Elevation View E-E

SCR Support Structure – Zachry Corporation Drawings

- E013992-SCRS23610, Sheet 5, Rev A – SCR Support Structure, Isometric View
- E013992-SCRS23610, Sheet 6, Rev B – SCR Support Structure, Isometric View
- E013992-SCRS13200, Sheet 1, Rev A – SCR Support Structure, Pile Plan
- E013992-SCRS13200, Sheet 2, Rev A – SCR Support Structure, Foundation Plan

2.2 Description of Proposed Ductwork

The ductwork assumed for the Phase II Air Quality Control Study must carry the exhaust gas exiting the two Unit 3 air heaters to the inlet of the PJFF tentatively located south of the common wet flue gas desulfurization (WFGD) unit to the west. Pending confirmation required during detailed design, the two existing ducts penetrating the south wall of the Unit 3 Boiler Building are approximately 31'-9" wide by 8'-0" high, inside dimensions. Top of duct elevation is approximately El 936'-0". New ductwork must mate to the existing ductwork at an expansion joint tentatively located just inside the

Boiler Building and extend south out of the building. The two new ducts must then turn direction to the west to avoid the existing chimney and minimize the need for demolition of the existing ESPs and ductwork to the south. At minimum, the existing ductwork between the expansion joint and the original ESP must be removed to install the new ductwork. The new ductwork may remain as two separate ducts each carrying 50% of the total unit exhaust flow or may be combined into a single 100% capacity duct extending to the PJFF inlet.

To match the existing ductwork downstream of the air heaters, the new ductwork must start as 31'-9" x 8'-0", but may then transition to a different shape. The size of the transitioned shape would be such that the minimum flow velocity through the duct would be no less than 3,500 ft/min to minimize settlement of entrained fly ash out of the flow. Velocities significantly greater than 3,500 ft/min are normally avoided to minimize erosion of the duct wall due to the fly ash particles carried in the gas stream. Based on the expected exhaust flow at Unit 3 and the recommended flow velocity, the open flow area of the ductwork routed to the PJFF should total approximately 460 square feet.

Ideally, to minimize frictional losses through the ductwork, round ductwork would be specified. However, round ductwork of this size is difficult to support and extremely difficult to fabricate in transitions or turns. The installed cost of large round ductwork is therefore relatively high. Accordingly, most exhaust gas ductwork is rectangular in shape; with the most efficient non-round shape approximately square (its "aspect ratio" of height vs. width ideally approaching 1.0). Rectangular ductwork of other aspect ratios can obviously be used, providing the associated frictional losses are reflected in the design.

Thus at Unit 3, the exhaust ductwork would ideally transition from the 31'-9" x 8'-0" shapes to two rectangular shapes approximately 15'-3" square inside dimension if the two-duct configuration is maintained or to a 21'-6" square inside dimension if the two ducts are combined into one.

Exhaust ductwork is constructed of welded steel plate to maintain a gastight conduit. To minimize the thickness of the plate used and thus decrease both its cost and the loads on supports, ductwork is commonly made up of thin plate (1/4" to 3/8") stiffened with steel beam or channel sections to provide the necessary strength to carry design loads. In addition, hot ductwork is normally covered with insulation and lagging to prevent heat loss to the environment as well as for personnel protection. The thickness of the stiffeners and insulation must be added to the theoretical open height by width of the duct to determine an acceptable routing without interferences. For this ductwork an 18-inch allowance was added all around to the theoretical dimensions to account for stiffeners and insulation.

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Ductwork can be supported either from below by a steel superstructure on a foundation or hung from above if suitable superstructure is available. The ductwork is anchored at a fixed point and designed to expand and contract due to the hot gases within in all directions from that "point of zero movement."

The description above was used as the basis for a conceptual design of ductwork to be routed beneath the SCR.

2.3 Impact of SCR Structure on Ductwork Routing

From the Riley drawings review, it appeared that all components of the SCR equipment itself south of the Unit 3 Boiler Building are located above El 956'-7". Accordingly, if the ductwork is kept below that elevation, it should not interfere with any part of the SCR itself. The new ductwork is tentatively routed with the interior surface of the duct no higher than El 940'-0". With the additional 18 inch allowance for stiffeners and insulation noted in Section 2.2, the top of the ductwork envelope should be no higher than El 941'-6". It appears that the new ductwork should not interfere with the SCR equipment above.

The two Zachry isometric drawings were reviewed to determine the extent of the superstructure supporting the SCR. These drawings are undimensioned and do not contain member size information. The review was completed based on dimensions from other drawings and under the assumption the isometric drawings are somewhat to scale.

Likely because of the difficulty of installing foundations in the congested, low-clearance area beneath the existing ductwork, Zachry laid out the SCR support structure to "bridge" across this area. Large "legs" consisting of heavily-braced column steel support the bridge at the corners outside the footprint of obstructions above, plus two more legs located in the center of the area at the north and south edges. The bridge steel is composed of several layers, but no layer appears to extend below the El 945'-0" elevation at the north-south truss along Column Line 22. Again, as currently routed, the ductwork should not interfere with the horizontal steel supporting the SCR.

The northwest leg of the support structure consists of a braced tower that extends to approximately 30'-0" south of N-line in the Boiler Building. It is unlikely that bracing in this tower could be removed to allow passage of a duct between the tower columns without seriously compromising the tower's structural integrity. Accordingly, it is assumed that the duct routed west from the area under the SCR must be located south of the tower to avoid interference. The clearance to the tower in the southwest corner is over 40 feet, leaving plenty of room in between in which to route the ductwork.

The isometric drawing shows a kneebrace structure on both towers on the west side of the support, intruding on the open area between the towers. The function of the kneebraces is not apparent from the drawings reviewed, but the kneebraces appear to extend no higher than approximately El 916'-0".

From the information provided, it appears that there is adequate room to route ductwork from the air heaters towards the PJFF without interfering with the SCR or the support structure. The duct should extend no higher than El 945'-0", no lower than El 916'-0", and be routed as close as practical south of the columns at Column Line SCR-D.

2.4 Proposed Ductwork Routing

A tentative conceptual ductwork arrangement meeting the above requirements is shown on the sketches included in Appendix A. Reference Sketch 1 for a plan view of the arrangement and Sketch 2 for elevations illustrating the relationship between the ductwork and other structures. All elevations and dimensions are preliminary and must be confirmed as design of the SCR and support structure is completed.

Two ducts sized to match the existing ductwork exiting the air heaters extend south from the Boiler Building. Nominal top of duct interior is El 936'-0", with an allowance for stiffeners and lagging, El 937'-6". This is well below the expected SCR support structure at El 945'-0".

The two ducts transition into a combined duct running east-west with an interior size of 21'-6" x 21'-6". Nominal top of duct interior is El 940'-0"; nominal bottom of duct interior is El 918'-6". With an allowance for stiffeners and lagging all around, the insulated duct envelope would extend from El 941'-6" to El 917'-0". Again, the duct should clear the SCR support structure steel top and bottom. The duct would end in another expansion joint located just outside the footprint of the SCR support structure to allow expansion of the ductwork as well as isolation of loads from ductwork downstream.

The north interior surface of the 21'-6" square duct is located 31'-0 1/2" south of N-line, making the south interior surface 52'-6 1/2" south of N-line. With the 18 inch clearance all around, the insulated duct should lie between 29'-5 1/2" south of N-line to 54'-0 1/2" south of N-line. This should clear the columns of the support structure tower at Column Line SCR-D. However, it will interfere with the existing original ESP located approximately 47'-0" south of N-line. That will require the original ESP to be at least partially demolished to allow installation of the ductwork.

The conceptual ductwork sketch shows an abrupt transition between the two rectangular and single common square ducts. At final design the duct will actually be designed with a more gradual transition between the two sizes of duct to minimize disturbances to the flow and unnecessarily high friction losses. Final duct configuration would be based on the results of flow modeling. But for purposes of demonstrating

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general size and orientation of the proposed duct, the approximate arrangement shown in the sketch is deemed adequate.

The duct could be supported from below on its own dedicated support framing. As indicated on the Zachry foundation drawings, the foundations currently existing in the area beneath the duct are extensive and congested. Moreover, the existence of the ductwork overhead would significantly interfere with installation of foundations below. As done with the SCR support structure, the ductwork could be supported on a trussed "bridge" to minimize the number of individual foundations required. However, the foundations supporting the ends of the bridge would, by necessity, be much heavier and more complex. Tentative foundation locations for a dedicated ductwork support framing are shown on Sketch 3 in Appendix A.

As an alternative to a separate ductwork support structure and additional foundations in an already congested area, consideration could be given to supporting the new ductwork off the planned SCR support structure. The SCR support structure would have to be modified during design to carry the additional load. The expected additional load would need to be estimated to allow LG&E/KU to consult with the SCR support structure designer to determine the practicality of this approach.

2.5 Estimated Ductwork Loads on SCR Support Structure

Estimates of the gravity (vertical) loads inherent in the proposed ductwork arrangement are included in Table 2-1. Loads are provided both on a per-linear-foot basis and on a total by-ductwork-section basis. Since the SCR support structure designer must determine where the best ductwork support points in his structure are located, it is believed that the per-linear-foot loads will allow him to apportion the loads appropriately among the selected support points. The ductwork sections noted in the table below are delineated in Sketch 1. The intent of providing the preliminary estimated loads is to allow consideration of the feasibility and cost effectiveness of adding support of the ductwork to the design of the SCR. Should the initial evaluation prove promising, more detailed design of the ductwork would be required to confirm the arrangement and the resulting loads.

Depending on the building code used in the design, loads of different types (dead load, live load, etc.) are incorporated into design equations differently. Accordingly, the loads listed in Table 2-1 are broken into categories for the designer's use in the design equations as follows.

- Dead Load. This is the gravity load of the plates, stiffeners, and integral support steel making up the ductwork itself. It can also be considered the "reliable" dead load available to resist uplift under overturning load cases.

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- Insulation and Lagging Load. This is an allowance for the weight of the insulation and outer metal lagging on the ductwork exterior. It is broken out separately but is usually treated as a dead load for gravity load design. It is, however, often not considered as "reliable" dead load for uplift conditions since it is an allowance only.
- Live Load and Snow Load. Depending on the building code design combinations, live load and snow load are used somewhat interchangeably. An estimate was made for both live load and snow load and a single value included covering both. This load is applied only to the top surface (roof) of the ductwork.
- Ash Load. No matter how well proportioned the ductwork, some fly ash carried by the exhaust gas will settle out of the flow and accumulate on the floor of the ductwork. The ductwork proposed contains several direction changes and shape changes, both of which contribute to ash drop-out and accumulation. A fairly significant allowance is included in Table 2-1 to cover ash accumulation on the ductwork floor. Ash is also considered as dead load for gravity conditions but cannot be considered as "reliable" dead load against uplift.

It should be noted that wind and seismic loads are not included in the table. Determination of wind and seismic loads are dependent on the support arrangements and locations as well as the method used to design the SCR support structure. Should the initial evaluation using gravity loads warrant it, wind and seismic loads can be developed as part of the more detailed design. In any case, the relatively small, light, and lower-elevation ductwork should generate far less horizontal wind and seismic loads than those resulting from the SCR above.

DRAFT - SIEMENS RW

Table 2-1
Loading Summary for Proposed Ductwork
Reference Attached Sketches for Duct Section Identification

Description	Section of Duct			
	Section 1A	Section 1B	Section 2	Section 3
Interior Dimension Width, ft	31.75	31.75	21.5	N/A
Interior Dimension Height, ft	8.00	8.00	21.5	N/A
Total Length, ft	30.0	30.0	133.0	N/A
Surface Area per linear foot, sf*	254	254	462	N/A
Surface Area over Total Length, sf	7,620	7,620	61,479	1130
On Per Foot Basis				
Dead Load of 30 psf, klf	7.6	7.6	13.9	N/A
Insulation/Lagging of 10 psf, klf	2.5	2.5	4.6	N/A
Live/Snow Load of 20 psf, klf	0.6	0.6	0.4	N/A
Ash Load of 100 psf, klf	3.2	3.2	2.2	N/A
Total Load Per Foot Length, klf	13.9	13.9	21.1	N/A
On Total Length Basis				
Dead Load of 30 psf, k	229	229	1,814	34
Insulation/Lagging of 10 psf, k	76	76	615	11
Live/Snow Load of 20 psf, k	19	19	57	3
Ash Load of 100 psf, k	95	95	286	17
Total Load Per Section, k	419	419	2,772	65
Total Load Overall, k	3,675			

* The eliminated wall area in Section 2 duct due to the intersection of the Section 1 runs are ignored in the per foot calculation and reflected only in the total surface area.

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3.0 Summary of Investigation

Based on the information reviewed, it appears reasonable to assume that exhaust ductwork from the Unit 3 air heaters to the new PJFF can be successfully routed beneath the planned SCR and through the supporting structure beneath. This investigation is based on conceptual information only and would have to be confirmed as additional information on the design of the SCR and its supports becomes available. The preliminary investigation concludes that sufficient space is available to accommodate the expected ductwork. However, it is likely that the existing (and to be bypassed) ESP immediately south of the Unit 3 Boiler Building will have to be demolished before the ductwork can be installed.

To avoid the costly and schedule-intensive work of installing a separate ductwork support structure and its foundations in the area, consideration should be given to supporting the new ductwork from the structure planned for supporting the SCR. This will require further investigation by LG&E/KU and the SCR support structure designer to verify the feasibility of this approach. Supporting the ductwork from the SCR support structure will likely result in some redesign, and associated cost increases, to that scope. To allow determination of the conceptual feasibility of this approach, high level approximate loads for the proposed ductwork were developed for the SCR designer's information and use. The loads are contained in Table 2-1, within.

Should a preliminary evaluation of the estimated loads conclude that incorporating support of the new ductwork into the support structure carrying the SCR is warranted, additional design work and coordination with the SCR support designer is recommended. The preliminary ductwork design described herein should be refined and more exact determination of expected loads at specific load points chosen by the SCR support structure designer should be completed.

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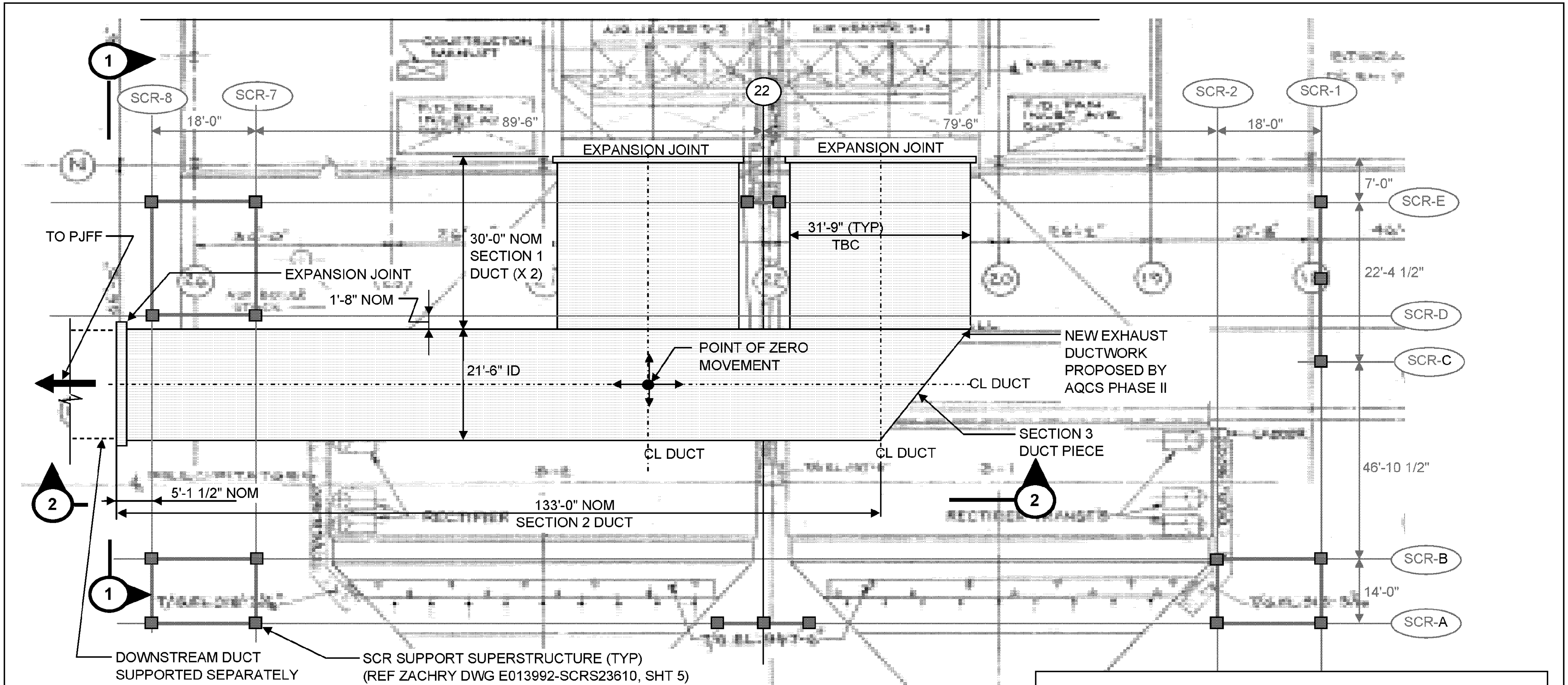
Appendix A
Conceptual Sketches

Ductwork/SCR Interface – Plan View



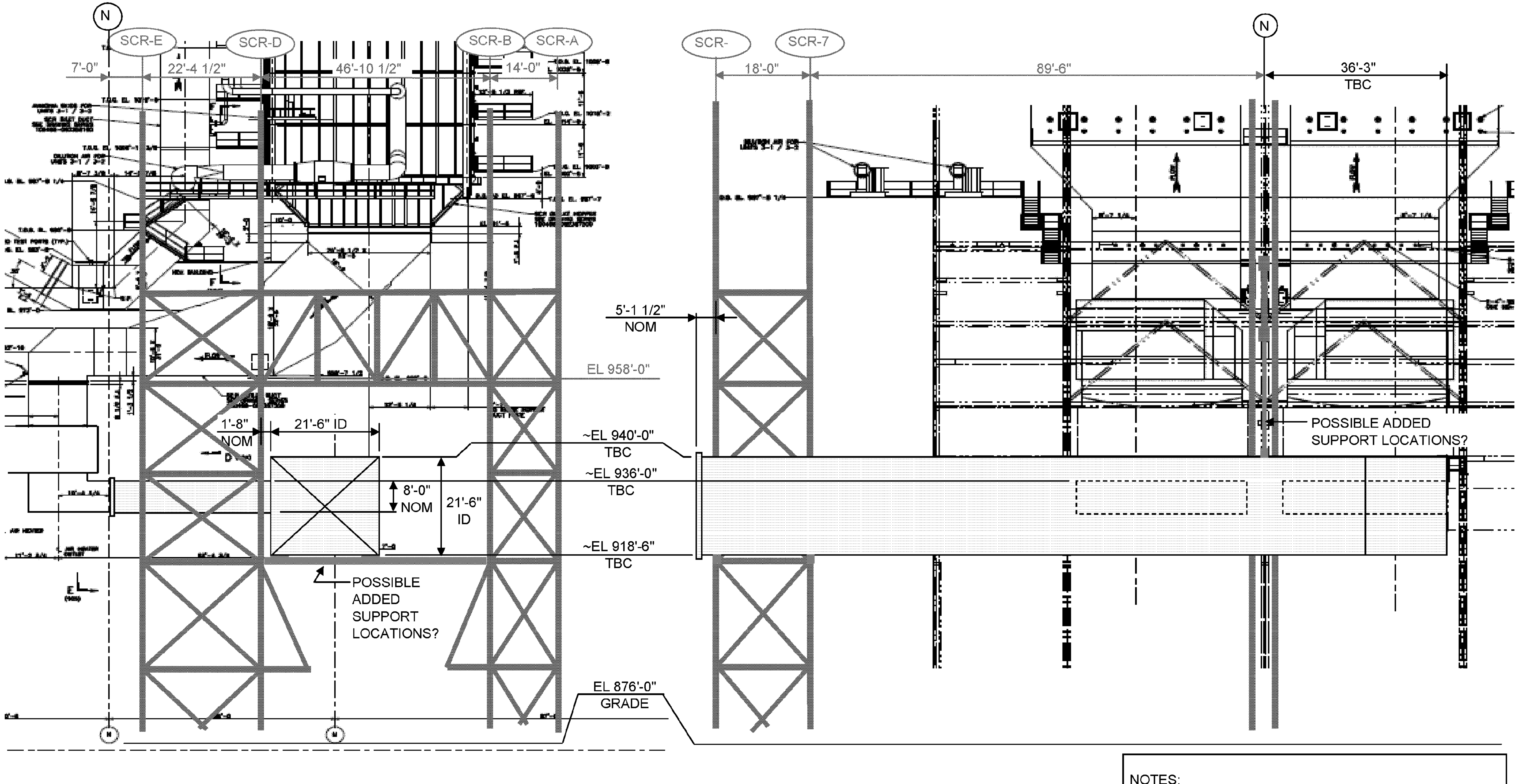
NOTES:
1. THIS DRAWING IS INTENDED TO PROVIDE AN APPROXIMATE ARRANGEMENT AND THE RELATIONSHIP BETWEEN NEW PROPOSED DUCTWORK AND THE SUPPORT SUPERSTRUCTURE CARRYING THE UNIT 3 SCR.
2. THE LOAD SUMMARY APPRXOXIMATES THE GRAVITY LOADS THAT WOULD RESULT ON A STRUCTURE SUPPORTING THE DUCT, BOTH ON A TOTAL AND PER LINEAR FOOT OF LENGTH BASIS.

APPENDIX A
CONCEPTUAL SKETCH 1
DUCTWORK/SCR INTERFACE - PLAN VIEW

LOAD SUMMARY	K PER LF	K TOTAL
SECTION 1 (TYP OF 2)		
DEAD LOAD INCLUDING INSULATION	10.1	305
LIVE/SNOW LOAD	0.6	19
ASH ALLOWANCE LOAD	3.2	95
SECTION 2		
DEAD LOAD INCLUDING INSULATION	18.5	2429
LIVE/SNOW LOAD	0.4	57
ASH ALLOWANCE LOAD	2.2	286
SECTION 3		
DEAD LOAD INCLUDING INSULATION	N/A	45
LIVE/SNOW LOAD	N/A	3
ASH ALLOWANCE LOAD	N/A	17

Ductwork/SCR Interface – Elevations

DRAFT IN-HOUSE REVIEW



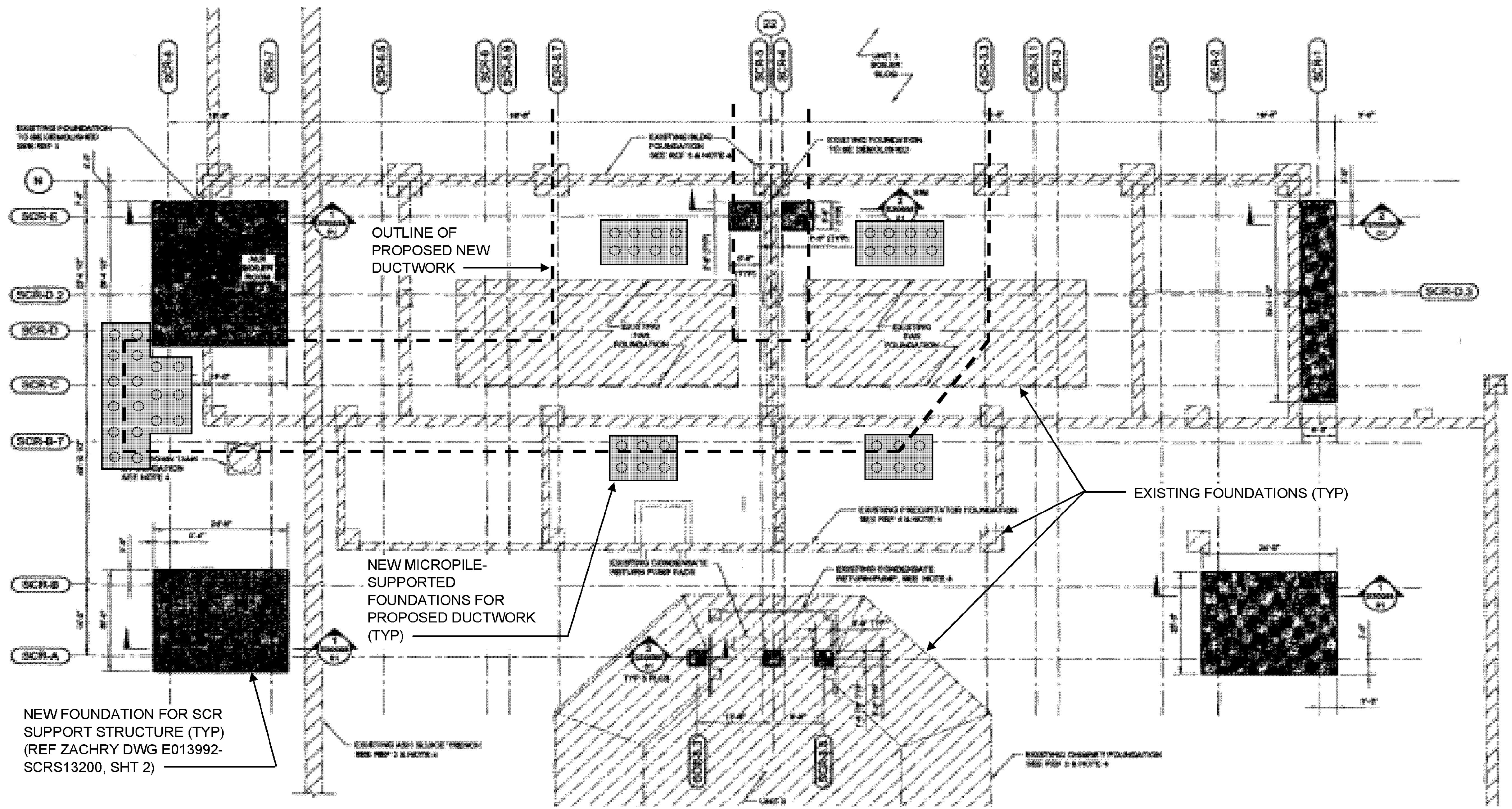
APPENDIX A

CONCEPTUAL SKETCH 2

DUCTWORK/SCR INTERFACE - ELEVATIONS

NOTES:
1. THIS DRAWING IS INTENDED TO PROVIDE AN APPROXIMATE ARRANGEMENT AND THE RELATIONSHIP BETWEEN NEW PROPOSED DUCTWORK AND THE SUPERSTRUCTURE CARRYING THE UNIT 3 SCR.
2. POSSIBLE DUCTWORK SUPPORT LOCATIONS ARE NOTED FOR CONSIDERATION.

Ductwork/SCR Interface – Foundations



APPENDIX A
CONCEPTUAL SKETCH 3
DUCTWORK/SCR INTERFACE - FOUNDATIONS

NOTES:
1. THIS DRAWING IS INTENDED TO ILLUSTRATE A CONCEPTUAL RELATIONSHIP BETWEEN EXISTING, SCR, AND DUCTWORK FOUNDATIONS SHOULD THE DUCTWORK NOT BE SUPPORTED BY THE SCR SUPPORT STRUCTURE.

From: Saunders, Eileen
To: Schroeder, Andrea
Sent: 2/1/2011 1:02:00 PM
Subject: FW: 168908.41.0803 101202 Ghent Draft Validation Report
Attachments: Draft Ghent Validation Report 120210.pdf; Ghent Validation Presentation 120210.pdf

Ghent Draft Report

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Thursday, December 02, 2010 4:47 PM
To: Saunders, Eileen
Cc: 168908 E.ON-AQC; Jackson, Audrey; Wehrly, M. R.; Lucas, Kyle J.; Mahabaleshwarkar, Anand; Hintz, Monty E.; Goodlet, Roger F.; Crabtree, Jonathan D.
Subject: 168908.41.0803 101202 Ghent Draft Validation Report

Eileen,

Please find attached an electronic copy of the Draft Ghent AQC Validation Report for your review and LG&E/KU's use during the technology validation meeting next week. The real intent of the draft report is to capture the considerations, reviews, constraints, and analyses conducted to date to validate that the selected AQC technologies could be accommodated and arranged on site with no obvious fatal flaws. The presentation next week will highlight the most salient points of the report, and the report will also serve as a reference document to address any detailed questions that may arise during the course of the meeting.

Finally, you will notice that the conclusion section of the report is incomplete at this point. Following the validation meeting, B&V anticipates that LG&E/KU will complete their review of the report and provide comments and direction in order to advance the project to conceptual design and cost estimating. B&V will then finalize the validation report by incorporating LG&E/KU's comments and completing the conclusions section.

We look forward to meeting with you and your team next week.

Best regards,

TIM HILLMAN | Project Manager, Energy
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LG&E/KU – Ghent Station

Phase II Air Quality Control Study

Air Quality Control Validation Report

DRAFT - CLIENT REVIEW

December 3, 2010
Revision B – Issued For Client Review

B&V File Number 41.0803

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DRAFT - CLIENT REVIEW

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Acronym List

AQC	Air Quality Control
As	Arsenic
Be	Beryllium
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
Cd	Cadmium
Co	Cobalt
Cr	Chromium
CS-ESP	Cold-side Electrostatic Precipitator
DCS	Distributed Control System
DOE	Department of Energy
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
Hg	Mercury
ID	Induced Draft
inw	Inch of Water
LNB	Low NO_x Burners
LV	Low Voltage
MACT	Maximum Achievable Control Technology
MBtu	Million British Thermal Unit
MCC	Motor Control Center
Mn	Manganese
MSW	Municipal Solid Waste
MV	Medium Voltage
MWC	Medical Waste Combustors
NAAQS	National Ambient Air Quality Standard
NFPA	National Fire Protection Association
Ni	Nickel
NN	Neural Network
NO_x	Nitrogen Oxides
OFA	Overfire Air
PAC	Powdered Activated Carbon

Pb	Lead
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
RAT	Reserve Auxiliary Transformer
RGFF	Reverse Gas Fabric Filters
SAM	Sulfuric Acid Mist
Sb	Antimony
SBS	Sodium Bisulfite
SCR	Selective Catalytic Reduction
Se	Selenium
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
tph	Tons per Hour
UAT	Unit Auxiliary Transformer
VFD	Variable Frequency Drives
WFGD	Wet Flue Gas Desulfurization

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1.0 Introduction

Following the submittal of the Phase I report on July 8, 2010, Black & Veatch developed scope to further define facility technology options based on the Phase I report. The purpose of this Phase II air quality control (AQC) validation study is to build upon the previous fleet-wide, high-level air quality technology review and cost assessment conducted for six LG&E/KU facilities (Phase I) in order to develop a facility-specific project definition consisting of a conceptual design and a budgetary cost estimate for selected AQC technologies (Phase II) for the Ghent Generating Station. The following AQC technology options have been assessed in this report:

- PJFF on Units 1-4.
- Sorbent injection (trona/lime/SBS) injection on Unit 2.
- SCR on Unit 2.
- Powdered activated carbon (PAC) injection on Units 1-4.
- Feasibility of neural network (NN) on Units 1-4.

This validation study confirms the feasibility of installing the aforementioned AQC equipment at Ghent, and presents the supporting considerations, arrangements, and preliminary validating analyses of the AQC equipment that will be built upon in the next step of this project to complete the conceptual design and budgetary cost estimate.

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2.0 Facility Description

2.1 Ghent- Units 1, 2, 3, and 4

The Ghent Station is located in Carroll County, approximately 9 miles northeast of Carrolton, Kentucky, on an approximately 1,670 acre site. Ghent Station includes four pulverized coal fired electric generating units with a gross total generating capacity of 2,107 MW. Ghent Station began commercial operations in 1973.

All four steam generators (boilers) fire high sulfur bituminous coal. Two of the boilers are manufactured by Combustion Engineering and two by Foster Wheeler. The Combustion Engineering boilers are tangential-fired, balanced draft forced circulation boilers, and Foster Wheeler boilers are balanced draft natural circulation boilers. Unit 1 has a gross capacity of 541 MW and is equipped with low NO_x burners (LNBs) and selective catalytic reduction (SCR) for nitrogen oxide (NO_x) control; cold-side dry electrostatic precipitator (ESP) for particulate matter (PM) control; wet flue gas desulfurization (WFGD) for sulfur dioxide (SO_2) control, and lime injection system for sulfuric acid (H_2SO_4) and/or sulfur trioxide (SO_3) control. Unit 2 has a gross capacity of 517 MW and is equipped with LNBs and overfire air (OFA) for NO_x control; hot-side dry ESP for PM control; and WFGD system for SO_2 control, and lime injection system for H_2SO_4/SO_3 control. Units 3 and 4 have a gross capacity of 523 MW and 526 MW, respectively, and are equipped with LNBs, OFA, and low-dust SCR for NO_x control; hot-side dry ESP for PM control; wet FGD system for SO_2 control, and trona injection system for H_2SO_4/SO_3 control.

Gypsum, a scrubber by-product, produced at Ghent is stored in the on-site landfill. Fly ash and bottom ash is sluiced to on-site storage ponds. Black & Veatch is also involved in a separate study for the transportation of coal combustion products. Layouts developed for the alternative transport systems will be taken into account during the Phase II Air Quality Control Study. All four units are cooled using mechanical draft cooling towers.

Figures 2-1 and 2-2 illustrate the plant location and Table 2-1 summarizes the plant's existing facilities.

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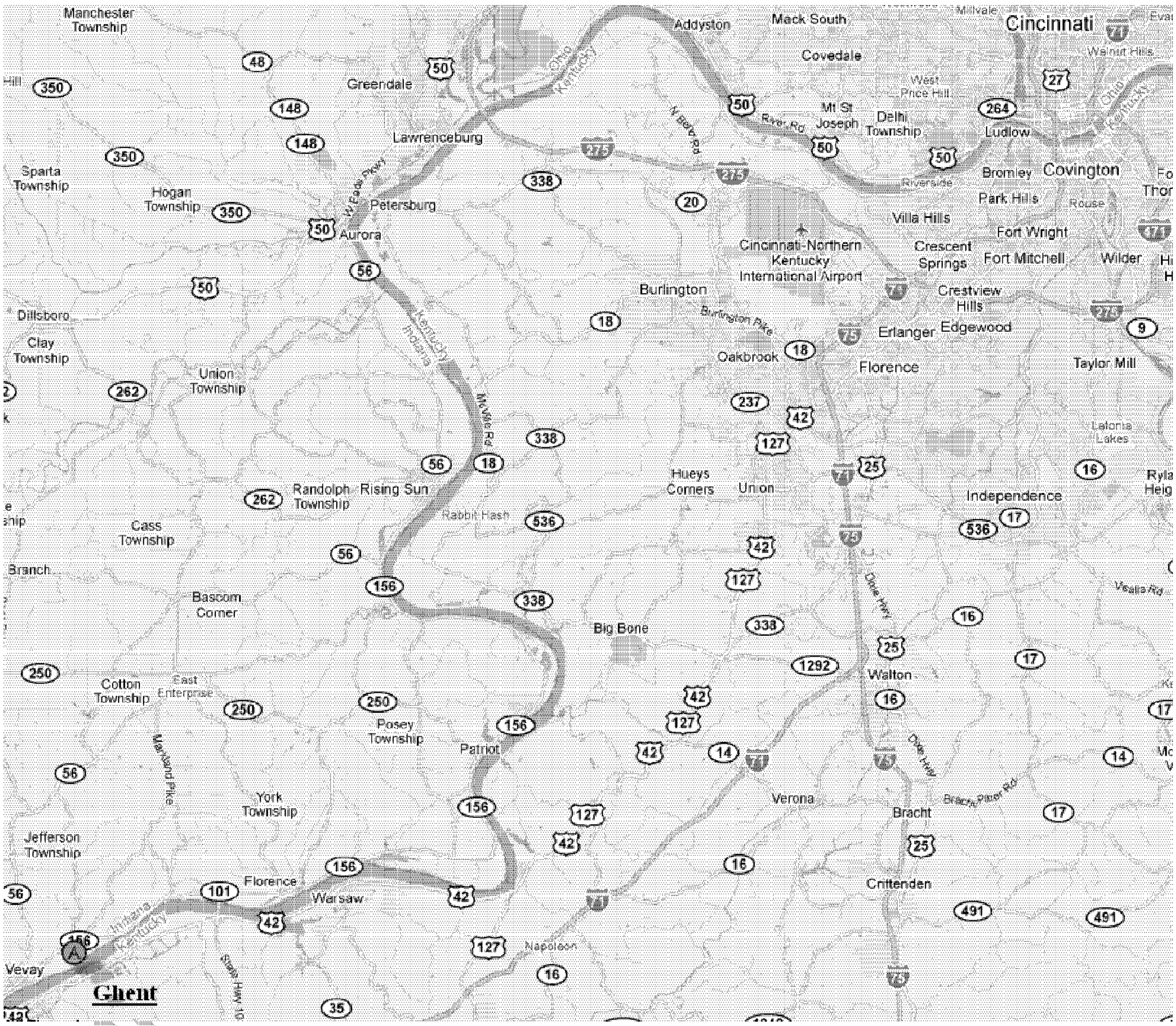
NORTH

Figure 2-1. Ghent Power Plant Site

NORTH



SOUTH

Figure 2-2. Ghent and Surrounding Area Map

Table 2-1. Existing Ghent Plant Facilities	
Existing On Site Generation Units:	• Unit 1 - 541 gross MW (in-service date 1973) • Unit 2 - 517 gross MW (in-service date 1977) • Unit 3 - 523 gross MW (in-service date 1981) • Unit 4 - 526 gross MW (in-service date 1984)
Existing AQC Equipment:	• Unit 1 - LNBs, SCR, Cold-side Dry ESP, WFGD, Lime Injection System • Unit 2 - LNBs, OFA System, Hot-side Dry ESP, WFGD, Lime Injection System • Unit 3 - LNBs, OFA, Low -dust SCR, Hot-side Dry ESP, WFGD, Trona Injection System • Unit 4 - LNBs, OFA, Low -dust SCR, Hot-side Dry ESP, WFGD, Trona Injection System

3.0 Emission Target Basis

LG&E/KU provided a matrix of estimated requirements under current and future environmental regulations, as well as a summary implementation schedule of regulatory programs. Table 3-1 summarizes the future pollution emission targets provided by LG&E/KU for each unit.

The current regulatory drivers include the NO_2 and SO_2 National Ambient Air Quality Standard (NAAQS). On January 22, 2010, the Environmental Protection Agency (EPA) announced a new 1-hour NO_2 NAAQS of 100 ppb. The final rule for the new hourly NAAQS was published in the Federal Register on February 9, 2010, and the standard became effective on April 12, 2010. Likewise, on June 2, 2010, EPA strengthened the primary SO_2 NAAQS. EPA established a new 1-hour standard at a level of 75 ppb and revoked the existing 24-hour and annual standards.

The potential impact of future regulations is the primary driver for both the timing and extent of environmental controls planned at the LG&E/KU plants. Among the regulatory drivers are the Utility Maximum Achievable Control Technology (MACT), and the Clean Air Transport Rule (CATR) -- Clean Air Interstate Rule (CAIR) replacement to be proposed by the United States EPA by spring 2011 and summer 2011, respectively.

From this information, LG&E/KU developed specific pollutant emission limit targets with the intent that the limits would be applied to each unit individually to assess current compliance and the potential for additional AQC equipment. These regulatory drivers and their associated emission levels serve as the primary basis used by Black & Veatch to develop unit-by-unit AQC technology recommendations. For the purposes of this study, compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) were not considered.

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Table 3-1. Primary Design Emission Targets

Pollutant	Unit 1	Unit 2	Unit 3	Unit 4
NO_x	N/A(b)	0.041 lb/MBtu	N/A(b)	N/A(b)
SO_2	N/A(b)	N/A(b)	N/A(b)	N/A(b)
Sulfuric Acid Mist (SAM)	2-10 ppm(a) TBD	2-10 ppm(a) TBD	2-10 ppm(a) TBD	2-10 ppm(a) TBD
Mercury (Hg)	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh
Hydrogen Chloride (HCl)	0.002 lb/MBtu	0.002 lb/MBtu	0.002 lb/MBtu	0.002 lb/MBtu
Particulate Matter (PM)(c),(d)	0.03(c) lb/MBtu	0.03(c) lb/MBtu	0.03(c) lb/MBtu	0.03(c) lb/MBtu
Arsenic (As) (e)	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu
CO	0.10 lb/MBtu	0.10 lb/MBtu	0.10 lb/MBtu	0.10 lb/MBtu
Dioxin/Furan	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu

Data from LG&E/KU Ghent Station kickoff meeting October 6, 2010 (Gary Revlett handouts and meeting notes) unless noted otherwise.

(a) Units provided in ppmvd at 3% O_2 as indicated in the draft H_2SO_4 BACT analysis dated September 30, 2010.

(b) Not applicable for this Phase II study.

(c) Emission rate target is higher than what can typically be achieved with chosen technology; a lower emission target may be possible.

(d) Particulate matter control limits for $PM_{2.5}$ or $PM_{condensable}$ have not been determined for this project.

(e) Particulate matter assumed to be the surrogate for emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)).

(f) Arsenic assumed to be the surrogate for non-mercury metallic HAP (i.e., arsenic (As), chromium (Cr), and selenium (Se)).

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4.0 Site Visit Summary

The following section describes the existing site conditions and site visit observations for the Ghent Generating Station.

4.1 Site Visit Observations and AQC

The following observations are from the October 6-7, 2010 site visit and summarize the site and equipment constraints. The following excerpts are from the October 22, 2010, site visit meeting memo that focused specifically on installing the specified AQC equipment.

- Emissions of SO_2 should not be a problem for the Ghent units since the existing FGDs basically achieve +98% removal on the units and the air dispersion modeling shows that they require 96% removal on a plant average. Thus, no modification of the FGDs is required.
- Hg is an issue at Ghent. However, LG&E/KU hopes that with the addition of an SCR on Unit 2, acceptable Hg control may be achieved without additional modifications.
- The hot-side ESPs are currently being used either for ash scavenging or because the existing SCRs are the low-dust type. B&V noted that a change in catalyst could convert the SCRs to operate in high-dust conditions if the possibility of lower catalyst life is acceptable.
- The area and facilities for dry ash conversion and ash handling need to be considered with this study. LG&E/KU commented that B&V had previously completed an ash handling study and that the AQC study must be coordinated with the plans developed in the ash handling study.
- B&V may consider designing the Unit 2 SCR as high-dust units from the onset, allowing deletion of the existing ESPs at Unit 2 if warranted by congestion and construction difficulties.
- LG&E/KU would like to sell fly ash on an opportunistic basis, but is not necessarily tied to the existing ESPs. Saleable fly ash would require "scalping" of the fly ash upstream of PAC injection and require the retention and use of the existing ESPs.
- LG&E/KU prefers no new axial fans and prefers the existing axial fans, if re-used, be located downstream of the PJFFs.
- B&V to investigate a refined layout for Unit 3 PJFF that would reduce the ductwork runs indicated in the Phase I study.

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- The courtyard area between Units 2 and 3 can be used for siting new equipment. The various maintenance shops on the south side of the courtyard could be relocated. There is no "sacred ground" onsite that must be avoided in locating new facilities. However, retention or re-establishment of the ground level breezeway and the overhead skyway between Units 2 and 3 is desirable.
- B&V believes it will likely not be feasible to reuse/upgrade the existing induced draft (ID) fans to avoid the addition of new booster or ID fans. Physical constraints on routing duct to and from the existing ID inlet fans is problematic. Locating the PJFFs to protect all of the existing ID fans is not practical in all cases, even for the axial fans at Units 3 and 4. The Unit 3 fans can be incorporated into the revised AQC system, but only in a location that may not be beneficial. B&V fan experts will review this, but new ID fans or booster fans are expected to be required for all units.
- Unit 1:
  - Sorbent injection will need to be relocated in the duct work to near the inlet of the PJFF. LG&E/KU questioned whether the PJFF vendors would be willing to offer SO3 guarantees based on sorbent injection. B&V noted that if the vendor is awarded both sorbent injection and the PJFF as a single package he will likely offer some guarantees, but the specific level will have to be negotiated.
  - Concern was expressed with the elevated PJFF for Unit 1 being located close to the Unit 2 cooling tower. B&V will investigate and provide opinions on the overall affect of the new structures on cooling tower performance and level of icing that could result.
  - If the impact to performance warrants it, it was discussed that a couple cells could be added to the east end of the tower to increase the overall tower capacity or allow impacted cells to be taken out of service.
  - Alternate arrangements at Unit 1 appear very limited at this time. LG&E/KU asked about relocating Unit 2's cooling tower to make more room for Unit 1 PJFF. The major issue with that approach is where to relocate the cooling tower. The potential of locating the new cooling tower towards the river or to the east of Unit 1's cooling tower was discussed. Any new construction towards the river, either relocating the Unit 2 cooling tower or the plant reagent piperack, would likely trigger permit concerns with the COE.

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Building a new tower in the "rock pile" area (formerly the limestone storage area east of the plant) was also discussed. Routing of the underground circulating water lines potentially would be a major issue.

- Unit 2:
  - Because of the high level of congestion in the existing arrangement at Unit 2, plus the need to add a PJFF, B&V considered three alternatives for the SCR location at Unit 2. Two alternatives (Alternates 1 & 3) include split SCR's – two separate reactors, one for each ESP train, with the only difference between the alternatives being the location of the west side SCR.
  - Alternate 1 locates the west SCR in the area just west of the west ID fan and the east SCR above the tower support for the Unit 1 SCRs. The area west of the ID fans appears sufficiently open to allow construction of a tower support for the SCR. The advantage of this arrangement is the short runs of ductwork required, and the SCR reactor box location can be reached by a crane set up in the area located immediately south of the abandoned Unit 2 chimney.
  - Alternate 3 locates the west SCR along the west side of the Unit 2 boiler structure and the east SCR in the same location as Alternate 1. The approach suggested in the Phase 1 study of locating both split SCRs on the west side of the boiler structure would be problematic because of the difficulty of routing duct work from east side Unit 2 duct to the courtyard and back.
  - Alternate 2 is similar to that used for the Unit 1 SCR, with a combined SCR located above the ESPs. However, the area beneath the SCRs in Alternate 2 is very congested, making foundation design and installation extremely difficult. Moreover, the lack of nearby open area adjacent to the SCR locations will limit crane access and greatly complicate constructability. Assuming sufficient free area is found to accommodate the necessary foundations, Alternate 1 is more favorable to construction and the most likely option.
  - Low dust SCRs will be assumed for Unit 2 unless elimination of the existing ESPs is warranted for some other reason.

