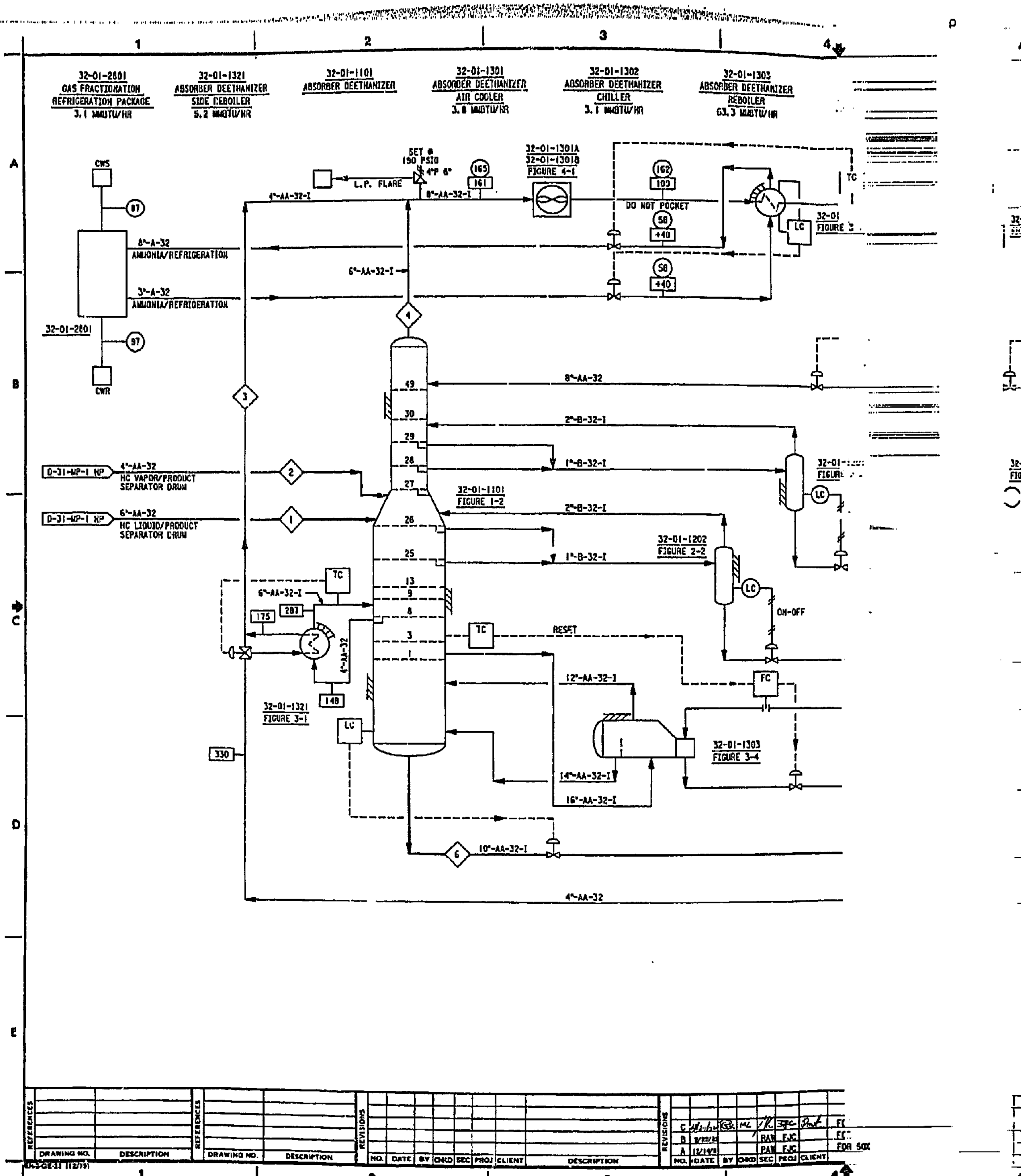
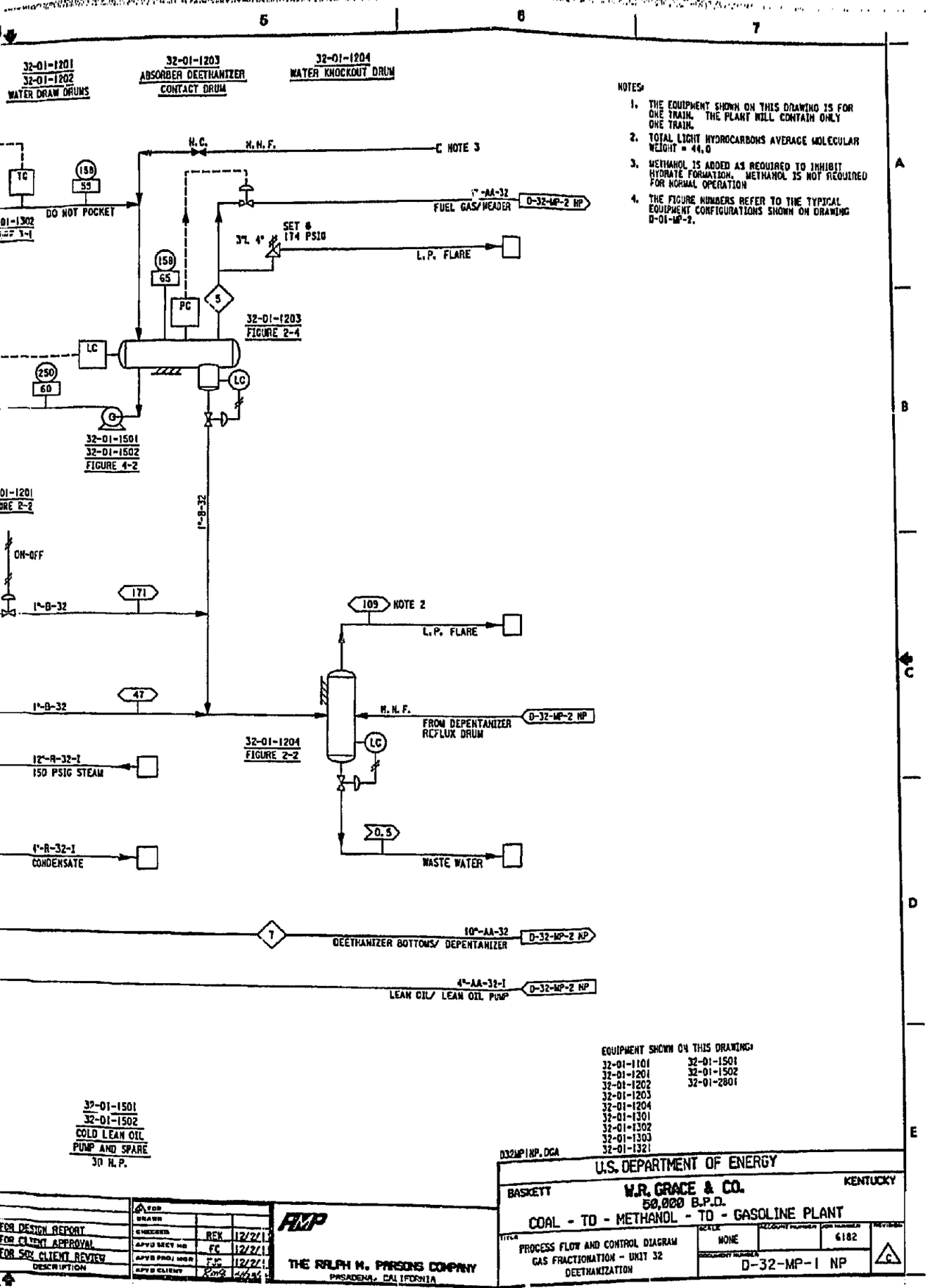
E. Process Flow and Control Diagrams (Including Material Balance)