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- LG&E/KU has previous studies which propose locating the SCR modules in the courtyard on the west side of the Unit 2 boiler structure. LG&E/KU offered to provide these studies to B&V.
- The Unit 2 PJFF is assumed to be located north of the existing ESPs and ductwork. A short temporary bypass ductwork can be installed between the air heater outlet duct and the ductwork to the scrubber inlet. This would allow the large section of ductwork located north of the bypass to be demolished and the PJFF installed in its place while Unit 2 is on line. The completed PJFF would be tied into the system during an outage. The new booster or ID fans for Unit 2 (not shown on the arrangement sketches) would tentatively be located at the west (downstream) end of the new PJFF.

- Unit 3:
  - The preliminary arrangement sketches show the PJFF location in the courtyard, requiring relocation of the maintenance shop. LG&E/KU has some ideas where the shop could be relocated. As currently configured, new booster or ID fans could be added south of the PJFF without impacting the existing tanks south of the shop.
  - The skyway connecting Units 2 and 3 would need to be temporarily removed while the PJFF is installed. The skyway would then be modified to route around the south side of the PJFF and reconnect to Unit 3. It may also be possible to modify the skyway to provide access from the turbine buildings to the PJFF. To avoid re-routing of the significant amount of interconnecting pipe located in the ground level breezeway between units, the PJFF would be designed to span over this piping and allow the breezeway structure to remain in place, if practical.
- Unit 4:
  - The most likely location for the new PJFF is between the existing Unit 4 ESP area and the Unit 3 cooling tower as shown on the sketch. This location avoids the large 96" diameter circulating water pipelines, the water well, and most of the underground utilities in the area.

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- The ID fans currently being installed at Unit 4 would be difficult to incorporate into the proposed ductwork configuration running between the existing ductwork tie in and the new PJFF and back, as shown on the arrangement sketches. A more favorable configuration may be accomplished by locating the new ID fans near the PJFF. The new fans would be sized to replace the current ID fans. New ID fans in this location would allow relatively easy connection directly to the ductwork at the FGD inlet.
- LG&E/KU expressed general agreement with the arrangement as discussed for Unit 4. An alternate version of the Unit 4 arrangement sketch was developed to more closely depict the arrangement discussed.

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5.0 Selected Air Quality Control Technology

The following sections present a general description of the AQC technologies considered for Ghent, as well as a unit by unit discussion of the key attributes of the technologies and special considerations for their application and arrangement at the affected units. Table 5-1 presents the selected AQC technologies that were considered in the validation process.

Table 5-1. AQC Technologies

	Unit 1	Unit 2	Unit 3	Unit 4
NO_x Control	Existing SCR	New SCR	Existing SCR	Existing SCR
SO_2 Control	Existing WFGD	Existing WFGD	Existing WFGD	Existing WFGD
PM Control	New PJFF	New PJFF	New PJFF	New PJFF
HCl Control	Existing WFGD and Existing Sorbent Injection	Existing WFGD and New Sorbent Injection	Existing WFGD and Existing Sorbent Injection	Existing WFGD and Existing Sorbent Injection
CO Control	New NN	New NN	New NN	New NN
SO_3 Control	Existing Sorbent Injection	New Sorbent Injection	Existing Sorbent Injection	Existing Sorbent Injection
Hg Control	New PAC Injection	New PAC Injection	New PAC Injection	New PAC Injection
Dioxin/Furan Control	New PAC Injection	New PAC Injection	New PAC Injection	New PAC Injection
Fly Ash Sales	Existing CS-ESP	Existing HS-ESP	Existing HS-ESP	Existing HS-ESP

CS-ESP = Cold-Side Electrostatic Precipitator.
HS-ESP = Hot-Side Electrostatic Precipitator.

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5.1 Technology Descriptions

The following sections provide a brief general description of the proposed AQC technologies.

5.1.1 Selective Catalytic Reduction System

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_X into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_X-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_X levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_X available for removal. Essentially, as NO_X is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature are costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure 5-1 shows a schematic diagram of SCR.

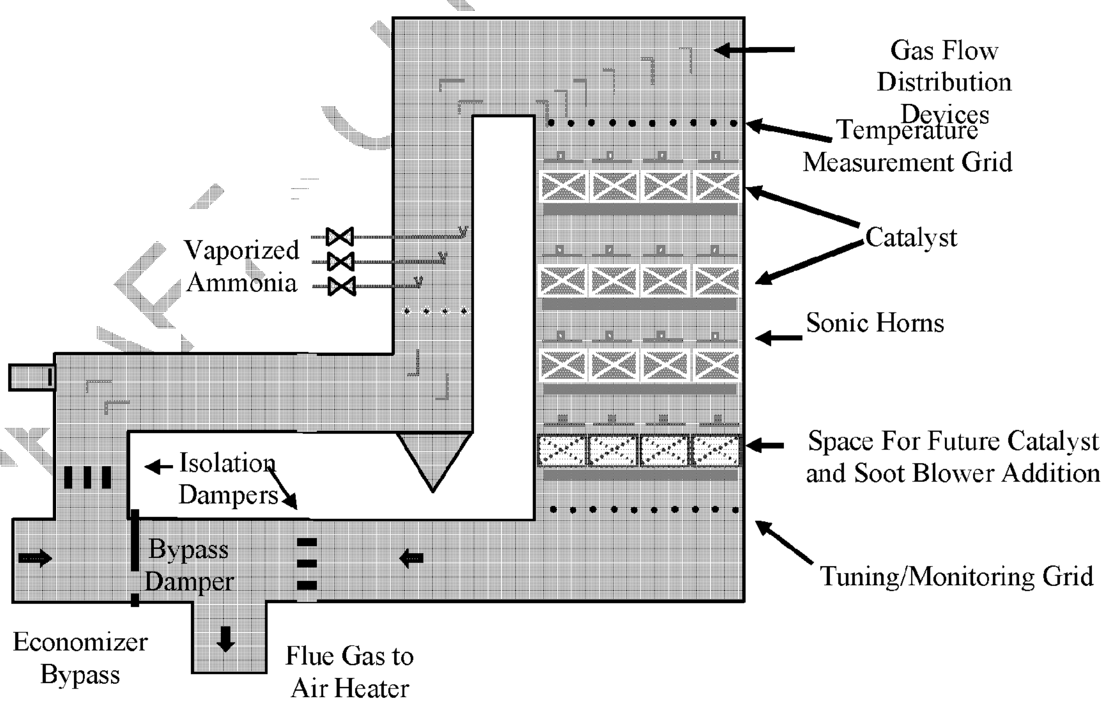

Figure 5-1. Schematic Diagram of a Typical SCR Reactor

5.1.2 Pulse Jet Fabric Filter

Pulse jet fabric filters (PJFFs) have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the PJFF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the PJFF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementation. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each PJFF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure 5-2.

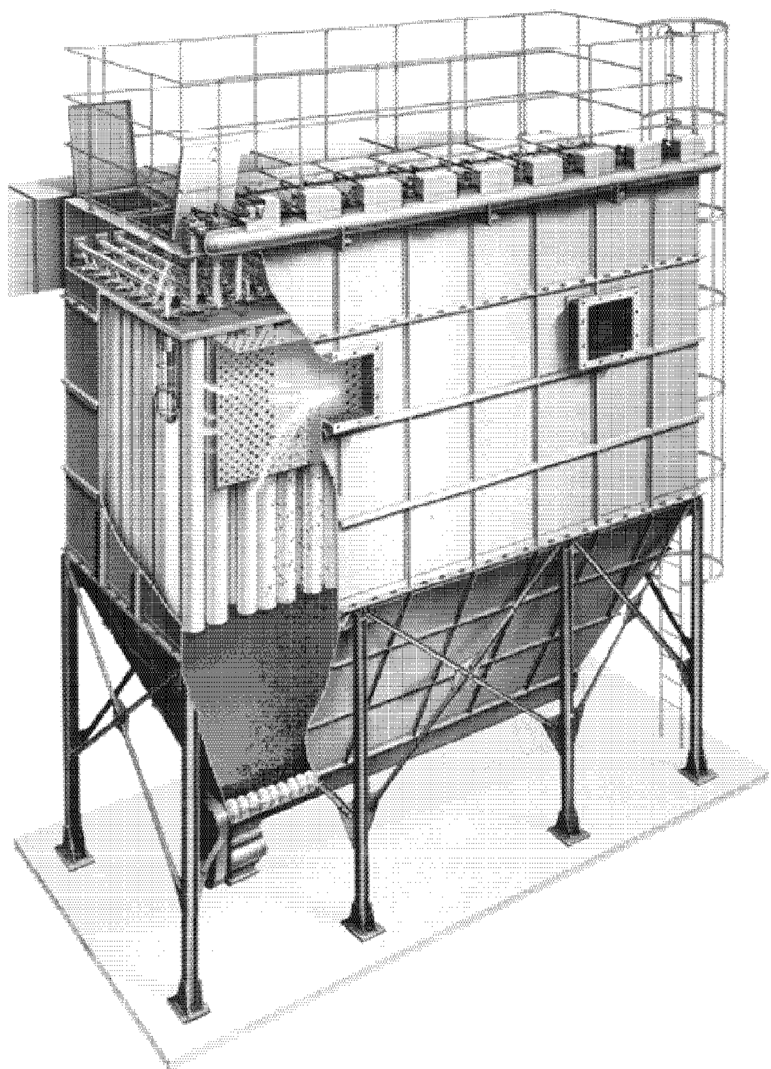

Figure 5-2. Pulse Jet Fabric Filter Compartment

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

5.1.3 Powdered Activated Carbon Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of Energy (DOE), EPA, Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure 5-3. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

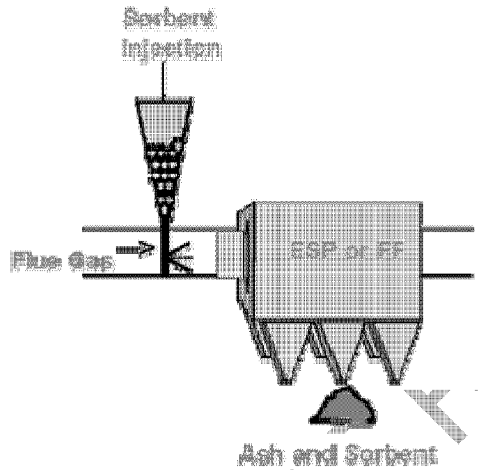

Figure 5-3. Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of an ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a CS-ESP can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of CS-ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a CS-ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC. (approximately $5.00/lb of iodine, $1.00/lb of bromine, and $0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

5.1.4 Sorbent Injection

Injection of finely divided alkalis into the flue gas has been demonstrated for the removal of SO_3 from flue gases. Most commercial experience is from units firing high sulfur oil where trace metals, mainly vanadium, increase SO_2 oxidation. Magnesium-based compounds have been used successfully for decades to capture SO_3 in oil fired units. As coal fired units burning high sulfur bituminous coals have been retrofitted with SCR systems, interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Sorbents such as SBS, trona, and hydrated lime have recently been used on large coal fired units, with reported results showing the achievement of high control efficiencies of SO_3 in high sulfur applications.

5.1.5 CO Reduction Technologies

Control of CO is divided into two basic categories, good combustion controls and neural networks.

5.1.5.1 Good Combustion Controls. As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits. Good combustion controls are an option to aid in reduction of CO but are assumed to currently be optimized. No further study of this option was considered in this report.

5.1.5.2 Neural Networks. Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions

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of NO_x, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation.

At this point, there are no proven and feasible post combustion AQC technologies for the control of CO emissions from coal-fired boilers of this size. DCS based computer furnace combustion monitoring systems, such as neural networks, may help reduce CO emissions by improving plant heat rate and optimizing the various combustion parameters responsible for the formation of CO. Improvising the coal mills and coal feed injection/air management and or burner modifications including the detuning of any existing NO_x combustion controls devices will help reduce the CO in combustion or pre-combustion stage. There are no arrangement fatal flaws or constraints associated with the installation of a NN at Ghent, although it cannot be validated at this point whether or not a NN can achieve the required CO target emission rate.

5.2 Unit by Unit Summary of AQC Selection

The following AQC control technologies comprise the selected technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the selected technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the AQC Technology Screening Workshop conducted on August 5-6, 2010, as well as information provided by LG&E/KU.

5.2.1 Ghent Unit 1

Table 5-2 identifies the selected AQC technologies for Ghent Unit 1. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-2. Unit 1– AQC Selection

AQC Equipment	Pollutant
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF	PM

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the ID fans but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the system. As such, the draft system needs to be investigated and new booster fans will be required. Additional auxiliary power requirement will need to be considered for new booster fans
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the existing ID fans and upstream of the new booster fans and can possibly be installed as suggested in the high level layout drawings as shown in Appendix B.
- The PJFF for Unit 1 will be located on the south side of the existing Unit 2 cooling tower and west side of the existing Unit 1 scrubber module. The PJFF will be elevated above the ground level. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

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5.2.2 Ghent Unit 2

Table 5-3 identifies the selected AQC technologies for Ghent Unit 2. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-3. Unit 2 – AQC Selection

AQC Equipment	Pollutant
New SCR	NOx
New PAC Injection	Hg, Dioxin/Furan
New Trona/Lime/SBS Injection	SO_3
New stand-alone full size PJFF	PM

New SCR

- SCR can consistently achieve NO_x emissions of lower than 0.041 lb/MBtu on a continuous basis. Therefore, SCR is the most feasible and expandable control technology considered for NO_x reduction including future NO_x reduction requirements.
- The SCR will increase pressure drop of the system. However, the existing ID fans have the capability to handle additional pressure drop for the SCR system..
- Ammonia consumption increases with the addition of SCR. Detailed investigation or study will be required to confirm if a new ammonia storage facility is required or if the existing ammonia storage facility can be upgraded for accommodating Unit 2 ammonia supply.
- An SO_3 mitigation system like alkali injection and PJFF will be required.
- Existing air heater will be retained. Air heater basket modifications for acid resistance may be necessary after the installation of SCR.
- A new SCR can be located downstream of the existing HS-ESP and upstream of the existing air heater.
- A new SCR will be arranged as 2 x 50% reactors.
- Elevated cables and overhead lines may need to be relocated.

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the ID fans but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the system. As such, the draft system needs to be investigated and new booster fans will be required. Additional auxiliary power requirement will need to be considered for new booster fans.
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the existing ID fans and upstream of the new booster fans and can possibly be installed as suggested in the high level layout drawings as shown in Appendix B.
- The PJFF for Unit 2 will be located on the north side of the existing Unit 2 hot-side ESP and east side of the existing Unit 2 scrubber modules. The PJFF will be elevated above the ground level. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

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New SO_3 Control System (Reagent Injection)

A reagent injection system that injects trona, Lime or SBS into the flue gas to remove SO_3 would be necessary.

- A PJFF is recommended in conjunction with a reagent injection system.
- Trona/lime/SBS would be injected downstream of the SCR but upstream of the air heater.
- Reagent injection can reduce the sulfuric acid emissions on a continuous basis and mitigate the visible blue plume formation from the chimney which is often associated when burning high sulfur coal.
- The use of sorbent system will slightly increase the truck traffic at the plant.

5.2.3 Ghent Units 3 and 4

Table 5-4 identifies the selected AQC technologies for Units 3 and 4. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-4. Units 3 and 4 – AQC Technology Selection

AQC Equipment	Pollutant
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF	PM

New PAC Injection

- A PJFF is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the existing air heater but upstream of new PJFF.
- PAC Injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant due to increased bulk deliveries.

New PJFF

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the system. As such, the draft system needs to be investigated and new ID fans will be required. The existing ID fans will be bypassed and abandoned in place. Additional auxiliary power requirement will need to be considered for the new ID fans
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- The PJFF can be located downstream of the existing air heater and upstream of the new ID fans and can possibly be installed as suggested in the high level layout drawings as shown in Appendix B.
- The PJFF for Unit 3 will be located on the east side of the Unit 3 boiler and west side of Unit 2 boiler. The PJFF will be elevated above the ground level. Existing structures which includes utility corridor walkway enclosure, maintenance shop, personnel skywalk, etc. will be investigated, evaluated, and, if necessary, relocated. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated. If practical, the utility walkway enclosure and personnel skywalk will be re-established upon completion of the PJFF.
- The PJFF for Unit 4 will be located on the north side of the Unit 4 WFGD and stack. Existing warehouse structure and foundation will be demolished. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

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6.0 Validation Analyses

The following sections describe the analyses of various balance of plant systems necessary to validate the selected AQC equipment.

6.1 Draft System Analysis

As a part of the draft system analysis of the AQC validation process for Ghent, the flue gas draft fans need to be evaluated to determine if modifications, replacements, or additions to the existing fans will be required. This is due to the installation of additional draft system equipment to control certain flue gas emissions. For Units 1, 3, and 4 the modifications and additions to the draft system being considered include new PJFF systems that will supplement the existing ESPs of each unit in the removal of particulate. For Unit 2 draft system modifications and additions being considered are a new SCR system for removing NO_x emissions and a new PJFF system. For more detail on the AQC equipment modifications, additions, etc. for each Ghent unit refer to Section 5.0.

For the sizing of any new fans for the Ghent site, the standard Black & Veatch fan sizing philosophy for developing Test Block conditions as additional margin on MCR conditions is recommended. This philosophy includes the application of the following items to the required MCR conditions for new or modified fans:

- 10 percent margin on flue gas flow exiting the boiler
- 50 percent margin on leakages throughout the draft system
- 50 percent margin on air heater differential pressure
- 25°F temperature increase at the fan inlet
- Adjustments of draft system pressure drops to correspond with increased Test Block flow rates
- 1.0 inch of water (inw) control allowance

The application of these items typically results in flow margins in the range of 20 to 30 percent and pressure margins in the range of 35 to 45 percent. If the flow and/or pressure margins for the Test Block conditions fall outside of these ranges the items listed above are typically adjusted appropriately.

Additionally, following the preliminary analyses of the Ghent draft systems, there will be a discussion on draft system stiffening, or transient design pressure, requirements per NFPA 85.

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6.1.1 Unit 1

Based on the additions to the Unit 1 draft system previously discussed and the flue gas flow through the draft system would change as follows. At the outlet of the existing ID fans the flue gas would travel to the new PJFF system allowing for the removal of finer particulate emissions before entering two new 50 percent capacity booster fans. The new booster fans, assumed to be equipped with variable speed control, would then send the flue gas to the WFGD system. An illustration of the Unit 1 future draft system based on these changes is shown in Figure 6-1.

With the expected installation of a PJFF system, the pressure demand on the draft fan system will be significantly higher than what the existing ID fans may deliver while still providing adequate margin. However, the efficient variable speed capabilities and recent major modifications are advantageous to operation and longevity of the existing ID fans. Therefore, it would be desirable to supplement the capabilities of the existing Unit 1 ID fans as opposed to replacing them. B&V proposes this be accomplished with two new 50 percent capacity centrifugal booster fans, also with variable speed control.

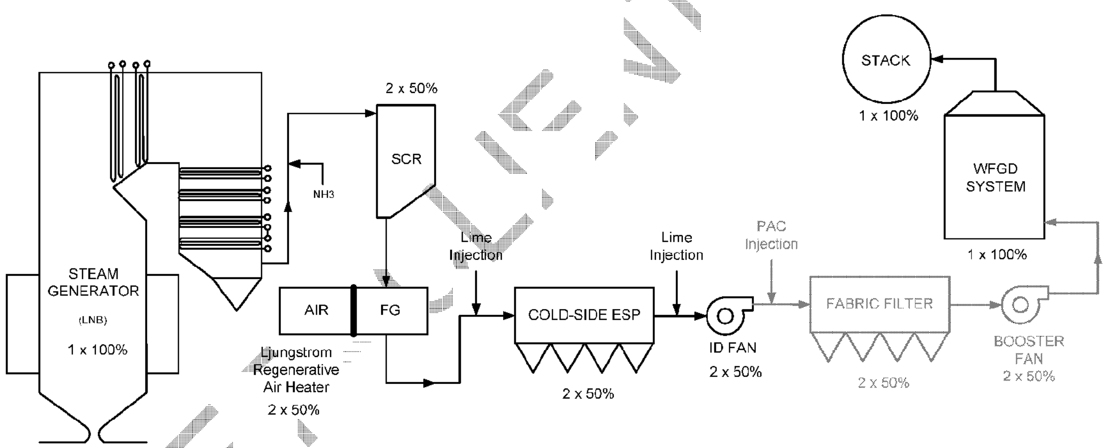

Figure 6-1. Unit 1 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 1 future draft system at MCR are as follows in Table 6-1. Note that the items in bold in Table 6-1 are new.

Table 6-1. Unit 1 Future Draft System Characteristics at MCR

SCR system leakage	2% (estimated)
Air heater leakage	10% (estimated)
ESP leakage	5% (estimated)
PJFF system leakage	**3%**
Flue gas temperatures	
Boiler outlet	729° F
SCR outlet	729° F
Air heater outlet	361° F
ESP outlet	358° F
PJFF outlet	**358° F**
ID fan outlet	~375° F (calculated)
Booster fan outlet	**~375° F (calculated)**
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	2.7 inw
SCR	10.0 inw
Air heater	9.2 inw
ESP	3.3 inw
PJFF	**8.0 inw**
WFGD	4.4 inw
Stack	1.7 inw

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Based on the layout of the future draft system in Figure 6-1 and the future draft system characteristics in Table 6-1, the estimated performance requirements of the new booster fans at MCR are shown in Table 6-2. Also in Table 6-2 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 25 and 39 percent, respectively. To keep the booster fan Test Block pressure margin within the typical range of 35 to 45 percent the 1.0 inw control allowance was removed.

Table 6-2. Unit 1 New Booster Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	------	900
Inlet Temperature (°F)	374	399
Inlet Density (lb/ft^3)	0.0461	0.0445
Flow per Fan (acfm) *	1,122,000	1,402,000
Inlet Pressure (inwg)	-8.0	-10.8
Outlet Pressure (inwg)	6.1	8.8
Static Pressure Rise (inw)	14.1	19.6
Shaft Power Required (HP) **	2,900	5,100
Efficiency (percent) **	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	25
Pressure Margin (percent)	---------	39

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.

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6.1.2 Unit 2

Based on the additions to the Unit 2 draft system previously discussed the flue gas would be redirected through the draft system as follows. At the outlet of the hot-side ESP the flue gas would travel to the new SCR system allowing for the removal of NOx emissions before entering the air heaters. Once the flue gas is through the air heaters it would enter the existing ID fans. Between the existing ID fans and WFGD system would be the new PJFF system and new booster fans. The new booster fans, assumed to be equipped with variable speed control, would draw flue gas through the PJFF system and send it to the WFGD system. An illustration of the Unit 2 future draft system based on this description is shown in Figure 6-2.

With the expected installation of both an SCR system and a PJFF system, the pressure demand on the draft fan system is expected to be significantly higher than what the existing ID fans may deliver while still providing adequate margin. However, the efficient variable speed capabilities and recent major modifications are advantageous to operation and longevity of the existing ID fans. Therefore, it would be desirable to supplement the capabilities of the existing Unit 2 ID fans as opposed to replacing them. B&V proposes this be accomplished with two new 50 percent capacity centrifugal booster fans as with Unit 1, also with variable speed control.

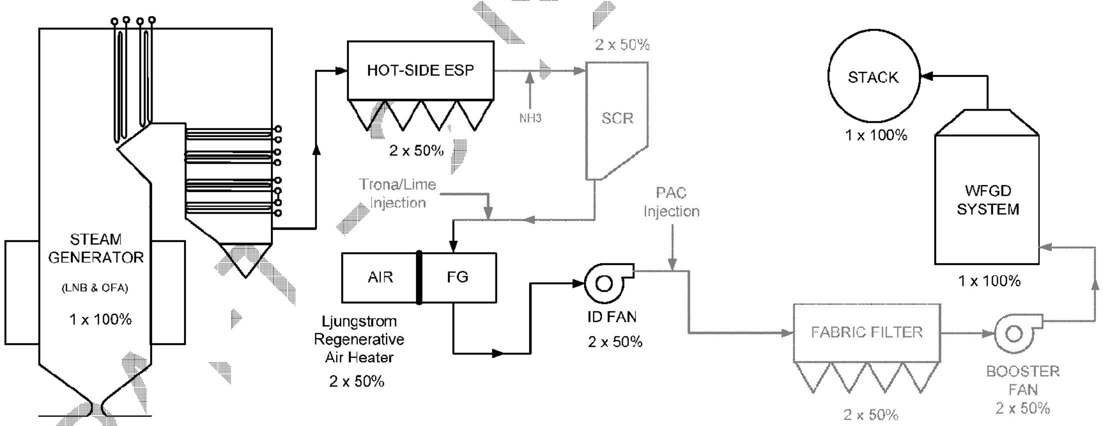

Figure 6-2. Unit 2 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 2 future draft system at MCR are as follows in Table 6-3. Note that the items in bold in Table 6-3 are new.

Table 6-3. Unit 2 Future Draft System Characteristics at MCR

ESP leakage	5% (estimated)
SCR system leakage	**2%**
Air heater leakage	10% (estimated)
PJFF leakage	**3%**
Flue gas temperatures	
Boiler outlet	610° F
ESP outlet	605° F
SCR outlet	**605° F**
Air heater outlet	309° F
PJFF outlet	**309° F**
ID fan outlet	~325° F (calculated)
Booster fan outlet	**~325° F (calculated)**
WFGD outlet	~125° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.6 inw
ESP	5.7 inw
SCR	**10.0 inw**
Air heater	7.8 inw
PJFF	**8.0 inw**
WFGD	9.9 inw
Stack	1.5 inw

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Based on the layout of the future draft system in Figure 6-2 and the future draft system characteristics in Table 6-3, the estimated performance requirements of the new ID fans at MCR are shown in Table 6-4. Also in Table 6-4 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 25 and 43 percent, respectively. To keep the booster fan Test Block pressure margin within the typical range of 35 to 45 percent the 1.0 inw control allowance was removed.

Table 6-4. Unit 2 New Booster Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	------	900
Inlet Temperature (°F)	325	350
Inlet Density (lb/ft^3)	0.0490	0.0471
Flow per Fan (acfm) *	1,088,000	1,364,000
Inlet Pressure (inwg)	-8.0	-11.3
Outlet Pressure (inwg)	11.4	16.5
Static Pressure Rise (inw)	19.4	27.8
Shaft Power Required (HP) **	4,000	7,100
Efficiency (percent)**	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	25
Pressure Margin (percent)	---------	43

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.

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6.1.3 Unit 3

Based on the additions to the Unit 3 draft system previously discussed, the flue gas would be redirected through the draft system as follows. At the outlet of the existing air heaters the flue gas would travel to the new PJFF system allowing for the removal of finer particulate. The three new 33 percent centrifugal ID fans, assumed to be equipped with variable speed control, would then draw the flue gas out of the PJFF system and send it to the WFGD system. An illustration of the Unit 3 future draft system based on this description is shown in Figure 6-3.

Due to operation and maintenance issues with the recently installed two 50 percent axial ID fans, the plant would like them to be replaced and bypassed with new centrifugal type fans. However, due to the B&V recommended margins on flow and pressure (Test Block conditions) above the MCR conditions with the addition of a PJFF system, the new centrifugal ID fans will be required to be in a three fan arrangement. An illustration of the Unit 3 future draft system based on this description is shown in Figure 6-3.

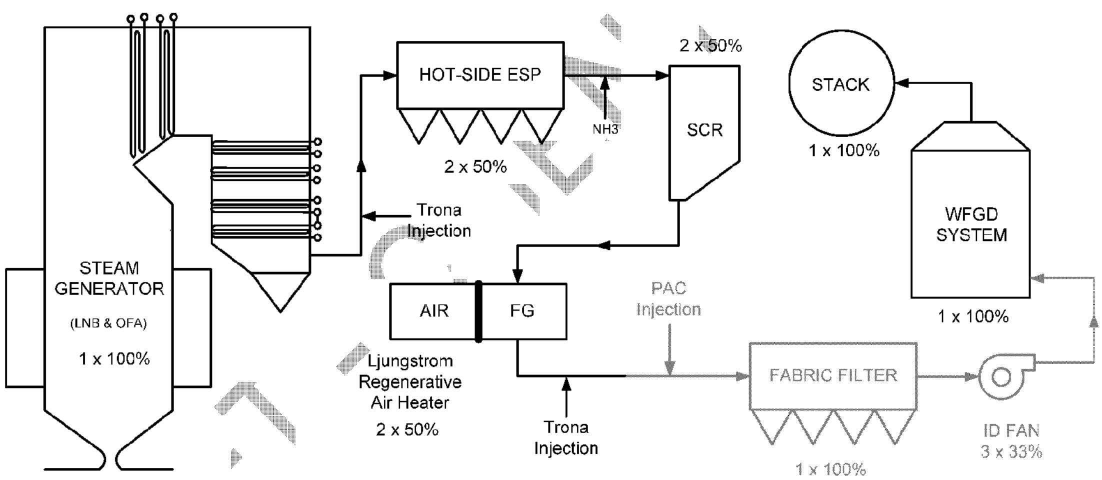

Figure 6-3. Unit 3 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 3 future draft system at MCR are as follows in Table 6-5. Note that the items in bold in Table 6-5 are new.

Table 6-5. Unit 3 Future Draft System Characteristics at MCR

SCR system leakage	2% (estimated)
Air heater leakage	10% (estimated)
ESP leakage	5% (estimated)
PJFF leakage	**3%**
Flue gas temperatures	
Boiler outlet	731° F
ESP outlet	708° F
SCR outlet	708° F
Air heater outlet	322° F
PJFF outlet	**322° F**
ID fan outlet	**~350° F (calculated)**
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.6 inw
ESP	5.8 inw
SCR	10.0 inw
Air heater	15.2 inw
PJFF	**8.0 inw**
WFGD	3.9 inw
Stack	2.0 inw

Based on the layout of the future draft system in Figure 6-3 and the future draft system characteristics in Table 6-5, the estimated performance requirements of the new ID fans at MCR are shown in Table 6-6. Also in Table 6-6 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 25 and 38 percent, respectively. To keep the ID fan Test Block flow and pressure margin within the typical ranges the 50 percent leakage margin and 50 percent margin on air heater differential pressure were both decreased to 25 percent.

Table 6-6. Unit 3 New ID Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	------	900
Inlet Temperature (°F)	322	347
Inlet Density (lb/ft^3)	0.0446	0.0413
Flow per Fan (acfm) *	796,000	991,000
Inlet Pressure (inwg)	-44.1	-60.0
Outlet Pressure (inwg)	5.9	8.8
Static Pressure Rise (inw)	50.0	68.8
Shaft Power Required (HP) **	7,400	12,700
Efficiency (percent)**	85	85
Number of Fans	3	3
Flow Margin (percent)	---------	25
Pressure Margin (percent)	---------	38

*Per fan basis with three fans in operation.
**Estimated – assumes variable speed operation.

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6.1.4 Unit 4

Based on the additions to the Unit 4 draft system previously discussed, the flue gas would be redirected through the draft system as follows. At the outlet of the existing air heaters the flue gas would travel to the new PJFF system allowing for the removal of finer particulate. The three new 33 percent centrifugal ID fans, assumed to be equipped with variable speed control, would then draw the flue gas out of the PJFF system and send it to the WFGD system. An illustration of the Unit 4 future draft system based on this description is shown in Figure 6-3.

Due to operation and maintenance issues with the recently installed two 50 percent axial ID fans, the plant would like them to be replaced and bypassed with new centrifugal type fans. However, due to the B&V recommended margins on flow and pressure (Test Block conditions) above the MCR conditions with the addition of a PJFF system, the new centrifugal ID fans will be required to be in a three fan arrangement. An illustration of the Unit 4 future draft system based on this description is shown in Figure 6-4.

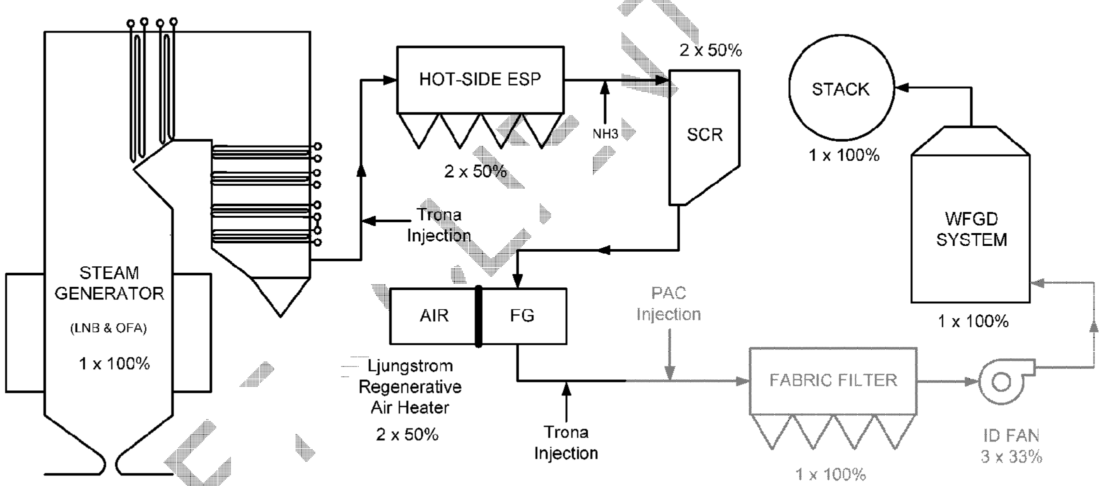

Figure 6-4. Unit 4 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 4 future draft system at MCR are as follows in Table 6-7. Note that the items in bold in Table 6-7 are new.

Table 6-7. Unit 4 Future Draft System Characteristics at MCR

SCR system leakage	2% (estimated)
Air heater leakage	10% (estimated)
ESP leakage	5% (estimated)
PJFF leakage	**3%**
Flue gas temperatures	
Boiler outlet	791° F
ESP outlet	770° F
SCR outlet	770° F
Air heater outlet	309° F
PJFF outlet	**309° F**
ID fan outlet	**~340° F (calculated)**
WFGD outlet	~125° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.0 inw
ESP	6.3 inw
SCR	10.0 inw
Air heater	8.6 inw
PJFF	**8.0 inw**
WFGD	13.0 inw
Stack	1.6 inw

Based on the layout of the future draft system in Figure 6-4 and the future draft system characteristics in Table 6-7, the estimated performance requirements of the new ID fans at MCR are shown in Table 6-8. Also in Table 6-8 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 23 and 35 percent, respectively. To keep the ID fan Test Block flow and pressure margin within the typical ranges the 50 percent leakage margin and 50 percent margin on air heater differential pressure were both decreased to 25 percent.

Table 6-8. Unit 4 New ID Fan MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	------	900
Inlet Temperature (°F)	309	334
Inlet Density (lb/ft^3)	0.0462	0.0433
Flow per Fan (acfm) *	760,000	935,000
Inlet Pressure (inwg)	-37.4	-49.6
Outlet Pressure (inwg)	14.6	20.4
Static Pressure Rise (inw)	52.0	70.0
Shaft Power Required (HP) **	7,400	12,200
Efficiency (percent) **	85	85
Number of Fans	3	3
Flow Margin (percent)	---------	23
Pressure Margin (percent)	---------	35

*Per fan basis with three fans in operation.
**Estimated – assumes variable speed operation.

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6.1.5 Draft System Transient Design Pressures

The AQC equipment additions and changes to all of the Ghent units will likely be considered major alterations or extensions to the existing facilities per the National Fire Protection Association (NFPA) 85 code - Section 1.3 (2007 Edition). The code, in this instance, would imply that the boiler and flue gas ductwork from the boiler outlet (economizer outlet) to the ID fan inlet (it should be implied that this would include booster fans) be designed for transient pressures of ± 35 inwg at a minimum per Section 6.5. Further research is needed to determine whether the existing boilers and draft systems of each of the Ghent units meets this criteria or if they will require stiffening. Each new piece of AQC equipment, and its associated ductwork, being considered for the Ghent units will also be required to meet this NFPA 85 requirement. Additionally, in some sections of the future draft systems, the transient design pressures will need to exceed the ± 35 inwg due to high negative draft pressures.

The Black & Veatch philosophy for calculating the minimum required transient design pressures is based on the draft system being designed to 66 percent of its yield stress for maximum continuous (fan Test Block) operating pressures and 95 percent for short durations, or transient conditions. This results in a 44 percent increase in the allowable stress throughout the draft system for short durations without resulting in permanent deformation or buckling of any structural components. For example, if a section of ductwork is expected to be exposed to negative draft pressures of -30 inwg when the ID fans are operating at Test Block conditions, the calculated negative transient design pressure would be 44 percent higher or -43.2 inwg. The positive transient design pressure would still be +35 inwg. Since NFPA 85 requires that flue gas ductwork between the boiler outlet and the ID fan inlet be designed for transient pressures of ± 35 inwg, calculated transient design pressures below ± 35 inwg are disregarded and the ± 35 inwg is used as the design transient pressure for that draft system component or section of ductwork. For calculated transient design pressures over ± 35 inwg such as in the previous example, the calculated pressure is used.

6.2 Auxiliary Electrical System Analysis

The existing Ghent auxiliary power systems includes 25 kV switchyard switchgear two bus system where 25 kV Bus A is fed from 138 kV–25 kV Reserve Auxiliary Transformer (RAT) A, and 25 kV Bus B is fed from 138 kV–25 kV RAT B. The 25 kV switchgear buses provide startup/backup power for each unit, and the unit scrubber FGD auxiliary electrical systems with the exception of Unit 2 scrubber FGD auxiliary electrical system. Unit 2 Scrubber FGD auxiliary electrical system 4KV buses 5A and 5B are fed from 25 kV–4.16 kV scrubber transformers SST FGD 5A and 5B.

The 25 kV switchgear bus A supplies reserve power to Unit 1 scrubber 25 kV–4.16 kV RAT 1C, Unit 1 and Unit 2 RAT1/2, and Plant Limestone Prep SST-LSA. The 25 kV switchgear bus B supplies reserve power to Unit 3 and Unit 4 scrubber 25 kV–13.8 kV RAT 3C and 4C, and 25 kV–4.16 kV RAT3/4, and Plant Limestone Prep SST-LSB. The RATs and SST-LSs auxiliary transformers are connected in an "A" or "B" fashion to each of the units' 4.16 kV and 13.8 kV auxiliary electrical reserve incoming circuit breakers for startup and backup power.

All units main plant auxiliary electrical system 4.16 kV switchgear buses UA and UB are fed from their own respective two two-winding unit auxiliary transformer (UAT) that is powered from their respective generator leads. Unit 1 4.16 kV switchgear scrubber buses FGD1A and FGD1B are fed respectively from one three winding UAT1C that is powered from Unit 1 generator leads. Unit 2 4.16 kV switchgear scrubber buses FGD5A and FGD5B are fed respectively from two two-winding 25 kV–4.16 kV SSTFG-5A and 5B respectively as described above. Unit 3 and Unit 4 13.8 kV switchgear scrubber buses FGD3A and FGD3B, and FGD4A and FGD4B are fed respectively from each of their respective two winding UAT3C/4C that is powered from their respective Unit 3 and Unit 4 generator leads. Each 13.8 kV switchgear bus will feed a 13.8 kV–4.16 kV step down transformer that provides power to the Unit 3 and Unit 4 4.16 kV switchgear buses.

The addition of PJFF on each unit and a SCR on Unit 2 will require the addition of new ID Fans (Unit 3 and 4) or new booster fans (Units 1 and 2). All new fans will have variable frequency drives (VFDs). The existing unit auxiliary transformers, reserve auxiliary transformers, and 13.8 kV/4.16 kV switchgear buses were determined to have insufficient spare capacity and short circuit ratings to power the PJFF and SCR additions, which include new technology and fan electrical loads.

Each unit will require one new two winding AQC UAT that will be fed from their respective generator leads. The secondary windings will power the new AQC 13.8 kV and 4.16 kV switchgear buses for the fans and other various AQC loads. The reserve/backup power for new AQC 13.8 kV and 4.16 kV switchgear buses will be fed from new outdoor AQC 25 kV reserve switchgear and two new Unit 1 and Unit 2 AQC 25 kV–4.16 kV, and two new Unit 3 and Unit 4 AQC 25 kV–13.8 kV two winding RATs fed from existing 25 kV switchgear described above. Unit 3 and Unit 4 AQC 13.8 kV buses will each supply power to a two winding 13.8 kV–4.16 kV transformers which supply power to the Unit 3 and Unit 4 AQC 4.16 kV switchgear buses. Further electrical studies (short circuit, motor starting, etc.) will be performed during detailed design to determine the final transformer impedance and MVA ratings. Also, further field investigation will be required to determine the best way to connect the new AQC 25 kV switchgear into the existing 25 kV buses A and B.

The recommended location of the four new AQC RATs that will be connected to the new 25 kV AQC switchgear will be in close proximity to the tie-in points on the south side of the units. The recommended locations of each of the four new AQC UATs will be in close proximity to each of their respective generator leads. Cable bus will be routed during detailed design from the secondary windings of these auxiliary transformers to the new AQC electrical buildings. The new electrical AQC buildings would be located in the vicinity of the PJFF equipment as shown in the conceptual sketches in Appendix A. The buildings will contain the new medium voltage (MV) and low voltage (LV) switchgear, motor control centers (MCCs), and distributed control system (DCS) cabinets. A DC and UPS system will also be included in the electrical buildings to provide control power to the switchgear and DCS system. Motor control centers and DCS I/O cabinets may be installed in a small electrical building adjacent to remote AQC equipment to minimize cable lengths for the equipment in this area.

6.3 AQC Mass Balance Analysis

Addition of PJFF will increase the amount of ash removed from the Ghent Units.

- **Ash Handling**--Additional new ash handling system will be required for new PJFF. Additional ash handling equipment may include but is not limited to pipes, blowers, valves, etc. There will be approximately total of 8,663 lb/hr of additional waste (ash) generated for Ghent Station.

6.4 Reagent Impact Analysis

- **Anhydrous Ammonia System**--There will be an increase in the amount of ammonia required if SCR systems are implemented on Unit 2. Additional equipment required for anhydrous ammonia system may include but is not limited to ammonia storage tank, ammonia feed pumps, dilution air blowers, vaporizers, pipes, valves, instrumentation and control equipments etc. There will be approximately total of 508 lb/hr of more anhydrous ammonia required for Ghent Unit 2.
- **PAC Injection System**--A new PAC injection system will be required for mercury and dioxin/furan control. Additional equipment required for PAC injection system may include but is not limited to PAC storage silo, PAC injection lances, blowers, pipes, valves, instrumentation and control equipments etc. There will be approximately total of 5,151 lb/hr of PAC required for Ghent Station.

- **Trona/Lime/SBS Injection System**-- A new sorbent (trona/lime/SBS) injection system will be required for SO_3 control on Unit 2. Additional equipment required for sorbent injection system may include but is not limited to sorbent storage silo, injection lances, blowers, pipes, valves, instrumentation and control equipments etc. There will be approximately total of 2,293 lb/hr of sorbent (trona) required for Ghent Unit 2.

6.5 Chimney Analysis

Based on the recommendations made in Section 5.2, analysis of the chimneys at Ghent Station is not required. The Ghent Station units 1-4 will reuse the existing chimneys.

6.6 Constructability Analysis

Several major AQC construction projects have been executed at the Ghent plant site over the last several years, with some projects still actively in construction as of the date of this report. The construction facilities, utilities, and services established to support these projects, such as parking, material laydown, fabrication areas, temporary utilities, and support services are expected to be adequate to support the work scope presented in this study. Some adjustment to construction facilities will be required to support unit-specific project execution. These needs will be addressed in the detailed construction execution plan submitted by the installing Contractor.

"Brown-field" construction of major new equipment on the existing Ghent plant footprint will present significant challenges in construction due to congestion, obstructions, and the need to keep existing units on line during construction. Each of the four units present unique access and construction execution challenges to implementing the selected AQC technologies. Accordingly, a high level constructability analysis was completed as part of this study in order to identify and evaluate potential concerns with the arrangement presented for each unit. A total of three conceptual plan sketches with corresponding elevation sketches are attached to this study in Appendix A. Each sketch depicts the current proposed arrangement, including refinements made per two site walk down inspections and joint project team discussion. Following is a generalized discussion of the sequence and concerns identified with the arrangement presented for each unit.

Because of limited onsite construction facilities and laydown area, the difficulty in outage scheduling, congested access, and the general confusion and complexity of several simultaneous projects, it is assumed that the work described below will be done sequentially by unit and not simultaneously. Due to the potential of new construction at

Unit 1 impacting construction access to the east side of Unit 2, consideration should be given to completing work at Unit 2 prior to start of work at Unit 1. Similarly, although of less concern, completion of Unit 2 modifications prior to Unit 3 would allow better access to Unit 2 from the courtyard area than after the addition of new structures required for Unit 3.

6.6.1 Unit 1 Arrangement

The AQC technology proposed for Unit 1 consists of a two 50 percent PJFFs, two 50 percent VFDs booster fans, PAC and trona transfer equipment, and the associated ductwork and ancillary equipment required to tie this equipment into the exhaust gas air stream.

The major equipment is proposed to be located immediately south of the southwest end of Unit 2 mechanical draft cooling tower, and west of the Unit 1 WFGD. The PJFF equipment will be located above, and straddle, the existing Unit 1 WFGD inlet duct. The new booster fans will be located below (west fan) or just south of (east fan) the existing inlet duct and new PJFFs adjacent to the existing Unit 2 ID fans. This arrangement minimizes obstruction to cooling tower inlet air flow, but places the PJFFs above the outlet stacks of the cooling tower draft fans. This may create icing conditions on the PJFFs during certain weather events. Crane access to the construction area is limited. The main erection crane can be established on the northwest corner of the proposed footprint; however, extensive temporary structural fill and crane matting will be required to protect the half-buried cooling water piping running through this area. Additional crane and construction access can be established along the north side of the proposed footprint, in the cooling tower maintenance road.

Construction activities must be closely coordinated with plant operations to ensure adequate access is maintained on the west end of the Unit 2 cooling tower to conduct routine maintenance. The congested footprint has limited area to stage material. Major components of ductwork and PJFFs must be modularized for efficient execution of the work scope. It is assumed that the major component modules will be fabricated in remote fabrication areas, transported to the work site via the north plant access road, raised over the Unit 2 cooling tower and set in place by the main lift crane located on the northwest end of the construction footprint.

The expected sequence of construction (and estimated timeframe) for installation for the Unit 1 arrangement is as follows and as noted:

- Install new flanges/blanking plates and transition duct pieces in the existing WFGD inlet duct and at the ID fan (2 weeks, outage, this work could also be completed at the time of the ductwork tie-in).

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- Construct new foundations and any supporting structural steel superstructure for the PJFF, ductwork and booster fans (5 months, non-outage).
- Install new PJFF, booster fans, ancillary systems such as PAC, trona and ash handling, plus ductwork to tie-in points (16 months, non-outage).
- Complete tie-in of ductwork to existing WFGD inlet duct and ID fans (2 weeks, outage).
- Start-up and tune new PJFF, booster fans, PAC, trona, and ash handling systems (10 weeks, combined outage and non-outage).

The main crane will have a limited boom swing due to its close proximity to the Unit 2 chimney. Detailed rigging and lift plans must be developed for each major component installed. The proposed arrangement requires the PJFF to be installed above the existing WFGD inlet duct, requiring substantial work at heights and the resulting complications and inefficiencies. Installation of foundations will be problematic due to the existing congestion and the need to maintain unit operation to the extent practical. Micropiles may be required for the booster fan foundations and the support steel foundations on the south side of the inlet duct. In addition, the following issues will have to be addressed in detail to support construction at Unit 1.

- Above and below ground utility interferences and relocations may be necessary, especially low overhead obstructions along the north access road.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed and special precautions taken in the area of the semi-exposed Unit 2 cooling water piping.
- The potential and magnitude of existing equipment relocations needed to support access, crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated.
- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment.
- Existing plant traffic along the north access road will be interrupted and must be rerouted. Existing traffic patterns must be reestablished prior to start of construction.
- Demolition/modification of existing ductwork will require selective dismantling operations in order to work around existing equipment and ancillaries.

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- Elevating the PJFF and ductwork above the existing equipment and structures will require a substantial new foundation and superstructure.
- New PAC and trona silos and associated transfer equipment must be carefully located to maintain crane access to Unit 2 SCR and PJFF construction activities. Combining the PAC and trona silos and associated equipment for both Unit 1 and Unit 2 should be considered.

6.6.2 Unit 2 Arrangement

The AQC technology proposed for Unit 2 consists of a two 50% PJFFs, two 50% VFD booster fans, two 50 percent SCR reactors, PAC and trona silos and transfer equipment; and the associated ductwork and ancillary equipment required to tie this equipment into the exhaust gas air stream.

The two SCR modules are proposed to be located close to their respective exhaust gas trains in order to facilitate construction access and minimize new ductwork. The conceptual arrangement places the east SCR module above an existing structural steel frame supporting the Unit 1 SCR located immediately east of the Unit 2 east ESP. The arrangement tentatively includes a new structural steel tower straddling the existing steel frame, although ideally the existing framing might be incorporated into the support for the Unit 2 SCR. The construction footprint can be accessed by construction equipment via a narrow lane running north/south from the north access road, then along the east side of Unit 2 chimney to the existing structural support frame. It is proposed that a lattice boom crawler crane or large hydraulic truck crane can be located immediately northeast of the support frame and used to erect the new steel support and then lift pre-fabricated SCR and ductwork modules into place on the framing.

The west SCR module is conceptually placed on a new structural support frame located on the southwest corner of Unit 2 west ESP, and below the Unit 3 and 4 coal conveyor. It is proposed that a large lattice boom crawler crane be assembled in the "courtyard" immediately southwest of the SCR footprint and used to lift pre-fabricated support steel, SCR module, and ductwork modules into place. Construction materials can be transported to the footprint via the north/south access alley running immediately east of the existing Unit 2 absorbers, or from the south through existing roll up doors installed in the enclosed ground level utility corridor. Components too large to pass through the roll up doors can be lifted over the existing personnel skywalk, utility corridor and maintenance shops using a second crane located to the south.

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The following issues will have to be addressed in detail to support construction of the east and west SCR modules and ductwork at Unit 2.

- The new steel structure supporting the east SCR module must be designed to coexist with the existing structural frame. Additional investigation regarding the actual incorporation of the existing support tower into the support for the new SCR module must be completed at time of detail design to ensure that the existing structure and its foundation can support the loads imposed by the new construction.
- Above and below ground utility interferences and relocations will be necessary to install the foundations and structural framing for the west SCR module. Additional investigation is recommended at both locations to identify and locate any underground utilities that might be impacted.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed, especially in the area of the Unit 2 cooling water lines east of Unit 2.
- The potential and magnitude of existing equipment and facility relocations needed to support crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated. This will be of particular importance in the area of the west SCR support tower due to existing congestion. A series of existing overhead power lines west of Unit 2 will likely require relocation, along with the demolition of several abandoned foundations in the area.
- The design of the support tower for the west SCR module must take into account existing equipment and structures that likely cannot be relocated. A support bent for the overhead coal conveyor, an existing elevated cable tray, and the Service Water Pump House are all located in the immediate area proposed for the west tower and the final arrangement and design must accommodate these obstructions.
- The west SCR is tentatively located directly beneath existing Coal Conveyor 3J, significantly complicating crane operation in the area. Although prefabrication of SCR support framing, modules, and ductwork sections should be used to the extent it is practical, size and weight of lifted components will be limited to that which can be maneuvered around the conveyor. Some temporary shoring or framing may be required to "land" prefabricated sections where they can be slid into place under the conveyor.

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- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment. Special consideration must be given to protecting the Unit 3 coal conveyor from damage during SCR erection.
- Plant traffic along the north access road and in the "courtyard" area will be interrupted by construction and must be rerouted. Essential plant operations traffic patterns must be defined and re-established prior to starting the project.
- Demolition/modification of existing ESP ductwork will require selective dismantling operations to be scheduled into plant outages in order to work around existing equipment and ancillaries.
- The support structures for both SCR modules and their ductwork will require substantial new foundations and superstructures installed in very congested areas. Micropiles may be required for the foundations.

The two PJFFs, two booster fans, PAC and trona silos and transfer equipment, and associated ductwork are proposed to be located immediately north of the existing Unit 2 ESPs. The footprint for the new equipment must be reclaimed by eliminating existing ductwork in this area. This will require installation of a bypass duct connecting the common duct ending at the north end of the ESPs and the existing duct leading to the inlets of the absorbers. The bypass will allow the remaining common duct to the north to be demolished and the area prepared for foundation and support steel framing erection. The dimensions of the proposed PJFF extend across the existing north access road. The PJFF, associated structural support frame, and ductwork must be elevated in order to allow the road to pass beneath the new construction. In addition, elevating the new equipment allows new electrical auxiliaries and ash handling equipment to be located beneath the elevated structure, concentrating equipment in the area it is needed and reducing the overall "sprawl" of the new construction.

The congested construction footprint contains limited area in which to stage material. Major components such as ductwork, booster fans, and PJFFs must be modularized for efficient execution of the work scope. It is assumed that the major component modules will be fabricated/dressed out in remote fabrication areas, transported to the work site via the north plant access road, and set in place by the main lift crane, which would be located in the access road on the east or west sides of the construction footprint. It should be noted that the cranes established on the west side of the PJFF construction will likely be hydraulic, truck mount units. The PJFF support steel spanning the roadway to the east and the low overhead obstructions spanning the

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roadway to the west will not allow a lattice boom crawler crane to walk into place along the west side of the new construction. These obstructions will also make it difficult to lay a lattice work crane boom down along the roadway in severe weather

The following issues will have to be addressed in detail to support construction of the PJFFs, booster fans, and ductwork at Unit 2.

- Above and below ground utility interferences must be identified and relocated in order to install the foundations and structural framing for the PJFF support frame.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed.
- The elevated structure supporting the PJFFs will require careful coordination with the existing road and the elevated piperack immediately to the north of the road. The piperack serves all four units; it cannot be taken out of service and must be accommodated in the structure's design. The foundations beneath the northernmost supports of the structure must also take into account the steeply sloping riverbank immediately to the north of the piperack.
- The magnitude of existing equipment and facility relocations needed to support crane setting, construction traffic flow, construction execution, and placement of new AQC equipment and ancillary equipment must be investigated, quantified and resolved. Special consideration must be given to relocation of overhead electrical lines for the existing scrubbers and modification of exhaust gas ductwork during outages.
- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment. Special consideration must be given to protecting the piperack north of the main access road.
- Plant traffic along the north access road will be interrupted by construction and must be rerouted. Essential plant operations traffic patterns must be defined and re-established prior to starting the project.
- Demolition/modification of existing ESP ductwork will require selective dismantling operations to be scheduled into plant outages in order to work around existing equipment and ancillaries.

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The expected sequence of construction (and estimated timeframe) for installation for the total Unit 2 arrangement is as follows and as noted:

- Install foundations and structural steel support frame for by-pass ductwork at PJFF (2 months, non-outage).
- Install new flanges/blanking plates on existing ductwork as necessary to install by-pass damper and install by-pass ductwork at PJFF (6 weeks, outage).
- Demo by-passed ductwork and associated support steel at PJFF (3 months, non-outage).
- Install foundations and superstructure for PJFF and ductwork support frame and booster fans (5 months, non-outage).
- Install PJFF, ductwork up to tie-in points, PAC/trona equipment, ash handling, and booster fans (16 months, non-outage)
- Install ductwork to tie PJFF into existing ductwork (2 weeks, outage)
- Start-up and tune new PJFF, booster fans, PAC, trona, and ash handling systems (10 weeks, combined outage and non-outage).
- Install foundations and structural steel framing supporting east side SCR reactor (4 months, non-outage)
- Install new flanges/blanking plates on existing ductwork as necessary to install east SCR inlet and outlet ductwork (4 weeks, outage).
- Erect east side SCR and ductwork up to tie-in points (18 months, non-outage).
- Tie-in east side SCR ductwork into existing duct and install blanking plates to re-direct flow through SCR (6 weeks, outage).
- Relocate overhead electrical lines and underground piping and ductbanks necessary to install foundations for west side SCR reactor. (6 weeks, outage, could be partially concurrent with outage for the east side SCR)
- Install foundations for west side SCR reactor structural steel support frame (4 months, non-outage, could be concurrent with east side SCR)
- Install new flanges/blanking plates on existing ductwork as necessary to install west SCR inlet and outlet ductwork (4 weeks, outage, could be concurrent with east side SCR).
- Install foundations and structural steel framing supporting for west side SCR reactor and ductwork (4 months, non-outage, could be concurrent with east side SCR).

- Erect west side SCR and ductwork up to tie-in points (18 months, non-outage, could be concurrent with east side SCR).
- Tie-in west side SCR ductwork into existing duct and install blanking plates to re-direct flow through SCR (6 weeks, outage, could be concurrent with east side SCR).
- Start-up and tune both east and west side SCRs (10 weeks, combined outage and non-outage).

6.6.3 Unit 3 Arrangement

The AQC technology proposed for Unit 3 consists of a single 100% PJFF, three 50% VFD ID fans, PAC and trona transfer equipment, and the associated ductwork and ancillary equipment required to tie this equipment into the exhaust gas air stream.

The major equipment is proposed to be located in the courtyard area south of the Unit 3 ID fans and east of the Unit 3 powerblock. The PJFF equipment will be elevated to allow ground-level access to existing silos and equipment east of Unit 3. The elevated PJFF will straddle the utility corridor currently located in the walkway enclosure between Units 2 and 3. New ductwork will connect the exhaust ductwork upstream of the existing ID fans to the PJFF inlet. New ID fans will be located at ground level between the PJFF outlet and existing Coal Transfer House 5 and adjacent waste sump. New ductwork downstream of the ID fans will connect to existing ductwork upstream of the Unit 3 scrubber inlet, bypassing the existing ID fans. The existing machine shop will require relocation to accommodate the PJFF and the skywalk will be temporarily removed during construction and then reincorporated into the new superstructures when complete.

The expected sequence of construction (and estimated timeframe) for installation for the Unit 3 construction is as follows:

- Demo and/or relocate existing structures in the way of new construction, i.e.; utility corridor walkway enclosure, maintenance shop, personnel skywalk, etc. (3 months, non-outage).
- Install new flanges/blanking plates and transition duct pieces in the existing inlet and outlet ductwork adjacent to the existing Unit 3 ID fans (2 weeks, outage, this work could also be completed at the time of the ductwork tie-in).
- Construct new foundations and any supporting structural steel superstructure for the PJFF, ductwork and booster fans. (4 months, non-outage).
- Install new PJFF, booster fans, ancillary systems such as PAC, trona and ash handling, plus ductwork to tie-in points. (16 months, non-outage).

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- Complete tie-in of ductwork to existing scrubber inlet duct and ID fans (3 weeks, outage).
- Start-up new PJFF, booster fans, PAC, trona, and ash handling systems (10 weeks, combined outage and non-outage).
- Reinstall modified utility corridor walkway enclosure and elevated skywalk (2 months, non-outage).

The main crane will be located in the "courtyard" area, in close proximity to operating plant systems. Limited amounts of construction material can be staged in the courtyard, making modularization of major ductwork and PJFFs components a necessity. Major component modules will be fabricated in remote fabrication areas, transported to the work site via the south plant access road, raised over the ground level pipe corridor by a second crane, and set in place by the main lift crane located in the courtyard. Detailed rigging and lift plans must be developed for each major component installed. The proposed arrangement requires the PJFF to be installed above the existing utility corridor between Unit 2 and Unit 3, and below the Unit 3 coal conveyor. This configuration will require substantial work at heights and the resulting complications and inefficiencies. Installation of foundations will be problematic due to the existing congestion of underground utilities and existing pipe trench, and the need to maintain unit operation to the extent practical. Micropiles may be required for the ID fan foundations and the ductwork support steel foundations located adjacent to existing Unit 3 building structure. In addition, the following issues will have to be addressed in detail to support construction at Unit 3.

- The new steel structure supporting the PJFF must be designed to maintain vehicle access to the east side of Unit 3, avoid disrupting the utility corridor in the ground level walkway, and avoid impact to the existing tanks to the south.
- Above and below ground utility interferences and relocations may be necessary, especially in the "courtyard" area. Particular care will be required to minimize impact on the existing pipe trench and the coal transfer house foundation.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed.
- The potential and magnitude of existing equipment relocations needed to support access, crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated. A series of existing overhead power lines across the north side of the courtyard will likely require relocation.

- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment. Special consideration must be given to incorporating the re-established ground level walkway and elevated skyway between Units 2 and 3 after completion of PJFF erection.
- Existing plant traffic along the utility corridor, maintenance skywalk, and "courtyard" area will be interrupted and must be rerouted. Existing traffic patterns must be reestablished prior to start of construction.
- Demolition/modification of existing ductwork will require selective dismantling operations in order to work around existing equipment and ancillaries.
- Elevating the PJFF and ductwork above the existing equipment and structures will require a substantial new foundation and superstructure.

6.6.4 *Unit 4 Arrangement*

The AQC technology proposed for Unit 4 consists of a single 100% PJFF, three 50% VFD ID fans, PAC and trona transfer equipment, and the associated ductwork and ancillary equipment required to tie this equipment into the exhaust gas air stream.

The major equipment is proposed to be located in the area west of the Unit 4 ESP area currently occupied by a warehouse. The PJFF equipment will be constructed on a ground-level foundation with inlet and outlet both on the east end of the PJFF. New common ductwork will connect the two exhaust ductwork trains immediately north of the Unit 4 powerblock and forward it to the PJFF. Three new ID fans will be located at ground level at the PJFF outlet and common ductwork will forward the treated exhaust to a tie-in point upstream of the existing WFGD. The existing ID fans will be bypassed.

The expected sequence of construction (and estimated timeframe) for installation for the Unit 4 arrangement is as follows and as noted:

- Demolish existing warehouse structure and foundation (6 weeks, non-outage)
- Install new flanges/blanking plates and transition duct pieces in the existing Unit 4 outlet duct and the inlet duct to the scrubber (3 weeks, outage, this work could also be completed at the time of the ductwork tie-in).
- Construct new foundations and any supporting structural steel superstructure for the PJFF, ductwork and ID fans (3 months, non-outage).

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- Install new PJFF, ID fans, ancillary systems such as PAC, trona and ash handling, plus ductwork to tie-in points (16 months, non-outage).
- Complete tie-in of ductwork to existing scrubber inlet duct and duct upstream of the existing ID fans (6 weeks, outage).
- Start-up new PJFF, booster fans, PAC, trona, and ash handling systems (10 weeks, combined outage and non-outage).

Crane access for construction of Unit 4 appears relatively good, although access may be limited to a great extent to the north side due to the shallow embedment of large bore circulating water piping on the south side of the construction footprint. Extensive coordination of existing ductwork modification and the installation of new ductwork on downstream of Unit 4 and around the existing ID fans will be required to minimize outage schedule. In addition, the following issues will have to be addressed in detail to support construction at Unit 4.

- Above and below ground utility interferences and relocations may be necessary, especially on the south side of the PJFF construction footprint in the area of the circ water pipe corridor. Ductwork supports in the pipe corridor area may be required to "bridge" the corridor to avoid excavations within the corridor.
- Ground and soil stability for setting cranes and heavy haul traffic must be confirmed, especially in the pipe corridor area.
- The potential and magnitude of existing equipment relocations needed to support access, crane setting, construction traffic flow, construction operations activities, and placement of new AQC equipment and ancillary equipment must be investigated.
- Conflicts with existing plant operations must be evaluated and minimized. Isolation of the work area from operating areas must be considered if practical, while still allowing maintenance access to existing equipment.
- Existing plant traffic along the west end of the north access road will be interrupted and must be rerouted. Existing traffic patterns must be reestablished prior to start of construction.
- Demolition/modification of existing WFGD inlet and ID fan ductwork will require selective dismantling operations in order to work around existing equipment and ancillaries.
- Design and installation of ductwork support foundations in the area of the existing ID fans will require careful coordination due to the congestion in the area. Micropiles may be required for those foundations.

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6.7 Truck/Rail Traffic Analysis

The modifications proposed for the four Ghent units will result in additional bulk material required to support the AQC processes. These materials will be delivered from offsite on a regular basis and stored onsite for use. Preliminary estimates of the rate of use of sorbents or reagents required in the proposed AQC processes by unit are listed in Table 6-9. Additional delivery traffic for the site as a whole will be addressed accordingly.

Table 6-9. Sorbents and Reagents Consumption Rates (tph)

Material	Unit 1	Unit 2	Unit 3	Unit 4	Station Total
PAC	0.657	0.637	0.652	0.630	2.58
Sorbent (trona)	Note 1	1.15	Note 1	Note 1	1.15 addn'l
Anhydrous ammonia	Note 2	0.254	Note 2	Note 2	0.254 addn'l

tph - tons per hour.

Notes:
1. Current rate of consumption of trona at Units 1, 3 and 4 will remain essentially unchanged.
2. Current rate of consumption of anhydrous ammonia at Units 1, 3 and 4 will remain essentially unchanged.

Although a rail spur exists and passes by the Ghent Station, it is not currently used for any materials deliveries. Due to the distance between the existing trackage and the units, using the existing rail system for periodic delivery of other bulk materials would be problematic. Accordingly, delivery of bulk sorbents and reagents for the proposed AQC systems will be assumed to be via truck on existing roads.

Dry bulk material, such as PAC and sorbent (trona), is normally delivered in fully-enclosed bulk delivery trucks and offloaded using a pneumatic transfer system integral to the truck. A standard over-the-road trailer truck size for these materials is nominally 20 tons per load. Anhydrous ammonia is usually transported in a pressurized tank truck with a nominal capacity of 10,000 gallons. Based on the consumption rates in the Table 6-9 above and the nominal truck sizes, the additional truck deliveries to the Ghent site can be summarized as follows.

- PAC — 22 loads per week
- Sorbent (trona) — 10 loads per week additional
- Anhydrous ammonia — 1.7 loads per week additional

Therefore, the total additional truck deliveries estimated to provide sorbents or reagents is approximately 34 loads per week. Assuming delivery operations are limited to five days a week and an 8-hour day, the maximum additional truck deliveries to site would be approximately 6.8 per day or 1 every 1.2 hours over and above the current deliveries being made. Existing roads onsite should be able to accommodate the additional deliveries. A tank or silo is often provided for each material at each unit to minimize the size and length of distribution systems. However, where practical, consideration should be given to consolidated tanks or silos located so as to serve more than one unit, in order to minimize unloading time and extended truck travel onsite. The arrangements as proposed combine the silos for Units 1 and 2 to minimize the new construction as well as decrease congestion.

The PJFF system added at each unit will capture additional particulate that will need to be landfilled. The total expected additional fly ash removed from the exhaust streams of the four units is estimated at 8,660 lb/hr, or approximately 104 tons per day of operation of all four units. This increased volume will require additional operating time for the existing (and augmented) ash transfer systems to deliver the ash to the ash handling area. Current ash disposal activities will have to increase accordingly.

The modifications proposed include no changes to the existing FGD scrubbers at any of the four units. Therefore limestone consumption and gypsum or scrubber byproduct production are not expected to change appreciably. No modifications to the existing limestone or scrubber byproduct bulk materials handling systems are expected to be required.

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7.0 Conclusion

(Later: To be completed based on the outcomes and decisions of the technology validation meeting.)

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Appendix A
Conceptual Sketches

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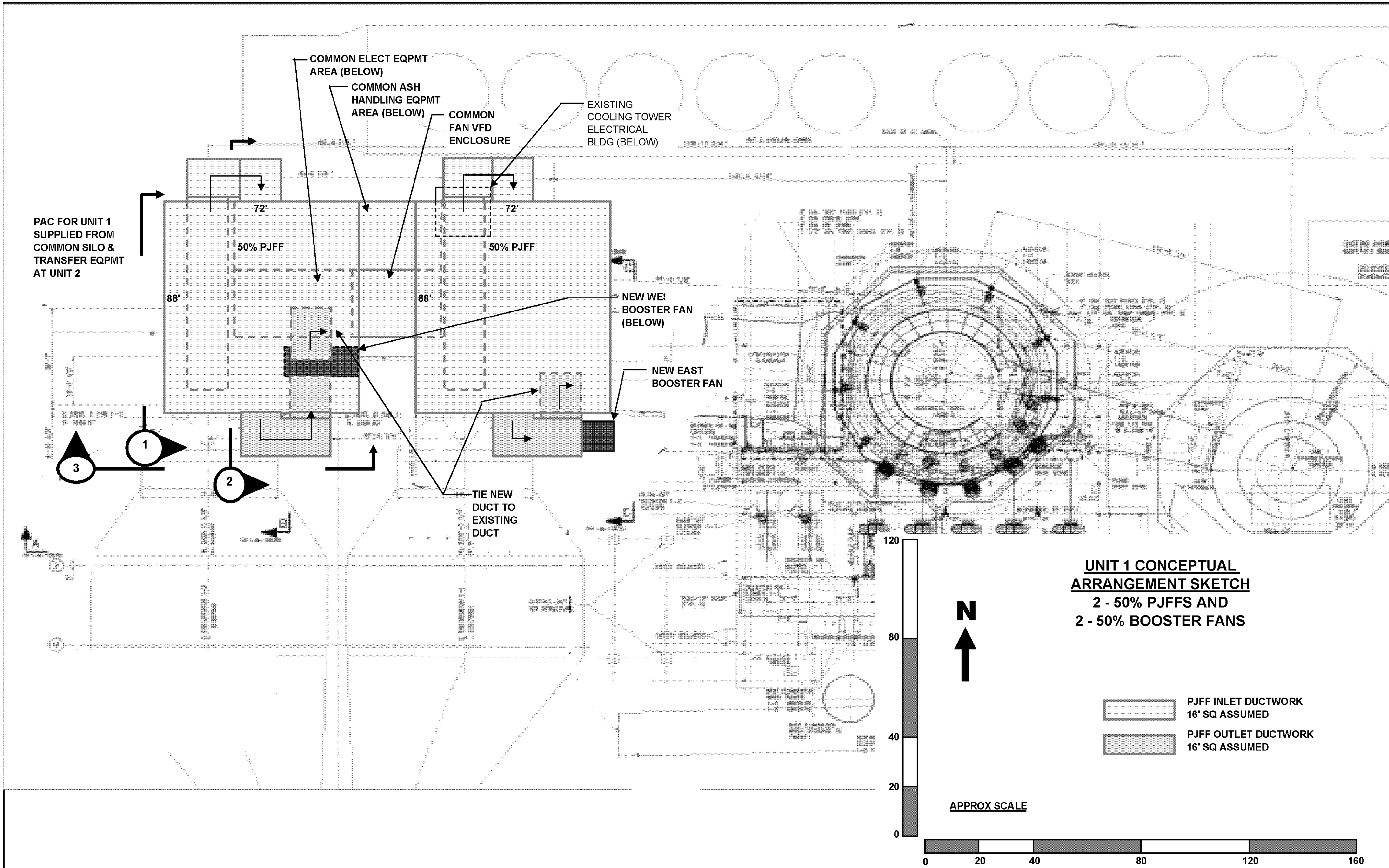
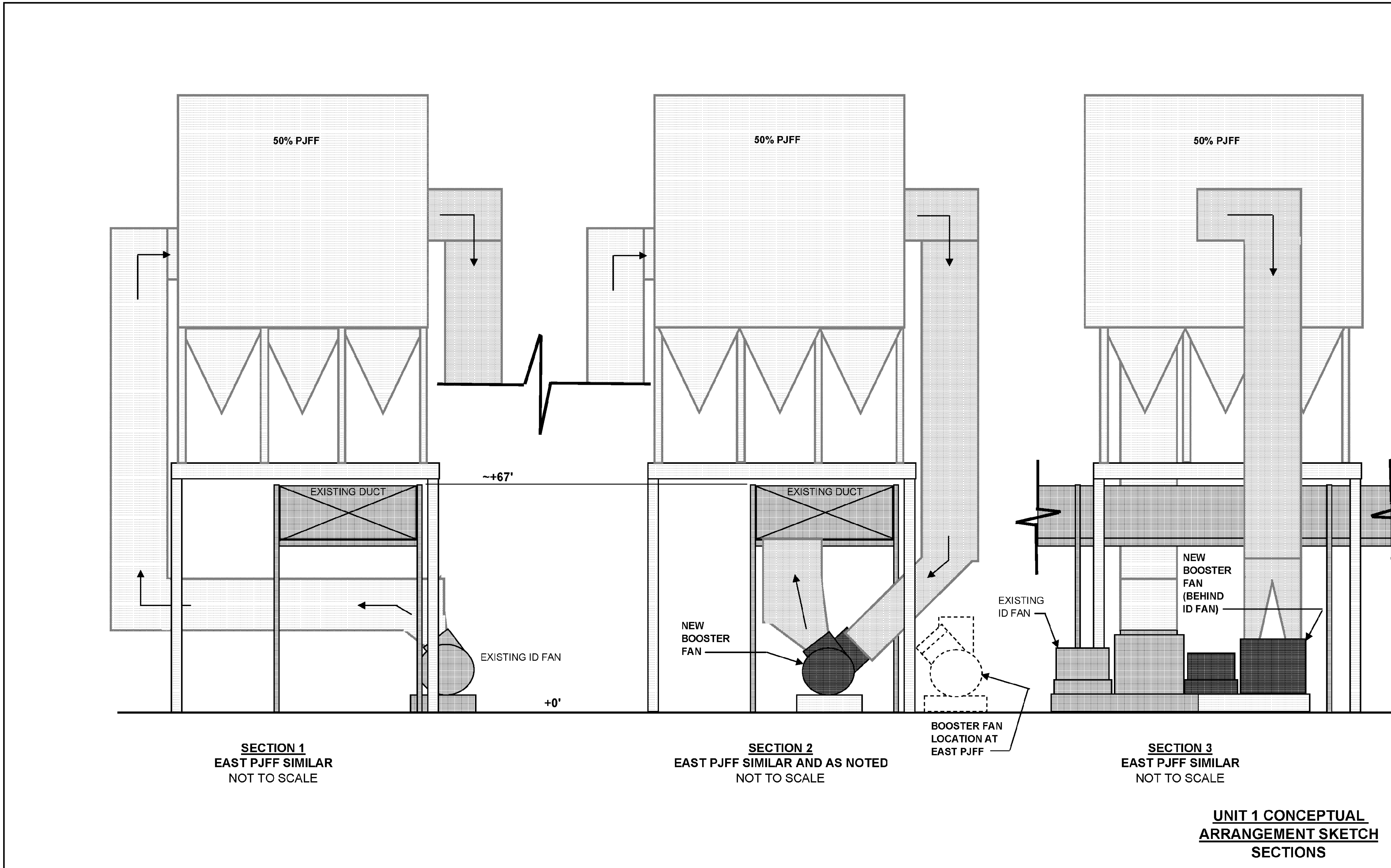
Unit 1 Arrangements


COMMON ELECT EQPMT AREA (BELOW)
COMMON ASH HANDLING EQPMT AREA (BELOW)
COMMON FAN VFD ENCLOSURE
EXISTING COOLING TOWER ELECTRICAL BLDG (BELOW)
PAC FOR UNIT 1 SUPPLIED FROM COMMON SILO & TRANSFER EQPMT AT UNIT 2
72'
72'
50% PJFF
50% PJFF
88'
88'
NEW WES BOOSTER FAN (BELOW)
NEW EAST BOOSTER FAN
TIE NEW DUCT TO EXISTING DUCT
1
2
3
UNIT 1 CONCEPTUAL ARRANGEMENT SKETCH
2 - 50% PJFFS AND
2 - 50% BOOSTER FANS
N
PJFF INLET DUCTWORK 16' SQ ASSUMED
PJFF OUTLET DUCTWORK 16' SQ ASSUMED
APPROX SCALE
0
20
40
80
120
160



50% PJFF
50% PJFF
50% PJFF
~+67'
EXISTING DUCT
EXISTING DUCT
EXISTING ID FAN
+0'
NEW BOOSTER FAN
BOOSTER FAN LOCATION AT EAST PJFF
EXISTING ID FAN
NEW BOOSTER FAN (BEHIND ID FAN)
SECTION 1
EAST PJFF SIMILAR
NOT TO SCALE
SECTION 2
EAST PJFF SIMILAR AND AS NOTED
NOT TO SCALE
SECTION 3
EAST PJFF SIMILAR
NOT TO SCALE
UNIT 1 CONCEPTUAL ARRANGEMENT SKETCH
SECTIONS

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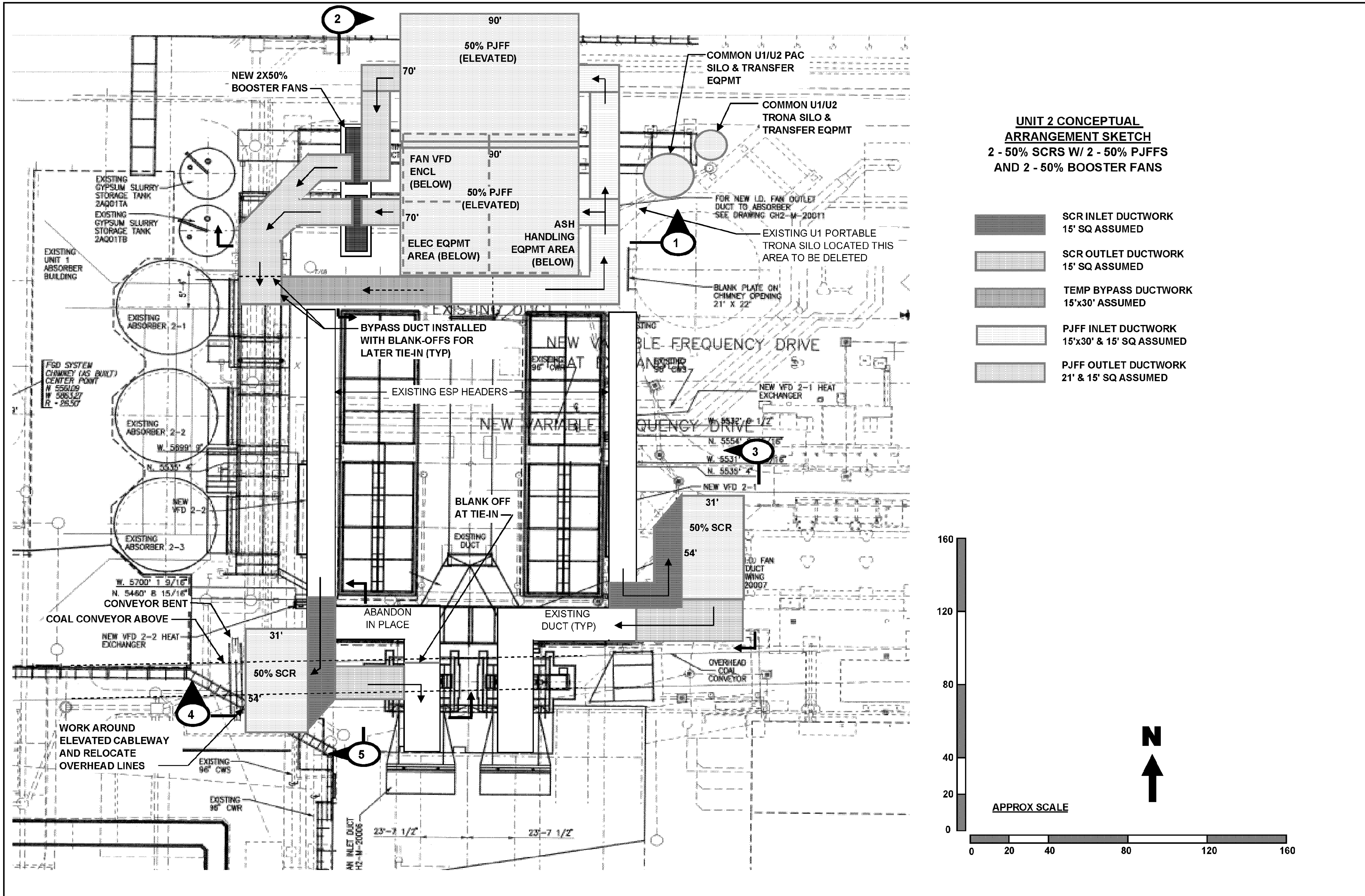
Unit 2 Arrangement


UNIT 2 CONCEPTUAL ARRANGEMENT SKETCH
2 - 50% SCRS W/ 2 - 50% PJFFS AND 2 - 50% BOOSTER FANS
SCR INLET DUCTWORK 15' SQ ASSUMED
SCR OUTLET DUCTWORK 15' SQ ASSUMED
TEMP BYPASS DUCTWORK 15'x30' ASSUMED
PJFF INLET DUCTWORK 15'x30' & 15' SQ ASSUMED
PJFF OUTLET DUCTWORK 21' & 15' SQ ASSUMED
50% PJFF (ELEVATED)
FAN VFD ENCL (BELOW)
ELEC EQPMT AREA (BELOW)
ASH HANDLING EQPMT AREA (BELOW)
NEW 2X50% BOOSTER FANS
COMMON U1/U2 PAC SILO & TRANSFER EQPMT
COMMON U1/U2 TRONA SILO & TRANSFER EQPMT
EXISTING U1 PORTABLE TRONA SILO LOCATED THIS AREA TO BE DELETED
BYPASS DUCT INSTALLED WITH BLANK-OFFS FOR LATER TIE-IN (TYP)
EXISTING ESP HEADERS
BLANK OFF AT TIE-IN
ABANDON IN PLACE
EXISTING DUCT (TYP)
50% SCR
CONVEYOR BENT
COAL CONVEYOR ABOVE
WORK AROUND ELEVATED CABLEWAY AND RELOCATE OVERHEAD LINES
NEW VARIABLE FREQUENCY DRIVE
EXISTING ABSORBER 2-1
EXISTING ABSORBER 2-2
EXISTING ABSORBER 2-3
OVERHEAD COAL CONVEYOR
APPROX SCALE
N

Unit 2 PJFF Arrangements

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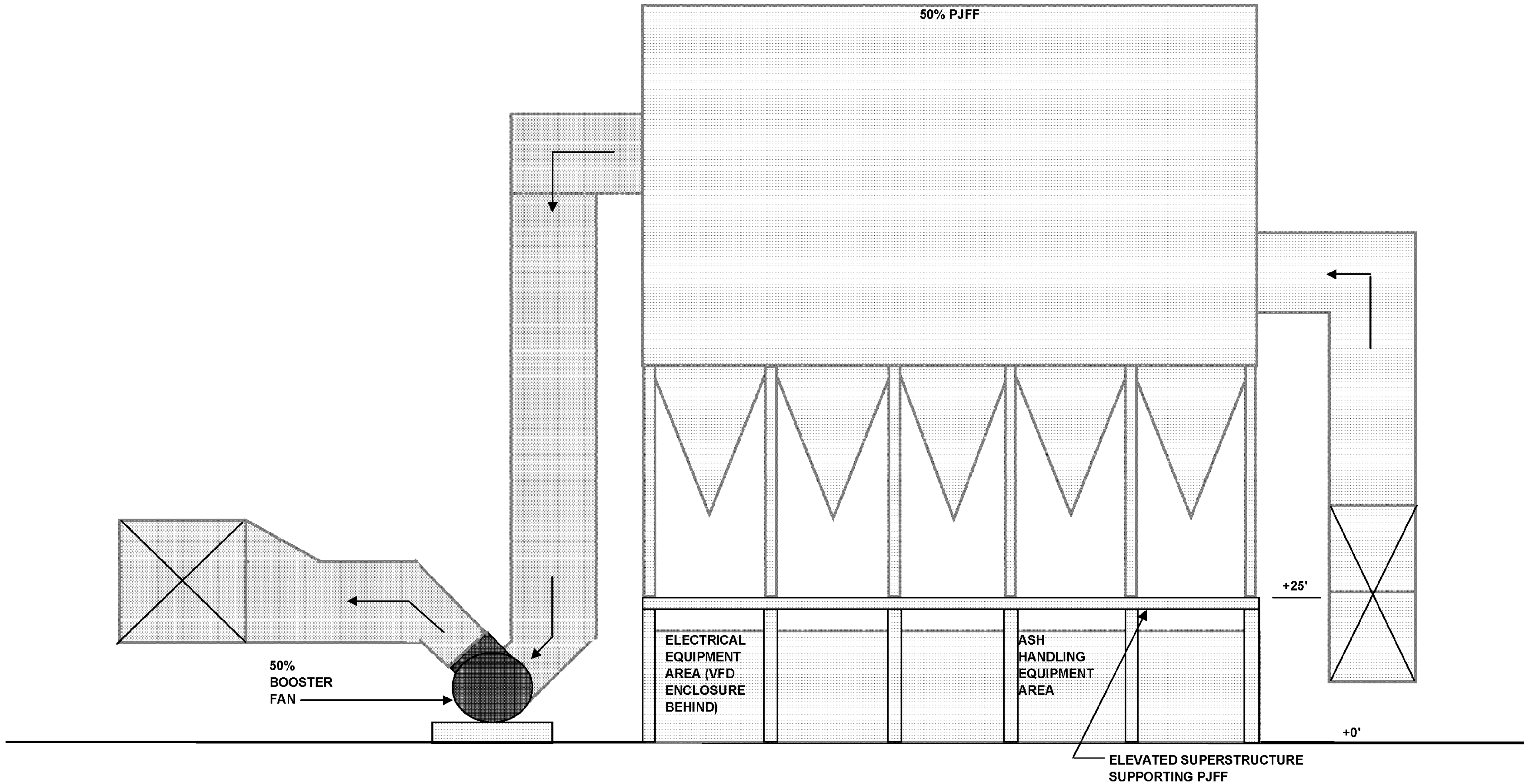
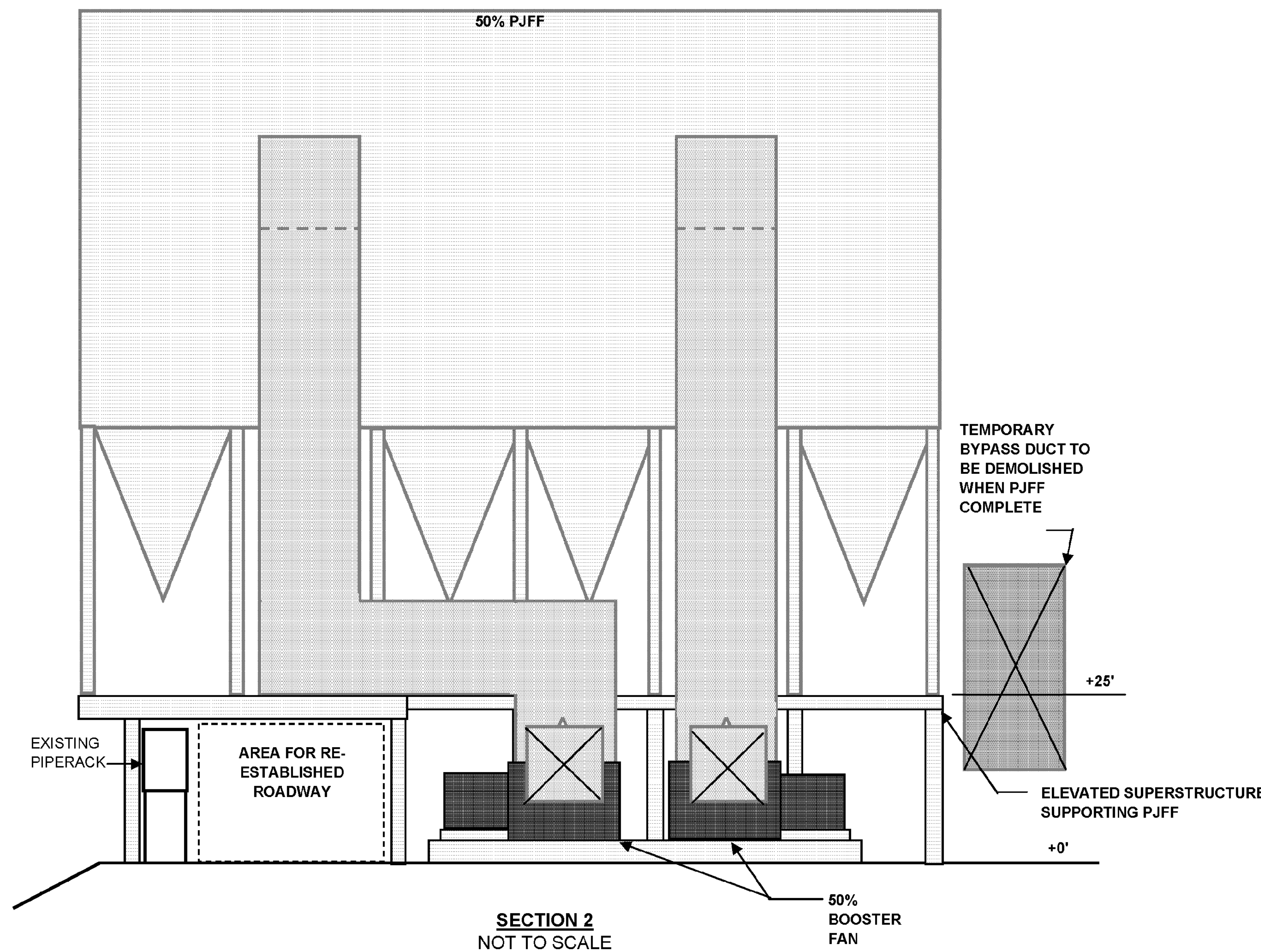


SECTION 1
NOT TO SCALE

UNIT 2 CONCEPTUAL ARRANGEMENT SKETCH
SECTIONS



SECTION 2
NOT TO SCALE

UNIT 2 CONCEPTUAL ARRANGEMENT SKETCH
SECTIONS

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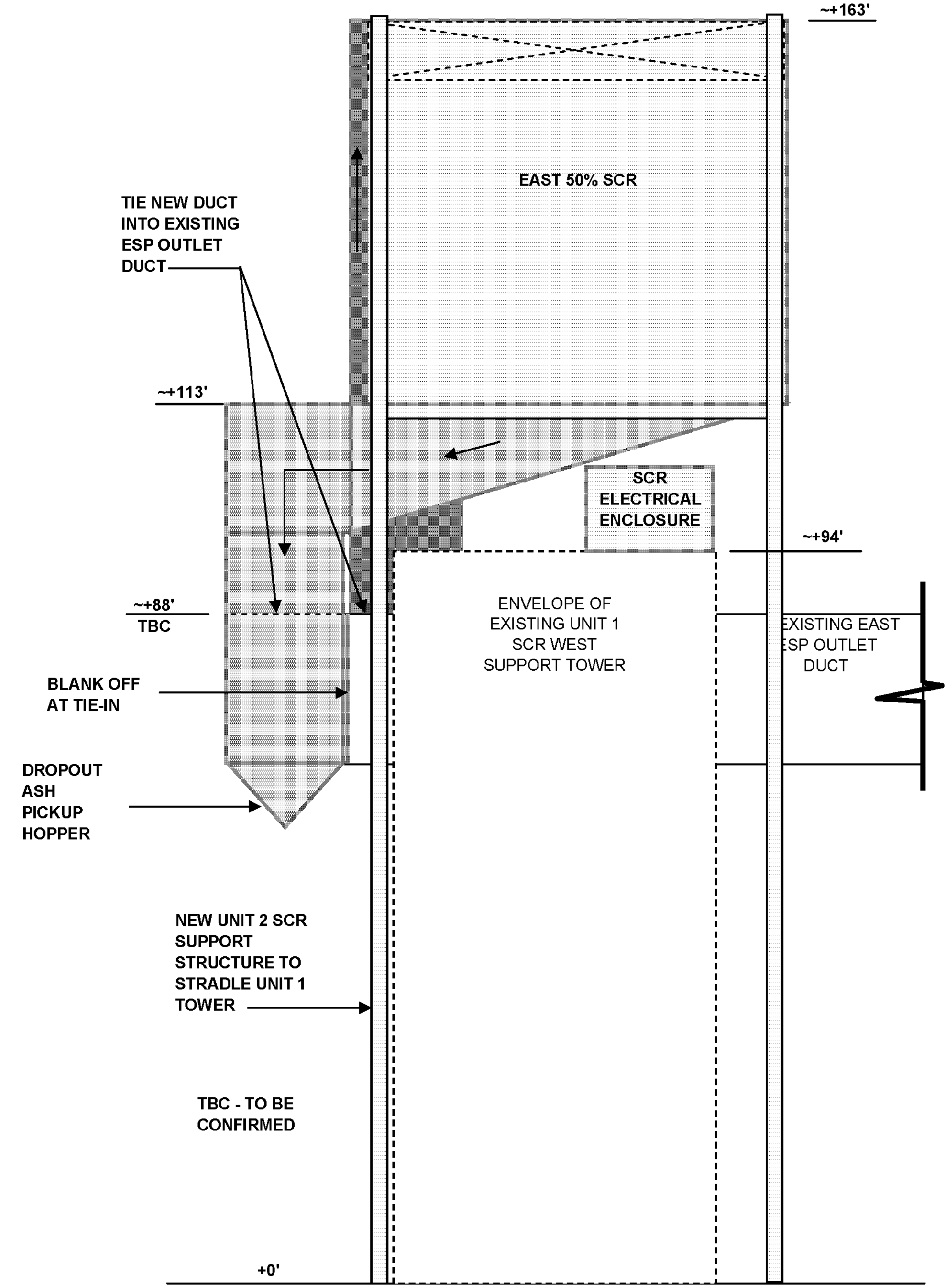
Unit 2 East SCR Arrangement