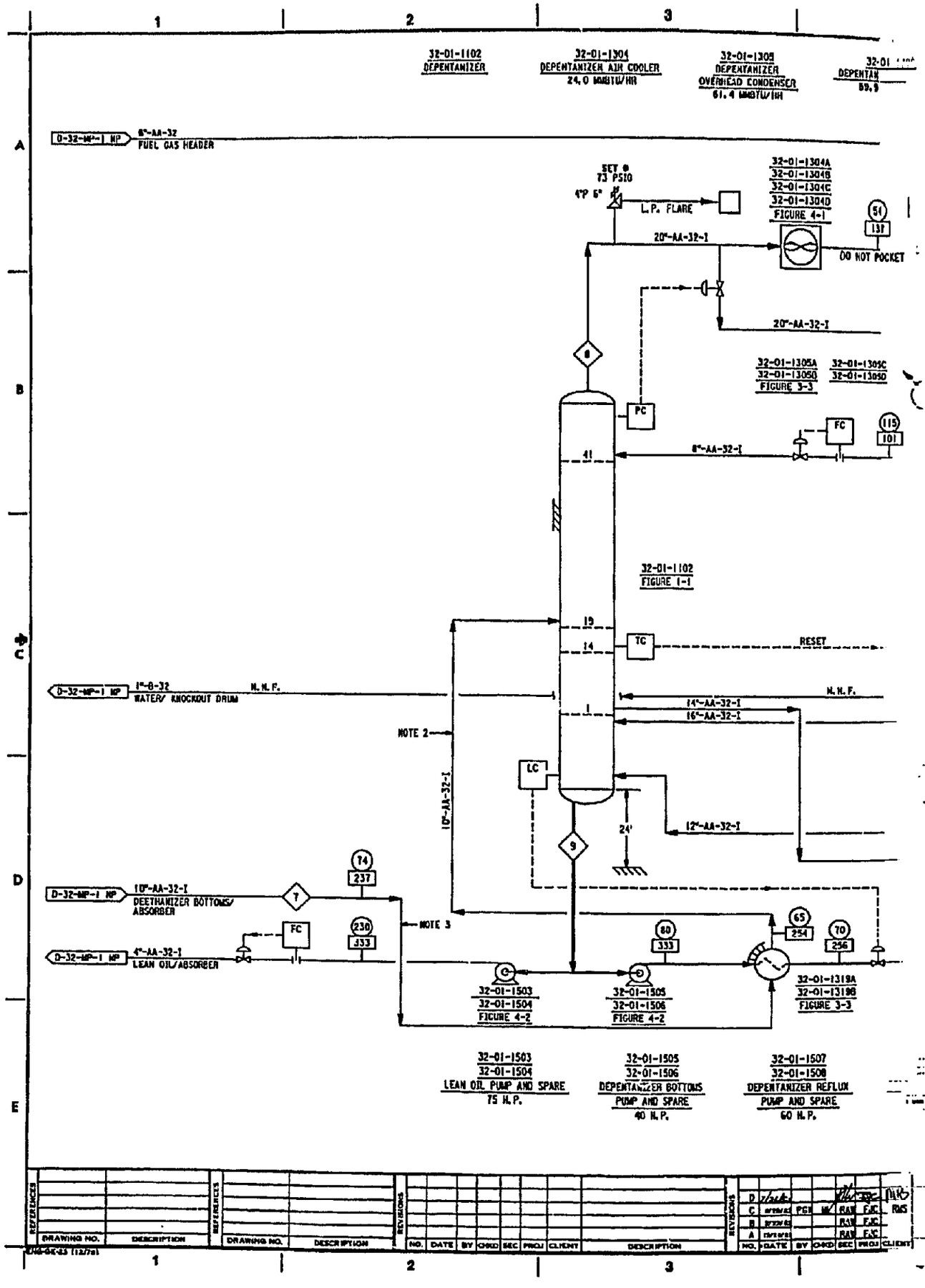
Process Flow and Control Diagrams for Gas Fractionation Unit 32 are as follows:

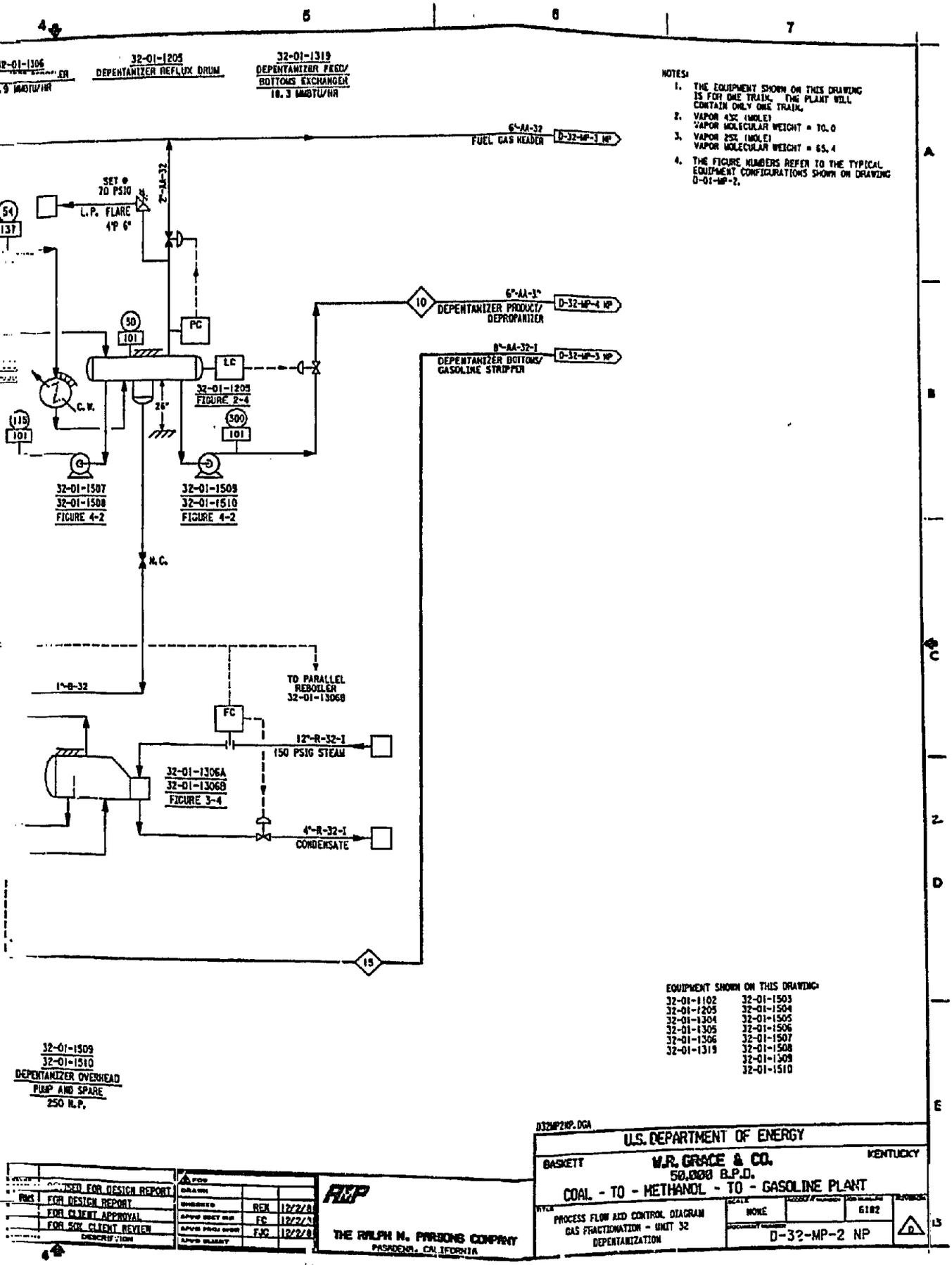
Drawing No.	Title
D-32-MP-1NP	PFCD Gas Fractionation - Depentanization
D-32-MP-2NP	PFCD Gas Fractionation - Depentanization
L-32-MP-3NP	PFCD Gas Fractionation - Gasoline Splitting
D-32-MP-4NP	PFCD Gas Fractionation - Depropanization
D-32-MP-5NP	Material Balance - Gas Fractionation



32-01-2801
GAS FRACTIONATION
REFRIGERATION PACKAGE
3.1 MMBTU/HR
32-01-1321
ABSORBER DEETHANIZER
SIDE REBOILER
5.2 MMBTU/HR
32-01-1101
ABSORBER DEETHANIZER
32-01-1301
ABSORBER DEETHANIZER
AIR COOLER
3.8 MMBTU/HR
32-01-1302
ABSORBER DEETHANIZER
CHILLER
3.1 MMBTU/HR
32-01-1303
ABSORBER DEETHANIZER
REBOILER
63.3 MMBTU/HR
CWS
CWR
8"-A-32
AMMONIA/REFRIGERATION
3"-A-32
AMMONIA/REFRIGERATION
32-01-2801
SET @
190 PSIG
4"P 6"
L.P. FLARE
4"-AA-32-I
8"-AA-32-I
32-01-1301A
32-01-1301B
FIGURE 4-1
DO NOT POCKET
6"-AA-32-I
TC
LC
8"-AA-32
2"-B-32-I
1"-B-32-I
D-31-MP-1 NP
4"-AA-32
HC VAPOR/PRODUCT
SEPARATOR DRUM
6"-AA-32
HC LIQUID/PRODUCT
SEPARATOR DRUM
32-01-1101
FIGURE 1-2
32-01-1202
FIGURE 2-2
ON-OFF
RESET
FC
12"-AA-32-I
14"-AA-32-I
16"-AA-32-I
32-01-1303
FIGURE 3-4
32-01-1321
FIGURE 3-1
10"-AA-32-I
4"-AA-32
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT


5
6
7
32-01-1201
32-01-1202
WATER DRAW DRUMS
32-01-1203
ABSORBER DEETHANIZER
CONTACT DRUM
32-01-1204
WATER KNOCKOUT DRUM
NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THE PLANT WILL CONTAIN ONLY ONE TRAIN.
2. TOTAL LIGHT HYDROCARBONS AVERAGE MOLECULAR WEIGHT = 44.0
3. METHANOL IS ADDED AS REQUIRED TO INHIBIT HYDRATE FORMATION. METHANOL IS NOT REQUIRED FOR NORMAL OPERATION
4. THE FIGURE NUMBERS REFER TO THE TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2.
N.C.
N.H.F.
NOTE 3
TC
158
55
DO NOT POCKET
1"-AA-32
FUEL GAS/HEADER
D-32-MP-2 NP
SET @ 174 PSIG
3"L 4"
L.P. FLARE
158
65
PC
5
32-01-1203
FIGURE 2-4
LC
250
60
LC
32-01-1501
32-01-1502
FIGURE 4-2
1"-B-32
ON-OFF
1"-B-32
171
109
NOTE 2
L.P. FLARE
1"-B-32
47
N.H.F.
FROM DEPENTANIZER
REFLUX DRUM
D-32-MP-2 NP
32-01-1204
FIGURE 2-2
LC
12"-R-32-I
150 PSIG STEAM
4"-R-32-I
CONDENSATE
0.5
WASTE WATER
7
10"-AA-32
DEETHANIZER BOTTOMS/ DEPENTANIZER
D-32-MP-2 NP
4"-AA-32-I
LEAN OIL/ LEAN OIL PUMP
D-32-MP-2 NP
32-01-1501
32-01-1502
COLD LEAN OIL
PUMP AND SPARE
30 H.P.
EQUIPMENT SHOWN ON THIS DRAWING:
32-01-1101
32-01-1201
32-01-1202
32-01-1203
32-01-1204
32-01-1301
32-01-1302
32-01-1303
32-01-1321
32-01-1501
32-01-1502
32-01-2801
D32MP1NP.DGA
U.S. DEPARTMENT OF ENERGY
BASKETT
W.R. GRACE & CO.
KENTUCKY
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT
PROCESS FLOW AND CONTROL DIAGRAM
GAS FRACTIONATION - UNIT 32
DEETHANIZATION
SCALE: NONE
JOB NUMBER: 6182
D-32-MP-1 NP
C
FOR DESIGN REPORT
FOR CLIENT APPROVAL
FOR 50% CLIENT REVIEW
DESCRIPTION
FOR BRAWN
CHECKED REK 12/27/1
APVD SECT MR FC 12/27/1
APVD PROJ MGR FC 12/27/1
APVD CLIENT
THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA


32-01-1102
DEPENTANIZER
32-01-1304
DEPENTANIZER AIR COOLER
24.0 MMBTU/HR
32-01-1305
DEPENTANIZER
OVERHEAD CONDENSER
61.4 MMBTU/HR
32-01
DEPENTAN
89.9
D-32-MP-1 MP
8"-AA-32
FUEL GAS HEADER
SET @
73 PSIG
4"P 6"
L.P. FLARE
32-01-1304A
32-01-1304B
32-01-1304C
32-01-1304D
FIGURE 4-1
51
137
20"-AA-32-I
DO NOT POCKET
20"-AA-32-I
32-01-1305A
32-01-1305B
32-01-1305C
32-01-1305D
FIGURE 3-3
PC
FC
115
101
8"-AA-32-I
41
32-01-1102
FIGURE 1-1
19
14
TC
RESET
D-32-MP-1 MP
1"-B-32
WATER/ KNOCKOUT DRUM
N. N. F.
N. N. F.
14"-AA-32-I
16"-AA-32-I
1
NOTE 2
10"-AA-32-I
LC
24'
12"-AA-32-I
9
74
237
D-32-MP-1 MP
10"-AA-32-I
DEETHANIZER BOTTOMS/
ABSORBER
7
FC
230
333
NOTE 3
D-32-MP-1 MP
4"-AA-32-1
LEAN OIL/ABSORBER
80
333
65
254
70
256
32-01-1503
32-01-1504
FIGURE 4-2
32-01-1505
32-01-1506
FIGURE 4-2
32-01-1319A
32-01-1319B
FIGURE 3-3
32-01-1503
32-01-1504
LEAN OIL PUMP AND SPARE
75 H.P.
32-01-1505
32-01-1506
DEPENTANIZER BOTTOMS
PUMP AND SPARE
40 H.P.
32-01-1507
32-01-1508
DEPENTANIZER REFLUX
PUMP AND SPARE
60 H.P.
A
B
C
D
E
1
2
3



NOTES:

1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THE PLANT WILL CONTAIN ONLY ONE TRAIN.
2. VAPOR 43% (MOLE)
   VAPOR MOLECULAR WEIGHT = 70.0
3. VAPOR 25% (MOLE)
   VAPOR MOLECULAR WEIGHT = 65.4
4. THE FIGURE NUMBERS REFER TO THE TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2.

EQUIPMENT SHOWN ON THIS DRAWING:

32-01-1102	32-01-1503
32-01-1205	32-01-1504
32-01-1304	32-01-1505
32-01-1305	32-01-1506
32-01-1306	32-01-1507
32-01-1319	32-01-1508
	32-01-1509
	32-01-1510