UNIT 2 CONCEPTUAL ARRANGEMENT SKETCH
SECTIONS

SECTION 3
NOT TO SCALE

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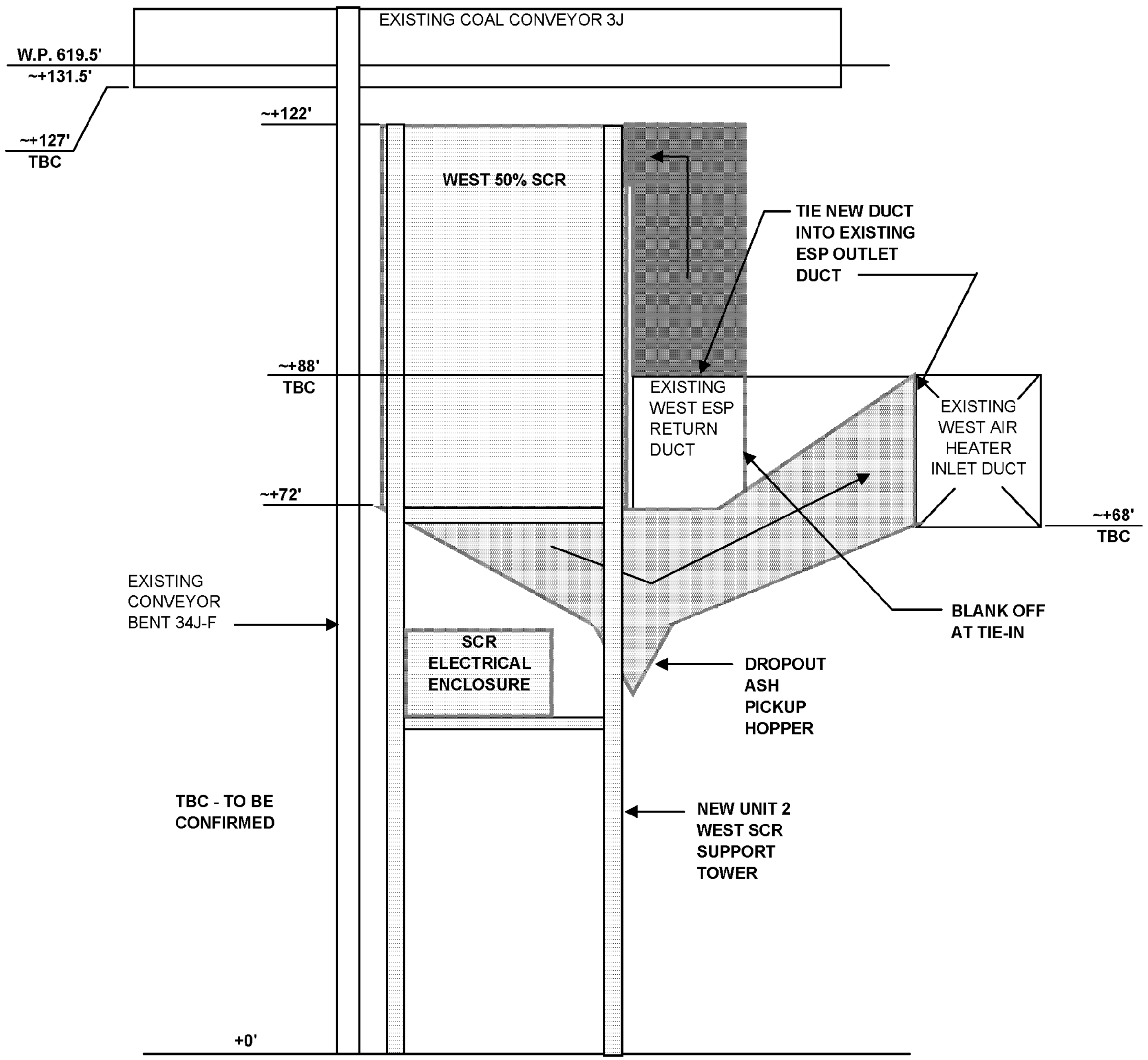
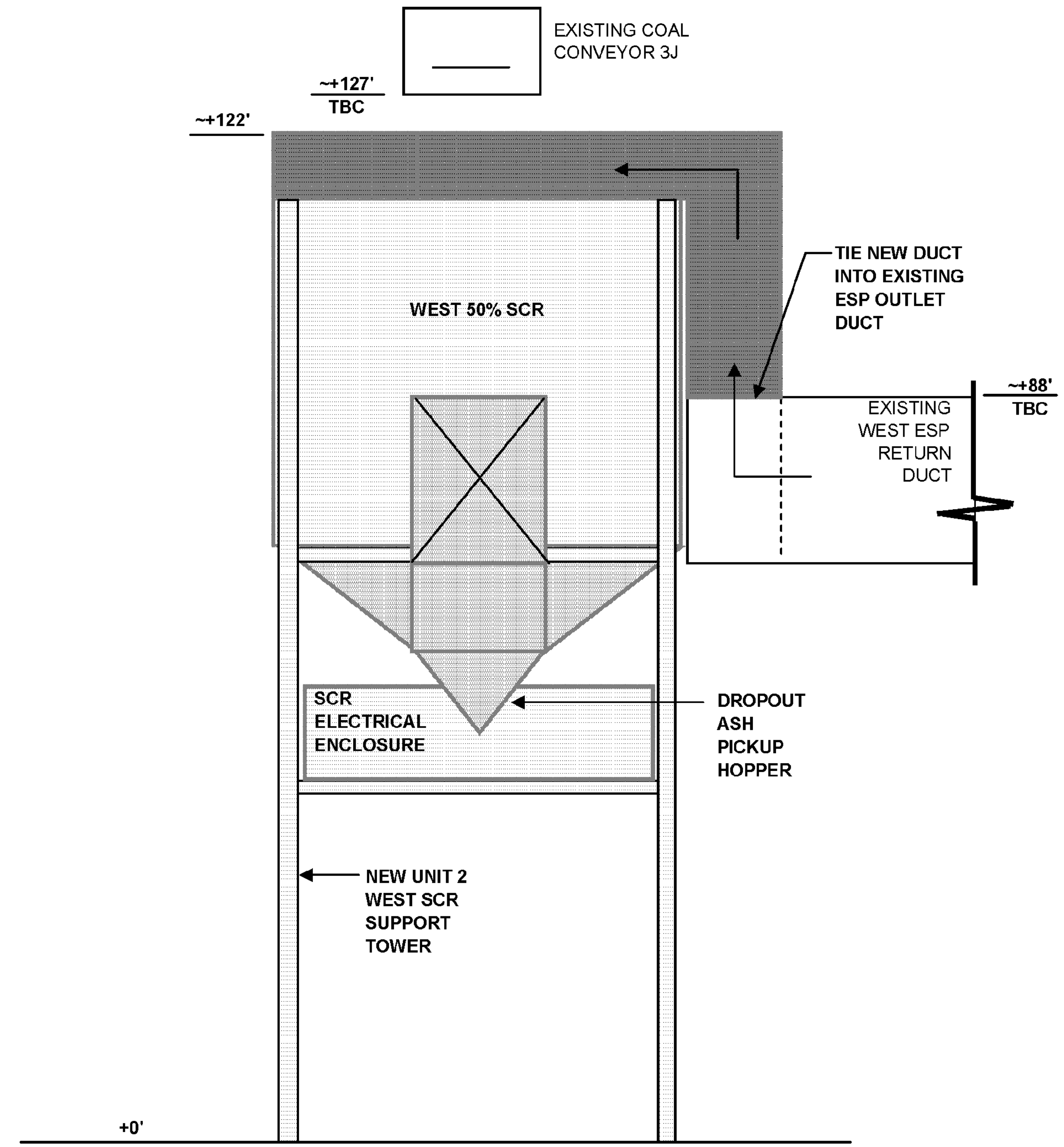
Unit 2 West SCR Arrangement



SECTION 4
NOT TO SCALE



SECTION 5
NOT TO SCALE

UNIT 2 CONCEPTUAL
ARRANGEMENT SKETCH
SECTIONS

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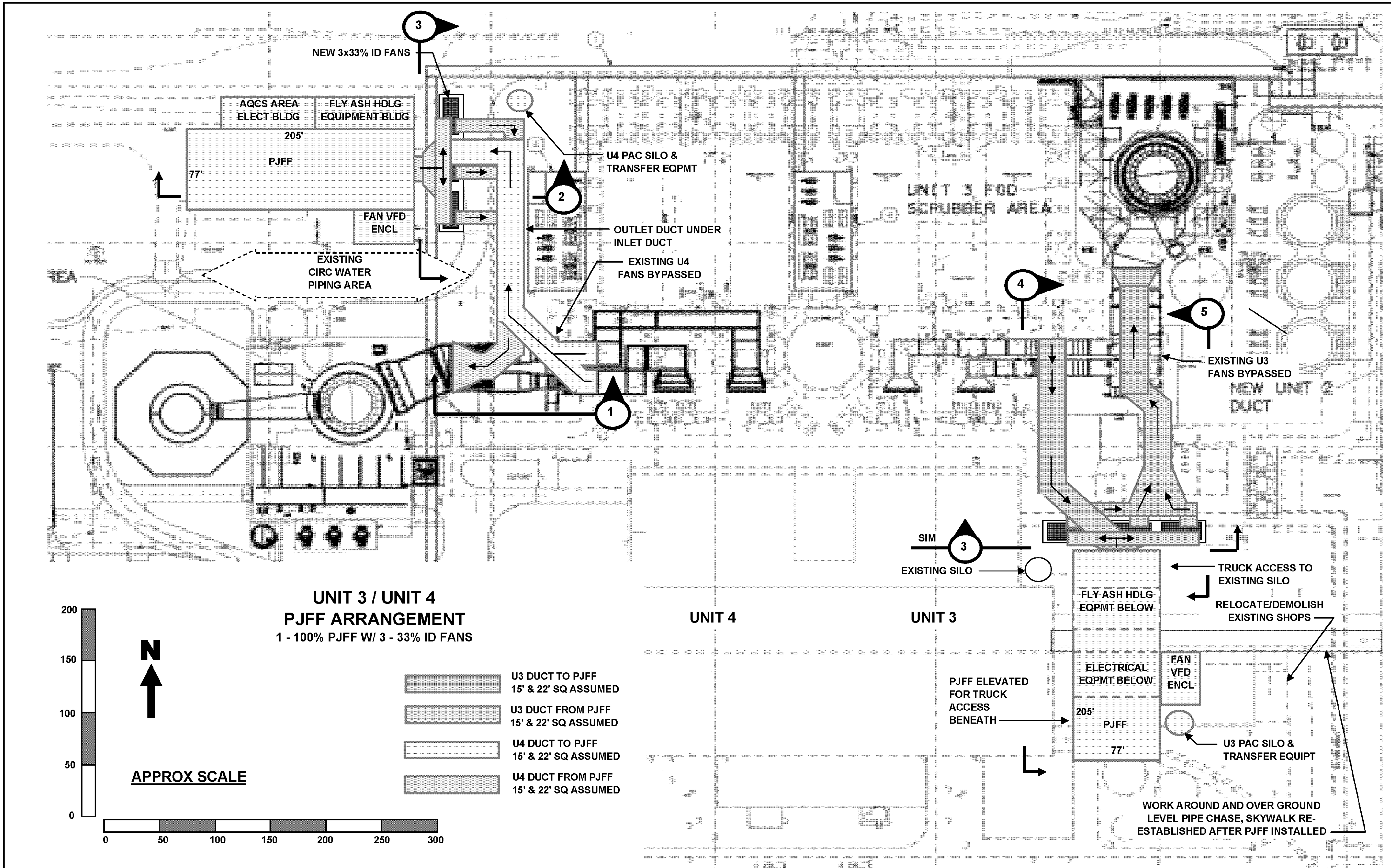
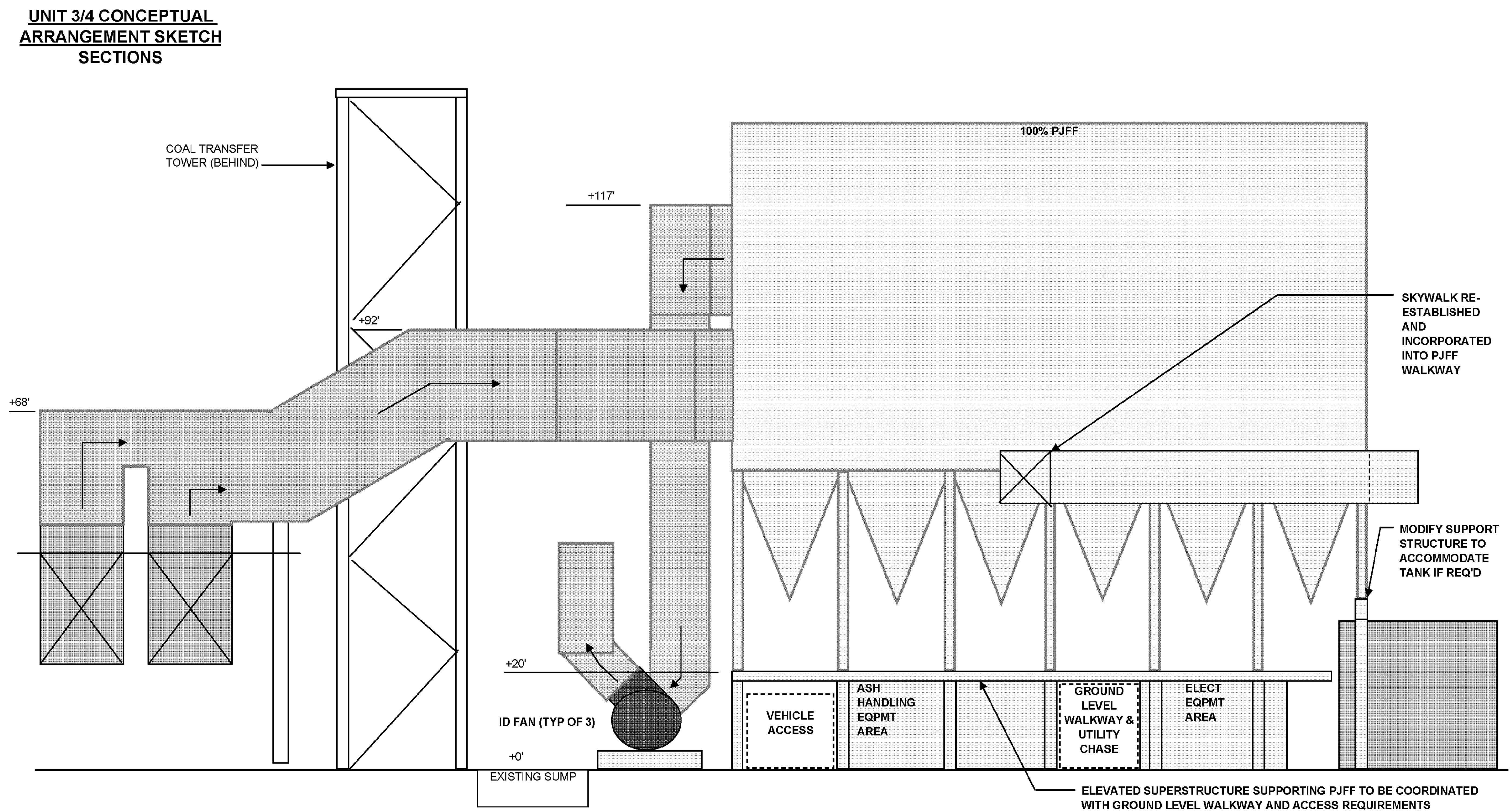
Unit 3 and 4 Arrangement



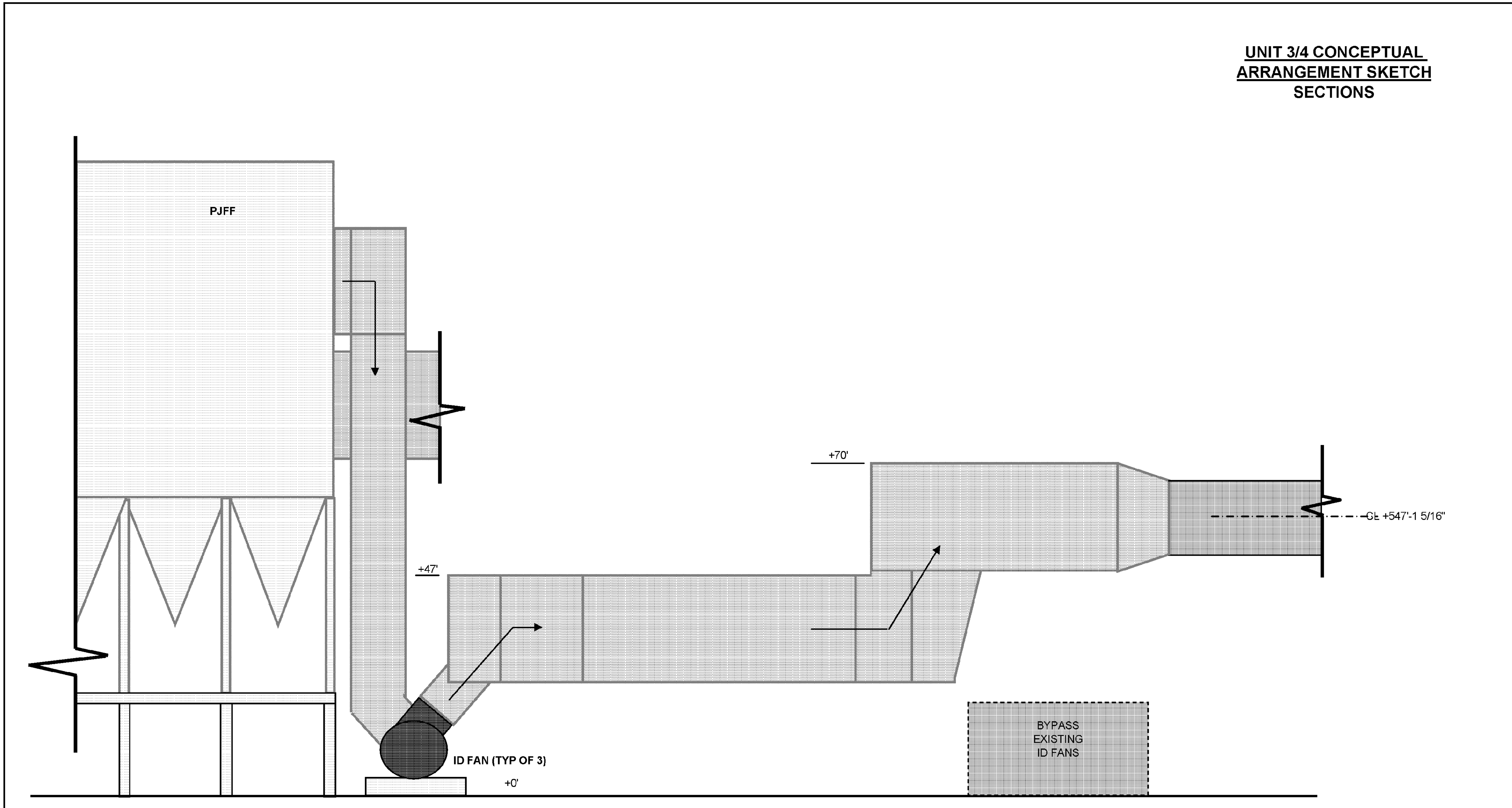
NEW 3x33% ID FANS
AQCS AREA ELECT BLDG
FLY ASH HDLG EQUIPMENT BLDG
205'
PJFF
77'
FAN VFD ENCL
U4 PAC SILO & TRANSFER EQPMT
OUTLET DUCT UNDER INLET DUCT
EXISTING U4 FANS BYPASSED
EXISTING CIRC WATER PIPING AREA
UNIT 3 FGD SCRUBBER AREA
EXISTING U3 FANS BYPASSED
NEW UNIT 2 DUCT
SIM
EXISTING SILO
TRUCK ACCESS TO EXISTING SILO
FLY ASH HDLG EQPMT BELOW
RELOCATE/DEMOLISH EXISTING SHOPS
ELECTRICAL EQPMT BELOW
FAN VFD ENCL
PJFF ELEVATED FOR TRUCK ACCESS BENEATH
205'
PJFF
77'
U3 PAC SILO & TRANSFER EQUIPT
WORK AROUND AND OVER GROUND LEVEL PIPE CHASE, SKYWALK RE-ESTABLISHED AFTER PJFF INSTALLED
UNIT 4
UNIT 3
UNIT 3 / UNIT 4
PJFF ARRANGEMENT
1 - 100% PJFF W/ 3 - 33% ID FANS
N
APPROX SCALE
U3 DUCT TO PJFF 15' & 22' SQ ASSUMED
U3 DUCT FROM PJFF 15' & 22' SQ ASSUMED
U4 DUCT TO PJFF 15' & 22' SQ ASSUMED
U4 DUCT FROM PJFF 15' & 22' SQ ASSUMED

DRAFT PREVIEW

Unit 3 Arrangements



SECTION 4
NOT TO SCALE



SECTION 5
NOT TO SCALE

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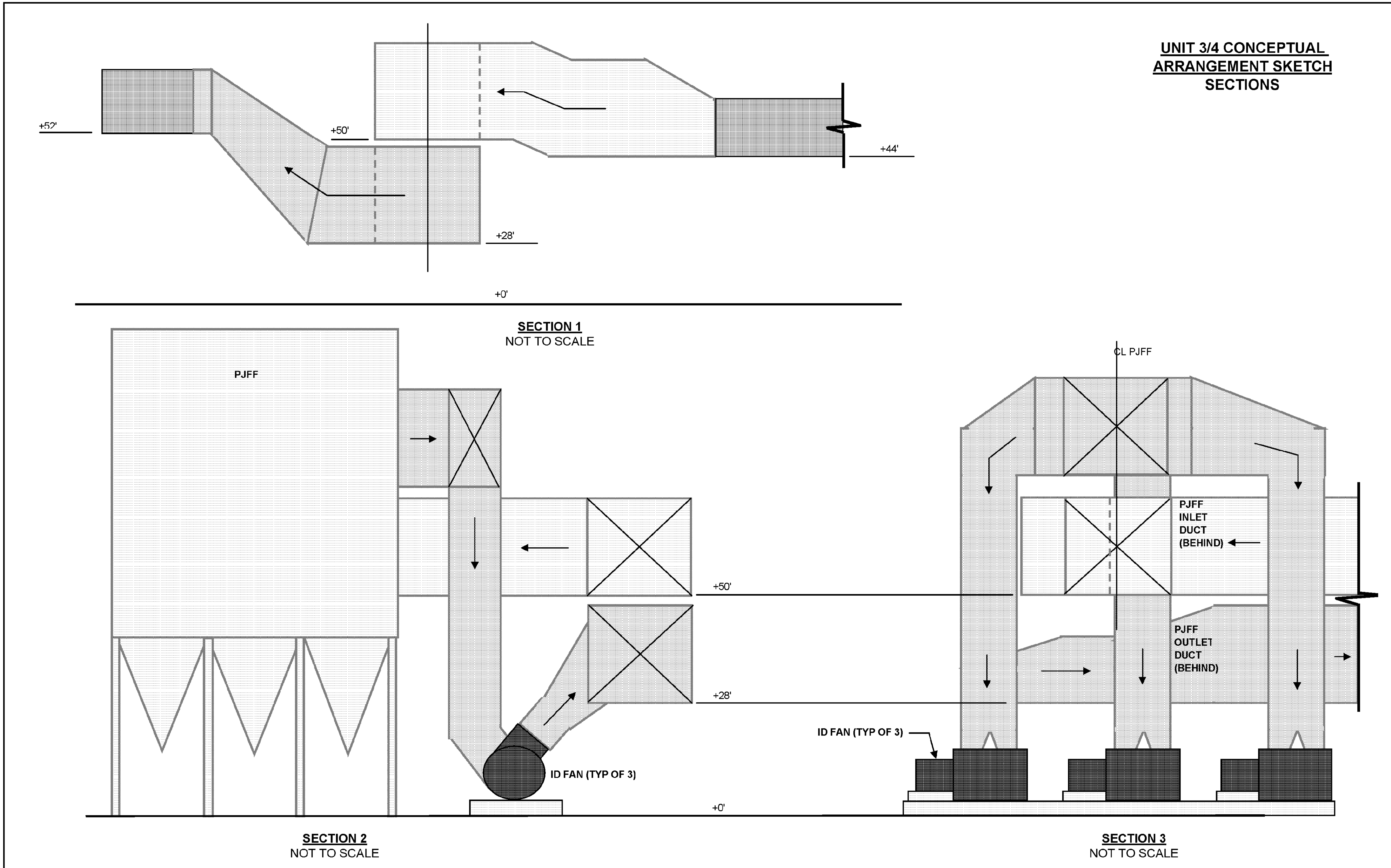
Unit 4 Arrangement


UNIT 3/4 CONCEPTUAL
ARRANGEMENT SKETCH
SECTIONS
+52'
+50'
+44'
+28'
+0'
SECTION 1
NOT TO SCALE
PJFF
+50'
+28'
ID FAN (TYP OF 3)
+0'
SECTION 2
NOT TO SCALE
CL PJFF
PJFF
INLET
DUCT
(BEHIND)
PJFF
OUTLET
DUCT
(BEHIND)
ID FAN (TYP OF 3)
SECTION 3
NOT TO SCALE

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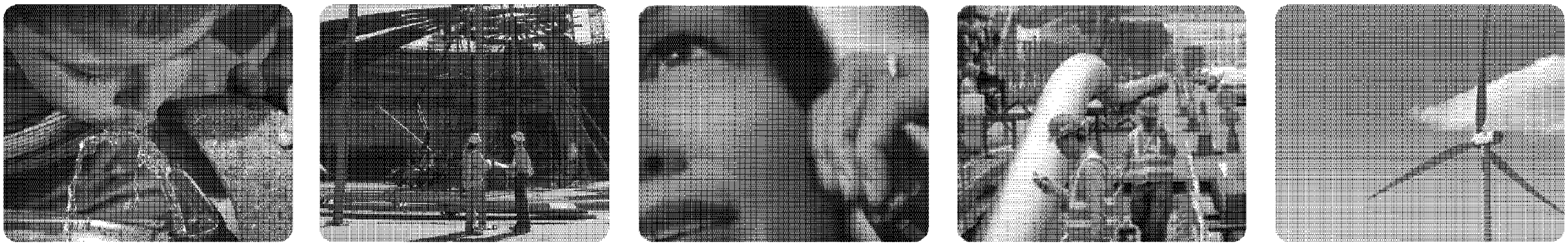

Phase II AQC Study
Ghent Validation

LG&E KU
PPL companies

Black & Veatch

December 2010

Agenda

- Units 1, 2, 3 and 4 AQC equipment train
- AQC equipment layout validation
  - Conceptual sketches
  - 3-D models
- Summary / wrap-up and discussions

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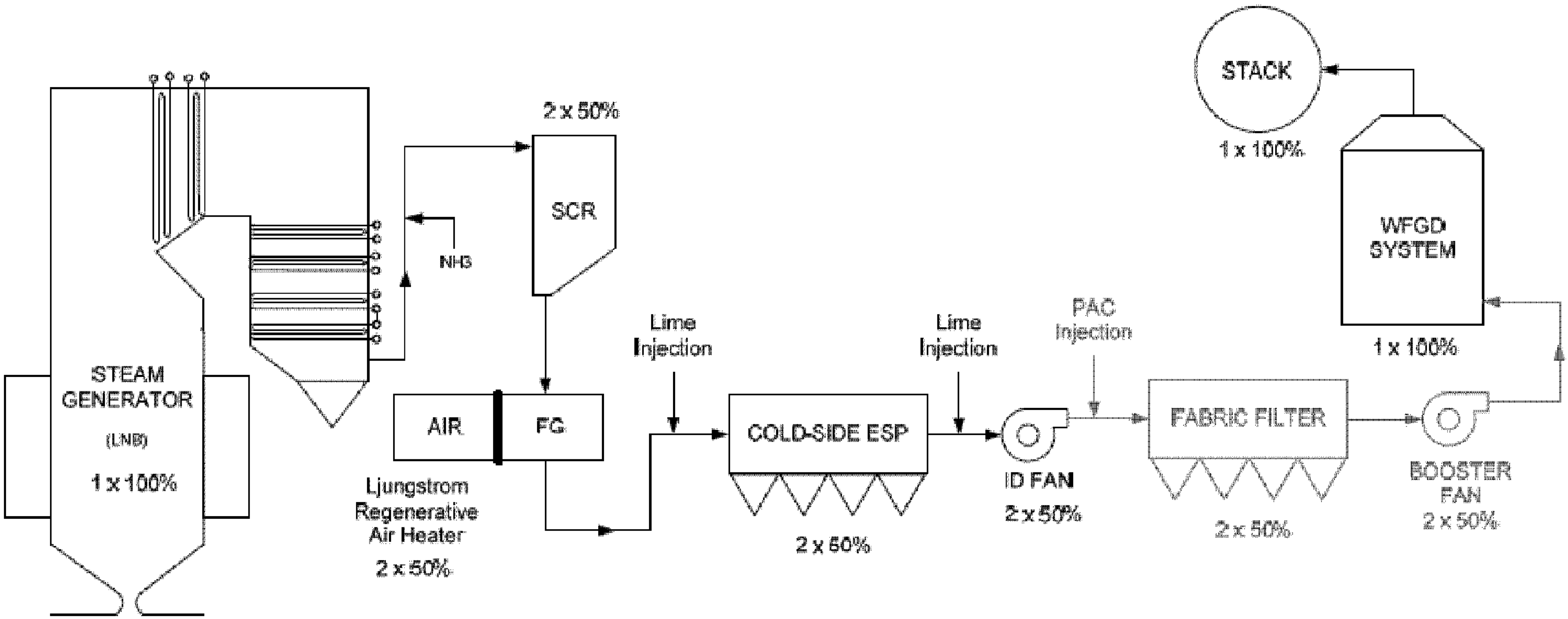
AQC Equipment Train
Ghent Units 1, 2, 3 and 4

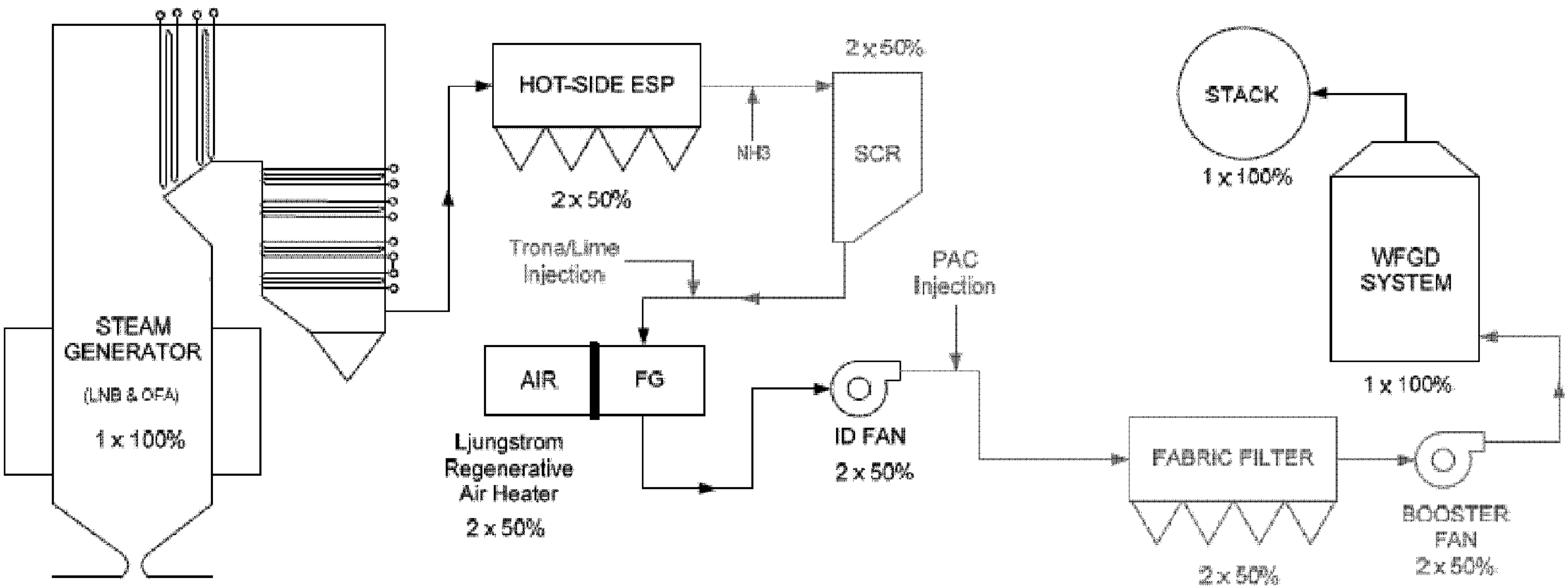
Ghent Unit 1 AQC process flow diagram

- Add new booster fans
- Add new PJFF
- Add new PAC injection system



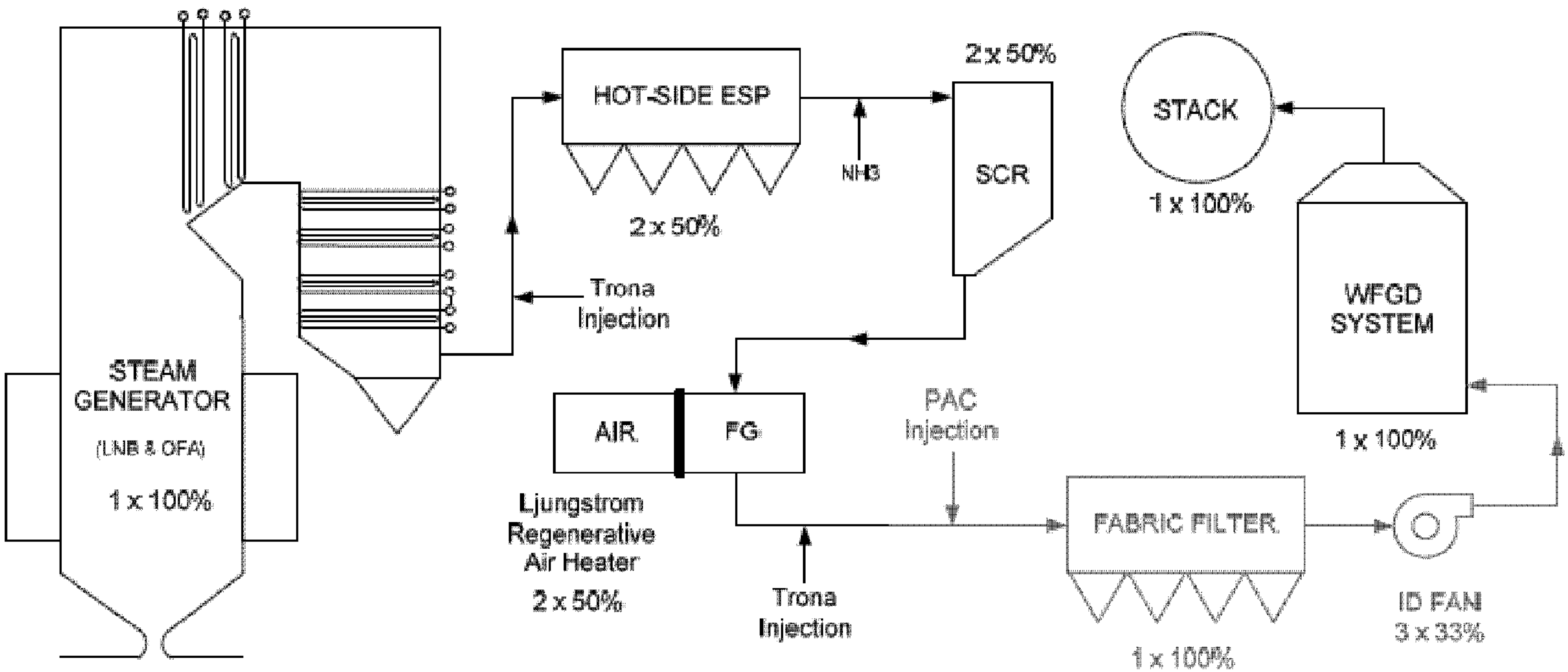
Ghent Unit 2 AQC process flow diagram

- Install bypass duct
- Add new booster fans
- Add new PJFF
- Add new PAC injection system
- Add new low-dust SCR
- Add new sorbent injection



Ghent Unit 3 and Unit 4 AQC process flow diagram

- Add new ID fans
- Add new PJFF
- Add new PAC injection system



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AQC Equipment Layout Validation

AQC validation

- Validation report determined no fatal flaws for the selected AQC equipment
- AQC equipment can meet identified emission targets

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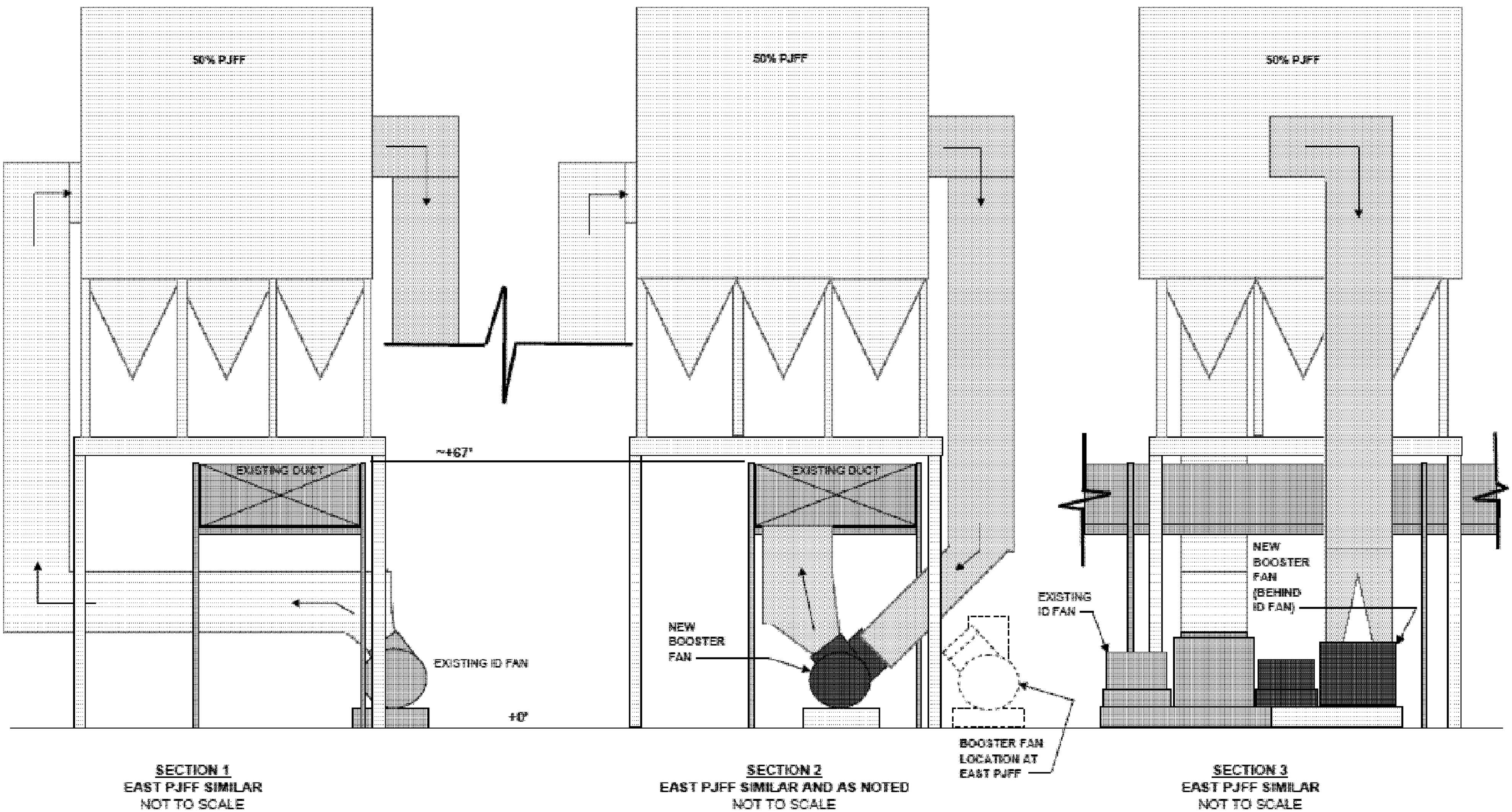
Unit 1
Conceptual Sketch

Ghent Unit 1 arrangement



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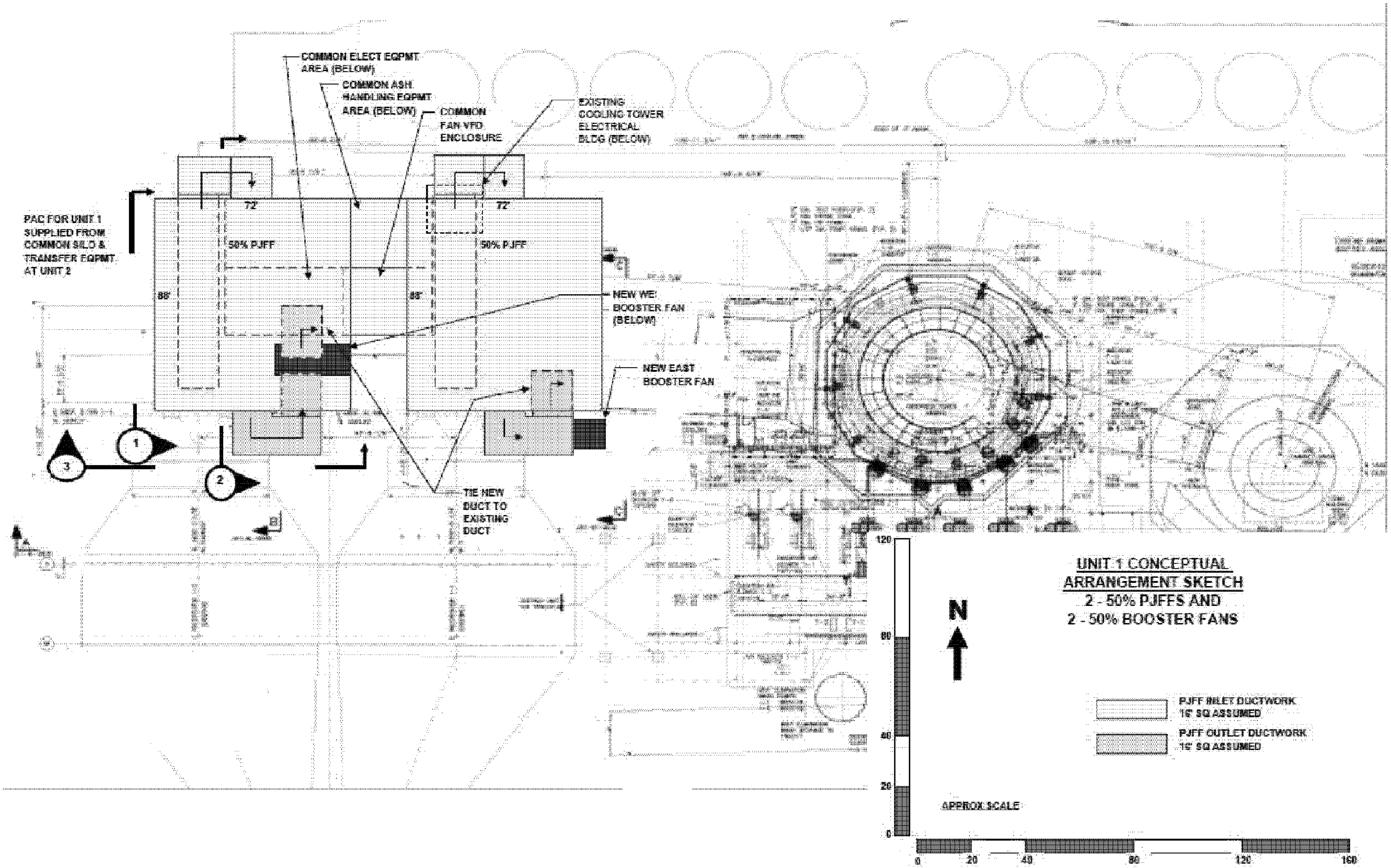
Ghent Unit 1 arrangement