D32MP2MP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

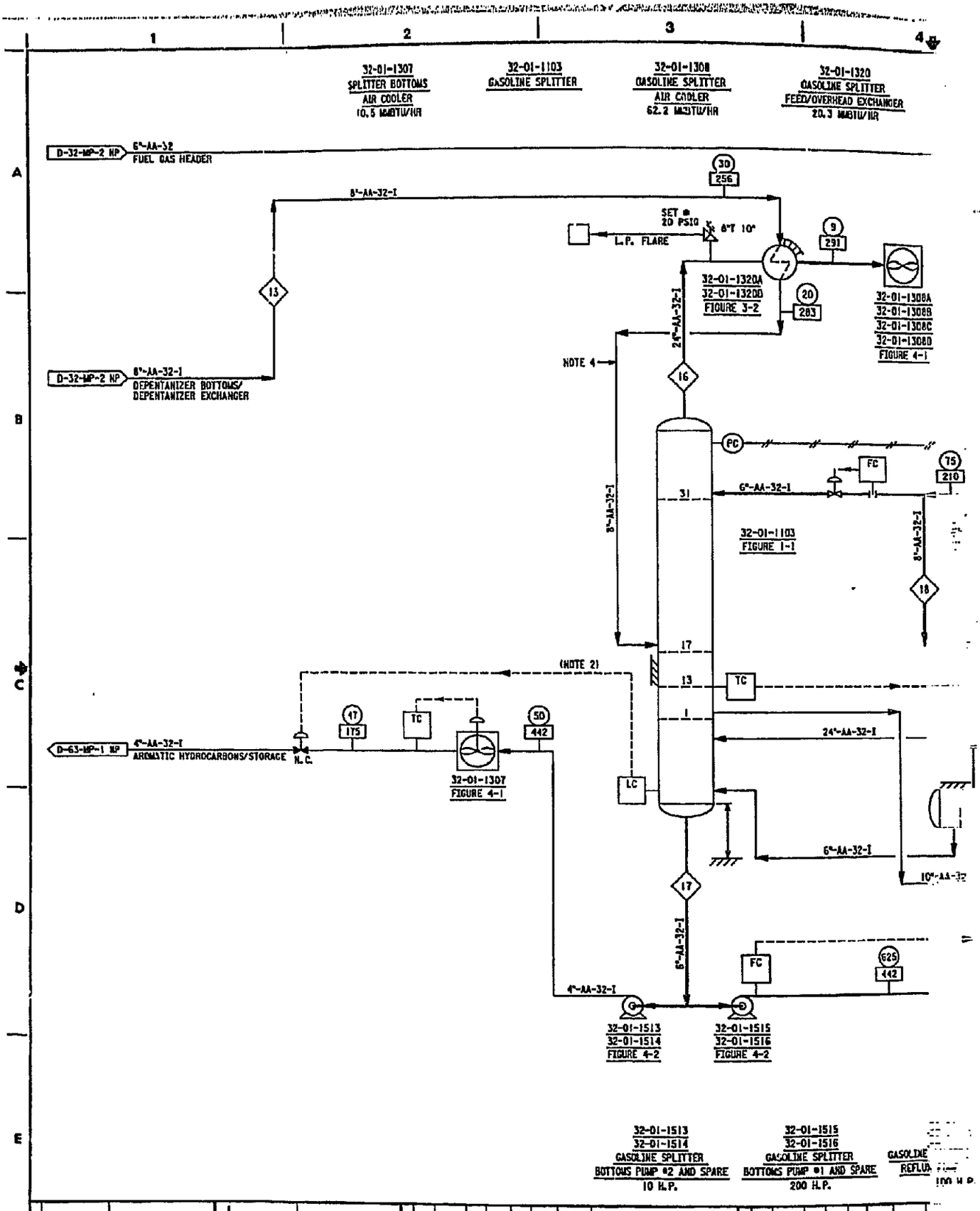
PROCESS FLOW AND CONTROL DIAGRAM
GAS FRACTIONATION - UNIT 32
DEPENTANIZATION

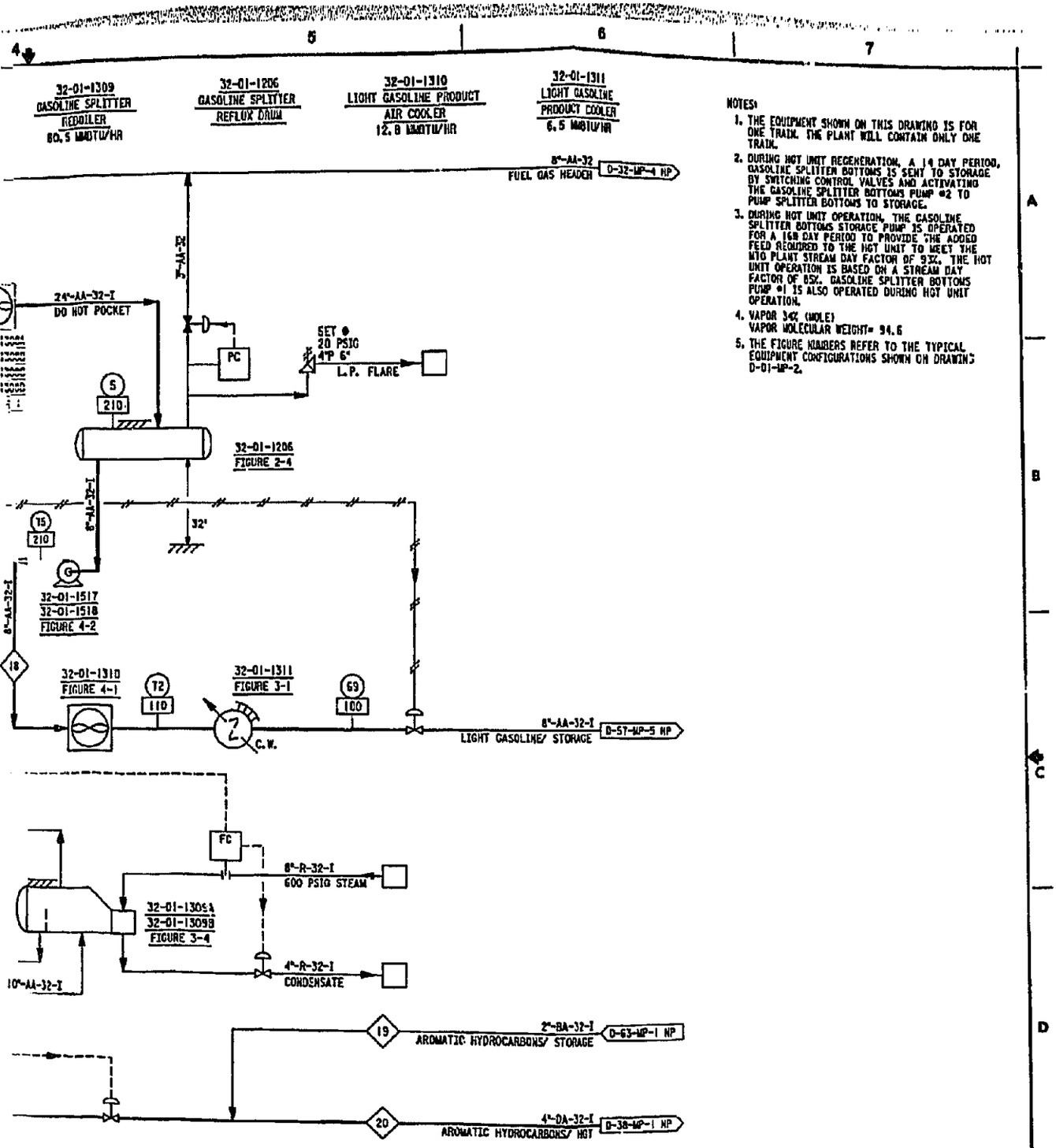
SCALE: NONE | JOB NUMBER: 6182 | DRAWING NUMBER: D-32-MP-2 NP | REVISION: D

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

PRINTS	DESCRIPTION
	REVISED FOR DESIGN REPORT
	FOR DESIGN REPORT
	FOR CLIENT APPROVAL
	FOR 50% CLIENT REVIEW

DRAWN	REK	12/2/8
CHECKED	FC	12/2/8
APVD PROJ MGR	FJC	12/2/8
APVD CLIENT		


32-01-1307
SPLITTER BOTTOMS
AIR COOLER
10.5 MMBTU/HR
32-01-1103
GASOLINE SPLITTER
32-01-1308
GASOLINE SPLITTER
AIR COOLER
62.2 MMBTU/HR
32-01-1320
GASOLINE SPLITTER
FEED/OVERHEAD EXCHANGER
20.3 MMBTU/HR
D-32-MP-2 NP
6"-AA-32
FUEL GAS HEADER
8"-AA-32-I
SET @ 20 PSIG
8"T 10"
L.P. FLARE
32-01-1320A
32-01-1320B
FIGURE 3-2
32-01-1308A
32-01-1308B
32-01-1308C
32-01-1308D
FIGURE 4-1
24"-AA-32-I
NOTE 4
D-32-MP-2 NP
8"-AA-32-I
DEPENTANIZER BOTTOMS/
DEPENTANIZER EXCHANGER
32-01-1103
FIGURE 1-1
6"-AA-32-I
(NOTE 2)
D-63-MP-1 NP
4"-AA-32-I
AROMATIC HYDROCARBONS/STORAGE
N.C.
32-01-1307
FIGURE 4-1
10"-AA-32
4"-AA-32-I
32-01-1513
32-01-1514
FIGURE 4-2
32-01-1515
32-01-1516
FIGURE 4-2
32-01-1513
32-01-1514
GASOLINE SPLITTER
BOTTOMS PUMP #2 AND SPARE
10 H.P.
32-01-1515
32-01-1516
GASOLINE SPLITTER
BOTTOMS PUMP #1 AND SPARE
200 H.P.
GASOLINE
REFLUX



NOTES:

1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THE PLANT WILL CONTAIN ONLY ONE TRAIN.
2. DURING HOT UNIT REGENERATION, A 14 DAY PERIOD, GASOLINE SPLITTER BOTTOMS IS SENT TO STORAGE BY SWITCHING CONTROL VALVES AND ACTIVATING THE GASOLINE SPLITTER BOTTOMS PUMP #2 TO PUMP SPLITTER BOTTOMS TO STORAGE.
3. DURING HOT UNIT OPERATION, THE GASOLINE SPLITTER BOTTOMS STORAGE PUMP IS OPERATED FOR A 168 DAY PERIOD TO PROVIDE THE ADDED FEED REQUIRED TO THE HOT UNIT TO MEET THE MTO PLANT STREAM DAY FACTOR OF 93%. THE HOT UNIT OPERATION IS BASED ON A STREAM DAY FACTOR OF 85%. GASOLINE SPLITTER BOTTOMS PUMP #1 IS ALSO OPERATED DURING HOT UNIT OPERATION.
4. VAPOR 34% (MOLE)
   VAPOR MOLECULAR WEIGHT= 94.6
5. THE FIGURE NUMBERS REFER TO THE TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2.

32-01-1517
32-01-1518
PRODUCT/
SPARE
100 H.P.

EQUIPMENT SHOWN ON THIS DRAWING:

32-01-1103	32-01-1513
32-01-1206	32-01-1514
32-01-1307	32-01-1515
32-01-1308	32-01-1516
32-01-1309	32-01-1517
32-01-1310	32-01-1518
32-01-1311	
32-01-1320	

DESCRIPTION			
FOR INTERNAL REPORT	DRAWN		
FOR CLIENT APPROVAL	CHECKED	REK	12/2/88
FOR 50% CLIENT REVIEW	APVD SECT MGR	FC	12/2/88
	APVD PROJ MGR	FJC	12/2/88
	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

032MP3NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

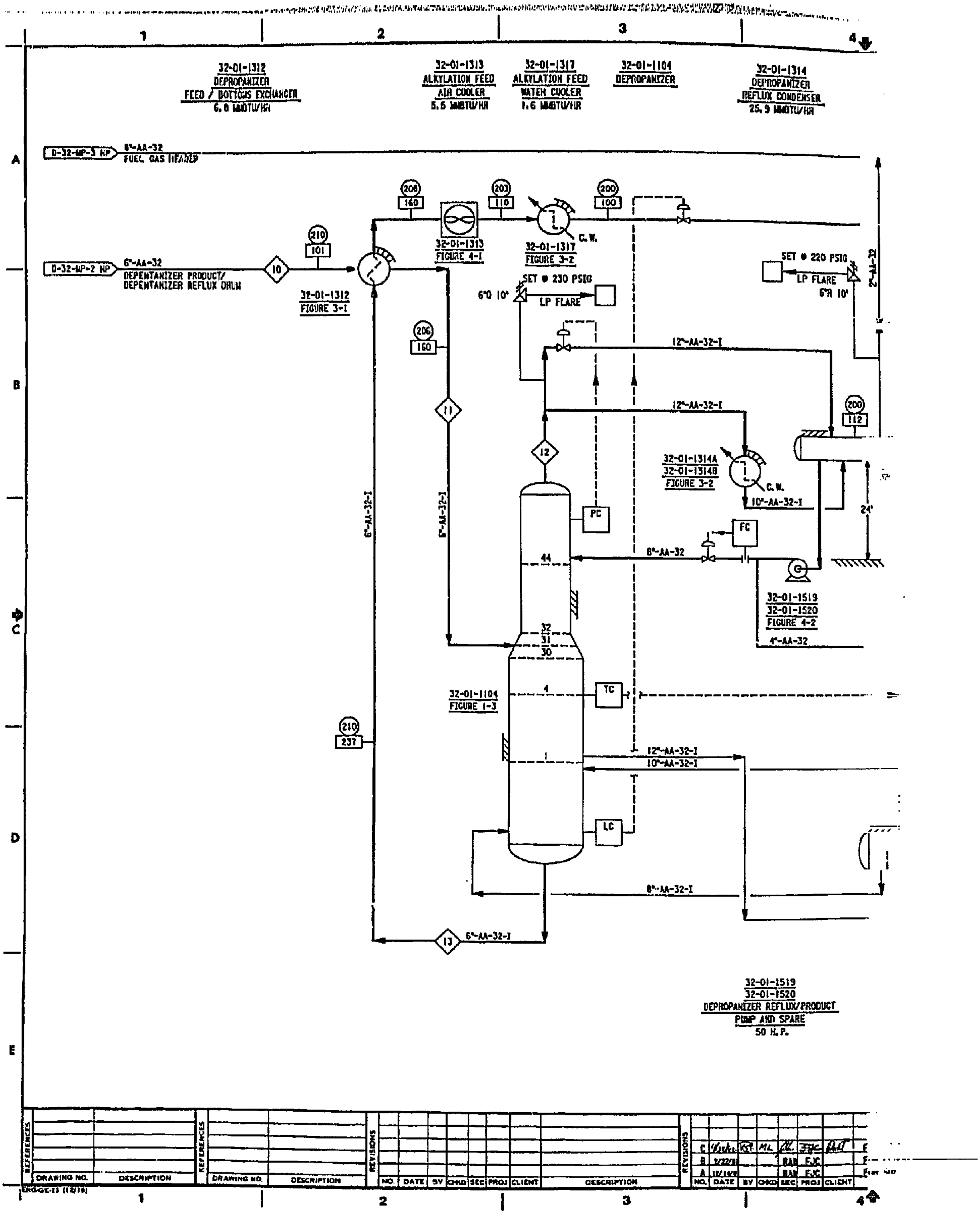
COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW AND CONTROL DIAGRAM
GAS FRACTIONATION - UNIT 32
GASOLINE SPLITTING