December 7, 2010

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Unit 2
Conceptual Sketch

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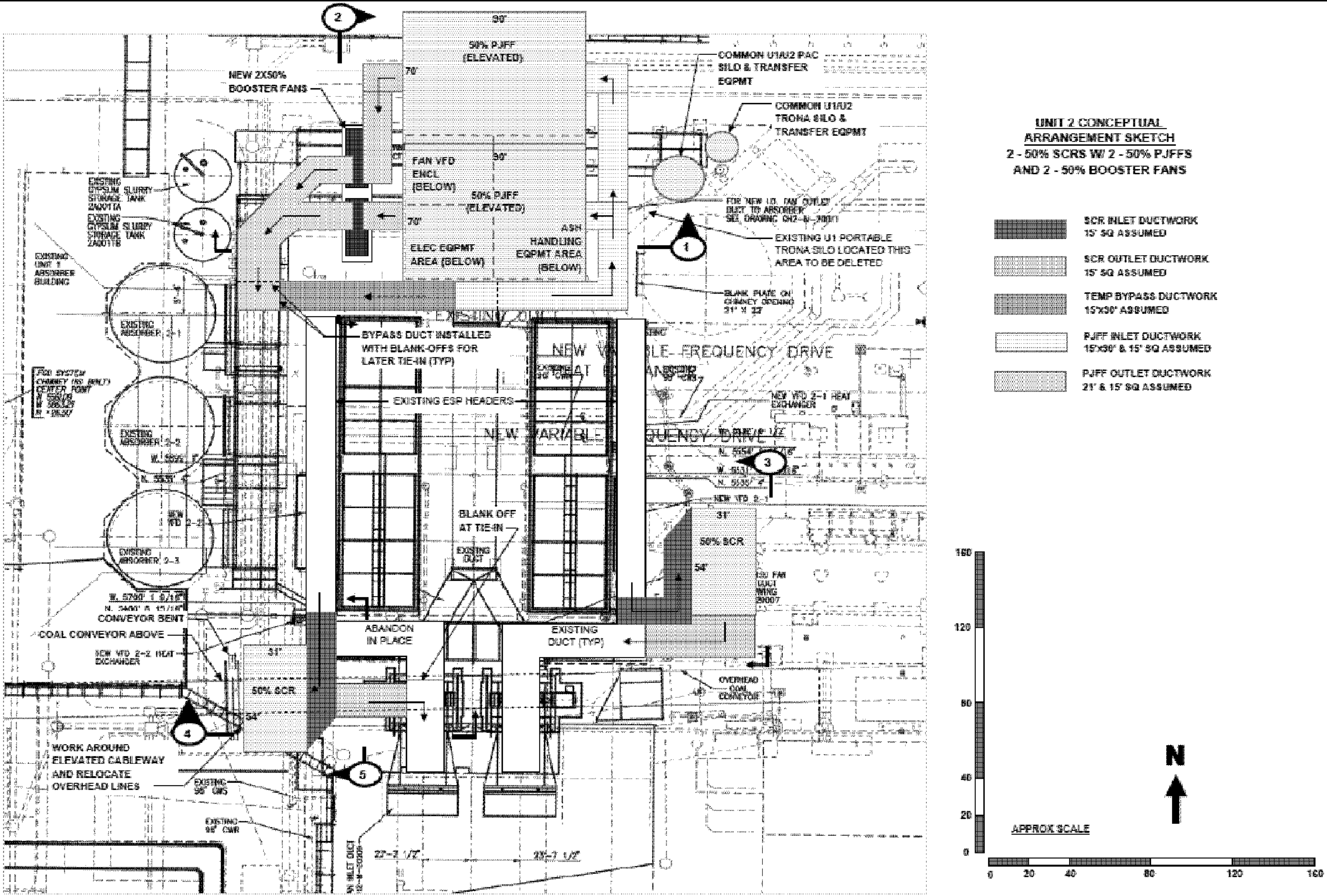
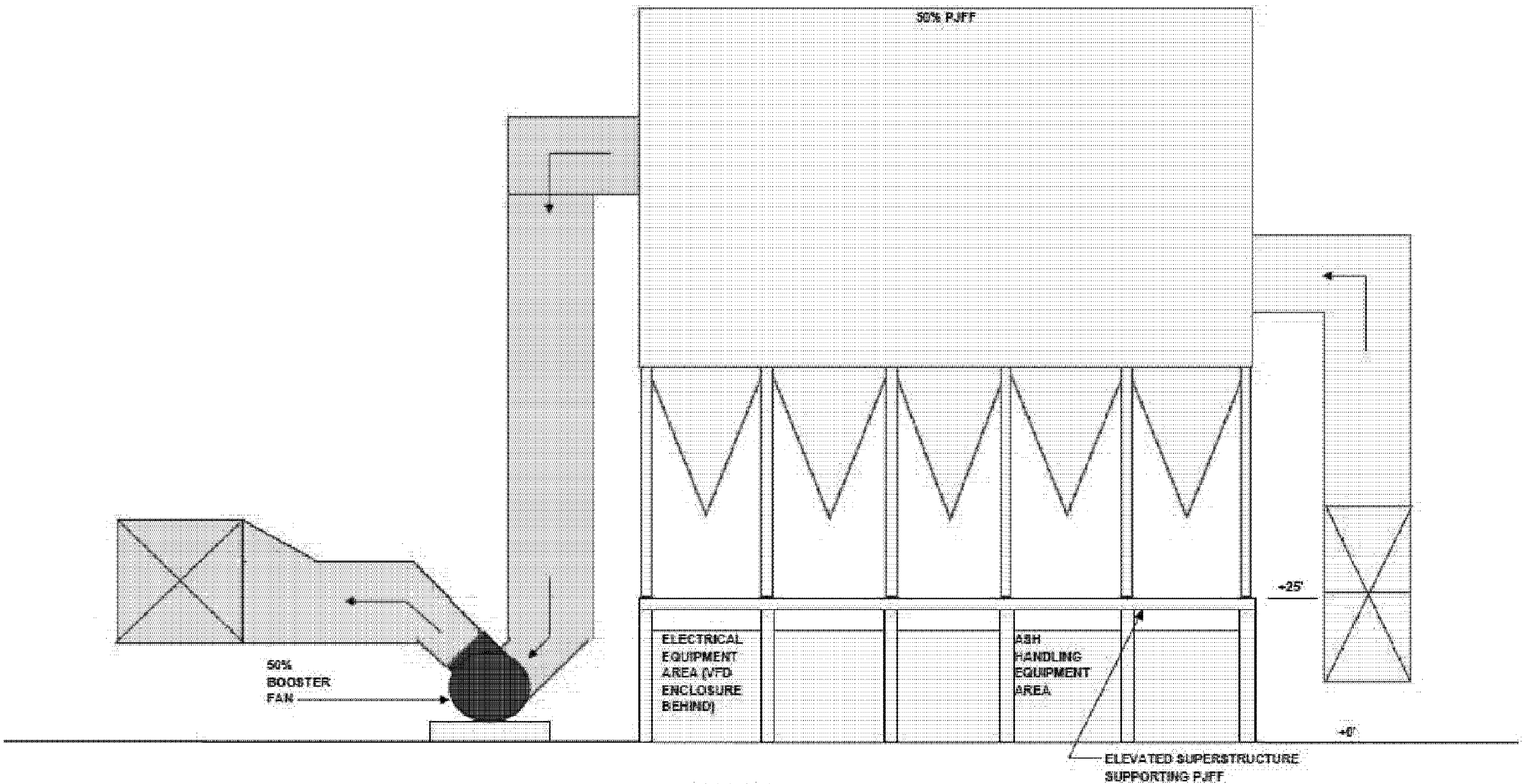
Ghent Unit 2 arrangement



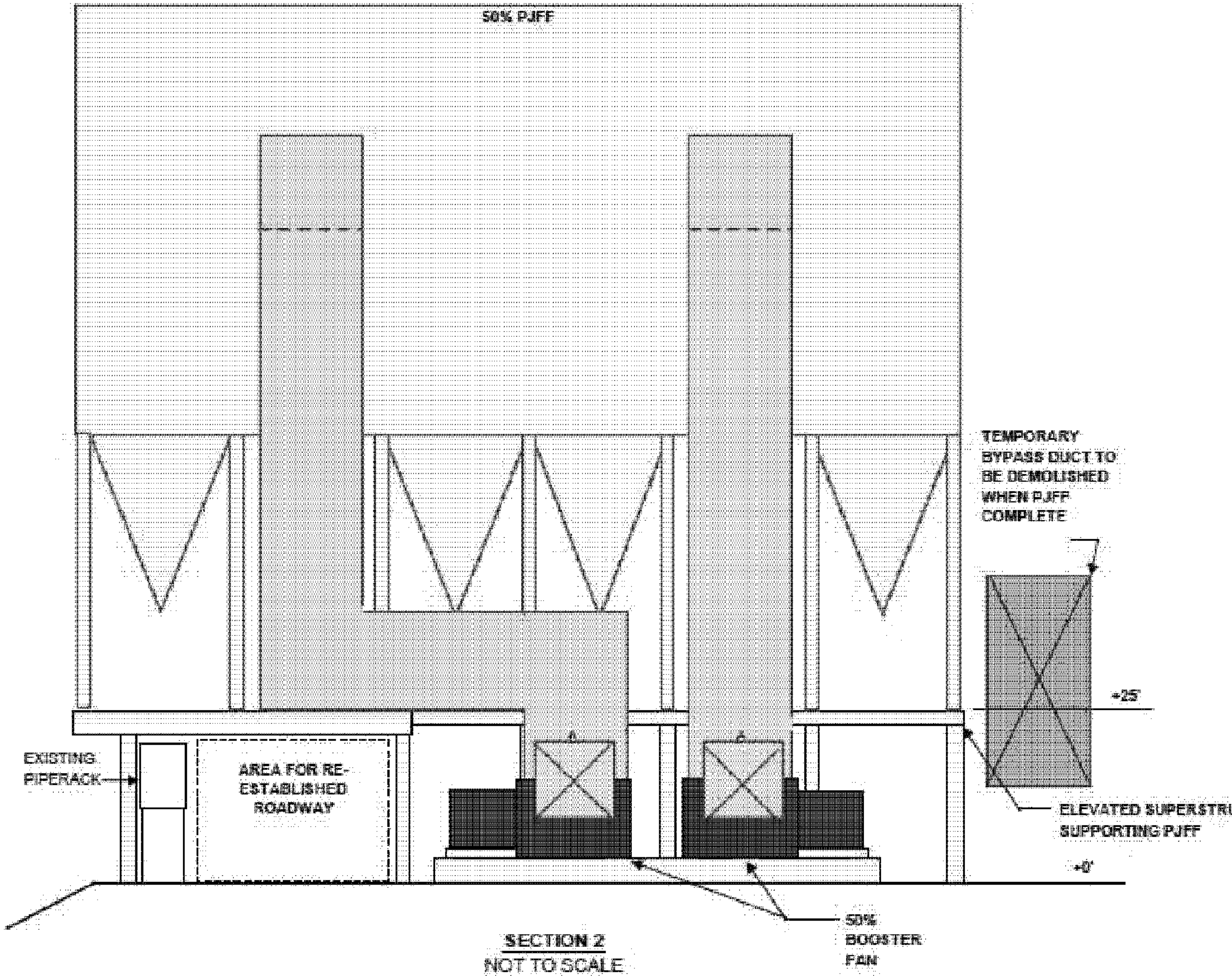
December 7, 2010

Ghent Unit 2 – PJFF arrangement



SECTION 1
NOT TO SCALE

Ghent Unit 2 – PJFF arrangement



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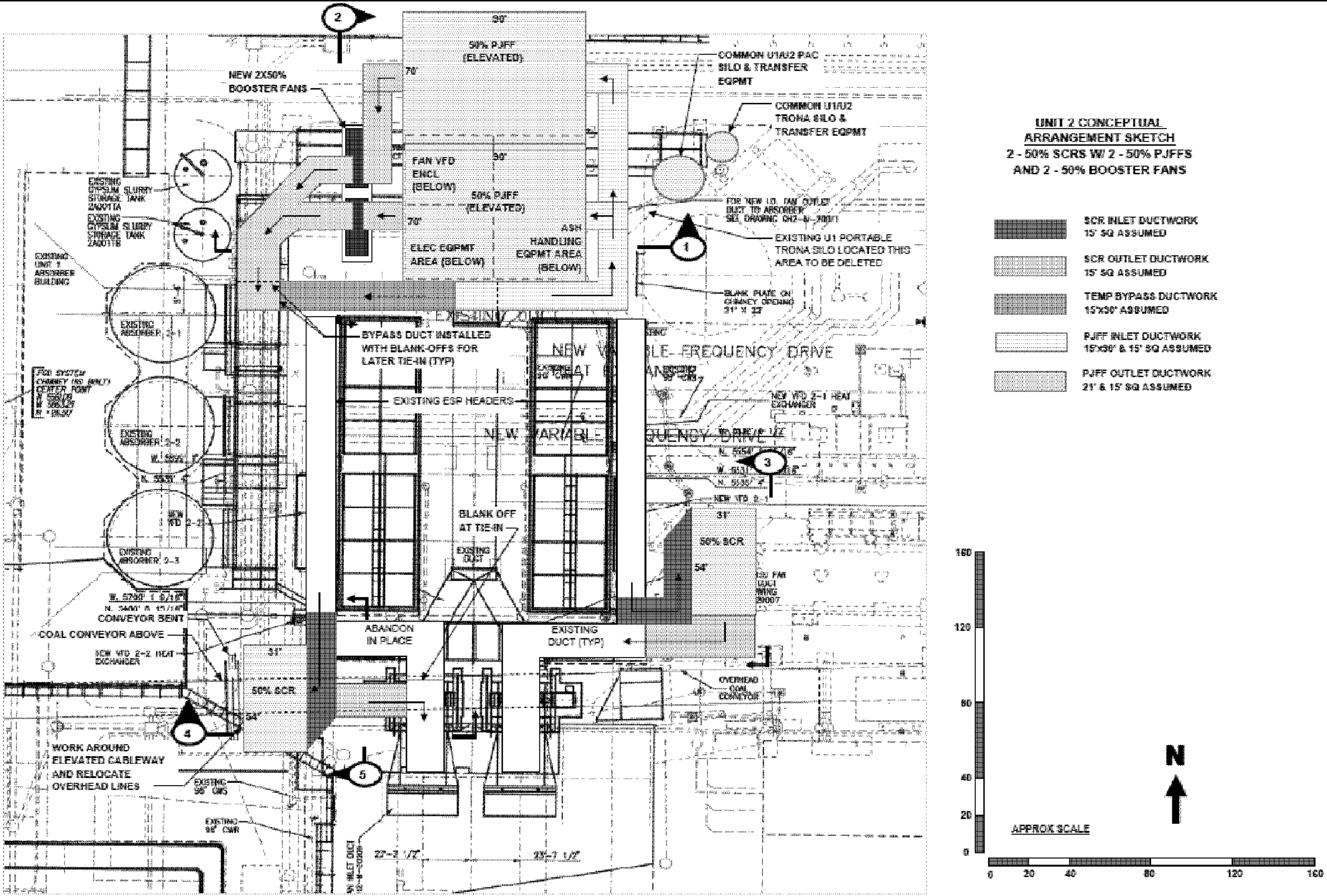
Ghent Unit 2 arrangement



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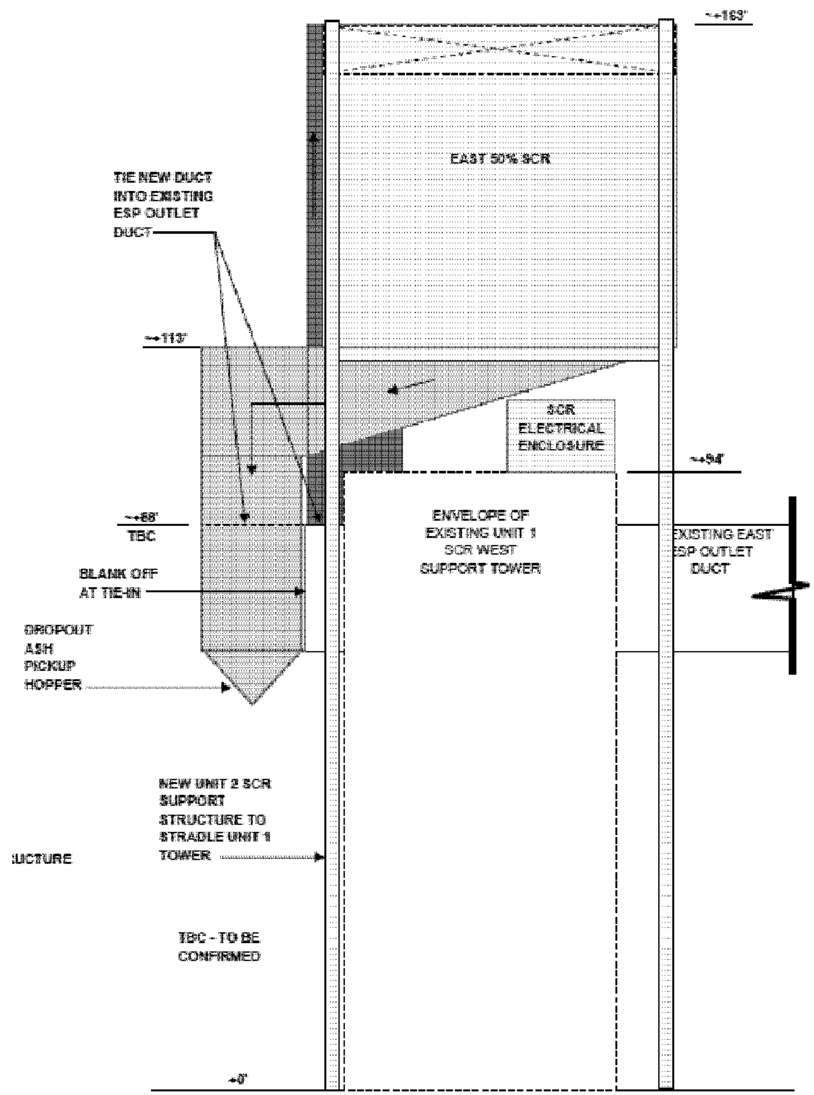
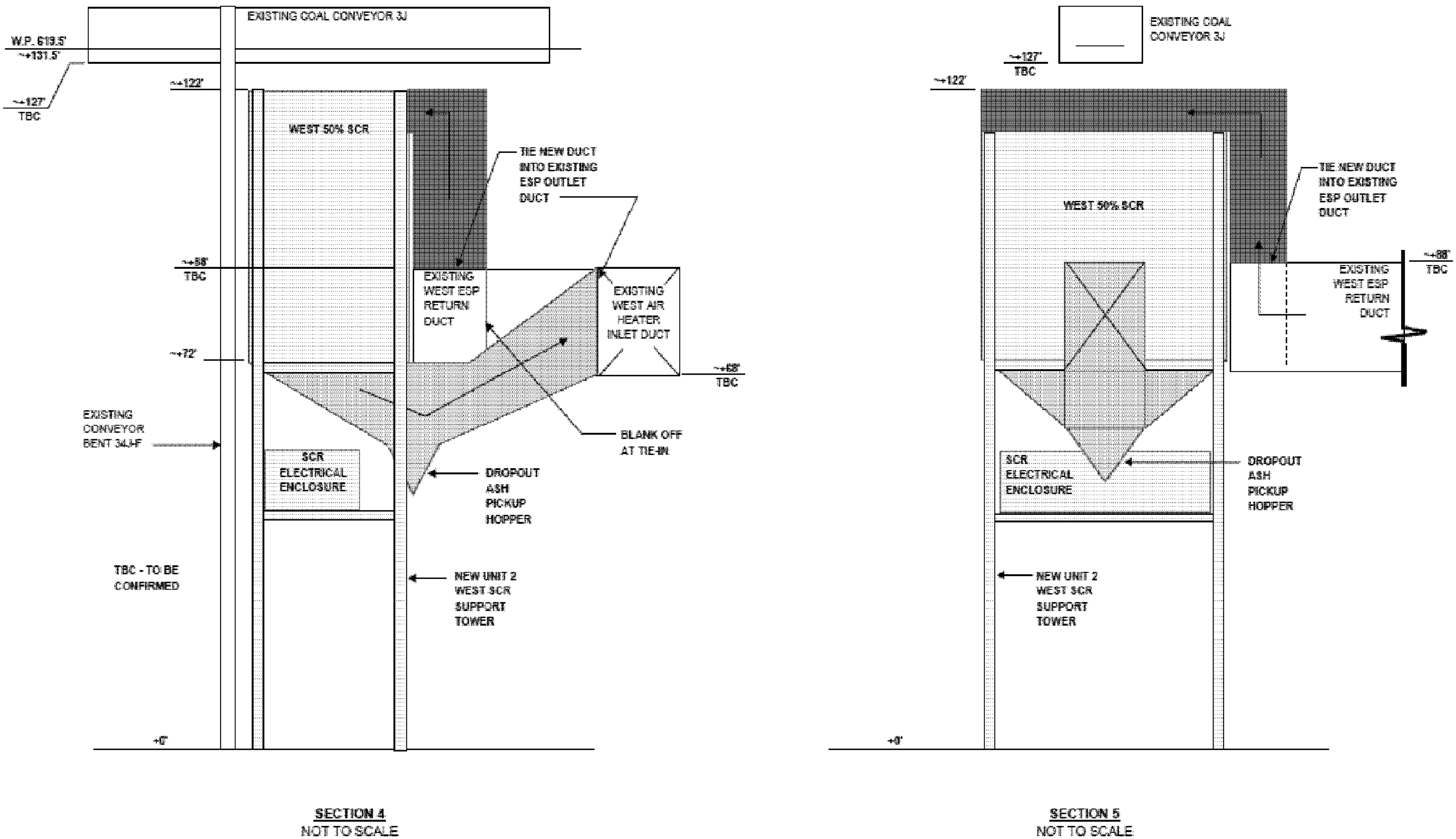
Ghent Unit 2 – East SCR arrangement



SECTION 3
NOT TO SCALE

Ghent Unit 2 – West SCR arrangement



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Unit 3 and Unit 4 Conceptual Sketch

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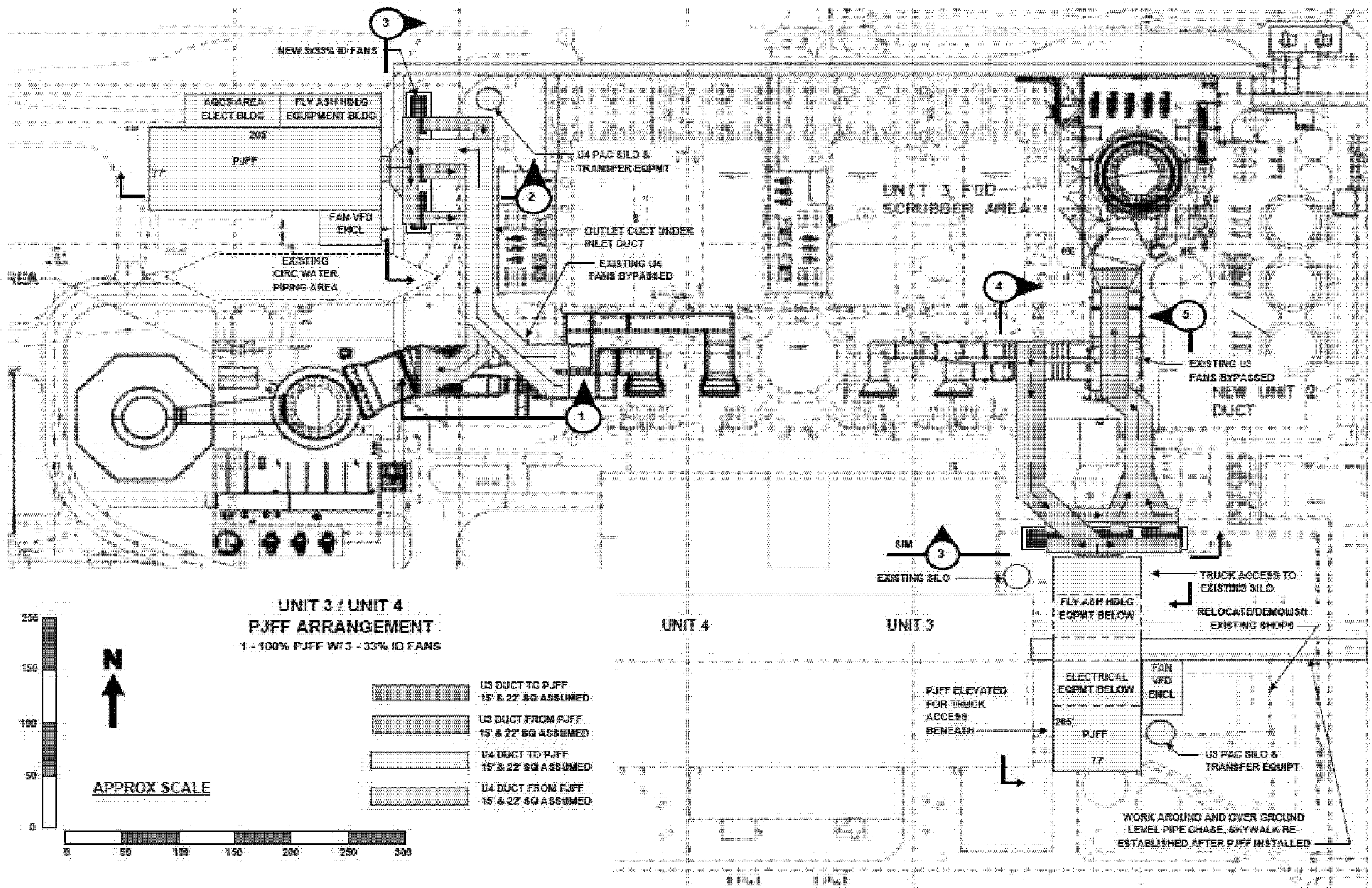
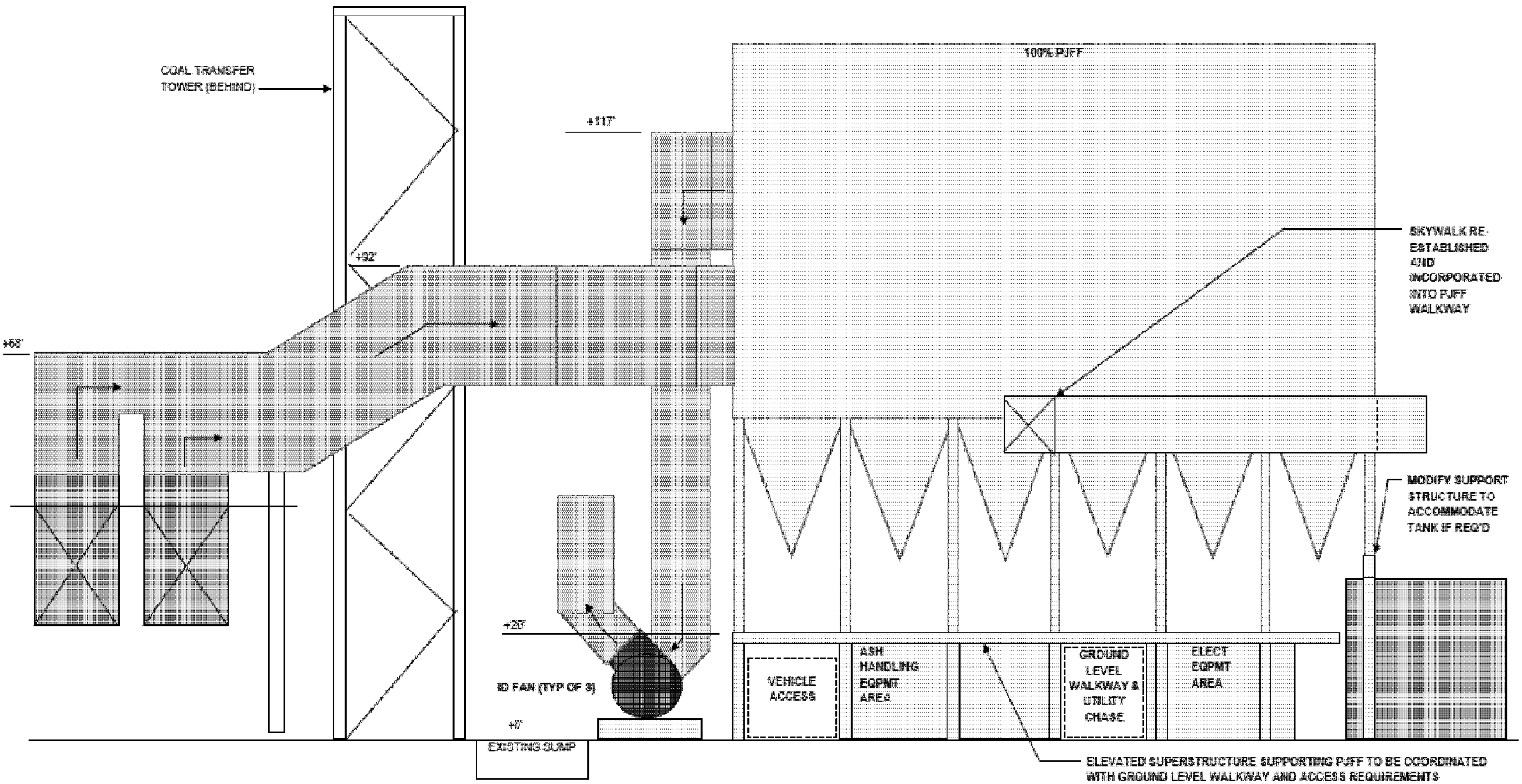
Ghent Unit 3 and Unit 4 arrangement

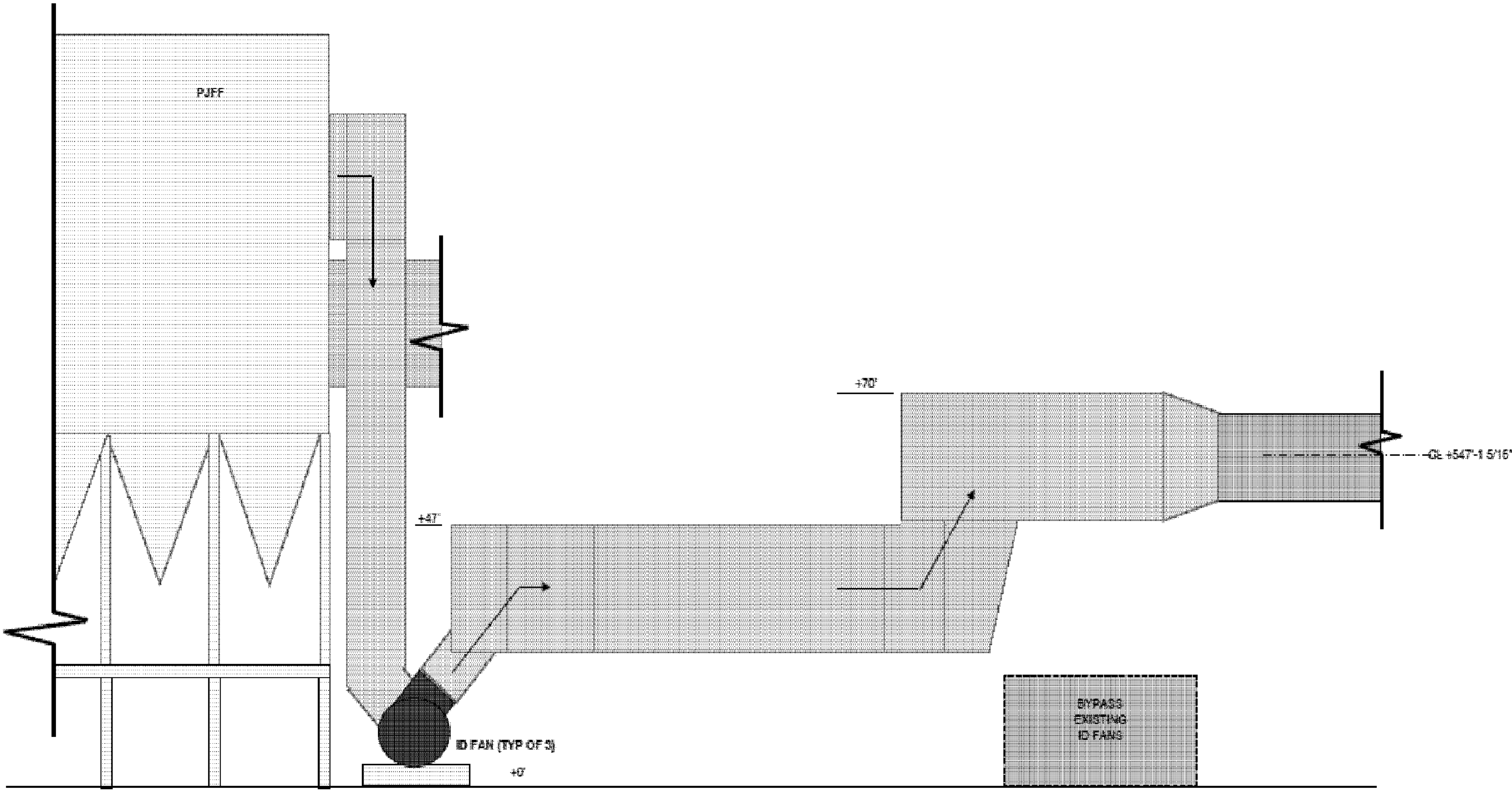


Ghent Unit 3 arrangement



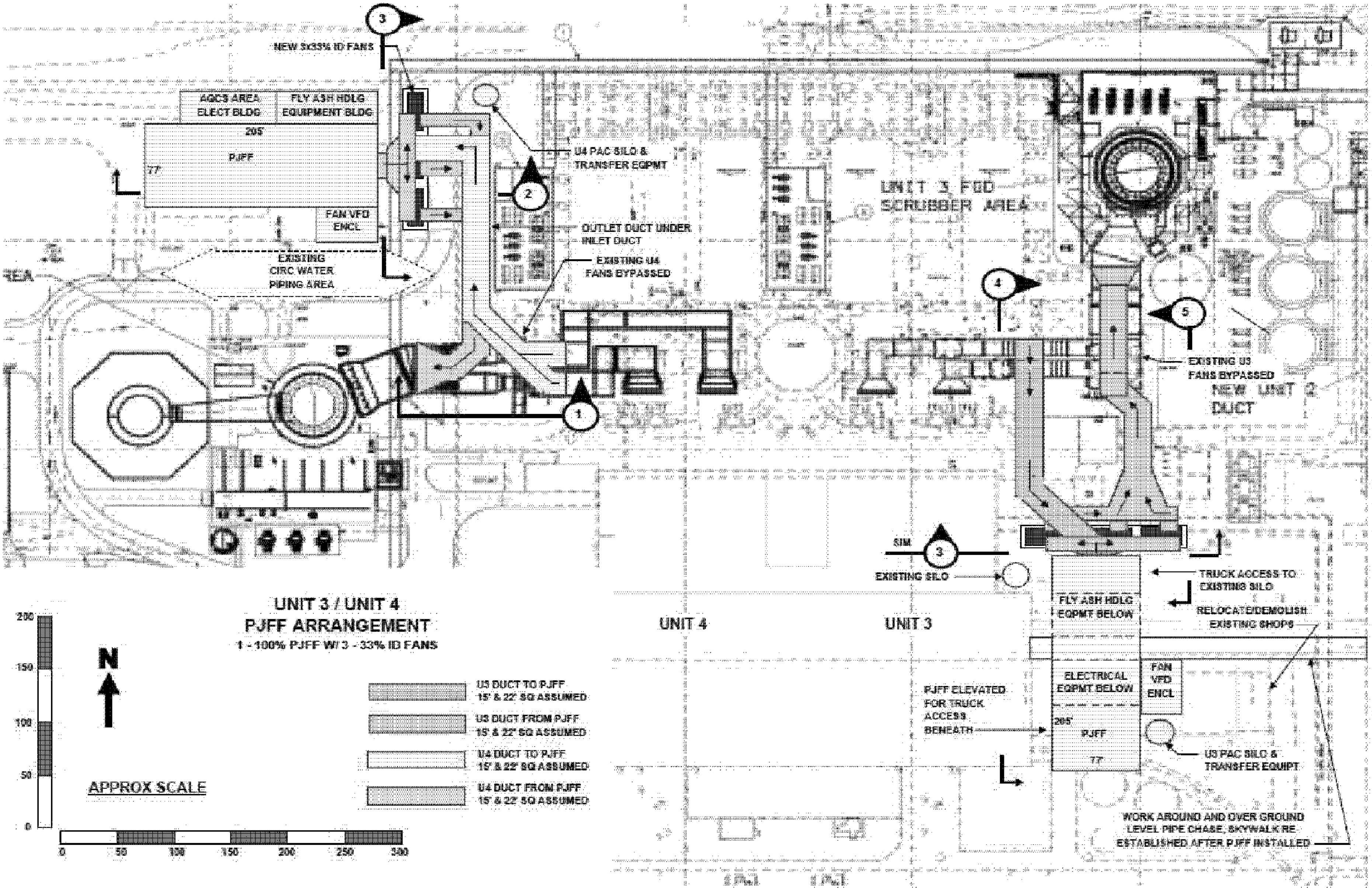
SECTION 4
NOT TO SCALE

Ghent Unit 3 arrangement



SECTION 5
NOT TO SCALE

Ghent Unit 3 and Unit 4 arrangement



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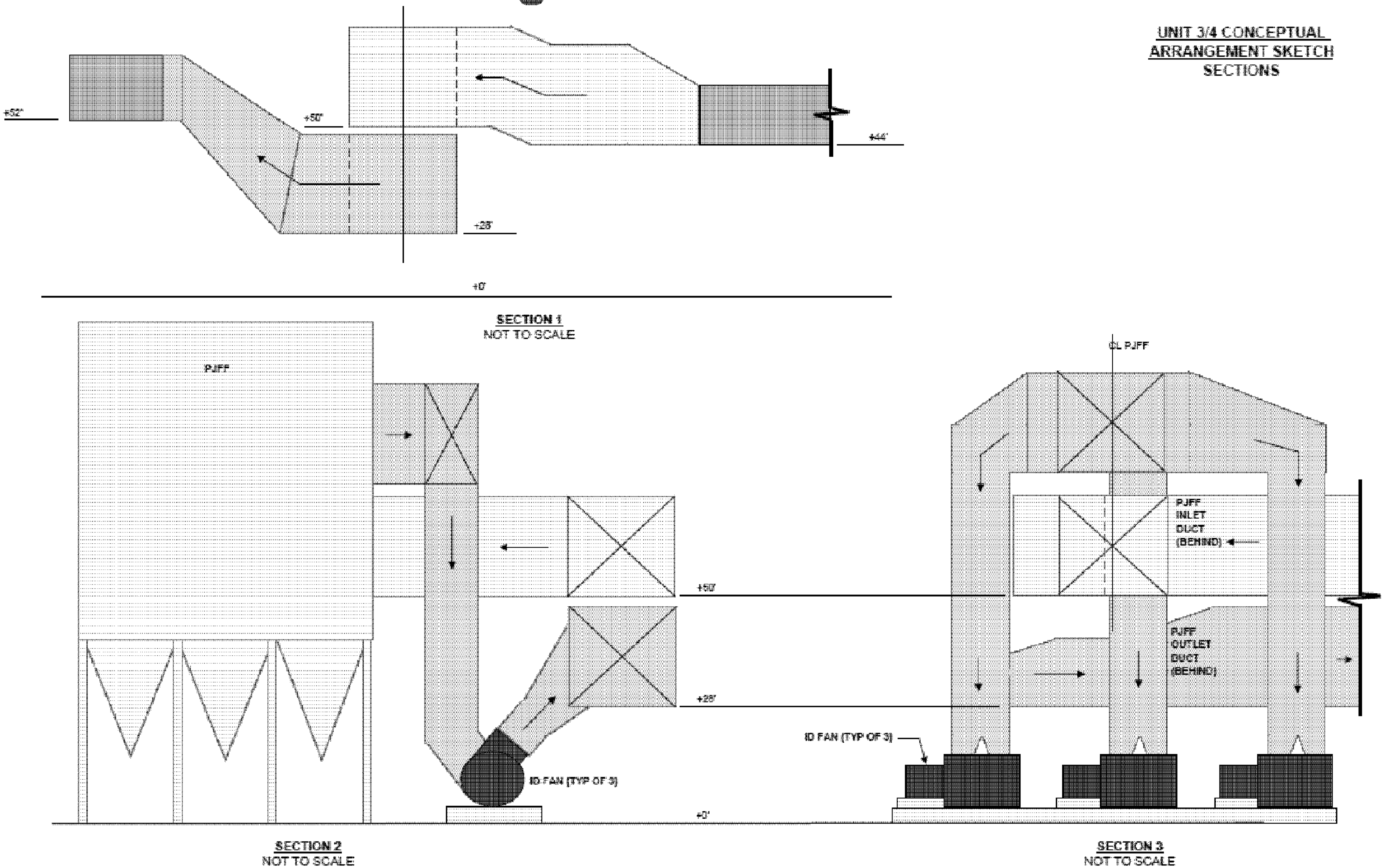
Ghent Unit 4 arrangement



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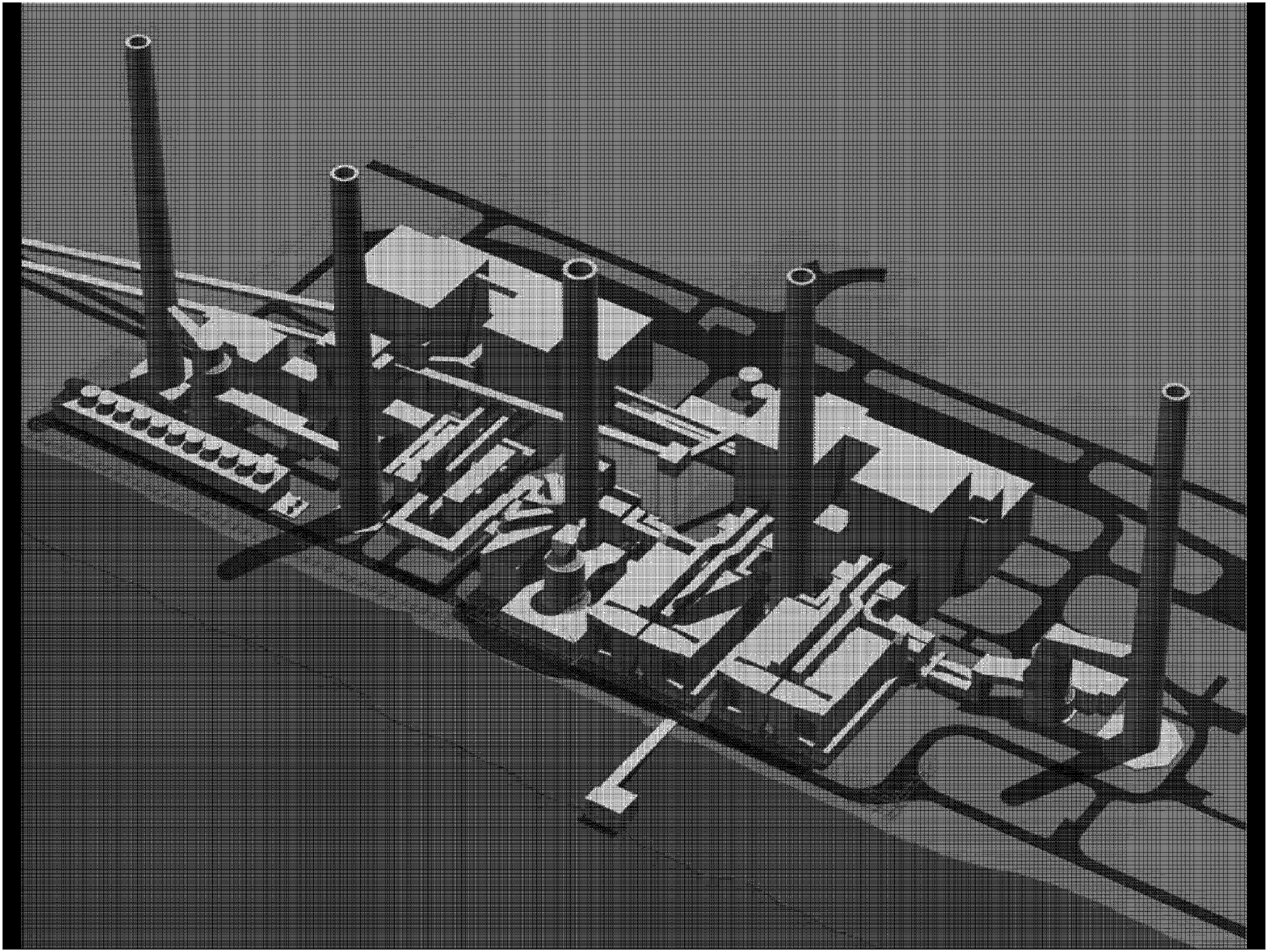
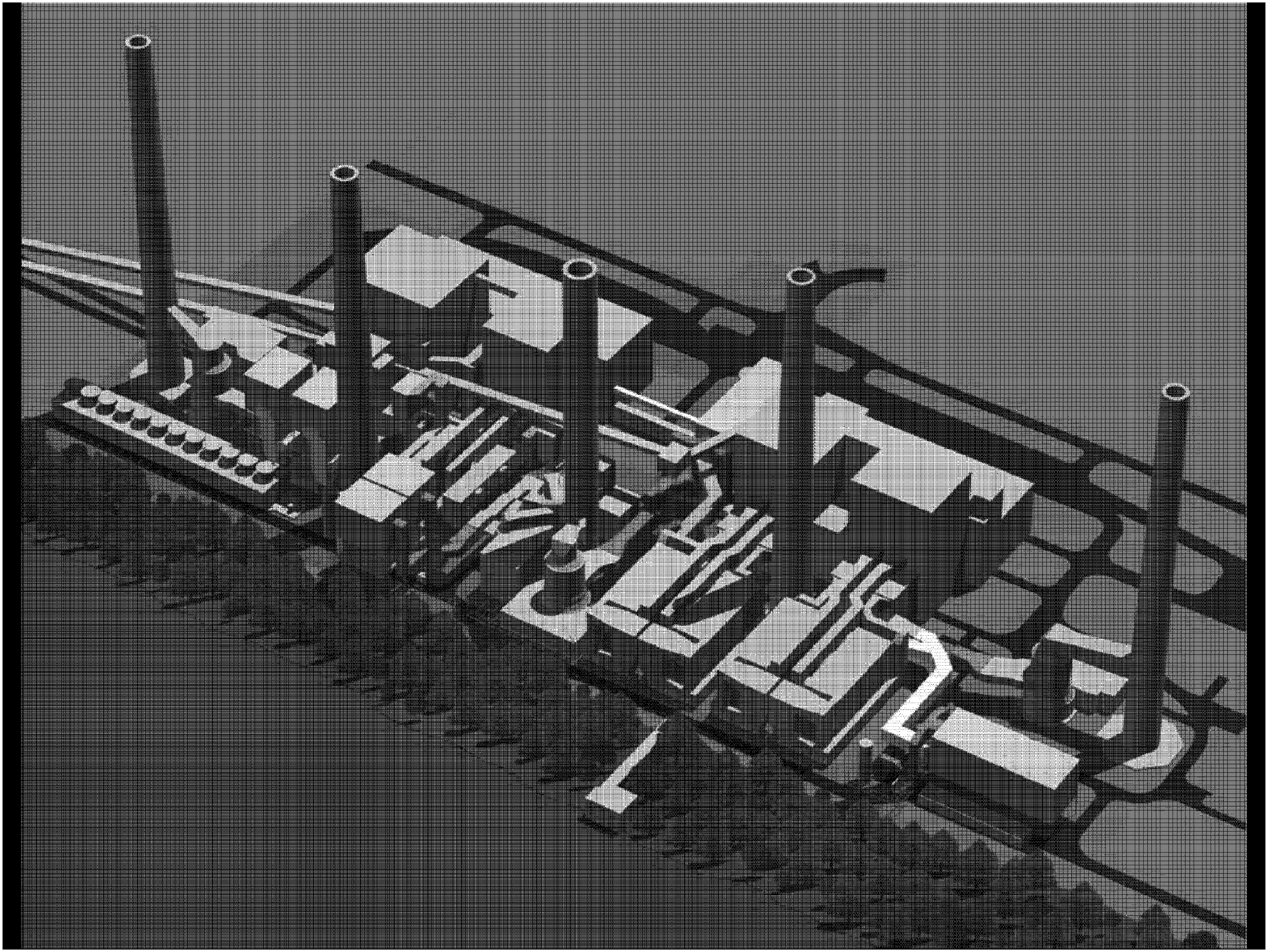
3-D Models
Overview: Before and After





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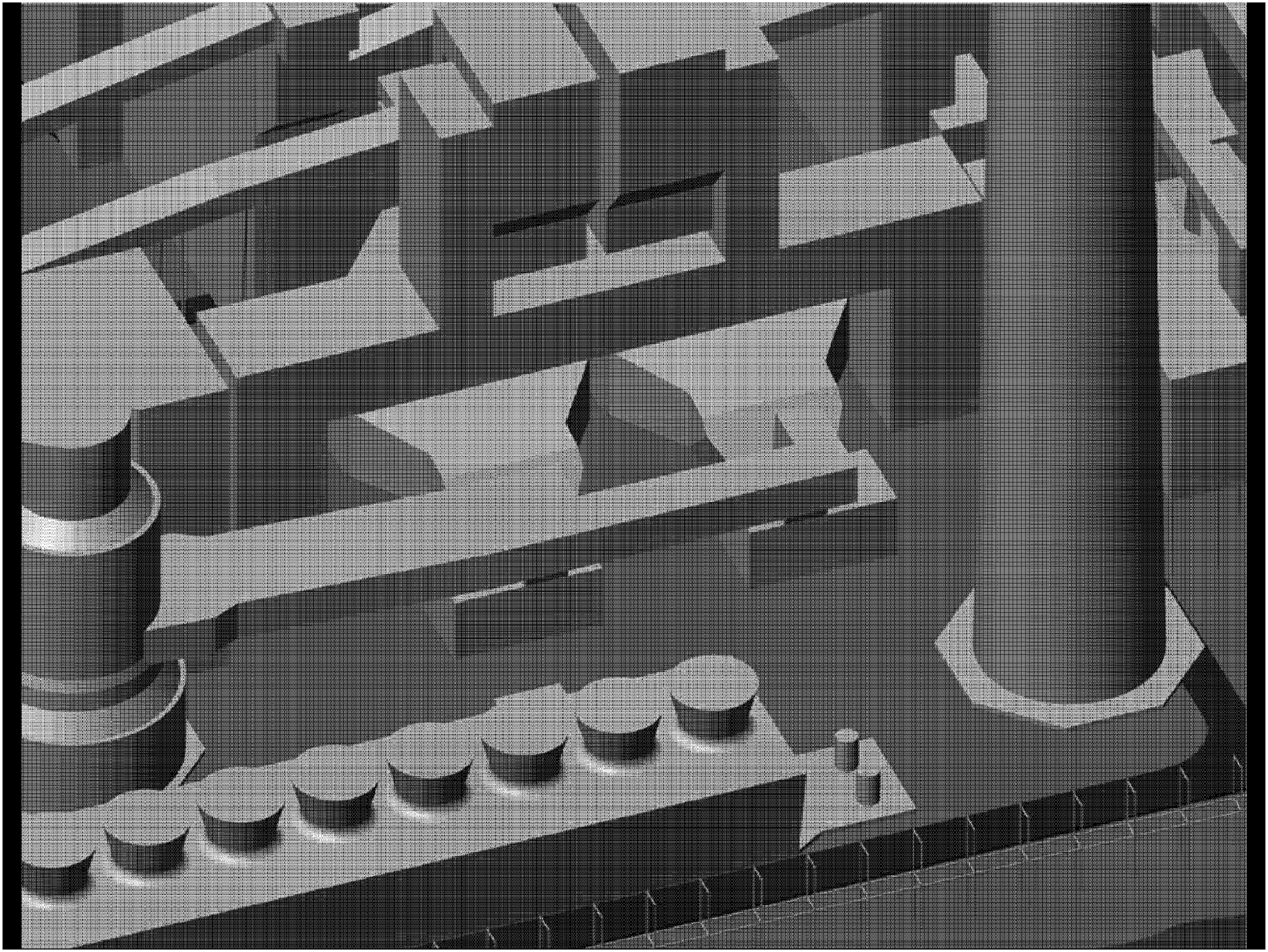
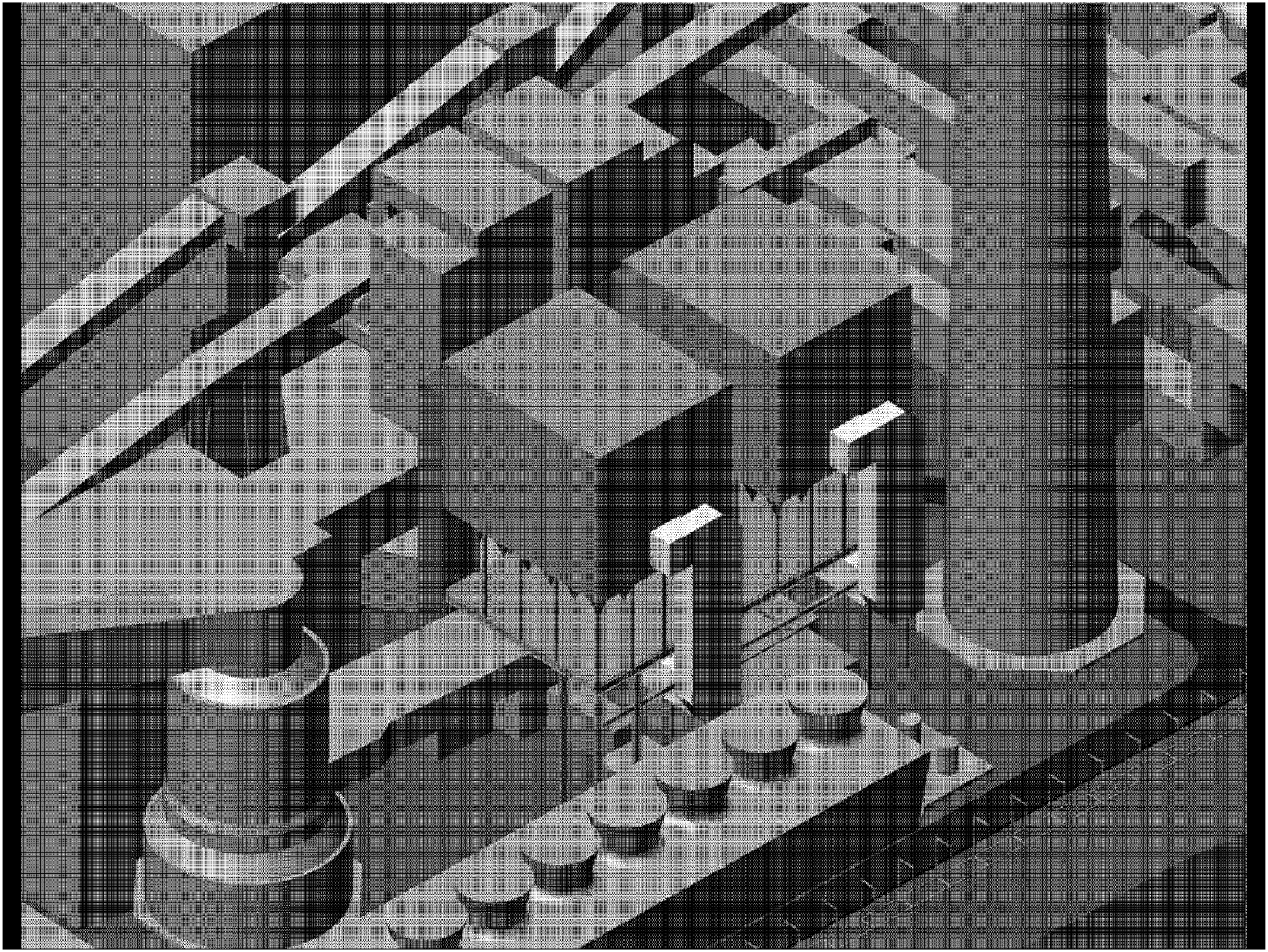
Unit 1
3-D Model





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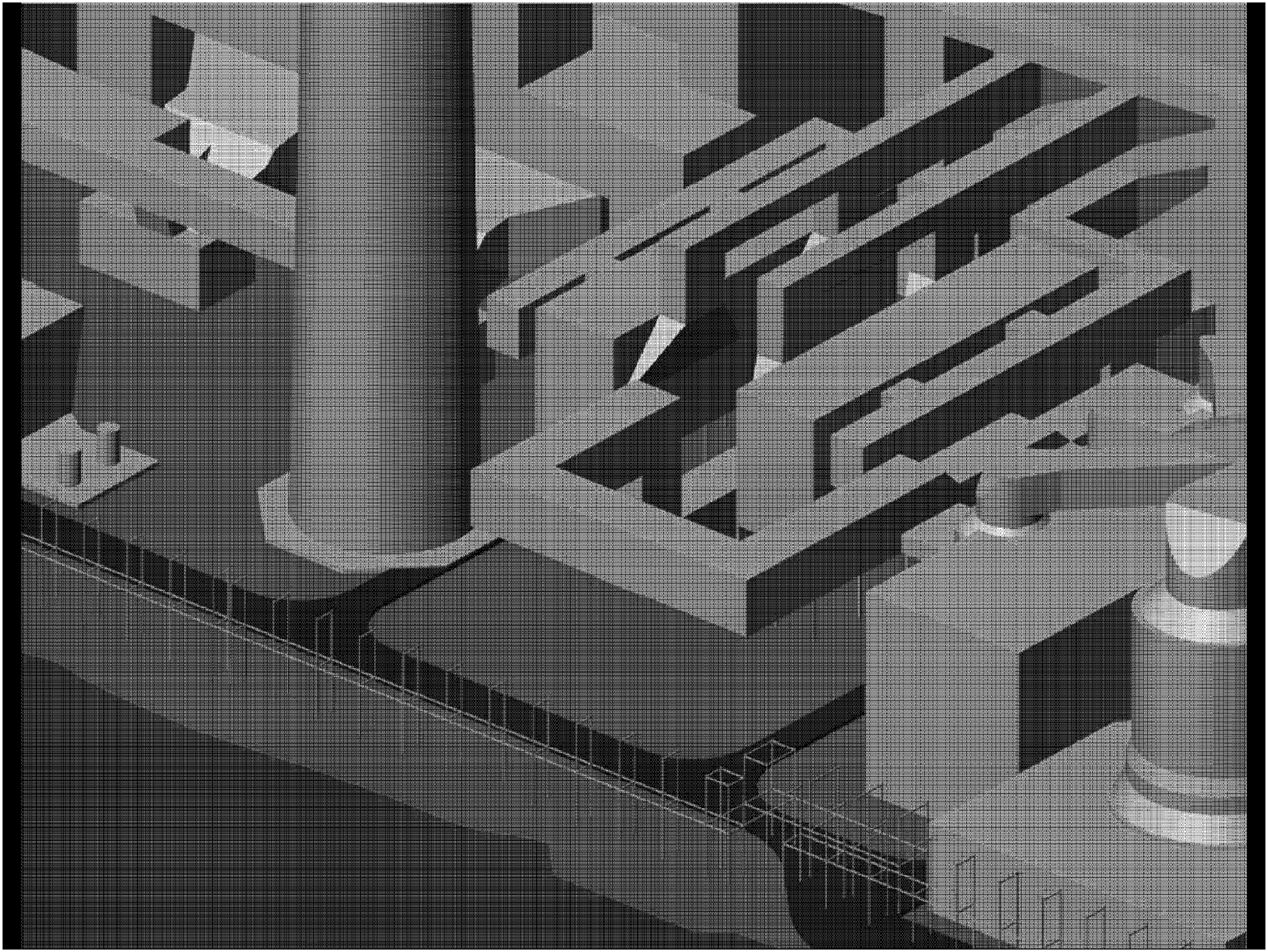
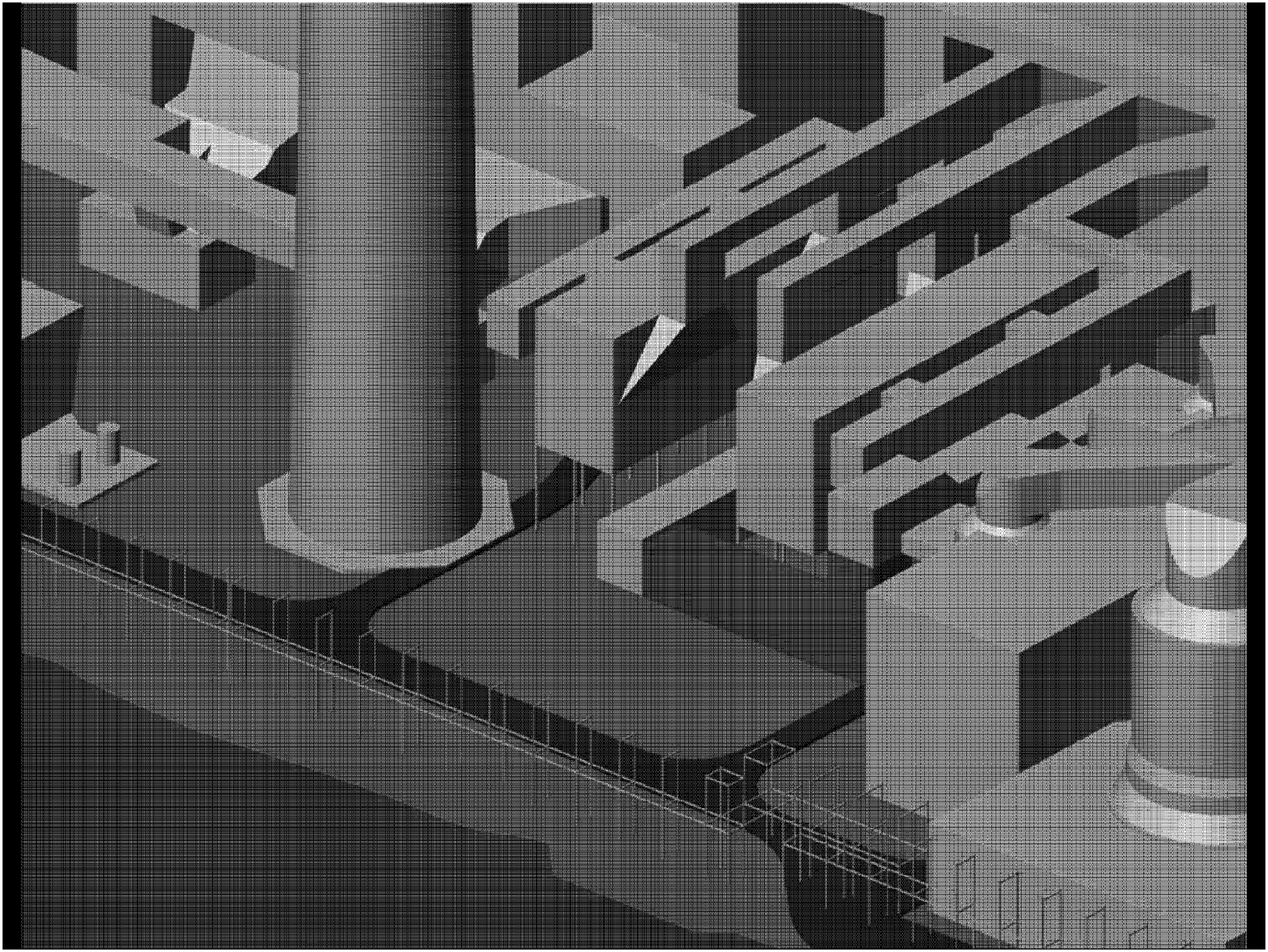
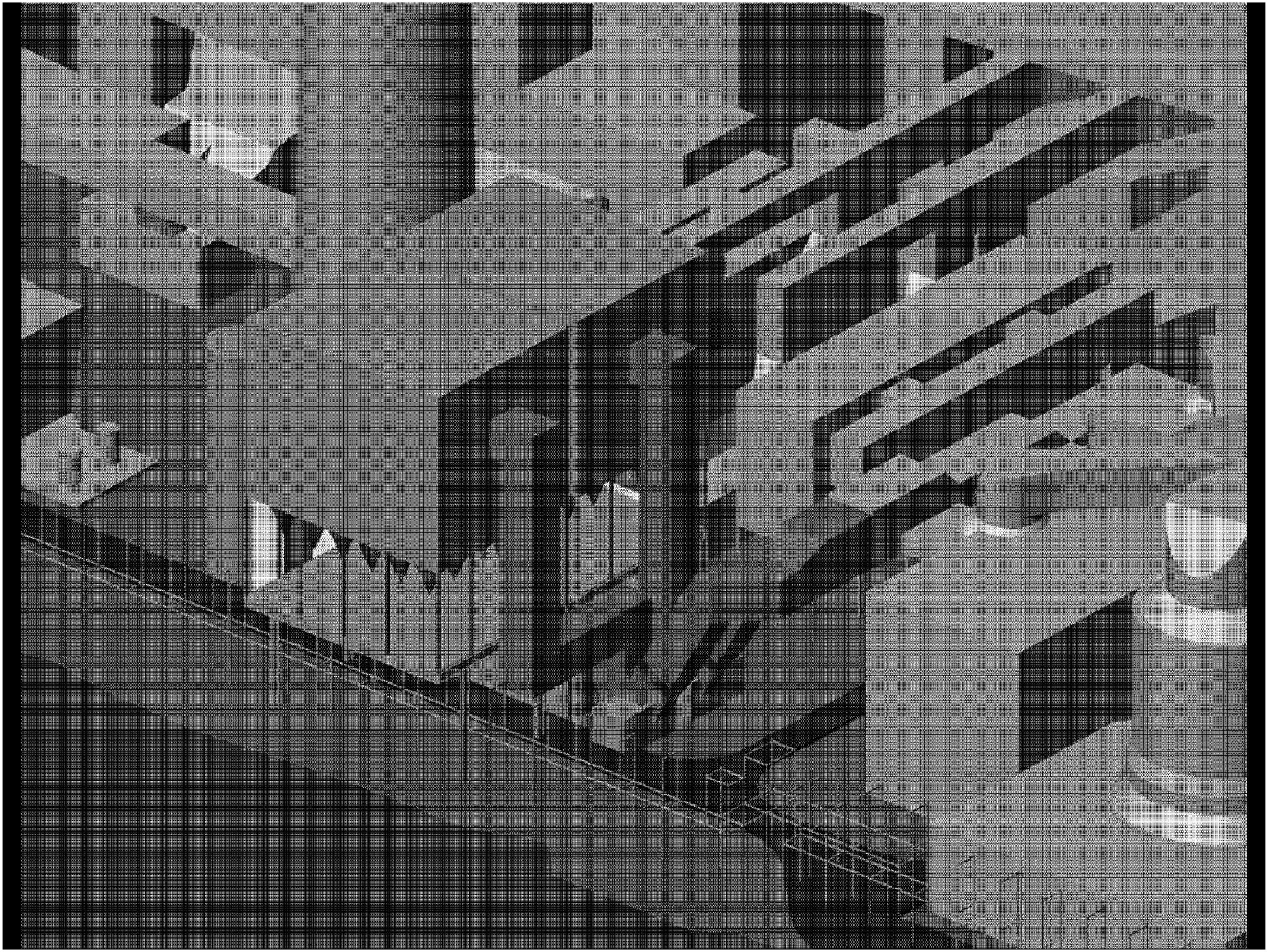
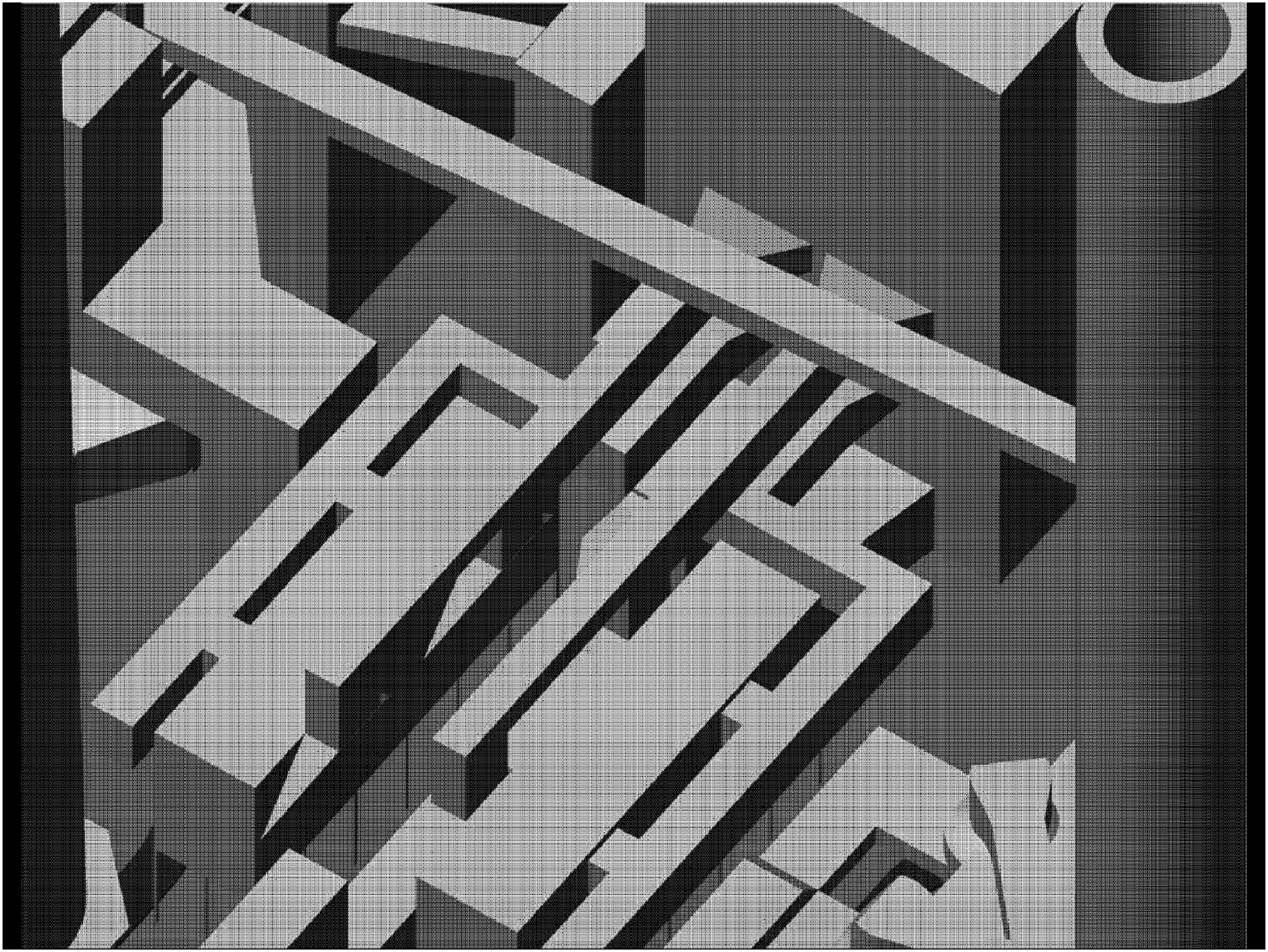
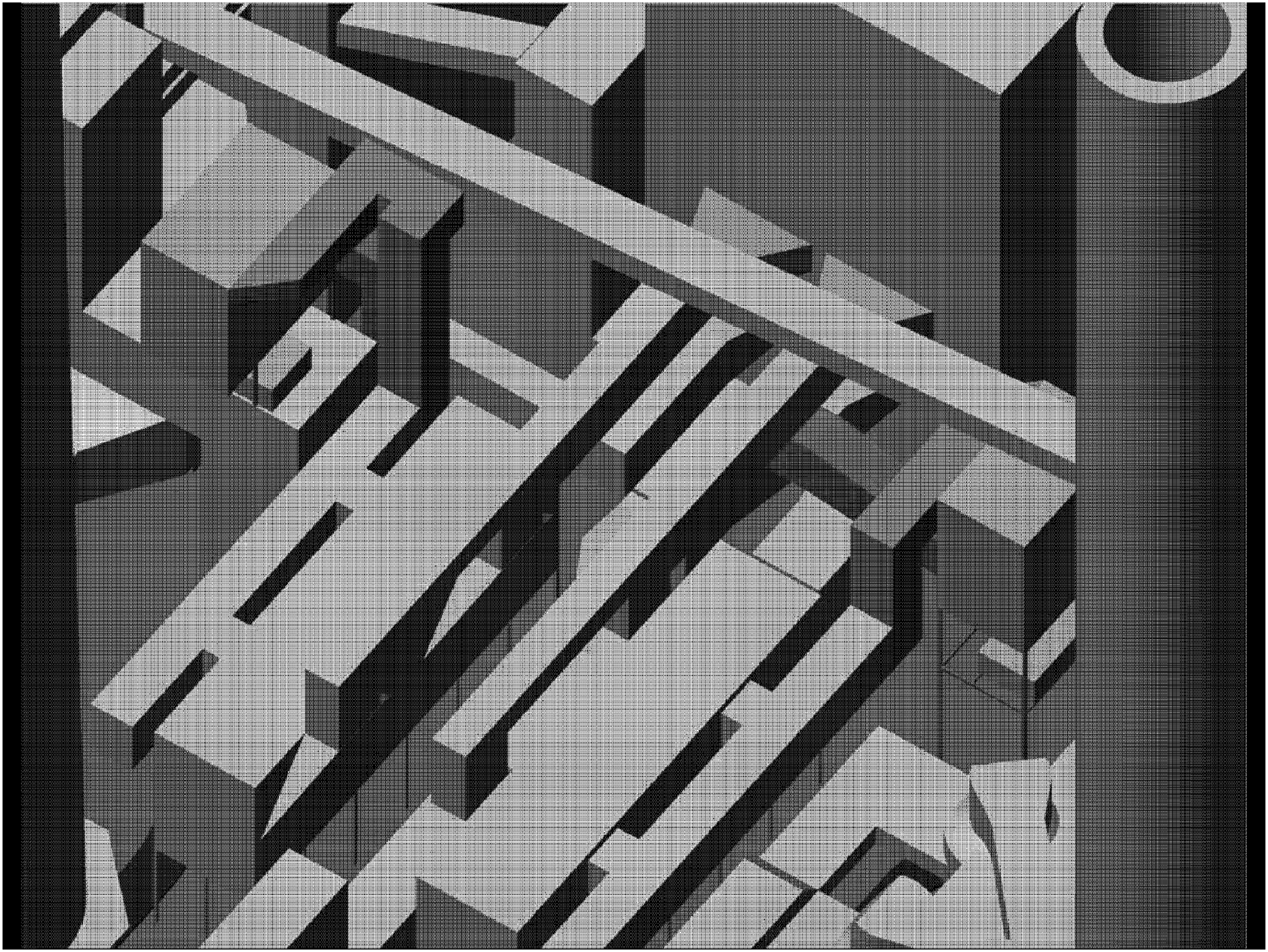
Unit 2
3-D Model











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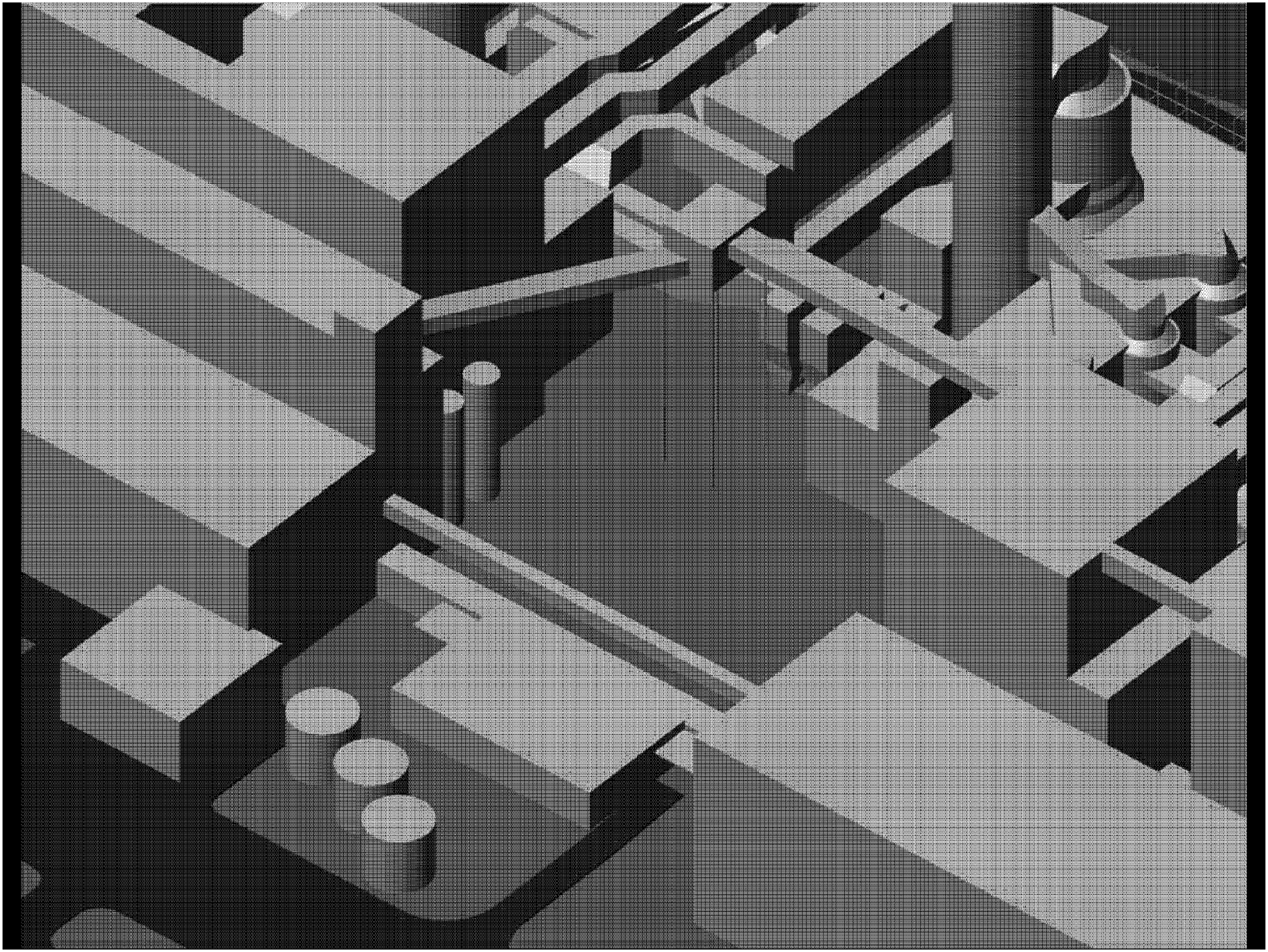
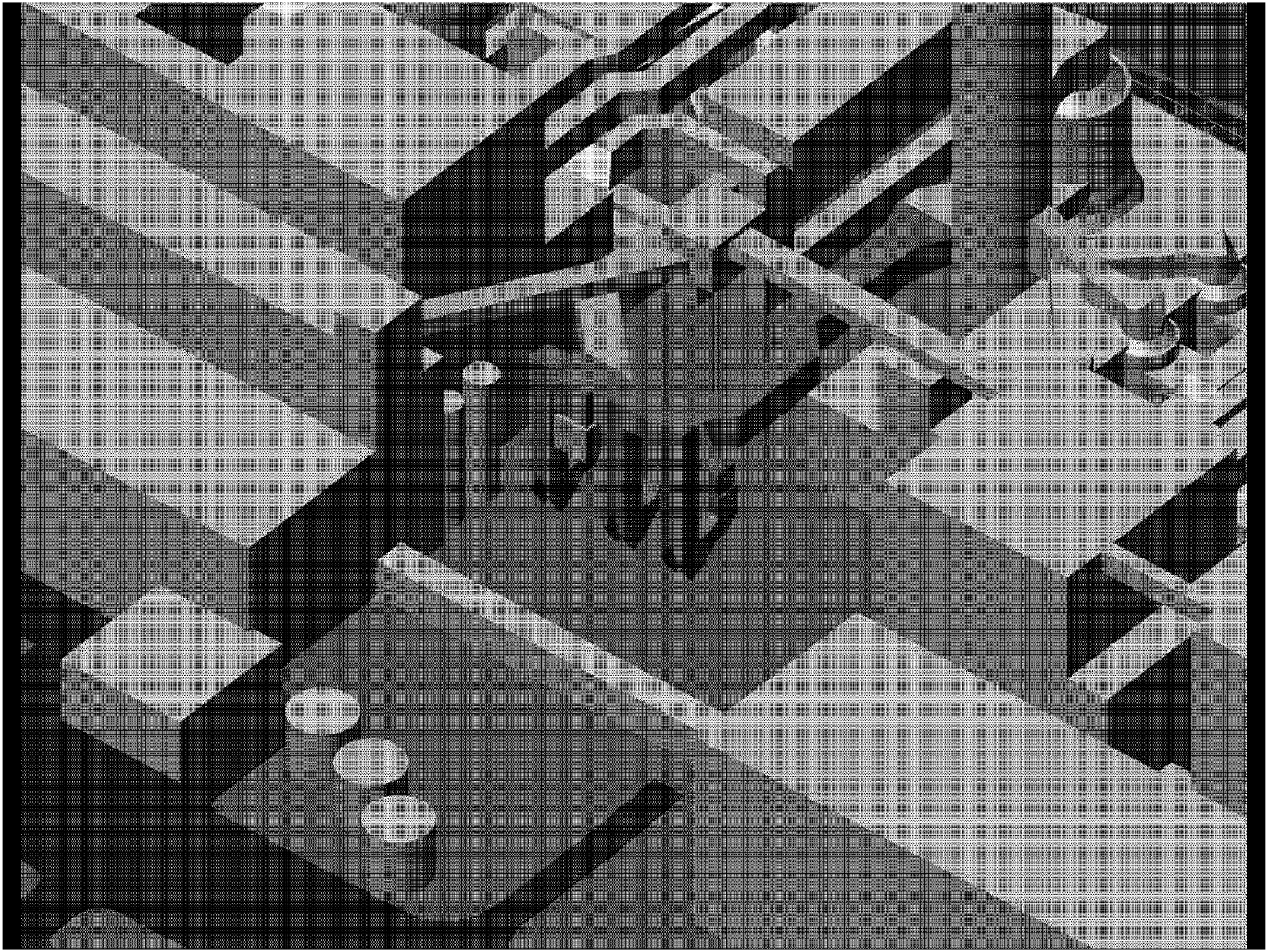
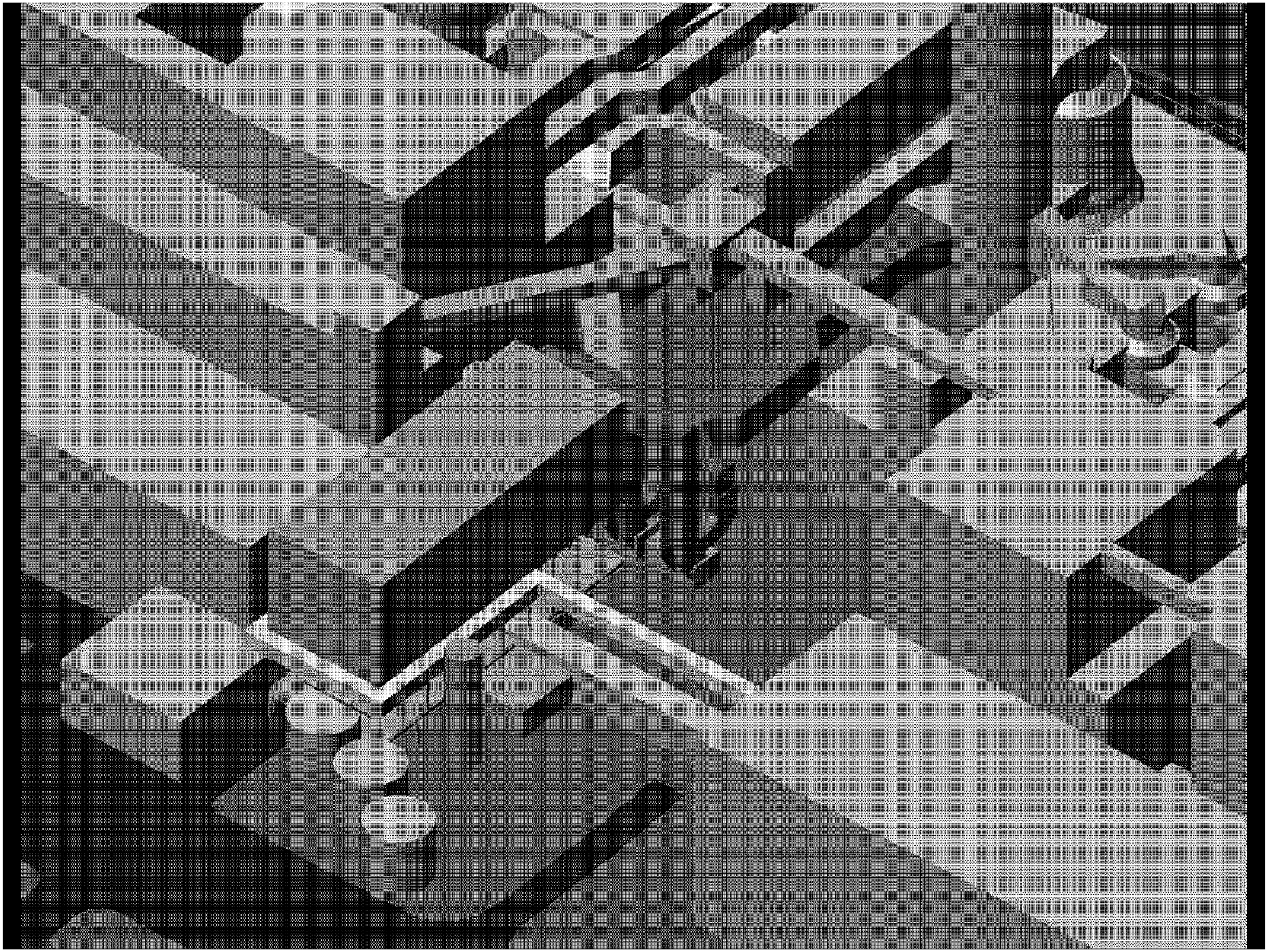
Unit 3
3-D Model







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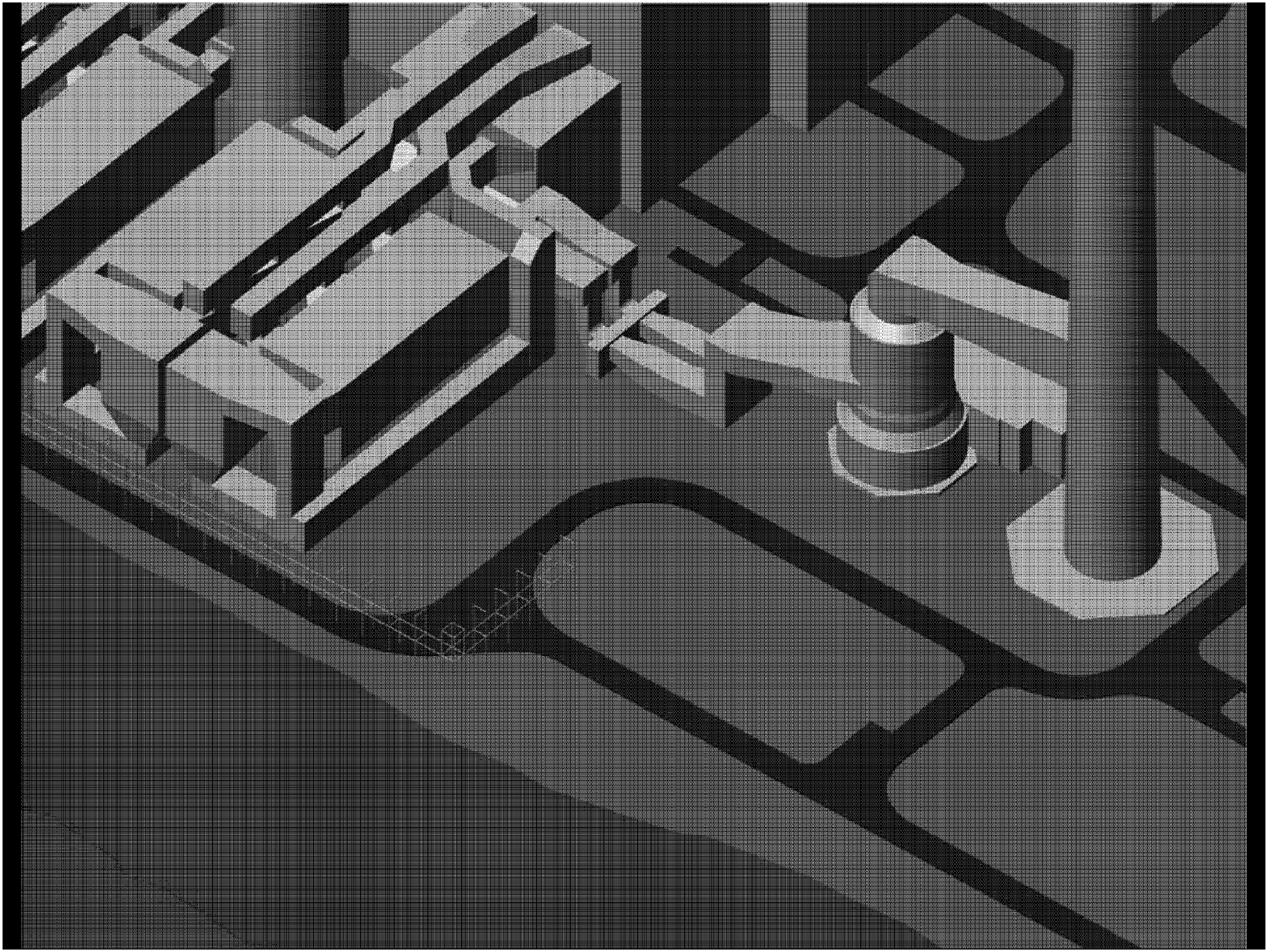
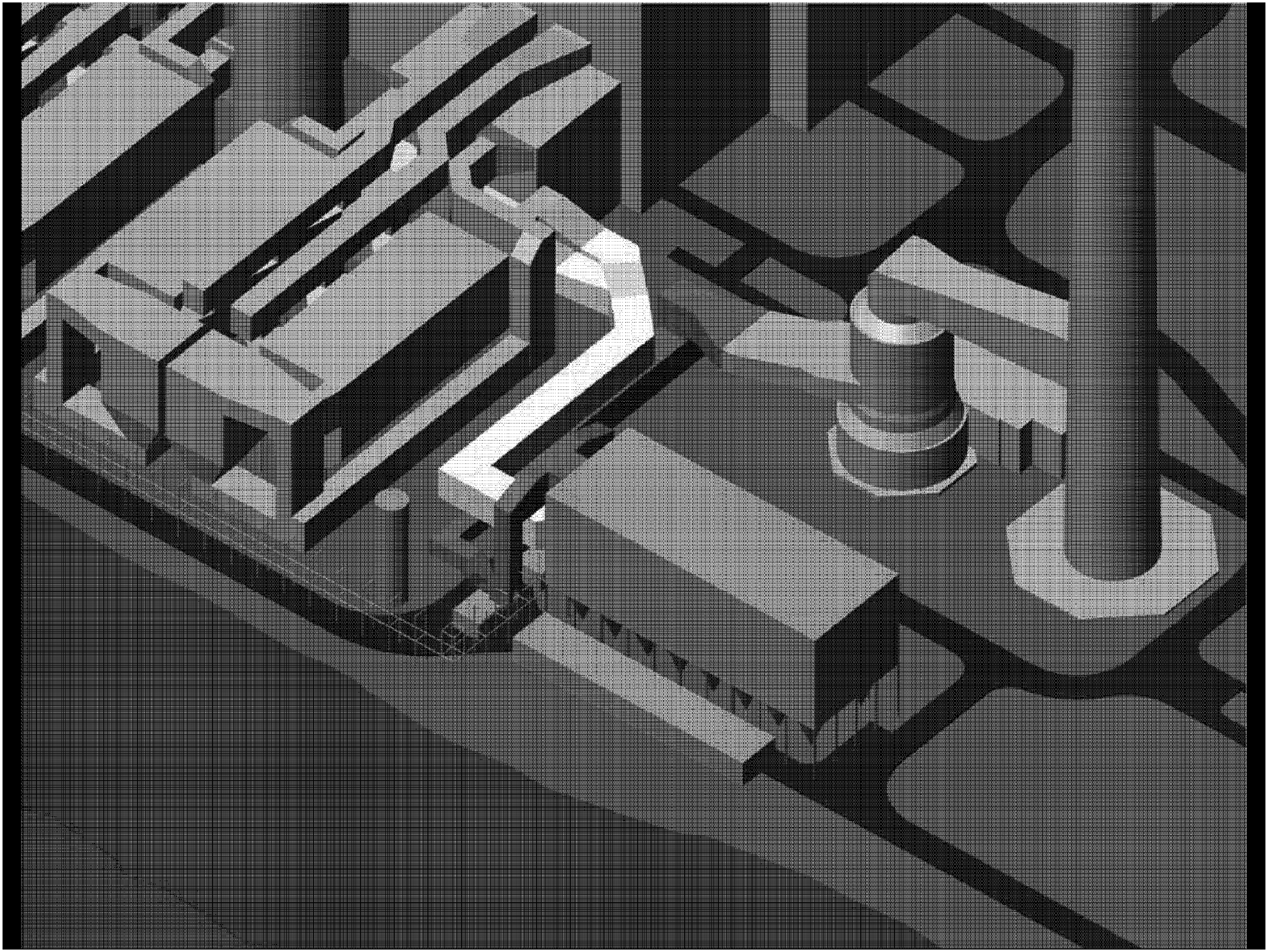
Unit 4
3-D Model





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Summary / Wrap-up and Discussions

From: Saunders, Eileen
To: Schroeder, Andrea
Sent: 2/1/2011 1:03:07 PM
Subject: FW: 168908.41.0803 110118 Mill Creek Validation Report - Rev C
Attachments: LGE&KU MC Validation Report Rev C.pdf; Mill Creek Validation Presentation.pdf

Andrea,

Here is the third revision for MC. I am including the presentation as well even though the presentation was based on the first revision.