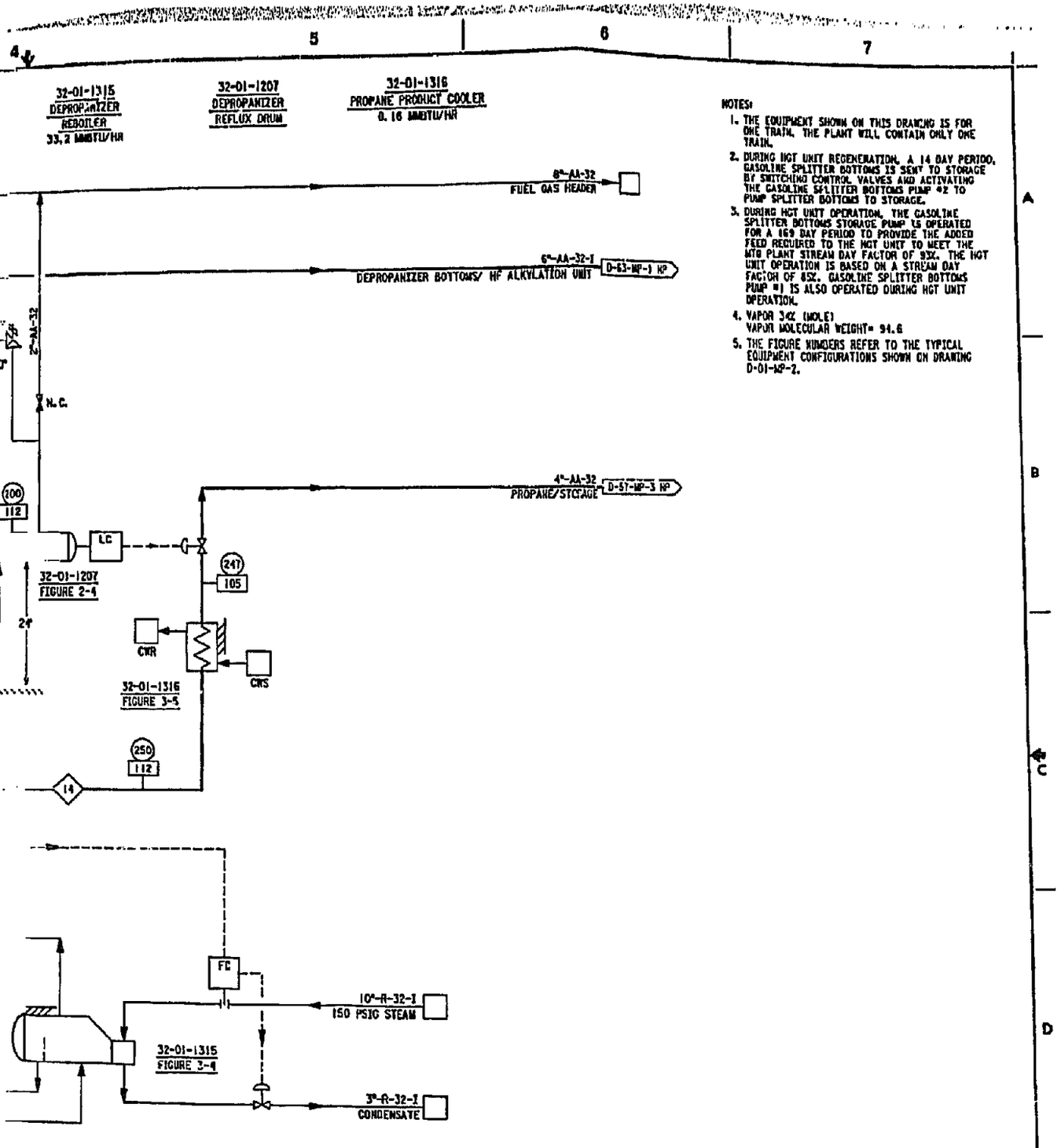
SCALE: NONE | JOB NUMBER: 6182

DOCUMENT NUMBER: D-32-MP-3 NP

REVISION: 2



32-01-1312
DEPROPANIZER
FEED / BOTTOMS EXCHANGER
6.0 MMBTU/HR
32-01-1313
ALKYLATION FEED
AIR COOLER
5.5 MMBTU/HR
32-01-1317
ALKYLATION FEED
WATER COOLER
1.6 MMBTU/HR
32-01-1104
DEPROPANIZER
32-01-1314
DEPROPANIZER
REFLUX CONDENSER
25.9 MMBTU/HR
D-32-MP-3 HP
8"-AA-32
FUEL GAS HEADER
D-32-MP-2 HP
6"-AA-32
DEPENTANIZER PRODUCT/
DEPENTANIZER REFLUX DRUM
32-01-1312
FIGURE 3-1
32-01-1313
FIGURE 4-1
32-01-1317
FIGURE 3-2
C.W.
SET @ 230 PSIG
LP FLARE
SET @ 220 PSIG
LP FLARE
12"-AA-32-I
32-01-1314A
32-01-1314B
FIGURE 3-2
10"-AA-32-I
PC
FC
8"-AA-32
24"
32-01-1519
32-01-1520
FIGURE 4-2
4"-AA-32
TC
32-01-1104
FIGURE 1-3
12"-AA-32-I
10"-AA-32-I
LC
8"-AA-32-I
6"-AA-32-I
32-01-1519
32-01-1520
DEPROPANIZER REFLUX/PRODUCT
PUMP AND SPARE
50 H.P.
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
DESCRIPTION



NOTES:

1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THE PLANT WILL CONTAIN ONLY ONE TRAIN.
2. DURING HGT UNIT REGENERATION, A 14 DAY PERIOD, GASOLINE SPLITTER BOTTOMS IS SENT TO STORAGE BY SWITCHING CONTROL VALVES AND ACTIVATING THE GASOLINE SPLITTER BOTTOMS PUMP #2 TO PUMP SPLITTER BOTTOMS TO STORAGE.
3. DURING HGT UNIT OPERATION, THE GASOLINE SPLITTER BOTTOMS STORAGE PUMP IS OPERATED FOR A 169 DAY PERIOD TO PROVIDE THE ADDED FEED REQUIRED TO THE HGT UNIT TO MEET THE MTG PLANT STREAM DAY FACTOR OF 93%. THE HGT UNIT OPERATION IS BASED ON A STREAM DAY FACTOR OF 85%. GASOLINE SPLITTER BOTTOMS PUMP #1 IS ALSO OPERATED DURING HGT UNIT OPERATION.
4. VAPOR 34% (MOLE)
   VAPOR MOLECULAR WEIGHT= 94.6
5. THE FIGURE NUMBERS REFER TO THE TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2.