Eileen

From: Hillman, Timothy M. [mailto:HillmanTM@bv.com]
Sent: Tuesday, January 18, 2011 1:58 PM
To: Saunders, Eileen
Cc: 168908 E.ON-AQC; Wehrly, M. R.; Lucas, Kyle J.; Crabtree, Jonathan D.; Jackson, Audrey; Fields, Ron L.; Mahabaleshwarkar, Anand; Mehta, Pratik D.; Keltner, Erik J.; Betz, Alex
Subject: 168908.41.0803 110118 Mill Creek Validation Report - Rev C

Eileen,

Please find attached a PDF of the Mill Creek AQC Validation Report, Revision C, issued for project use. All LG&E/KU and B&V internal comments were picked up and the conclusion was updated. Changes due to comments include addition of Arrangement D for Unit 1 and 2 (attached in appendix A), increased fly ash handling quantities, change in ID/booster fan motor voltage from 13.8 kV to 4.16kV at plant's request by using variable frequency drives, and minor editorial changes. Most importantly, the conclusion was updated to reflect LG&E/KU's direction to advance the following tasks: conceptual engineering, project cost estimate, and schedule. Please let us know if you have any questions or concerns.

Best regards,

TIM HILLMAN | Project Manager, Energy
Black & Veatch Corporation | 11401 Lamar Ave., Overland Park, KS 66211
+ 1 913-458-7928 P |HillmanTM@BV.com
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LG&E/KU – Mill Creek Station

Phase II Air Quality Control Study

Air Quality Control Validation Report

January 18, 2011
Revision C – Issued For Project Use

B&V File Number 41.0803

LG&E KU

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Acronym List

AHJ	Authority Having Jurisdiction
AQC	Air Quality Control
As	Arsenic
B&W	Babcock & Wilcox
Be	Beryllium
CAIR	Clean Air Interstate Rule
CATR	Clean Air Transport Rule
Cd	Cadmium
Co	Cobalt
Cr	Chromium
CS-ESP	Cold-side Electrostatic Precipitator
DCS	Distributed Control System
DOE	Department of Energy
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FRP	Fiberglass-Reinforced Plastic
HCl	Hydrogen Chloride
Hg	Mercury
ID	Induced Draft
Inw	Inch of Water
LNB	Low NO_x Burners
LV	Low Voltage
MACT	Maximum Achievable Control Technology
MBtu	Million British Thermal Unit
MCC	Motor Control Center
Mn	Manganese
MSW	Municipal Solid Waste
MV	Medium Voltage
MWC	Medical Waste Combustors
NAAQS	National Ambient Air Quality Standard
NFPA	National Fire Protection Association
Ni	Nickel
NID	Novel Innovative Desulfurization
NN	Neural Network

NO_x	Nitrogen Oxides
OFA	Overfire Air
PAC	Powdered Activated Carbon
Pb	Lead
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
RGFF	Reverse Gas Fabric Filters
SAM	Sulfuric Acid Mist
Sb	Antimony
SBS	Sodium Bisulfite
SCA	Specific Collection Area
SCR	Selective Catalytic Reduction
Se	Selenium
SO_2	Sulfur Dioxide
tph	Tons per Hour
TR	Transformer/Rectifier
WFGD	Wet Flue Gas Desulfurization

1.0 Introduction

Following the submittal of the Phase I report on July 8, 2010, Black & Veatch met with LG&E/KU on August 5-6, 2010 and conducted a technology option review to further define facility technology options based on the Phase I report. The purpose of this Phase II air quality control (AQC) validation study is to build upon the previous fleet-wide, high-level air quality technology review and cost assessment conducted for six LG&E/KU facilities (Phase I) in order to develop a facility-specific project definition consisting of a conceptual design and a budgetary cost estimate for selected AQC technologies (Phase II) for the Mill Creek Generating Station. The following AQC technology options resulted from the August meeting and have been assessed in this report:

- NID or PJFF with sorbent (trona/lime/SBS [sodium bisulfite]) injection on Units 1-4.
- SCR on Units 1 and/or 2.
- Refurbishing or replacing WFGD on Units 1, 2 and 4, including using Unit 4's WFGD for Unit 3.
- New WFGD on Unit 4.
- Powdered activated carbon (PAC) injection on Units 1-4.
- Feasibility of neural network (NN) on Units 1-4.
- Feasibility of cold-side electrostatic precipitators (CS-ESPs) for pre-filtering on Units 1 and 2.

This validation study confirms the feasibility of installing the aforementioned AQC equipment at Mill Creek, and presents the supporting considerations, arrangements, and preliminary validating analyses of the AQC equipment that will be built upon in the next step of this project to complete the conceptual design and budgetary cost estimate.

2.0 Facility Description

2.1 Mill Creek - Units 1, 2, 3, and 4

The Mill Creek Station is located in southwestern Jefferson County, approximately 10.5 miles southwest of the city of Louisville, Kentucky, on a 509 acre site. Mill Creek Station includes four coal fired electric generating units with a gross total generating capacity of 1,608 MW. Mill Creek Station Unit 1 was placed in service in 1972, Mill Creek Station Unit 2 was placed in service in 1974, and Mill Creek Station Units 3 and 4 were each placed in service at 4 year intervals afterward in 1978 and 1982, respectively.

All four boilers fire high sulfur bituminous coal (i.e., high sulfur western Kentucky bituminous coal from Illinois Basin, natural gas for startup). Each Mill Creek Station unit includes one GE reheat tandem compound, double-flow turbine with a condenser and hydrogen-cooled generator. Units 1 and 2 each consist of one Combustion Engineering subcritical, balanced draft boiler and have a gross capacity of 330 MW each. Units 1 and 2 are equipped with LNBs and OFA for NO_x control, a CS-ESP for PM control, and a WFGD for SO_2 and HCl (hydrogen chloride) control. Units 3 and 4 each consist of one Babcock & Wilcox (B&W) balanced draft, Carolina type radiant boiler and have a gross capacity of 423 MW and 525 MW, respectively. Each is equipped with LNBs and SCR for NO_x control; a CS-ESP for PM control and a WFGD for SO_2 and HCl control.

Gypsum, a scrubber by-product, produced at Mill Creek is either stored in the on-site landfill or sold for use in manufacture of wall board for the home construction industry. Fly ash is either stored in the on-site landfill or sold for beneficial reuse to the concrete industry. Bottom ash is sluiced to on-site storage ponds. Initially, all four units were cooled using water from the nearby Ohio River; however, Units 2, 3, and 4 were retrofitted with mechanical draft cooling towers. Plant water is supplied by the Ohio River, well water and city water.

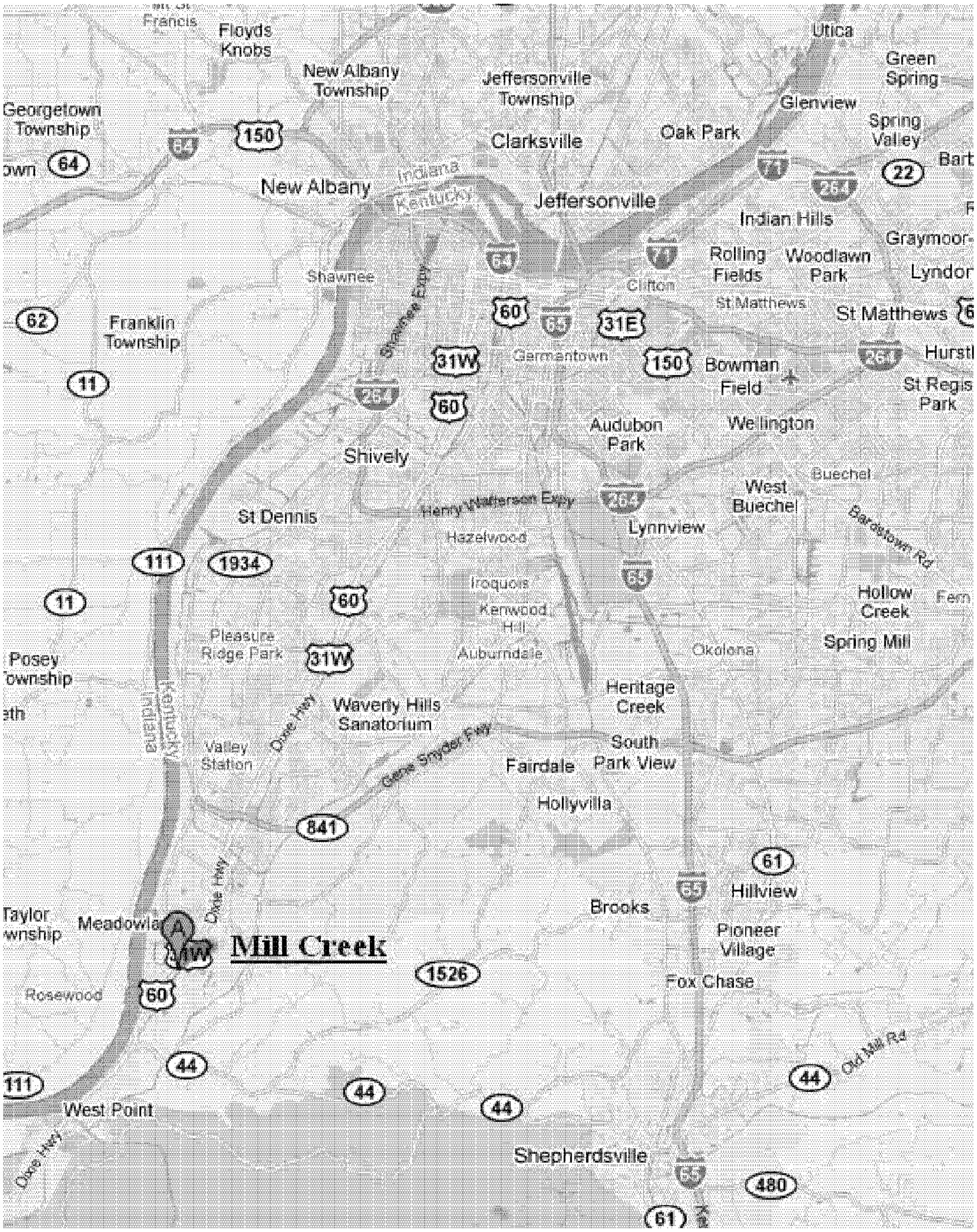
Figures 2-1 and 2-2 illustrate the plant location and Table 2-1 summarizes the plant's existing facilities.

NORTH

SOUTH

Figure 2-1. Mill Creek Power Plant Site

NORTH



SOUTH

Figure 2-2. Mill Creek and Surrounding Area Map

Table 2-1. Existing Mill Creek Plant Facilities

• Existing On Site Generation Units:	• Unit 1 - 330 gross MW (in-service date 1972) • Unit 2 - 330 gross MW (in-service date 1974) • Unit 3 - 423 gross MW (in-service date 1978) • Unit 4 - 525 gross MW (in-service date 1982)
• Existing AQC Equipment:	• Unit 1 - Low NO_x Burners (LNBs), Overfire Air System (OFA), CS-ESP, Wet Flue Gas Desulfurization (WFGD) • Unit 2 - LNBs, OFA, CS-ESP, WFGD • Unit 3 - LNBs, Selective Catalytic Reduction (SCR), CS-ESP, WFGD • Unit 4 - LNBs, SCR, CS-ESP, WFGD

3.0 Emission Target Basis

LG&E/KU provided a matrix of estimated requirements under current and future environmental regulations, as well as a summary implementation schedule of regulatory programs. Table 3-1 summarizes the future pollution emission targets provided by LG&E/KU for each unit.

The current regulatory drivers include the NO_2 and SO_2 National Ambient Air Quality Standard (NAAQS). On January 22, 2010, the Environmental Protection Agency (EPA) announced a new 1-hour NO_2 NAAQS of 100 ppb. The final rule for the new hourly NAAQS was published in the Federal Register on February 9, 2010, and the standard became effective on April 12, 2010. Likewise, on June 2, 2010, EPA strengthened the primary SO_2 NAAQS. EPA established a new 1-hour standard at a level of 75 ppb and revoked the existing 24-hour and annual standards.

The potential impact of future regulations is the primary driver for both the timing and extent of environmental controls planned at the LG&E/KU plants. Among the regulatory drivers are the Utility Maximum Achievable Control Technology (MACT), and the Clean Air Transport Rule (CATR) -- Clean Air Interstate Rule (CAIR) replacement to be proposed by the United States EPA by spring 2011 and summer 2011, respectively.

From this information, LG&E/KU developed specific pollutant emission limit targets with the intent that the limits would be applied to each unit individually to assess current compliance and the potential for additional AQC equipment. These regulatory drivers and their associated emission levels serve as the primary basis used by Black & Veatch to develop unit-by-unit AQC technology recommendations. For the purposes of this study, compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) were not considered.

Table 3-1. Primary Design Emission Targets

Pollutant	Unit 1	Unit 2	Unit 3	Unit 4
NO_x	0.139[b] lb/MBtu	0.139[b] lb/MBtu	N/A[a]	N/A[a]
SO_2	N/A[a]	N/A[a]	N/A[a]	98% removal
Sulfuric Acid Mist (SAM)	N/A[a]	N/A[a]	64.3 lb/hr	76.5 lb/hr
Mercury (Hg)	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh	90% control or 0.012 lb/GWh
HCl	0.002 lb/MBtu	0.002 lb/MBtu	0.002 lb/MBtu	0.002 lb/MBtu
Particulate Matter (PM)[c],[d]	0.03[b] lb/MBtu	0.03[b] lb/MBtu	0.03[b] lb/MBtu	0.03[b] lb/MBtu
Arsenic (As) [e]	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu	0.5×10^{-5} lb/MBtu
CO	0.10 lb/MBtu	0.10 lb/MBtu	0.10 lb/MBtu	0.10 Lb/MBtu
Dioxin/Furan	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu	15×10^{-18} lb/MBtu

Data from Mill Creek kickoff meeting of September 15, 2010 (Gary Revlett handouts and meeting notes) unless noted otherwise.
[a]Not applicable for this Phase II study.
[b]Emission rate target is higher than what can typically be achieved with chosen technology; a lower emission target may be possible.
[c]Particulate matter control limits for $PM_{2.5}$ or $PM_{condensable}$ have not been determined for this project.
[d]Particulate matter assumed to be the surrogate for emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)).
[e]Arsenic assumed to be the surrogate for non-mercury metallic HAP (i.e., arsenic (As), chromium (Cr), and selenium (Se)).

4.0 Site Visit Summary

The following section describes the existing site conditions and site visit observations for the Mill Creek Generating Station.

4.1 Site Visit Observations and AQC

The following observations are from the September 14-16, 2010 site visit and summarize the site and equipment constraints based on the AQC technology refinement meeting held on August 5-6, 2010. The following excerpts are from the September 24, 2010, site visit meeting memo that focused specifically on installing the AQC equipment resulting from the aforementioned August meeting.

- If the new Unit 4 WFGD and stack require the relocation of the ammonia storage area, it may be possible to consolidate it with the ammonia storage requirements for the new Unit 1 and 2 SCRs.
- It may be possible to reuse Unit 4's fans on Unit 3 should the existing fans become superfluous in the new Unit 4 arrangement. It then may be possible to reuse the Unit 3 fans on Unit 1 and/or Unit 2.
- Mill Creek confirmed there is no "sacred ground" around the existing units, areas reserved for other uses and unavailable for use in the AQC upgrade. B&V requested if any balance-of-plant upgrades are currently under consideration that should be taken into account in the AQC work, beyond the plans for an additional ball mill at the limestone prep building.
- Unit 4 NID or PJFF likely to be required to be installed above the Unit 4 scrubber electrical building.
- Unit 3 would be tied into the current Unit 4 scrubber after the new Unit 4 WFGD is built. The large capacity of the Unit 4 scrubber as compared to the Unit 3 unit would allow SO_2 reductions on Unit 3. The current Unit 3 WFGD, with the below grade reaction tanks and pumps provide limited opportunity for upgrading the performance of the units and presents maintenance issues. The old Unit 3 WFGD would be torn down to allow new AQC equipment to be potentially located in that area.
- Unit 3 and 4 structural steel was generally in good shape for lower areas that could be inspected. Relatively isolated examples of steel corrosion, most likely due to exposure to flue gas, were noted in the superstructures at the scrubbers. Higher areas of Unit 3 and 4 could not be assessed due to the large flue gas leaks in the duct that limited access for personal safety reasons.

- Duct configuration will be complicated, but appears possible, and will depend on the specific fan arrangement and if new ID fans or booster fans will be used.
- The potential for locating the Unit 4 PJFF/NID unit and new WFGD, plus a new chimney, to the south of Unit 4 was considered as a possibility. The original location for the new WFGD and chimney was in the area of the demolished thickener south of the limestone prep building. This location, however, involved crossing the limestone conveyor with relatively high ductwork, plus moving both an overhead Unit 3 and Unit 4 345kV T-line and the ammonia tanks and electrical building to provide necessary working space for new construction.
- Alternately, it was determined that there is likely sufficient space for the new Unit 4 AQC train directly south of Unit 4, running more or less straight east to west with the new chimney located opposite of the Unit 4 turbine building. This arrangement, if it fits, has the advantage of relatively short ductwork runs, no impact to the overhead T-line, and no impact to the existing ammonia tank farm. It would, however, require relocation of the existing annex building and lab, plus limit construction access to one side of the train. This arrangement would serve as first choice for Unit 4, with the thickener area location used as a fall-back alternate. Should either of the above arrangements fit, it appeared that it would be advantageous to upgrade the existing Unit 4 WFGD in place and reuse it for Unit 3. The flue gas from Unit 3 would be rerouted to the Unit 4 scrubber in the short term (Phase I) and the Unit 3 scrubber demolished. A new Unit 3 PJFF/NID unit could be built in its place and tied into the Unit 3 ductwork as Phase II of a two phase construction sequence on Unit 3.
- Both Unit 1 and Unit 2 offer significant challenges for the addition of an SCR as an immediate and priority modification. The existing ESP at both units is located within a few feet of the boiler structure, leaving insufficient room to route ductwork to a new SCR overhead of the ESP. The ESP would have to be demolished or extensively modified before the SCR could be constructed, resulting in either an extended outage while the ESP is moved or reconstructed or the installation of a separate new ESP in another location prior to installation of the SCR. In addition, area available for new structures for either Units 1 or 2 is very limited, by the narrow alleyway between Units 1 and 3 for Unit 1 and by the new RO facility

north of the power block at Unit 2. No obvious arrangement for the AQC upgrades at Units 1 and 2 were immediately noted, and required additional investigation.

- The structural steel at the existing Unit 1 and 2 scrubbers is in poor condition. Severe corrosion and loss of structural mass was noted in a significant number of areas at Units 1 and 2. The most severe damage noted was in lighter components, such as platform and grating, but instances of chemical attack on the major structural steel members were also noted on Units 1 and 2.
- New AQC will likely restrict vehicle and maintenance access in some areas of the facility.
- The existing Unit 4 AQC equipment (i.e., ESP and WFGD) are powered by the Unit 4 auxiliary power supply. Should the Unit 4 WFGD be reused for Unit 3, an alternate source of auxiliary power for the refurbished equipment must be included. Otherwise, an outage on Unit 4 would result in the loss of AQC for Unit 3.
- No auxiliary power supply greater than 4,160V is currently available in the immediate plant area. However, there are spare cubicles which might be able to be modified to accept feeder breakers as potential sources of medium voltage power for new loads such as fans in the AQC upgrade.

5.0 Selected Air Quality Control Technology

The following sections present a general description of the AQC technologies considered for Mill Creek, as well as a unit by unit discussion of the key attributes of the technologies and special considerations for their application and arrangement at the affected units. Table 5-1 presents the selected AQC technologies that were considered in the validation process.

Table 5-1. AQC Technologies

	Unit 1	Unit 2	Unit 3	Unit 4
NO_X Control	New SCR	New SCR	Existing SCR	Existing SCR
SO_2 Control	Refurbish existing WFGD	Refurbish existing WFGD	Refurbish and reuse Unit 4 WFGD	New WFGD
PM Control	New NID or New PJFF	New NID or New PJFF	New NID or New PJFF	New NID or New PJFF
HCl Control	New NID or refurbished WFGD	New NID or refurbished WFGD	New NID or refurbished WFGD	New NID or New WFGD
CO Control	New NN	New NN	New NN	New NN
SO_3 Control	New NID or New PJFF with Sorbent Injection	New NID or New PJFF with Sorbent Injection	New NID or New PJFF with Sorbent Injection	New NID or New PJFF with Sorbent Injection
Hg Control	New PAC Injection	New PAC Injection	New PAC Injection	New PAC Injection
Dioxin/Furan Control	New PAC Injection	New PAC Injection	New PAC Injection	New PAC Injection
Fly Ash Sales	New CS-ESP (Optional)	New CS-ESP	Existing CS-ESP	Existing CS-ESP

5.1 Technology Descriptions

The following sections provide a brief general description of the proposed AQC technologies.

5.1.1 Selective Catalytic Reduction System

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_X into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_X-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_X levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_X available for removal. Essentially, as NO_X is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature are costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure 5-1 shows a schematic diagram of SCR.

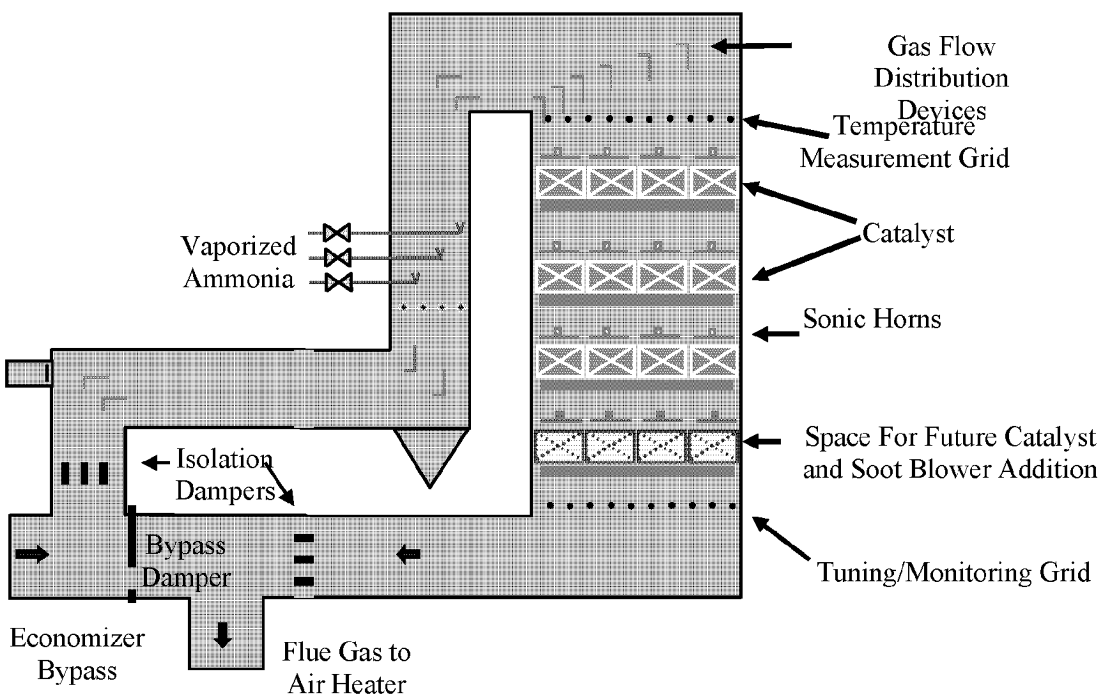


Figure 5-1. Schematic Diagram of a Typical SCR Reactor

5.1.2 Wet Flue Gas Desulfurization System

Wet limestone-based FGD processes are frequently applied to pulverized coal fired boilers that burns medium-to-high sulfur eastern coals. All of the FGD systems installed in response to Phase I of the 1990 CAA were based on a WFGD system using either lime or limestone as the reagent. Typically, the WFGD processes on a pulverized coal facility are characterized by high efficiency (> 98 percent) and high reagent utilization (95 to 97 percent) when combined with a high sulfur fuel. The ability to realize high removal efficiencies on higher sulfur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes. It is well known that SO_2 removal efficiencies for WFGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove SO_2 are faster if the inlet SO_2 concentration is higher. The absolute emissions level becomes a limiting factor due to a reduction in the chemical driving forces of the reactions that are occurring. Thus, the calculated removal efficiency of the various types of WFGDs declines as the fuel sulfur content decreases; this is the case for low sulfur western and PRB coals.

In a WFGD system, the absorber module is located downstream of the induced draft (ID) fans (or booster ID fans, if required). Flue gas enters the module and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3{\bullet}1/2H_2O$ and $CaSO_4{\bullet}2H_2O$. SO_2 reacts with limestone reagent through the following overall reactions:

$$SO_2 + CaCO_3 + \tfrac{1}{2}H_2O \rightarrow CaSO_3{\bullet}\tfrac{1}{2}H_2O + CO_2$$
$$SO_2 + CaCO_3 + 2H_2O + \tfrac{1}{2}O_2 \rightarrow CaSO_4{\bullet}2H_2O + CO_2$$

The flue gas leaving the absorber will be saturated with water, and the stack will have a visible moisture plume. Because of the chlorides present in the mist carry-over from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and the flue stack. Careful design of the stack is needed to prevent the "rainout" from condensation that occurs in the downstream ductwork and stack. These factors contribute to the relatively high capital costs of the WFGD SO_2 control alternative.

The reaction products are typically dewatered by a combination of hydrocyclones and vacuum filters. The resulting filter cake is suitable for landfill disposal. In early lime- and limestone-based FGD processes, the byproduct solids were primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$), and the byproduct solids were mixed with fly ash (stabilization) or fly ash and lime (fixation) to produce a physically stable material (Figure 5-2). In the current generation of WFGD systems, air is bubbled through the reaction tank (or in some cases, a separate vessel) to practically convert all of the $CaSO_3 \bullet 1/2H_2O$ into calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$), which is commonly known as gypsum. This step is termed “forced oxidation” and has been applied to both lime- and limestone-based FGD processes. Compared to calcium sulfite hemihydrate, gypsum has much superior dewatering and physical properties, and forced oxidized FGD systems tend to have few internal scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many FGD systems in the United States are using the forced-oxidation process to produce a commercial grade of gypsum that can be used in the production of portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

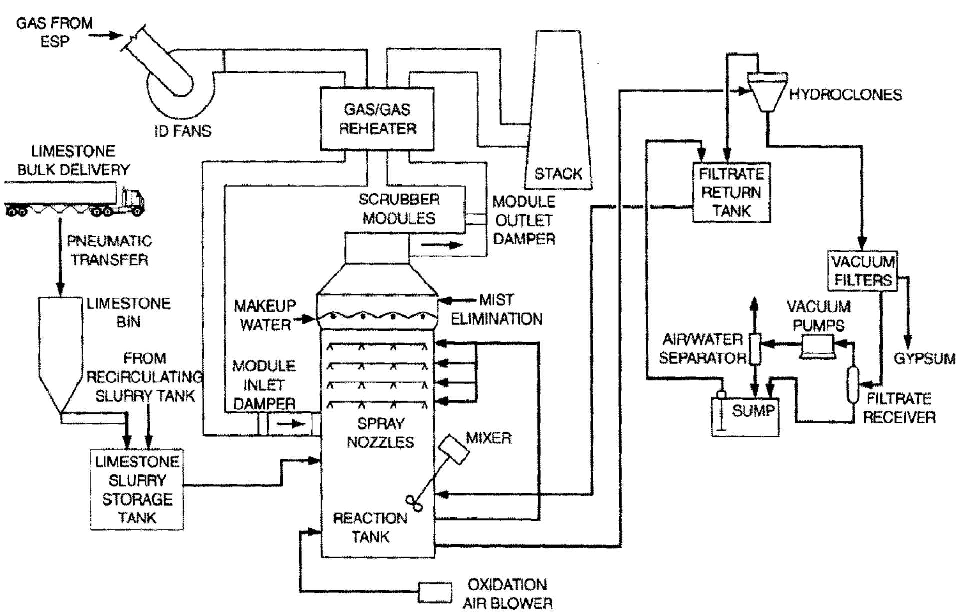


Figure 5-2. Process Flow Diagram of FGD Process

The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinyl ester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The byproduct dewatering equipment is also relatively complex and expensive. These factors result in relatively higher initial capital costs. WFGD processes are also characterized by higher raw water usage than semi-dry FGD systems. This can be a significant disadvantage or even a fatal flaw in areas where raw water availability is in short supply.

A countercurrent spray tower has become one of the most widely used absorber types in wet limestone-based FGD service (Figure 5-3). Flue gas enters at the bottom of the absorber and flows upward. Slurry with 10 to 15 percent solids is sprayed downward from higher elevations in the absorber and is collected in a reaction tank at its base. The SO_2 in the flue gas is transferred from the flue gas to the recycle slurry. The hot flue gas is also cooled and saturated with water. Recycled slurry is pumped continuously from the reaction tank to the slurry spray headers. Each header has numerous individual spray nozzles that break the slurry flow into small droplets and distribute them evenly across the cross section of the absorber. Prior to leaving the absorber, the treated flue gas passes through a two-stage, chevron-type mist eliminator that removes entrained slurry droplets from the gas. The mist eliminator is periodically washed to keep it free of solids.

In the reaction tank, the SO_2 absorbed from the flue gas reacts with soluble calcium ions in the recycle slurry to form insoluble calcium sulfite and calcium sulfate solids. In forced-oxidization processes, air is bubbled through the slurry to convert all of the solids to calcium sulfate dihydrate (gypsum). A lime or limestone reagent slurry is added to the reaction tank to replace the calcium consumed.

To control the solids content of the recycle slurry, a portion of the slurry is discharged from the reaction tank to the byproduct dewatering equipment. Depending on the ultimate disposal of the byproduct solids, the dewatering equipment may include settling ponds, thickeners, hydrocyclones, vacuum filters, and centrifuges. The liquid that is separated from the byproduct solids slurry is stored in the reclaim water tank. Water in the reclaim water tank is returned to the absorber reaction tank as makeup water and used to prepare the reagent slurry.

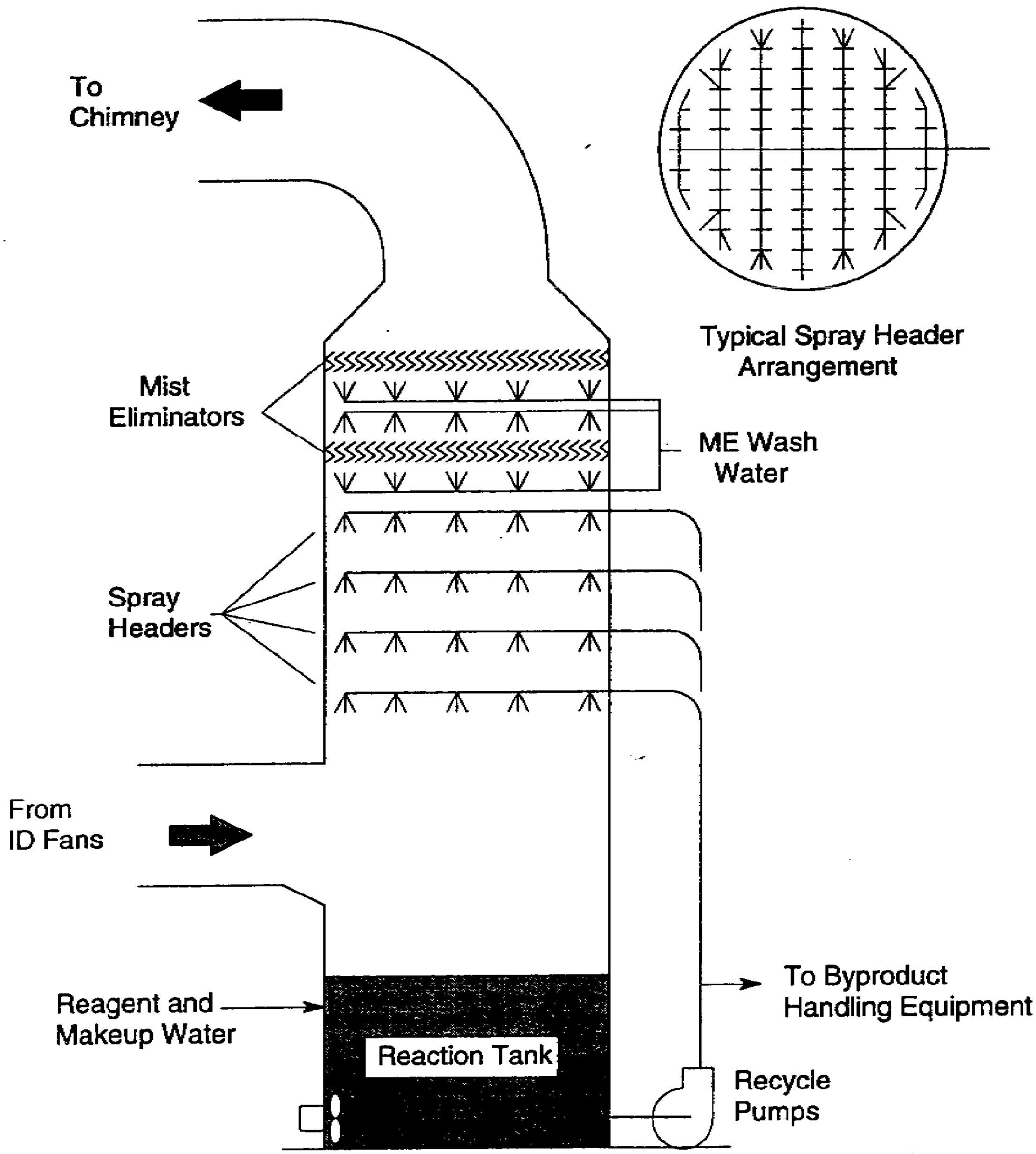


Figure 5-3. Countercurrent Spray Tower FGD Process

5.1.3 Dry Electrostatic Precipitator

Electrostatic precipitators (ESPs) are the most widely installed utility PM removal technology. ESPs use transformer/rectifiers (TRs) to energize “discharge electrodes” and to produce a high voltage, direct current electrical field between the discharge electrodes and the grounded collecting plates. PM entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. This migration can be expressed in engineering terms as an empirically determined effective migration velocity, but takes place in a turbulent flow regime with the particulate entrained within the turbulent gas patterns. Thus, the charged particles are actually captured when the combined effect of electrical attraction and gas flow patterns moves the PM close enough for it to attach to the collecting surfaces. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically impacting or “rapping” the plates. The collected particulate matter drops into hoppers below the precipitator and is removed by the ash handling system. Some particulate is also re-entrained and either collected in subsequent electrical fields or emitted from the ESP. A graphic showing the sections of an ESP is shown on Figure 5-4.

The required particulate removal efficiency, the expected electrical resistivity of the fly ash to be collected, and the expected electrical characteristics of the energization system determine the physical size of an ESP. Many parameters determine the ESP’s capability for particulate collection including the following major items:

- The first parameter is the Specific Collection Area (SCA). ESP size is often measured in terms of SCA. SCA is defined as the total collecting area in square feet (ft^2) divided by the volumetric flue gas flow rate (1,000’s of actual cubic feet per minute [acfm]).
- The treatment time of the flue gas within the electric collection fields of the ESP is an important aspect of particulate collection. High efficiency ESPs typically have treatment times between 7 and 20 seconds. Treatment time is becoming a major design parameter as lower particulate emissions are being mandated.
- Flue gas velocity, which is the speed at which the flue gas moves through the ESP, is important in the design and sizing of an ESP. Design gas velocities that range between 3 to 4 fps are common. The aspect ratio of the treatment length to the collection plate height is also important in the design and sizing of the ESP. As the aspect ratio increases, the re-entrainment losses from the ESP are minimized. Many existing ESPs have aspect ratios of approximately 0.8 to 1.2; newer ESPs, especially those meeting new particulate emission limits, have aspect ratios of approximately 1.2 to 2.0.

- The gas distribution for optimum particulate removal requires a uniform gas velocity throughout the entire ESP treatment volume, with minimal gas bypass around the discharge electrodes or collecting plates. If flue gas distribution is uneven, the particulate removal efficiency will decrease, and re-entrainment losses will increase in high velocity areas and reduce overall collection efficiency.
- Fly ash resistivity is a measure of how easily the ash or particulate acquires an electric charge. Typical coal fly ash resistivity values range from 1 x 10^8 ohm-cm to 1 x 10^{14} ohm-cm. The ideal resistivity range for electrostatic precipitation of fly ash is 5 x 10^9 to 5 x 10^{10} ohm-cm. Operating resistivity varies with flue gas moisture, SO_3 concentration, temperature, and ash chemical composition. As a result of fly ash resistivity being sensitive to these constituents, ESPs can be affected greatly by changes in fuel or operating conditions.

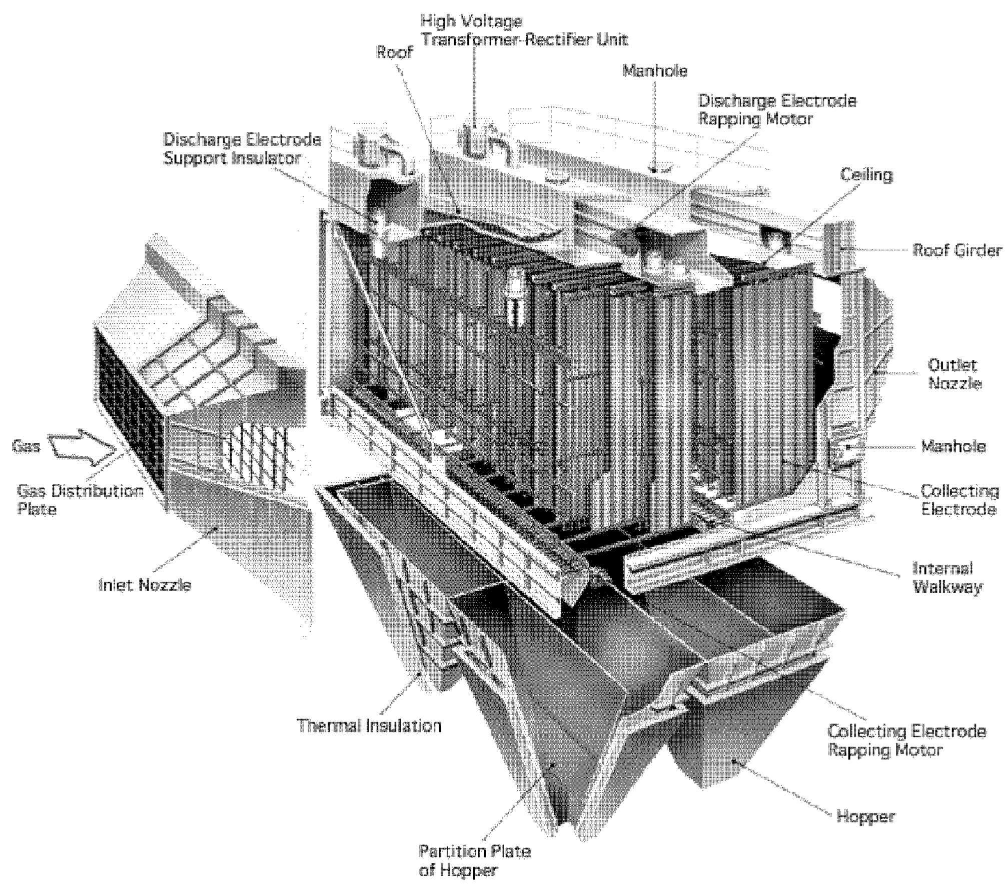


Figure 5-4. Electrostatic Precipitator System (MHI)

5.1.4 Pulse Jet Fabric Filter

Pulse jet fabric filters (PJFFs) have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the PJFF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the PJFF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementations. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each PJFF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure 5-5.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

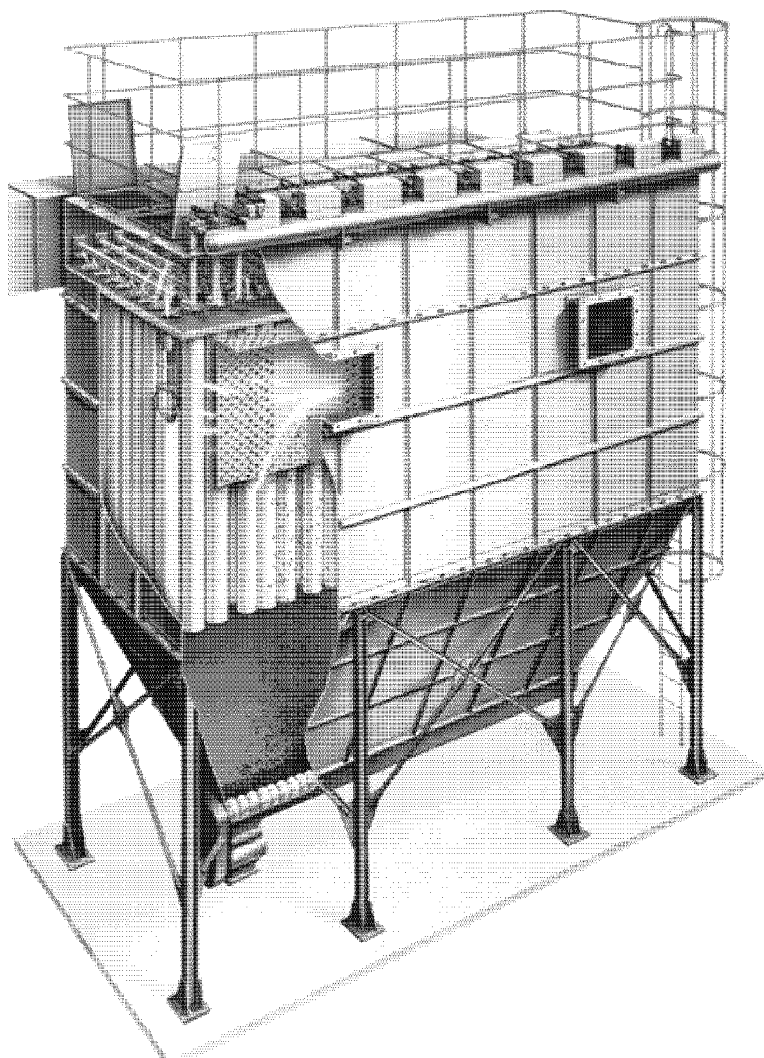


Figure 5-5. Pulse Jet Fabric Filter Compartment

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

5.1.5 Powdered Activated Carbon Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of Energy (DOE), EPA, Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure 5-6. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

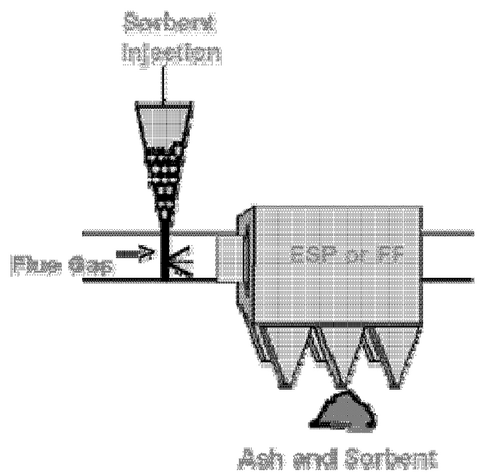


Figure 5-6. Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of an ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a CS-ESP can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of CS-ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a CS-ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC: (approximately $5.00/lb of iodine, $1.00/lb of bromine, and $0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

5.1.6 Sorbent Injection

Injection of finely divided alkalis into the flue gas has been demonstrated for the removal of SO_3 from flue gases. Most commercial experience is from units firing high sulfur oil where trace metals, mainly vanadium, increase SO_2 oxidation. Magnesium-based compounds have been used successfully for decades to capture SO_3 in oil fired units. As coal fired units burning high sulfur bituminous coals have been retrofitted with SCR systems, interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Sorbents such as SBS, trona, and hydrated lime have recently been used on large coal fired units, with reported results showing the achievement of high control efficiencies of SO_3 in high sulfur applications.

5.1.7 CO Reduction Technologies

Control of CO is divided into two basic categories, good combustion controls and neural networks.

5.1.7.1 Good Combustion Controls. As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits. Good combustion controls are an option to aid in reduction of CO but are assumed to currently be optimized. No further study of this option was considered in this report.

5.1.7.2 Neural Networks. Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions

of NO_x, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation.

At this point, there are no proven and feasible post combustion AQC technologies for the control of CO emissions from coal-fired boilers of this size. DCS based computer furnace combustion monitoring systems, such as neural networks, may help reduce CO emissions by improving plant heat rate and optimizing the various combustion parameters responsible for the formation of CO. Improvising the coal mills and coal feed injection/air management and or burner modifications including the detuning of any existing NO_x combustion controls devices will help reduce the CO in combustion or pre-combustion stage. There are no arrangement fatal flaws or constraints associated with the installation of a NN at Mill Creek, although it cannot be validated at this point whether or not a NN can achieve the required CO target emission rate.

5.1.8 Novel Innovative Desulfurization

The Novel Innovative Desulfurization (NID) technology was developed by Alstom in late 1980's and had numerous pilot plant demonstrations in US and Sweden. The first commercial installation of the NID technology was completed in 1996 at Elektrownia Power's Laziska Power Plant in Poland on 2 x 125 MW PC boilers. The first commercial installation of the NID technology in the US was completed in 2004 at Reliant Energy's Seward Station Units 1 & 2 on 2 x 285 MW CFB units. In the United States, the NID technology has been installed and operated at:

- Reliant Energy – Seward Station Units 1 & 2 (2 x 285 MW CFB units commercial operation – 2004).
- Eastern Kentucky Power Cooperative – Gilbert Unit 3 (300 MW CFB unit commercial operation – 2004).
- Eastern Kentucky Power Cooperative – Spurlock Unit 4 (300 MW CFB unit commercial operation – 2008).

It is important to note that all of the US installations have been completed on CFB type boilers where the NID system is only used as a polishing type scrubber where the initial SO_2 removal occurs in the CFB. Some of the current ongoing NID installations occurring in the US include PC boilers where the NID system will be the only SO_2 control. The ongoing NID installations are at:

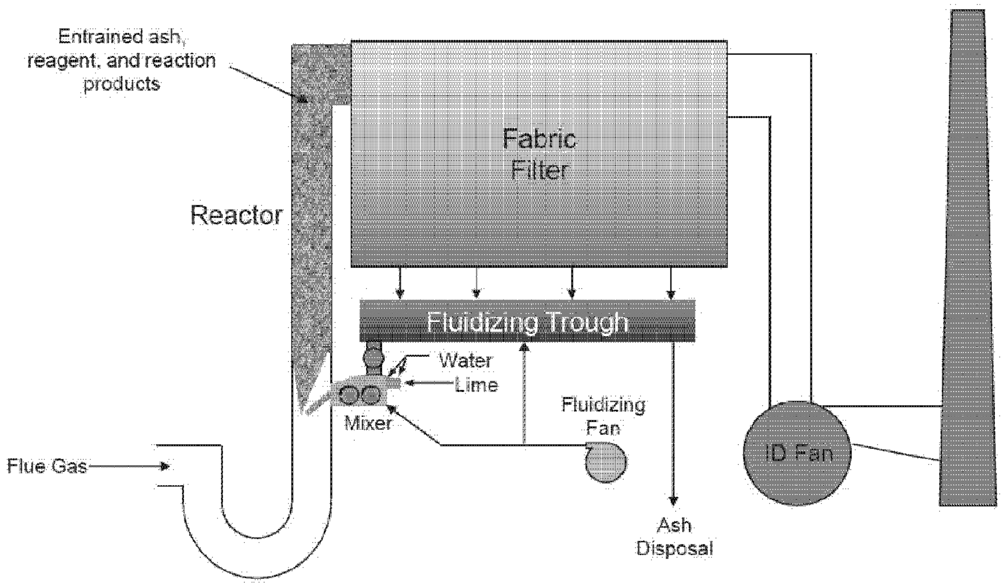
- Dominion/Kiewit – Brayton Point Unit 3 (630 MW PC units – potential start-up – February 2014).
- NRG – Indian River Unit 4 (440 MW PC units – potential start-up – Spring 2011).

In the NID system, the flue gas enters through a J-shaped reactor duct, as shown on Figure 5-7. An individual reactor duct can handle 50 to 90 MW of flue gas. Depending on the size of the boiler unit, there are multiple reactor ducts in the NID system. Each reactor duct is integrated with the compartment of PJFF. Conceptual proposal data received from Alstom indicates that a NID system for Boswell 4 would use a 10 reactor duct-PJFF compartment assembly. PM and SO_2 emission limits can be achieved with at least one reactor-PJFF compartment out of service. The ten-train system, with each train consisting of a NID reactor and a PJFF compartment, is required because of the size limitations of this technology.

Fresh lime and recirculating fly ash collected on the fluidized trough from a PJFF compartment is fed to corresponding mixer/hydrator dedicated to that compartment. The fresh lime is hydrated with water and mixed with the recirculating solids and water in a mixer-hydrator assembly. Figure 5-8 represents the mixer-hydrator assembly provided by Alstom. The mixed lime and recirculation solids are then fed from the mixer/hydrator into the NID reactor by gravity.

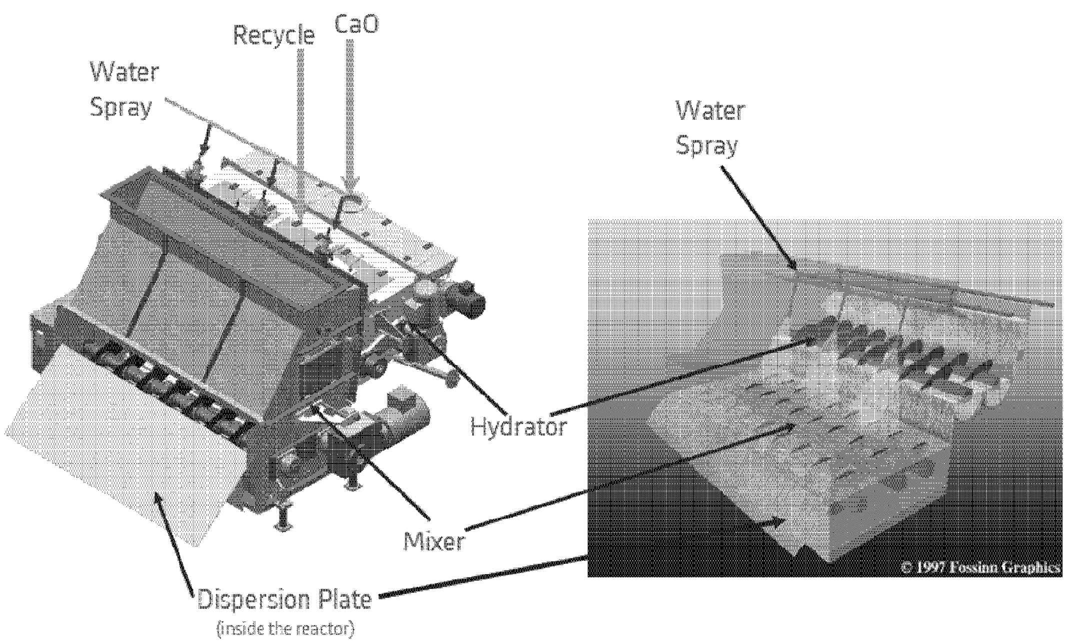
The amount of water added in the mixer-hydrator assembly depends on the temperature difference between the inlet and outlet flue gas (measured at NID inlet ductwork and outlet ductwork). The amount of SO_2 removal can be increased by adding additional fresh lime and by maintaining lower outlet flue gas temperature or high relative humidity.

The hot inlet flue gas is mixed with the moist mixture of fresh lime and recirculating ash and co-currently moves up the reactor duct. In this process, the flue gas is cooled and humidified while the mixture of fresh lime and recirculating solids is dried. The material is sufficiently dry before entering the PJFF. Majority of the acid gases and SO_2 up to 80 percent is removed in the reactor duct. The captured solids held on the bags in the respective PJFF compartment provide additional SO_2 capture.



(Courtesy: Alstom Power)

Figure 5-7. NID System



(Courtesy: Alstom Power)

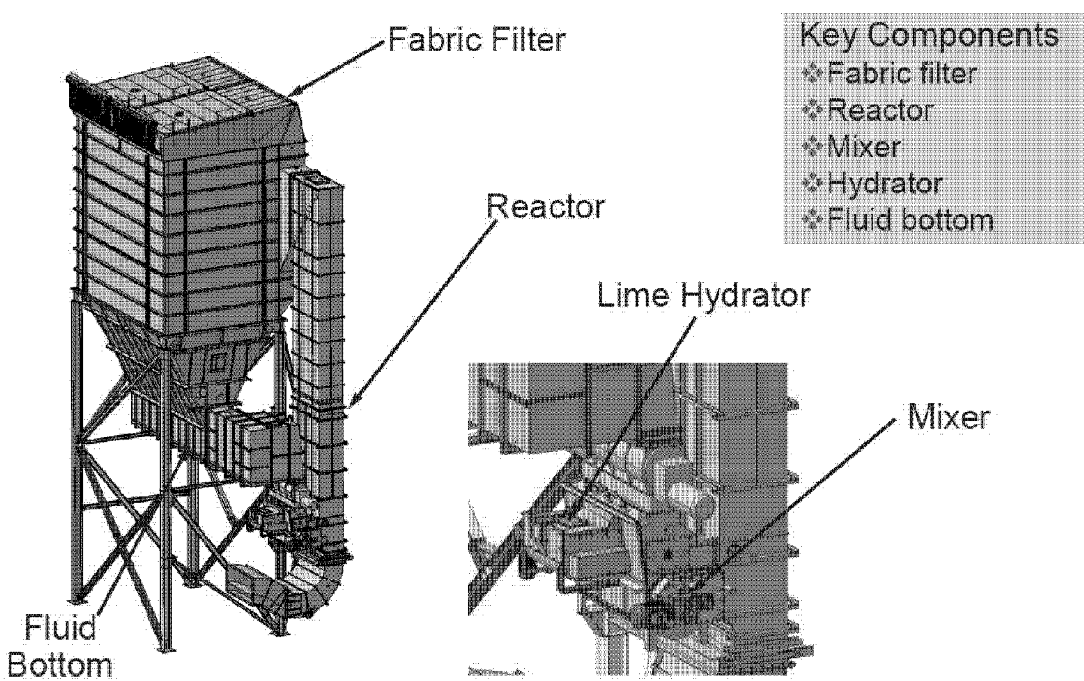
Figure 5-8. Mixer-Hydrator Assembly

Ash and byproduct solids removed form the compartment is collected in the fluidizing trough which is supplied with fluidizing air to prevent solids settlement and allow gravity flow to the mixer.

The NID system has the following major components:

- J-shaped reactor duct with inlet damper, venture, and outlet transition.
- Common lime silo with pneumatic conveyors.
- Lime day-bin for reactor pair with respective feeder.
- Hydrator and mixer assembly for each reactor.
- Fluidizing trough for each PJFF compartment.
- PJFF with outlet damper from each compartment.
- Inlet and outlet plenum with transition sections.
- Bypass provisions from inlet plenum to outlet plenum.

Figure 5-9 represents the various components of the NID system.



(Courtesy: Alstom Power)

Figure 5-9. NID Key Components

B&V has past experience with industrial units where NID system has been installed. Following is the summary of operational issues that B&V would anticipate for a NID system as identified by Alstom, other written sources and B&V's own experience:

- NID requires higher maintenance due to potential plugging of the mixer or water nozzles of the hydrator-mixer assembly. The wet/dry interfaces along with the chemical reaction that take place in the mixer when water is directly mixed with lime and recirculating ash in the mixer can lead to plugging in the mixer. On the similar application that B&V worked with, the frequency of cleaning the hydrator-mixer assembly led to the bolts on the mixer access panel being stripped within 6 months.
- The water nozzles on all the hydrator-mixer assembly require cleaning once a day. Alstom reports that 1 nozzle/mixer/day is required to be cleaned. The nozzles have quick disconnects and only weigh around 2 pounds, so operators can accomplish the cleaning manually by hand with no special equipment necessary. The daily cleaning cycle will require implementation of a specific routine and recording process so that the operator will know which nozzles require cleaning.
- The NID is provided with just one spare reactor module. Multiple failures which includes but is not limited to plugging of more than one reactor module or mixer could lead to load limiting of the unit.
- The low approach temperature may lead to cold spot and corrosion and would need to be investigated during detailed evaluation.
- During start-up of the NID system on one of the industrial units in France, reports indicate that the sealing of the fluidizing trough was not properly completed, which resulted in a rupture of the binding on the overlapping cloth.

The NID system does present some concern with regard to the specific application and the available experience with the mixer/hydration units. The NID systems currently installed in the U.S. operate on circulating fluid bed boilers, a boiler type where the large majority of the SO_2 is removed in the boiler. None of the current US NID applications have the hydration system included with the solids/water mixer, as would be required for Mill Creek units. These mixers are the area of most concern with this technology due to the number of mixers required and potential operability of these mixers for which additional information is unavailable. The mixer/hydration unit seems to be the weakest point of this technology, since it is really the only moving part and is not in wide use. Being unable to confirm the operability of these systems does present a significant uncertainty.

5.2 Unit by Unit Summary of AQC Selection

The following AQC control technologies comprise the selected technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the selected technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the AQC Technology Screening Workshop conducted on August 5-6, 2010, as well as information provided by LG&E/KU.

5.2.1 Mill Creek Units 1 and 2

Table 5-2 identifies the selected AQC technologies for Units 1 and 2. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-2. Units 1 and 2 – AQC Selection

AQC Equipment	Pollutant
New SCR	NO_x
Upgrade Existing WFGD	SO_2, HCl
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF (option)	PM
New Trona/Lime/SBS Injection (option)	SO_3
New NID System which includes a PJFF (option)	SO_3, HCl, PM
New CS-ESP for fly ash sales	Fly ash

New SCR

- SCR can consistently achieve NO_x emissions of lower than 0.11 lb/MBtu on a continuous basis. Therefore, SCR is the most feasible and expandable control technology considered for NO_x reduction including future NO_x reduction requirements.
- The SCR will increase pressure drop of the system, so the draft system needs to be investigated and new ID fans will be required. Additional auxiliary power requirement will need to be considered for new ID fans.

- Ammonia consumption increases with the addition of SCR. Detailed investigation or study will be required to confirm if a new ammonia storage facility is required or if the existing ammonia storage facility can be upgraded for accommodating Units 1 and 2 ammonia supply.
- Require SO_3 mitigation system like alkali injection and PJFF or dry scrubbing technology like NID.
- Existing air heater will be retained. Air heater basket modifications for acid resistance may be necessary after the installation of SCR.
- A new SCR can be located downstream of the existing economizer and upstream of the existing air heater for Units 1 and 2. Existing CS-ESP for each unit will be demolished and SCR will be installed in same physical location as existing CS-ESP of respective units.
- The SCR will be constructed after installing and operating the new CS-ESP of respective units (where a new CS-ESP is possible).

Upgrading Existing WFGD System

- Upgrade the existing WFGD system to consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis when burning high sulfur content coals. Upgrading the existing WFGD with additional spray levels and/or flue gas contact rings/trays and flue gas flow modifications is the most feasible control technology considered for SO_2 reduction.
- Upgrading the existing WFGD system can consistently achieve HCl emissions of less than 0.002 lb/MBtu on a continuous basis.
- Existing wet stack will be re-used.
- Impact on existing wastewater treatment system will be checked and verified.
- The amount of limestone required and byproduct produced may by increased by approximately 5 percent.
- Existing scrubber refurbishment can be accomplished ahead of time during regular plant maintenance outages.

New PAC Injection

- A PJFF or NID is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the air heater but upstream of new PJFF or NID.
- PAC Injection can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant.

New PJFF (Option)

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has the capability to expand in order to meet PM emissions lower than 0.03 lb/MBtu. Hence, a PJFF is the most feasible and expandable control technology considered for PM reduction, including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- The PJFF will increase pressure drop of the system. As such, the draft system needs to be investigated and new ID fans will be required. Additional auxiliary power requirement will need to be considered for new ID fans
- A new ash handling system will be required to collect ash from PJFF hoppers.
- Additional maintenance will be required for replacing bags and cages.
- For Units 1 and 2, the PJFF can be located downstream of the existing air heater and upstream of the new ID fans and can possibly be installed at three different locations as suggested in the high level layout drawings as shown in Appendix A.
- **Arrangement A**--The PJFF for Unit 1 on this option will be located on the south side of the existing chimney of Units 1 and 2 and west side of the Unit 1 scrubber module. The PJFF will be elevated above the existing electrical equipment building, new ash handling equipment and existing

Unit RATS. This arrangement cuts off access for materials and construction for the new Unit 1 SCR. It also cuts off access for a crane to maintain the new Unit 1 SCR. The CS-ESP for Unit 1 cannot be constructed with this arrangement thereby increasing the ash land-filling capacity requirements of the plant. The PJFF for Unit 2 on this option will be located on the North side of Unit 2 in the area of the existing auxiliary boiler building for Units 1 & 2, which will be demolished. The PJFF will be elevated and installed over the new Unit 2 CS-ESP. The existing over-head Unit 1 and Unit 2 transmission lines will be relocated to eliminate interference. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

- **Arrangement B**--The PJFF for Unit 1 on this option will be located between Unit 1 and Unit 2 scrubber modules. The PJFF will be elevated above the existing SDRS service building. However, the space between the two scrubber modules is very tight and there will be significant construction constraints to install the PJFF at this location. The CS-ESP for Unit 1 cannot be constructed with this arrangement thereby increasing the ash land-filling liability of the plant. The PJFF for Unit 2 on this option will be located on the north side of Unit 2 scrubber modules. The PJFF in this location need not be elevated. The existing over-head transmission lines will be relocated. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.
- **Arrangement C**--The PJFF for Unit 1 on this option will be located on the north side of the existing Unit 2 scrubber. The PJFF will be elevated and installed over the new Unit 1 CS-ESP, allowing collection of Unit 1 fly ash for possible beneficial re-use, reducing landfill requirements. The biggest drawback with this arrangement is the long and complicated runs of ductwork which have the potential to overload the duct and structure with ash. The PJFF for Unit 2 on this option will be located on the north side of Unit 2 adjacent to and west of the Unit 1 PJFF. The existing auxiliary boiler building for Units 1 & 2 will be demolished to make room. The PJFF will be elevated and installed over the new Unit 2 CS-ESP. The existing over-head transmission lines will be relocated. Above and under ground utilities will be investigated, evaluated, and, if necessary, relocated.

New SO_3 Control System (Reagent Injection) (Option)

A reagent injection system that injects Trona, Lime or SBS into the flue gas to remove SO_3 would be necessary if a NID system is not included.

- A PJFF is recommended in conjunction with a reagent injection system.
- Trona/Lime would be injected downstream of the air heater but upstream of new PJFF. SBS would be injected upstream of the air heater.
- Reagent injection can reduce the sulfuric acid emissions on a continuous basis and mitigate the visible blue plume formation from the chimney which is often associated when burning high sulfur coal.
- The use of sorbent system will slightly increase the truck traffic at the plant.

New NID (Option)

- The NID, which includes a PJFF, offers more direct benefits or co-benefits as follows:
  - Mercury removal using some form of injection upstream.
  - Sulfuric acid emissions reduction and visible blue plume elimination.
  - HCl emissions reduction of less than 0.002 lb/MBtu on a continuous basis.
  - PM emissions reduction of less than 0.03 lb/MBtu on a continuous basis.
  - Reduce wastewater stream generated by WFGD using NID.
- The NID will increase pressure drop of the system, so the draft system needs to be investigated and new ID or booster fans may be required. Additional auxiliary power requirement will need to be considered for new ID/booster fans.
- A new ash handling system will be required to collect ash from the associated PJFF hoppers of the NID.
- Additional maintenance will be required for replacing bags and cages.
- Additional reagent (lime) handling system will be required. This will include lime storage silo, lime day bins and associated equipment.
- There will be additional water requirements for cooling the flue gas to 90° F above saturation point.
- Additional maintenance will be required every day to clean water nozzle in the mixer-hydrator assembly of each NID reactor.
- The use of lime reagent will slightly increase the truck traffic of the plant.

- For Units 1 & 2, the NID can be located downstream of the existing air heater and upstream of the new ID fans analogous to the three different alternate locations proposed for the PJFF, as suggested in the conceptual sketches as shown in Appendix A.
- **Arrangement A**--The NID for Unit 1 on this option will be located on the south side of the existing chimney of Units 1 and 2 and the Unit 1 scrubber module. The NID will be elevated similar to the arrangement described for the PJFF arrangement previously described. All concerns noted regarding the PJFF installation in this area are also applicable to installation of a NID in this location.
- **Arrangement B**--The NID for Unit 1 on this option will be located on the between Unit 1 and Unit 2 scrubber modules. The NID will be elevated above the existing SDRS service building similar to the arrangement described for the PJFF arrangement previously described. All concerns noted regarding the PJFF installation in this area are also applicable to installation of a NID in this location.
- **Arrangement C**--The NID for Unit 1 on this option will be located on the north side of the existing Unit 2 scrubber. The NID will be elevated and installed over the new Unit 1 CS-ESP. All concerns noted regarding the PJFF installation in this area are also applicable to installation of a NID in this location.

New CS-ESP

- Where it can be installed, a new CS-ESP will be used as a pre-filter to remove 80 to 85 percent fly ash that can be sold to the cement plant to lower the ash land filling liability.
- A new ash handling system will be required to collect ash from CS-ESP hoppers.
- Due to lack of available space, a new CS-ESP for Unit 1 can only be accommodated in the Arrangement C layout as described above, while a new CS-ESP for Unit 2 can be installed in Arrangements A, B, or C. The CS-ESP will be located downstream of the existing air heater and upstream of the new PJFF or NID at each unit.

5.2.2 Mill Creek Units 3 and 4

Table 5-3 identifies the selected AQC technologies for Units 3 and 4. The key attributes of the technologies and special considerations for their application and arrangements are presented in a bulleted format for each technology.

Table 5-3. Units 3 and 4 – AQC Technology Selection

AQC Equipment	Pollutant
Upgrade Unit 4 existing WFGD System and reuse it for Unit 3. New state-of-art WFGD system for Unit 4.	SO_2, HCl
New PAC Injection	Hg, Dioxin/Furan
New stand-alone full size PJFF (option)	PM
New Trona/Lime/SBS Injection (option)	SO_3
New NID System which includes a PJFF (option)	SO_3, HCl, PM

Upgrade Unit 4 Existing WFGD and Reuse as Unit 3 WFGD, Including Wet Stack

- Upgrading Unit 4 existing WFGD system to reuse for Unit 3 can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis when burning high sulfur content coals. The existing Unit 4 WFGD system is bigger in size and currently performs better than Unit 3 WFGD system. Therefore, upgrading the existing Unit 4 WFGD with additional spray levels and/or flue gas contact rings/trays and flue gas flow modifications is the most feasible control technology considered for SO_2 reduction.
- Upgrading the Unit 4 existing WFGD system for Unit 3 can consistently achieve HCl emissions of less than 0.002 lb/MBtu on a continuous basis.
- Existing Unit 4 wet stack will be re-used and Unit 3 current wet stack will be abandoned in place.
- Existing Unit 3 WFGD modules will be demolished to make room for Unit 3 NID/PJFF system.
- The amount of limestone required and byproduct produced may by increased by approximately 5 percent.
- Existing scrubber refurbishment can be accomplished ahead of time during regular plant maintenance outages.
- Existing Unit 4 WFGD will be tied-in to Unit 3 after installation of new AQC train for Unit 4.

New WFGD System for Unit 4

- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu when burning high sulfur content coals. WFGD is the most feasible and expandable control technology considered for SO_2 reduction, including future requirements.
- WFGD can consistently achieve HCl emissions of less than 0.002 lb/MBtu on a continuous basis.
- Existing Unit 4 WFGD modules will be reused by Unit 3.
- Existing wet stack will be re-used by Unit 3.
- New wet stack will be required for Unit 4.
- The amount of limestone required and byproduct produced may by increased by approximately 5 percent.
- A new absorber slurry holding tank will be required.
- A new additional ball-mill may be required for limestone requirements.
- The WFGD will increase pressure drop of the system, so the draft system needs to be investigated and new ID or booster fans may be required. Additional auxiliary power requirement will need to be considered for new ID/booster fans.
- A new WFGD system can be located downstream of the new booster fans and upstream of the new chimney. The WFGD can possibly be installed at two alternate locations as suggested in the conceptual sketches as shown in Appendix A.
- **Arrangement A**--The WFGD absorber will be installed south of the reagent preparation building and northeast side of the cooling tower. The abandoned Unit 4 thickener will be demolished and new WFGD absorber module for Unit 4 will be installed in that area. The ammonia storage area and overhead transmission lines will be relocated. The ductwork serving the WFGD absorber in this arrangements must accommodate the existing limestone conveyor and pipe rack in the area. This location is in close proximity with the cooling tower which may cause icing concerns on the AQC equipment. Above and below ground utilities will be investigated, evaluated, and, if necessary, relocated.

- **Arrangement B**--The WFGD absorber will be installed on the west side of the reagent preparation building and south side of Unit 4 boiler. The existing annex building, lab building and old auxiliary boiler building for Unit 4 will be demolished or relocated and new WFGD absorber module for Unit 4 will be installed in that location. Above and below ground utilities will be investigated, evaluated, and, if necessary, relocated.

New PAC Injection

- A PJFF or NID is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the existing CS-ESP but upstream of existing ID fans.
- PAC injection can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.
- Dioxin and Furan removal will be a co-benefit with targeted Hg emissions removal, and additional PAC consumption beyond Hg removal will be required.
- The use of PAC system will slightly increase the truck traffic at the plant.

New PJFF (Option)

- A PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- PJFF offers more direct benefits or co-benefits of removing future multi-pollutants like mercury and sulfuric acid using some form of injection upstream.
- A new PJFF can be located downstream of the existing ID fans and upstream of the new booster fans.
- The PJFF will increase pressure drop of the system, so the draft system needs to be investigated and new ID or booster fans may be required. Additional auxiliary power requirement will need to be considered for new ID/booster fans.
- A new ash handling system will be required to collect ash from PJFF hoppers.

- Additional maintenance will be required for replacing bags and cages.
- Existing WFGD modules of Unit 3 will be demolished and PJFF for Unit 3 will be installed in that location.
- For Unit 4, the PJFF can possibly be installed at two alternate locations as suggested in the high level layout drawings as shown in Appendix A.
- **Arrangement A**--The PJFF for this option will be located on the south side of the existing reagent preparation building in the area of the abandoned Unit 4 thickener, which will be demolished. Concerns noted regarding the ammonia storage area, overhead transmission lines, limestone conveyor, and pipe racks in the discussion for the WFGD Arrangement A also apply to this arrangement for the PJFF.
- **Arrangement B**--The PJFF for this option will be located south side of the existing Unit 4 ESP and west of the existing reagent preparation building. The PJFF will be installed over the existing switchgear building for Unit 4 (which will be modified as required to allow it to serve Unit 3.

New SO_3 Control System (Reagent Injection) (Option)

A reagent injection system that injects Trona, Lime or SBS into the flue gas to remove SO_3 would be necessary if a NID system is not included.

- A PJFF is recommended in conjunction with new reagent injection system.
- Trona/Lime/SBS to be injected downstream of the ID fans but upstream of new PJFF.
- Reagent injection can reduce the sulfuric acid emissions on a continuous basis and mitigate the visible blue plume formation from the chimney which is often associated when burning high sulfur coal.
- The use of sorbent will slightly increase the truck traffic at the plant.

New NID (Option)

- The NID, which includes a PJFF, offers more direct benefits or co-benefits as follows:
  - Mercury removal using some form of injection upstream.
  - Sulfuric acid emissions reduction and visible blue plume elimination.
  - HCl emissions reduction of less than 0.002 lb/MBtu on a continuous basis.

  - PM emissions reduction of less than 0.03 lb/MBtu on a continuous basis.
  - Reduce wastewater stream generated by WFGD using NID.
- The NID will increase pressure drop of the system, so the draft system needs to be investigated and new ID or booster fans may be required. Additional auxiliary power requirement will need to be considered for new ID/booster fans.
- A new ash handling system will be required to collect ash from the associated PJFF hoppers of the NID.
- Additional maintenance will be required for replacing bags and cages.
- Additional reagent (lime) handling system will be required. This will include lime storage silo, lime day bins and associated equipment.
- There will be additional water requirements for cooling the flue gas to 90° F above saturation point.
- Additional maintenance will be required every day to clean water nozzle in the mixer-hydrator assembly of each NID reactor.
- The use of lime reagent will slightly increase the truck traffic at the plant.
- Existing WFGD modules of Unit 3 will be demolished and NID for Unit 3 will be installed in that location.
- For Unit 4, a new NID with new PJFF can be located downstream of the existing ID fans and upstream of the new booster fans. The NID can possibly be installed at two alternate locations as suggested in the high level layout drawings as shown in Appendix A.
- **Arrangement A**--The NID for this option will be located on the south side of the existing reagent preparation building, analogous to the location of the PJFF in Arrangement A described above. Concerns described for the PJFF in Arrangement A also apply to the PJFF in this location.
- **Arrangement B**--The NID for this option will be located south of the existing Unit 4 ESP and west of the existing reagent preparation building, analogous to the location of the PJFF in Arrangement B described above. Concerns described for the PJFF in Arrangement B also apply to the PJFF in this location.

6.0 Validation Analyses

The following sections describe the analyses of various balance of plant systems necessary to validate the selected AQC equipment.

6.1 Draft System Analysis

A preliminary analysis of the flue gas draft systems and fans was completed to determine if modifications or replacements of the existing draft fans will be required. This is due to the installation of additional draft system equipment to control certain flue gas emissions. For Unit 1 the modifications and additions to the draft system being considered include a new SCR system, new PJFF or NID system, and the refurbishment and upgrading of the existing WFGD system. In addition, the Unit 1 ESP is expected to be demolished to make room for the new SCR system. The Unit 1 ESP may or may not be replaced depending on the final arrangement chosen. For the purpose of this analysis, it was assumed the existing Unit 1 ESP will not be replaced. Unit 2 would be similar to Unit 1 except that a new ESP would replace the demolished ESP at a different site location to retain ash for salability. Added to Unit 3 would be a new PJFF or NID system and new ductwork to utilize the Unit 4 WFGD system. The Unit 3 WFGD system would be abandoned. Unit 4 would have a new PJFF or NID system and a new WFGD system. In all cases for this analysis, it was assumed the NID system will be installed. This will be confirmed and revised if necessary during conceptual design based on the arrangement selected. For more detail on the AQC equipment modifications, additions, etc. for each Mill Creek unit refer to Section 5.0.

For the sizing of any new fans for the Mill Creek site, the standard Black & Veatch fan sizing philosophy for developing Test Block conditions as additional margin on MCR conditions is recommended. This philosophy includes the application of the following items to the required MCR conditions for new or modified fans:

- 10 percent margin on flue gas flow exiting the boiler.
- 50 percent margin on leakages throughout the draft system.
- 50 percent margin on air heater differential pressure.
- 25° F temperature increase at the fan inlet.
- Adjustments of draft system pressure drops to correspond with increased Test Block flow rates.
- 1.0 inch of water (inw) control allowance.

The application of these items typically results in flow margins in the range of 20 to 30 percent and pressure margins in the range of 35 to 45 percent.

Additionally, following the preliminary analyses of the Mill Creek draft systems, there is also a discussion on draft system transient design pressure requirements per NFPA 85.

6.1.1 Unit 1

Both an SCR system and a NID system are expected to be installed on Unit 1 as shown in Figure 6-1. Due to this additional equipment, the overall draft fan and drive system horsepower demand at MCR is expected to be higher than the combined 5,500 horsepower that each of the existing ID and booster fan combinations can deliver. This includes the consideration of removing and not replacing the ESP. In addition, since the existing ESP is expected to be demolished, the ID fans will likely move to a different location allowing them to be downstream of the NID system. The continued use of the existing ID and booster fans, if upgraded, downstream of the NID system would require additional ductwork on an already space limited portion of the Mill Creek site. With the likely relocation of the ID fans and increase in overall draft fan horsepower, or capacity, it is expected that the existing Unit 1 ID and booster fans will be replaced with a single set of new ID fans.

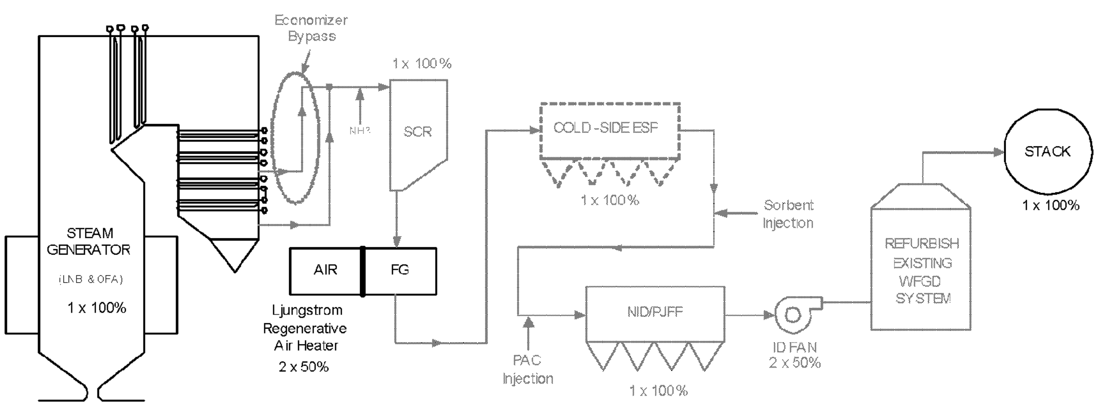


Figure 6-1. Unit 1 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 1 future draft system at MCR are as follows in Table 6-1. Note that the items in bold in Table 6-1 are components in the draft system that are new or have been modified for the AQC upgrade.

Table 6-1. Unit 1 Future Draft System Characteristics at MCR

SCR system leakage	**2%**
Air heater leakage	10% (estimated)
ESP leakage	**(demolished)**
NID system leakage	**3%**
Flue gas temperatures	
Boiler outlet	760° F
SCR outlet	**760° F**
Air heater outlet	375° F
ESP outlet	**(demolished)**
NID outlet	**213° F**
New ID fan outlet	**236° F**
Booster fan outlet	**(not replaced)**
WFGD outlet	~132° F
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.5 inw
SCR	**10.0 inw**
Air heater	5.0 inw
ESP	**(demolished)**
NID	**14.0 inw**
NID outlet to ID fan inlet	**(included in NID)**
WFGD	**12.0 inw (refurbished & upgraded)**
Stack	1.0 inw

Based on the layout of the future draft system in Figure 6-1 and the future draft system characteristics in Table 6-1, the estimated performance requirements of the new ID fans at MCR are shown in Table 6-2. Also in Table 6-2 are the recommended Test Block conditions developed using the recommended Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 26 and 39 percent, respectively.

Table 6-2. Unit 1 New ID Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	------	900
Inlet Temperature (°F)	213	238
Inlet Density (lb/ft^3)	0.0530	0.0494
Flow per Fan (acfm) *	576,000	728,000
Inlet Pressure (inwg)	-34.0	-46.4
Outlet Pressure (inwg)	13.0	19.1
Static Pressure Rise (inw)	47.0	65.5
Shaft Power Required (HP) **	5,100	8,800
Efficiency (percent) **	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	26
Pressure Margin (percent)	---------	39

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.

6.1.2 Unit 2

Both an SCR system and a NID system are expected to be installed on Unit 2 as shown in Figure 6-2. Due to this additional equipment, the overall draft fan and drive system horsepower demand at MCR is expected to be higher than the combined 5,500 horsepower that each of the existing ID and booster fan combinations can deliver. In addition, since the existing ESP is expected to be relocated, the ID fans will likely be relocated as well allowing them to be downstream of the NID system. The continued use of the existing ID and booster fans, if upgraded, downstream of the NID system would require additional ductwork on an already space limited portion of the Mill Creek site . With the likely relocation of the ID fans and increase in overall draft fan horsepower, or capacity, it is expected that the existing Unit 2 ID and booster fans will be replaced with a single set of new ID fans.

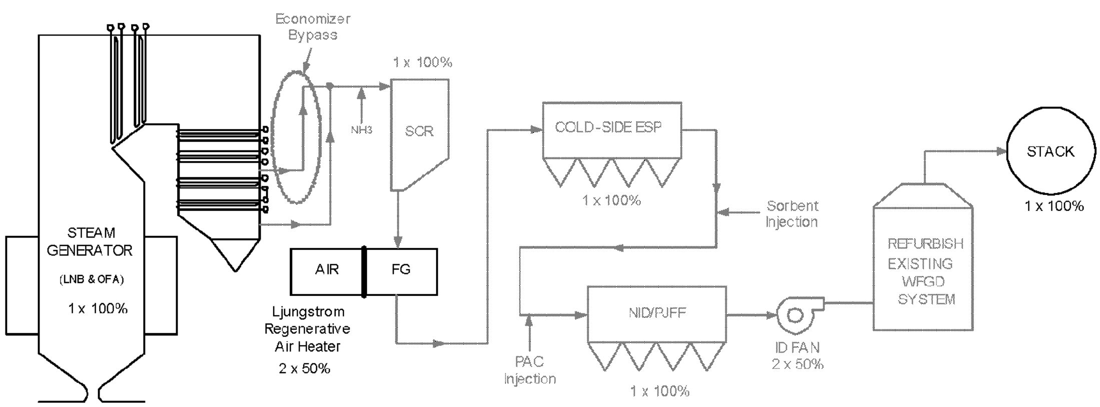


Figure 6-2. Unit 2 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 2 future draft system at MCR are as follows in Table 6-3. Note that the items in bold in Table 6-3 are components in the draft system that are new or have been modified for the AQC upgrade.

Table 6-3. Unit 2 Future Draft System Characteristics at MCR

SCR system leakage	**2%**
Air heater leakage	10% (estimated)
New ESP leakage	**3%**
NID system leakage	**3%**
Flue gas temperatures	
Boiler outlet	760° F
SCR outlet	**760° F**
Air heater outlet	375° F
ESP outlet	375° F
NID outlet	**212° F**
New ID fan outlet	**238° F**
Booster fan outlet	**(not replaced)**
WFGD outlet	~130° F
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.5 inw
SCR	**10.0 inw**
Air heater	5.0 inw
New ESP	**5.0 inw**
NID	**14.0 inw**
NID outlet to ID fan inlet	**(included in NID)**
WFGD	**12.0 inw (refurbished & upgraded)**
Stack	1.0 inw

Based on the layout of the future draft system in Figure 6-2 and the future draft system characteristics in Table 6-3, the estimated performance requirements of the new ID fans at MCR are shown in Table 6-4. Also in Table 6-4 are the recommended Test Block conditions developed using the recommended Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 29 and 40 percent, respectively.

Table 6-4. Unit 2 New ID Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	212	237
Inlet Density (lb/ft^3)	0.0523	0.0485
Flow per Fan (acfm) *	616,000	794,000
Inlet Pressure (inwg)	-39.0	-53.2
Outlet Pressure (inwg)	13.0	19.5
Static Pressure Rise (inw)	52.0	72.7
Shaft Power Required (HP) **	6,000	10,700
Efficiency (percent)**	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	29
Pressure Margin (percent)	---------	40

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.

6.1.3 Unit 3

A NID system and the use of the Unit 4 WFGD system are expected to be the new AQC additions for Unit 3 as shown in Figure 6-3. To compensate for the additional draft loss of the NID system and the additional ductwork and upgrades for the Unit 4 WFGD, Black & Veatch's initial approach is to install a set of new booster fans. Booster fans would allow the NID system with its integral PJFF to be under negative draft pressures without constructing additional ductwork to reuse the existing ID fans. The installation of PJFFs in draft system sections under positive pressures is not recommended. However, further analyses will be performed during conceptual design to determine the possibility and practicality of reusing the existing ID fans.

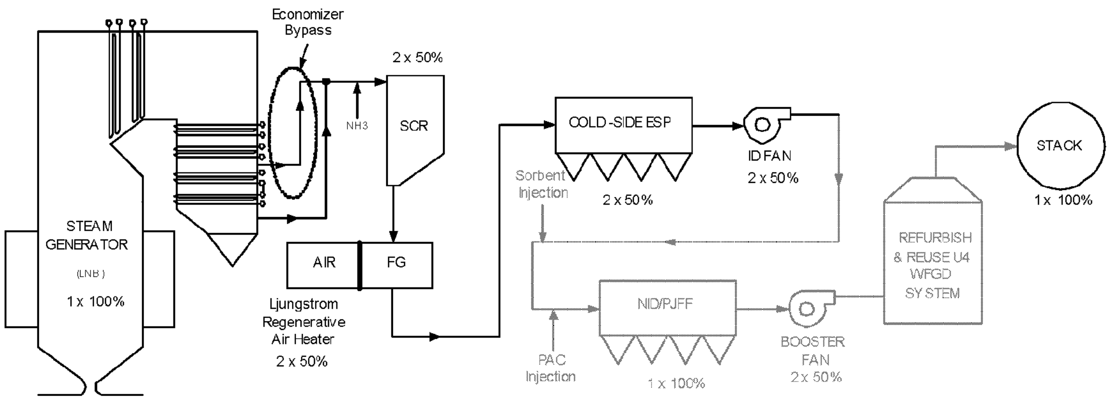


Figure 6-3. Unit 3 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 3 future draft system at MCR are as follows in Table 6-5. Note that the items in bold in Table 6-5 are components in the draft system that are new or have been modified for the AQC upgrade.

Table 6-5. Unit 3 Future Draft System Characteristics at MCR

SCR system leakage	2% (estimated)
Air heater leakage	10% (estimated)
ESP leakage	5% (estimated)
NID system leakage	**3%**
Flue gas temperatures	
Boiler outlet	690° F
SCR outlet	690° F
Air heater outlet	330° F
ESP outlet	330° F
ID fan outlet	343° F (calculated)
NID outlet	**212° F (calculated)**
New booster fan outlet	**223° F (calculated)**
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.5 inw
SCR	8.0 inw
Air heater	5.0 inw
ESP	5.0 inw
NID	**14.0 inw**
Unit 4 WFGD	**12.0 inw (refurbished & upgraded)**
Unit 4 Stack	**1.0 inw**

Based on the layout of the future draft system in Figure 6-3 and the future draft system characteristics in Table 6-5, the estimated performance requirements of the new booster fans at MCR are shown in Table 6-6. Also in Table 6-6 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 27 and 43 percent, respectively.

Table 6-6. Unit 3 New Booster Fan
MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	212	237
Inlet Density (lb/ft^3)	0.0562	0.0535
Flow per Fan (acfm) *	744,000	941,000
Inlet Pressure (inwg)	-14.0	-18.9
Outlet Pressure (inwg)	13.0	19.9
Static Pressure Rise (inw)	27.0	38.7
Shaft Power Required (HP) **	3,800	6,800
Efficiency (percent)**	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	27
Pressure Margin (percent)	---------	43

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.

6.1.4 Unit 4

A NID system and a new WFGD system are expected to be the new AQC additions for Unit 4 as shown in Figure 6-4. To compensate for the additional draft loss of the NID system and new WFGD, Black & Veatch's initial approach is to install a set of new booster fans. Booster fans would allow the NID system with its integral PJFF to be under negative draft pressures without constructing additional ductwork to reuse the existing ID fans. The installation of PJFFs in draft system sections under positive pressures is not recommended. However, further analyses will be performed during conceptual design to determine the possibility and practicality of reusing the existing ID fans.

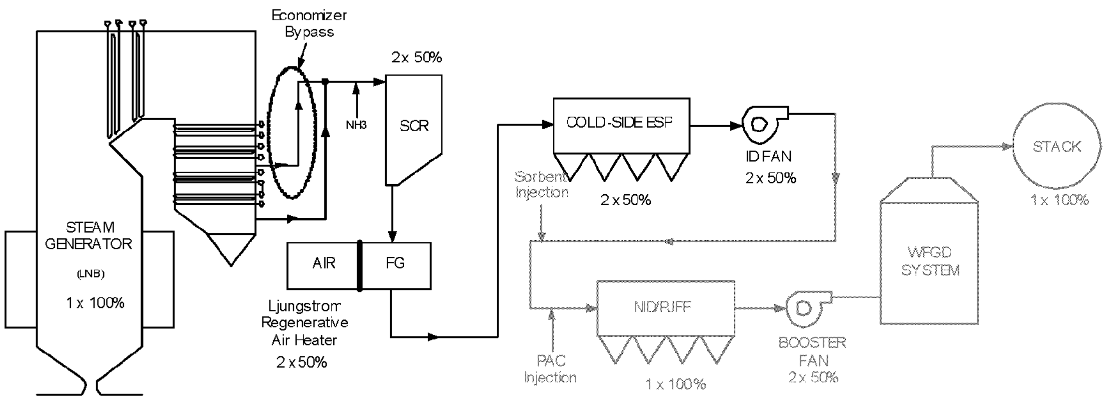


Figure 6-4. Unit 4 Future Draft System

Future Draft System Characteristics

The major performance characteristics of the Unit 4 future draft system at MCR are as follows in Table 6-7. Note that the items in bold in Table 6-7 are components in the draft system that are new or have been modified for the AQC upgrade.

Table 6-7. Unit 4 Future Draft System Characteristics at MCR

SCR system leakage	2% (estimated)
Air heater leakage	10% (estimated)
ESP leakage	5% (estimated)
NID system leakage	**3%**
Flue gas temperatures	
Boiler outlet	640° F
SCR outlet	640° F
Air heater outlet	330° F
ESP outlet	330° F
ID fan outlet	343° F (calculated)
NID outlet	**212° F (calculated)**
New booster fan outlet	**223° F (calculated)**
WFGD outlet	~130° F (calculated)
Furnace pressure	-0.5 inwg
Draft system differential pressures	
Boiler	4.5 inw
SCR	8.0 inw
Air heater	5.0 inw
ESP	5.0 inw
NID	**14.0 inw**
New WFGD	**10.0 inw (refurbished & upgraded)**
New Stack	**1.0 inw**

Based on the layout of the future draft system in Figure 6-4 and the future draft system characteristics in Table 6-7, the estimated performance requirements of the new booster fans at MCR are shown in Table 6-8. Also in Table 6-8 are the recommended Test Block conditions developed using the Black & Veatch fan sizing philosophy previously outlined in this section. Note the flow and pressure margins of 27 and 43 percent, respectively.

Table 6-8. Unit 4 New Booster Fan MCR and Recommended Test Block Conditions

	MCR	Test Block
Fan Speed (rpm), maximum	900	900
Inlet Temperature (°F)	212	237
Inlet Density (lb/ft^3)	0.0562	0.0535
Flow per Fan (acfm) *	905,000	1,145,000
Inlet Pressure (inwg)	-14.0	-18.9
Outlet Pressure (inwg)	11.0	17.0
Static Pressure Rise (inw)	25.0	35.8
Shaft Power Required (HP) **	4,200	7,600
Efficiency (percent) **	85	85
Number of Fans	2	2
Flow Margin (percent)	---------	27
Pressure Margin (percent)	---------	43

*Per fan basis with both fans in operation.
**Estimated – assumes variable speed operation.