EQUIPMENT SHOWN ON THIS DRAWING:
32-01-1104
32-01-1207
32-01-1312
32-01-1313
32-01-1314
32-01-1315
32-01-1316
32-01-1317
32-01-1519
32-01-1520

	FOR		
	DRAWN		
FOR DESIGN REPORT	CHECKED	REK	12/2/8
FOR CLIENT APPROVAL	APVD DSGN MGR	FJC	12/2/8
FOR 50% CLIENT REVIEW	APVD PROJ MGR	FJC	12/2/8
DESCRIPTION	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

032MP4NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW AND CONTROL DIAGRAM
GAS FRACTIONATION - UNIT 32
DEPROPANIZATION

SCALE: NONE | JOB NUMBER: 6182 | DOCUMENT NUMBER: D-32-MP-4 NP | REVISION: C

COMPONENT	M.W.	① DEETHANIZER LIQUID FEED	② DEETHANIZER VAPOR FEED	③ DEETHANIZER LEAN OIL FEED	④ DEETHANIZER VAPOR OVERHEAD	⑤ DEETHANIZER REFLUX DRUM OVERHEAD
HYDROGEN	2.016	6.18	85.71		98.292	91.62
METHANE	16.042	204.33	479.25		731.184	682.10
CARBON MONOXIDE	28.010	5.01	32.46		39.474	37.35
CARBON DIOXIDE	44.010	190.50	174.33		429.040	364.14
NITROGEN	28.016	0.63	4.59		5.488	5.20
ETHENE	28.052	4.65	3.15		9.095	7.78
ETHANE	30.068	57.87	26.70		98.072	79.22
PROPENE	42.078	24.45	3.93		6.419	3.77
PROPANE	44.094	565.44	79.77		117.995	64.99
ISO BUTANE	58.120	889.86	55.14		4.430	1.15
1-BUTENE	56.104	113.97	5.82		0.176	0.04
N-BUTANE	58.120	279.51	12.18		0.138	0.03
ISO PENTANE	72.146	1,013.04	18.99	5.57	0.917	0.59
1-PENTENE	72.146	189.27	3.60	1.12	0.135	0.10
N-PENTANE	72.146	115.74	1.65	0.56	0.058	0.04
CYCLO PENTANE	70.130	20.64	0.21	0.06	0.003	0.00
2 METHYL PENTANE	86.172	867.15	5.79	159.79	7.027	5.03
C_6+HEAVIER		2,995.47	3.54	554.69	3.74	2.58
WATER	18.016	8.43	5.28			
TOTAL - MOL/HR (DRY)		7,543.71	996.84	721.79	1,526.304	1,346.31
TOTAL - LB/HR		618,499.86	27,980.55	76,100.75	42,057.	34,770.65
MOLECULAR WEIGHT		81.98	28.07	105.43	27.55	25.83
BBL/STREAM DAY		61,236.	——	6,815.	——	——
MSCFD		——	9,076.82	——	13,901.0	12,258.94
PRESSURE - PSIG		168.30	168.30	170.30	165.40	158.40
TEMP - °F		100.	100.	206.	66.23	55.
H - MBTU/HR		79,818.81	6,855.10	13,580.00		6,718.01

COMPONENT	M.W.	⑪ DEPROPANIZER FEED	⑫ DEPROPANIZER VAPOR OVERHEAD	⑬ DEPROPANIZER BOTTOMS	⑭ DEPROPANIZER OVERHEAD	⑮ SPLITTER FEED
HYDROGEN	2.016		0.000			
METHANE	16.042		0.000			
CARBON MONOXIDE	28.010		0.000			
CARBON DIOXIDE	44.010	0.02	0.034		0.02	
NITROGEN	28.016		0.000			
ETHENE	28.052	0.01	0.014		0.01	
ETHANE	30.068	5.18	34.334		5.18	
PROPENE	42.078	24.51	169.269	0.01	24.60	
PROPANE	44.094	580.08	3978.127	1.92	578.16	
ISO BUTANE	58.120	943.85	69.939	933.70	10.15	
1-BUTENE	56.104	119.75	2.797	119.29	0.46	
N-BUTANE	58.120	291.66	1.600	291.43	0.23	
ISO PENTANE	72.146	1016.53	0.009	1016.53		14.91
1-PENTENE	72.146	192.54	0.001	192.54		0.23
N-PENTANE	72.146	107.88		107.88		9.47
CYCLO PENTANE	70.130	11.03		11.03		9.82
2 METHYL PENTANE	86.172	59.99		59.99		807.91
C +HEAVIER		4.14	——	4.14	——	2992.31
WATER	18.016					
TOTAL - MOL/HR		3,357.25	4,257.660	2,738.45	618.80	3,834.65
TOTAL - LB/HR		206,240.46	187,884.	178,898.66	27,306.81	405,411.21
MOLECULAR WEIGHT		61.43	44.13	65.33	44.13	105.72
BBL/STREAM DAY		24,014.	——	20,332.	3,680.	36,290.
MSCFD		——	38,777.14	——	——	——
PRESSURE - PSIG		207.30	205.30	210.80	200.30	30.0
TEMP - °F		160.	115.91	237.	112.	256.
H - MBTU/HR		37,080.90		39,891.35	4,480.75	97,254.01

REFERENCES

DRAWING NO.	DESCRIPTION

REFERENCES

DRAWING NO.	DESCRIPTION

REVISIONS

NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION

REVISIONS

NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT
C	5/24/82	RAK				
B	5/24/82			RAK	EJC	
A	5/14/82			RAK	EJC	FOR

5 REFLUX DRUM OVERHEAD	6 DEETHANIZER LIQUID PRODUCT BOTTOMS	7 DEPENTANIZER FEED	8 DEPENTANIZER VAPOR OVERHEAD	9 DEPENTANIZER BOTTOMS	10 DEPENTANIZER REFLUX PRODUCT
91.62			0.000		
692.10			0.000		
31.35			0.000		
364.14	0.02	0.02	0.013		0.02
5.20			0.000		
7.78	0.01	0.01	0.005		0.01
79.22	5.18	5.18	12.695		5.18
3.77	24.61	24.61	62.606		24.61
64.99	580.08	580.08	1475.801		580.08
1.15	943.85	943.85	2405.699		943.85
0.04	119.75	119.75	305.255		119.75
0.03	291.66	291.66	743.500		291.66
0.59	1037.01	1037.01	2590.993	20.48	1016.53
0.10	193.89	193.89	490.870	1.35	192.54
0.04	117.91	117.91	276.840	10.03	107.88
0.00	20.90	20.90	31.029	9.88	11.0[illegible]
5.03	1027.69	1027.69	150.047	967.71	59.99
2.58	3551.03	3551.03	9.846	3547.01	4.14
—					
1,346.31	7,913.69	7,913.69	8,555.753	4,556.46	3,357.25
34,770.65	687,739.58	687,739.58	525,503.	481,511.96	206,240.46
28.83	86.91	86.91	61.42	105.68	61.43
	67,055.	52,600.		43,043.	24,014.
12,258.94		17,932.	77,922.50		
158.40	172.00	74.0	58.30	63.88	50.30
55.	274.	237.	151.27	333.	101.
6,718.01	154,856.71	154,776.20		118,312.97	30,311.64

16 GASOLINE SPLITTER VAPOR OVERHEAD	17 SPLITTER BOTTOMS	18 SPLITTER OVERHEAD	19 SPLITTER BOTTOMS TO HGT FROM STORAGE	20 TOTAL SPLITTER BOTTOMS TO HGT
14.91		14.91		
0.23		0.23		
9.47		9.47		
9.82		9.82		
807.91		807.91		
3397.392	508.07	2484.24	40.58	548.65
4,549.169	508.07	3,326.58	40.58	548.65
461,877.	67,658.58	337,761.72	5,403.94	73,079.97
101.53	133.17	101.53	133.17	133.20
	5,208.	31,021.	416.	5,624.
41,432.08				
13.30	16.66	75.0	625.00	575.00
302.60	442.	210.	175.	415.
	18,447.94	61,351.67		

NOTES:

1. THIS MATERIAL BALANCE IS FOR ONE TRAIN. THE PLANT WILL CONTAIN ONLY ONE TRAIN.
2. METHANOL IS ADDED AS REQUIRED TO INHIBIT HYDRATE FORMATION. METHANOL IS NOT REQUIRED FOR NORMAL OPERATION.
3. DURING MOT UNIT REGENERATION, A 14 DAY PERIOD, GASOLINE SPLITTER BOTTOMS IS SENT TO STORAGE BY SWITCHING CONTROL VALVES AND ACTIVATING THE GASOLINE SPLITTER BOTTOMS PUMP #2 TO PUMP SPLITTER BOTTOMS TO STORAGE.
4. DURING MOT UNIT OPERATION, THE GASOLINE SPLITTER BOTTOMS STORAGE PUMP IS OPERATED FOR A 169 DAY PERIOD TO PROVIDE THE ADDED FEED REQUIRED TO THE MOT UNIT TO MEET THE MTG PLANT STREAM DAY FACTOR OF 93%. THE MOT UNIT OPERATION IS BASED ON A STREAM DAY FACTOR OF 85%. GASOLINE SPLITTER BOTTOMS PUMP #1 IS ALSO OPERATED DURING MOT UNIT OPERATION.
5. AN INTERFACE TEMPERATURE DIFFERENCE OF THE MOT UNIT FEED STREAM, 415°F VERSUS 322°F, EXISTS. NO EQUIPMENT CHANGES WILL BE MADE AT THIS TIME TO COMPENSATE FOR THE TEMPERATURE DIFFERENCE.
6. THE INTERFACE DIFFERENCE BETWEEN UNIT 31 AND UNIT 32 MATERIAL BALANCES, MTG UNIT PRODUCT STREAMS VS GAS FRACTIONATION UNIT FEED STREAMS, APPEARS IN THE C6+ HEAVIER COMPONENTS DUE TO DIFFERENCES IN COMPUTER PHYSICAL PROPERTY DATA FOR THE HEAVY FRACTIONS.

	DRAWN	
	CHECKED	
FOR DESIGN REPORT	APVD SECT MGR	
FOR CLIENT APPROVAL	APVD PROJ MGR	
FOR ADD CLIENT REVIEW	APVD CLIENT	
DESCRIPTION		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

D32MP5NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

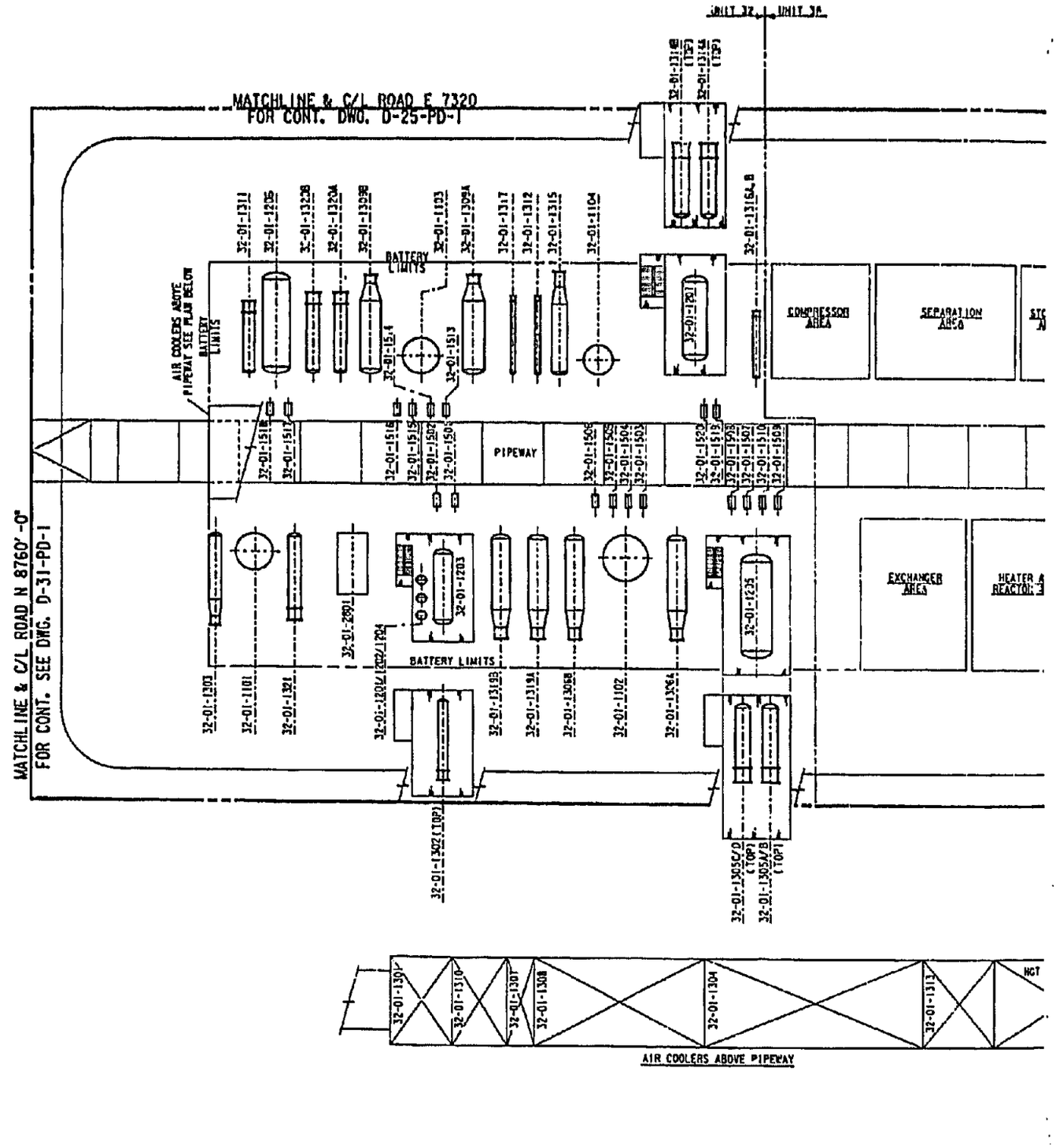
COAL - TO - METHANOL - TO - GASOLINE PLANT

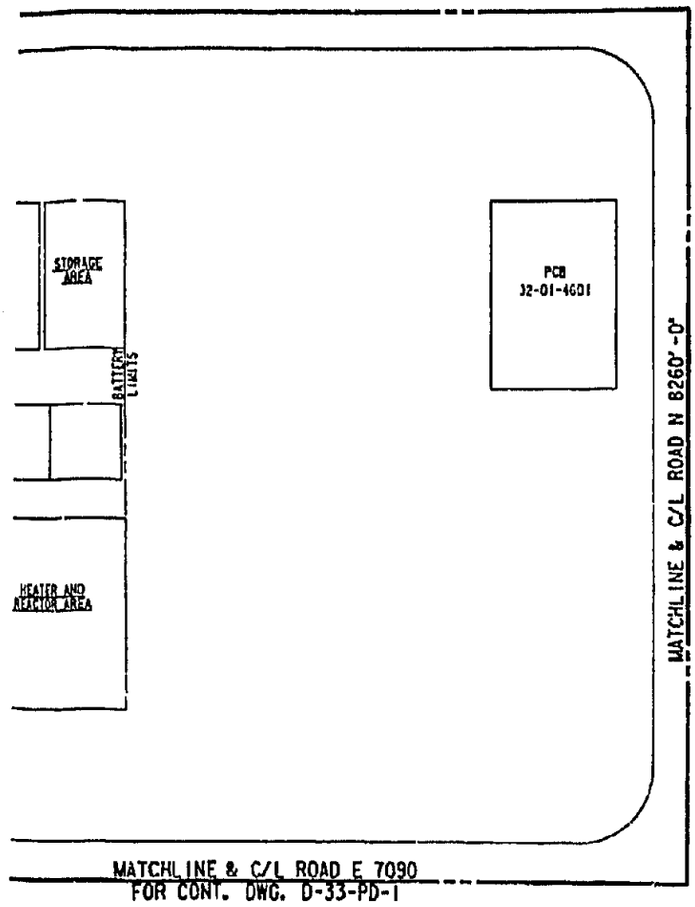
TITLE	SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
MATERIAL BALANCE GAS FRACTIONATION - UNIT 32	NONE	2800	6182	C
	DOCUMENT NUMBER D-32-MP-5 NP			

F. Plot Plan/General Arrangement Drawings

Plot Plan and General Arrangement Drawings for Gas Fractionation Unit 32 are as follows:

Drawing No.	Title
D-32-PD-1NP	Plot Plan - Unit 32 and Unit 38 Gas Fractionation and HGT
D-32-PD-2NP	Elevation - Unit 32 and Unit 38 Gas Fractionation and HGT





EQUIPMENT LIST

FRACTIONATION UNIT 32

32-01-1101	ABSORBER DEETHANIZER
32-01-1102	DEPENTANIZER
32-01-1103	GASOLINE SPLITTER
32-01-1104	DEPROPANIZER
32-01-1201	WATER DRAW DRUM 1
32-01-1202	WATER DRAW DRUM 2
32-01-1203	ABSORBER DEETHANIZER REFLUX DRUM
32-01-1204	WATER K.O. DRUM
32-01-1205	DEPENTANIZER REFLUX DRUM
32-01-1206	GASOLINE SPLITTER REFLUX DRUM
32-01-1207	DEPROPANIZER REFLUX DRUM
32-01-1301	ABSORBER DEETHANIZER AIR COOLER
32-01-1302	ABSORBER DEETHANIZER CHILLER
32-01-1303	ABSORBER DEETHANIZER REBOILER
32-01-1304	DEPENTANIZER AIR COOLER
32-01-1305A, B, C, D	DEPENTANIZER OVHD. CONDENSER
32-01-1306A, B	DEPENTANIZER REBOILER
32-01-1307	SPLITTER BOTTOMS AIR COOLER
32-01-1308	GASOLINE SPLITTER AIR COOLER
32-01-1309A, B	GASOLINE SPLITTER REBOILER
32-01-1310	LIGHT GASOLINE PRODUCT AIR COOLER
32-01-1311	LIGHT GASOLINE PRODUCT COOLER
32-01-1312	DEPROPANIZER FEED/BOTTOMS EXCHANGER
32-01-1313	ALKYLATION FEED AIR COOLER
32-01-1314A, B	DEPROPANIZER REFLUX CONDENSER
32-01-1315	DEPROPANIZER REBOILER
32-01-1316A, B	PROPANE PRODUCT COOLER
32-01-1317	ALKYLATION FEED WATER COOLER
32-01-1319A, B	DEPENTANIZER FEED/BOTTOMS EXCHANGER
32-01-1320-A, B	GASOLINE SPLITTER FEED/OVHD. EXCHANGER
32-01-1321	ABSORBER DEETHANIZER SIDE REBOILER
32-01-1501, 1502	COLD LEAN OIL PUMP AND SPARE
32-01-1503, 1504	LEAN OIL PUMP AND SPARE
32-01-1505, 1506	DEPENTANIZER BOTTOMS PUMP AND SPARE
32-01-1507, 1508	DEPENTANIZER REFLUX PUMP AND SPARE
32-01-1509, 1510	DEPENTANIZER OVHD. PUMP AND SPARE
32-01-1513, 1514	GASOLINE SPLITTER BOTTOMS PUMP NO. 2 AND SPARE
32-01-1515, 1516	GASOLINE SPLITTER BOTTOMS PUMP NO. 1 AND SPARE
32-01-1517, 1518	GASOLINE SPLITTER PRODUCT/REFLUX PUMP AND SPARE
32-01-1519, 1520	DEPROPANIZER REFLUX PUMP AND SPARE
32-01-2801	GAS FRACTIONATION REFRIGERATION PACKAGE

NOTE:
UNIT 38 IS PROPRIETARY.

HGT AIR COOLERS

0 10 20 40 60 80
SCALE: 1" = 20'-0"

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PLOT PLAN UNIT 32 AND UNIT 38 FRACTIONATION AND HGT

SCALE: 1"=20'-0" | ACCOUNT NUMBER: 7243 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-32-PD-1NP

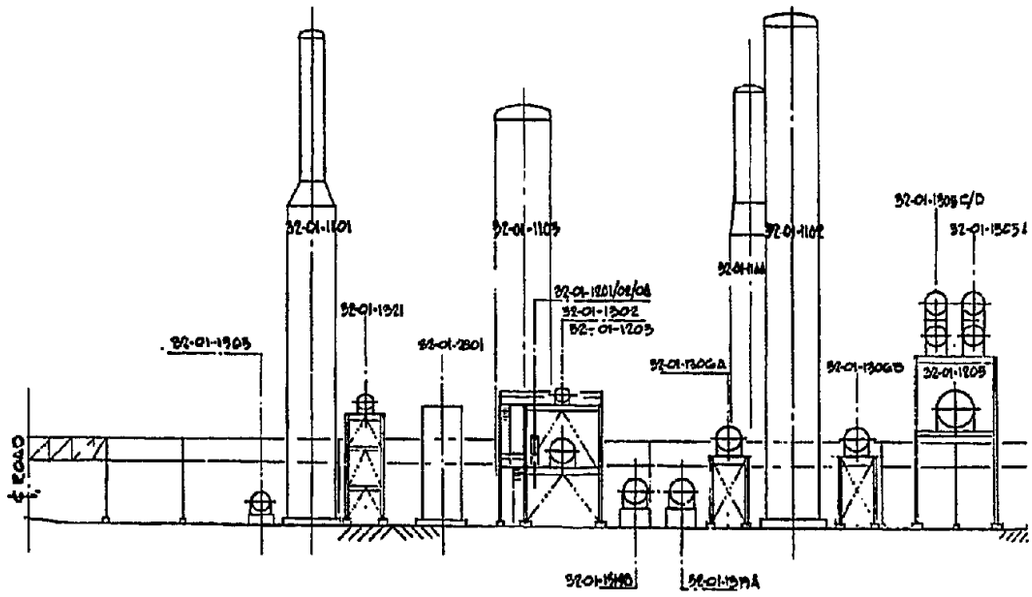
REVISION: D

	PSD		
FOR DESIGN REPORT	DRAWN	RR	
FOR CLIENT APPROVAL	CHECKED		
FOR LICENSOR APPROVAL	APVD DEPT MGR	MH	
ISSUED CLIENT REVIEW SOX COMP	APVD PROJ MGR	FJC	
DESCRIPTION	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

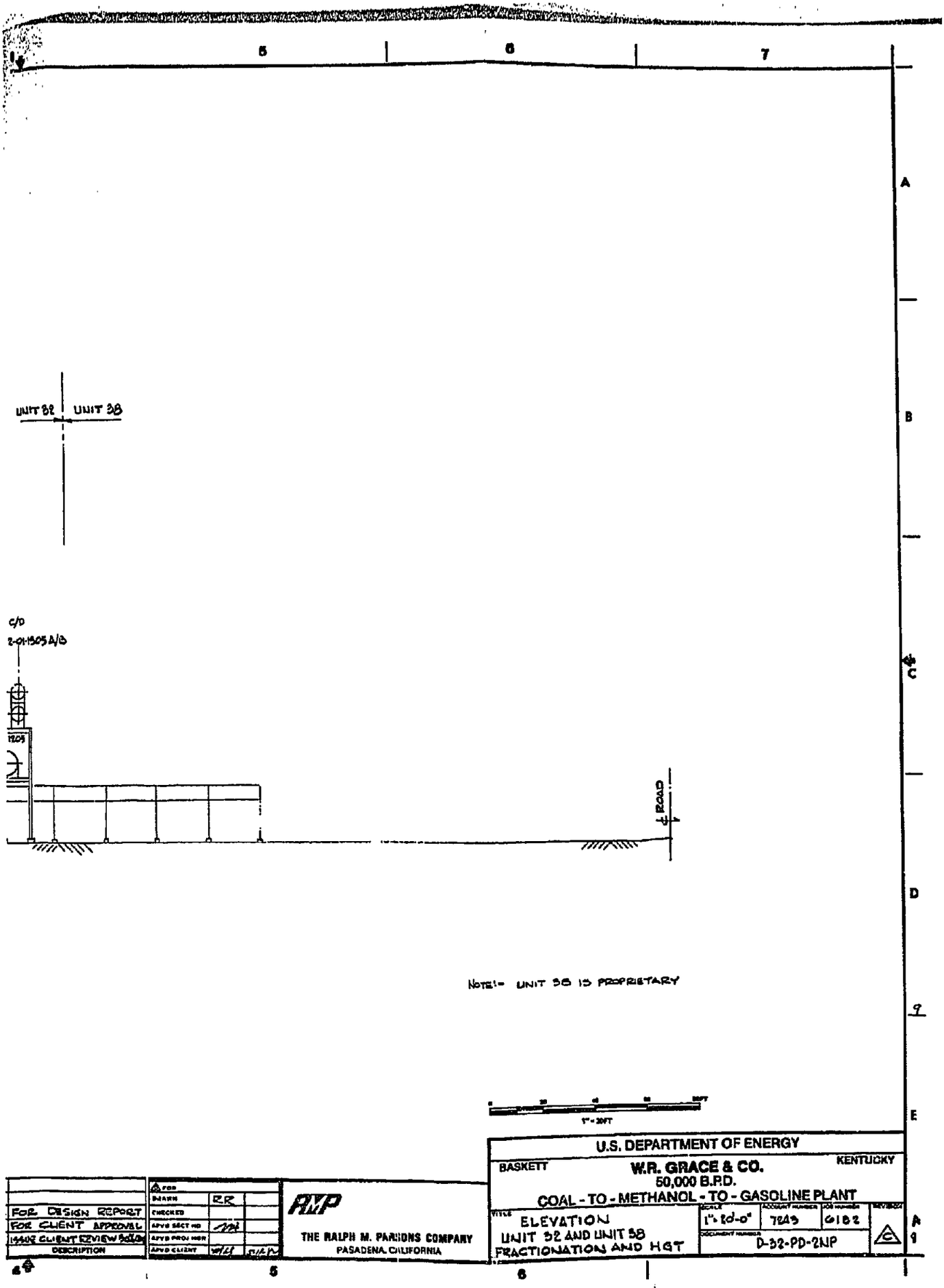
1 2 3 4

UNIT 3



REFERENCES			REFERENCES			REVISIONS									REVISIONS	
DRAWING NO.	DESCRIPTION		DRAWING NO	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION			
D-32-PD-1	PLOT PLAN															

ORIGINAL (12/79)



	DRAWN	RR	
FOR DESIGN REPORT	CHECKED		
FOR CLIENT APPROVAL	APVD SECT MGR		
ISSUE CLIENT REVIEW SET	APVD PROJ MGR		
DESCRIPTION	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ELEVATION
UNIT 32 AND UNIT 38
FRACTIONATION AND HGT

SCALE: 1"= 20'-0" | ACCOUNT NUMBER: 7243 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-32-PD-2NP

REVISION: C

A 9

G. Single-Line Diagram

See Volume II, 1.2.12(G) for the Single-Line Diagram for Gas Fractionation Unit 32.

1.2.14 HF ALKYLATION - UNIT 33

A. Basis of Design

A hydrofluoric acid (HF) alkylation unit has been selected for the conversion of a mixture of butylenes, amylenes, and isobutane to produce alkylate as a blending component of finished gasoline. The HF Alkylation Unit is a conventional-type facility without octane upgrading. The HF Alkylation Unit selected is based on a proprietary alkylation process licensed by Phillips Petroleum Company.

The feed stream is derived from the conversion of methanol to gasoline in a Mobil MTG unit with subsequent fractionation to separate the butylene and amylene components in depentanizer and depropanizer towers. The feed is depentanized to keep the C_6+ fraction at a low level so that the hexane fraction is less than 0.2% by volume of alkylation feed. This is necessary to reduce tar and decrease acid consumption during the alkylation process. The feed is also depropanized to keep total propanes at a low level for alkylation and to reduce acid losses that occur when propane is vented.

The feed contains a high-amylene content with about 60% dry volume amylenes to the total olefins present in the feed. Phillips has experience processing feeds with a high-amylene content, up to about 31% by volume amylenes to the total olefins present in the feed.

The HF Alkylation unit product streams consist of alkylate as a gasoline-blending component, n-butane to adjust gasoline vapor pressure, and isobutane to adjust gasoline vapor pressure with the excess to sales. The synthetic alkylate product is about 7.5% by volume of the total gasoline pool, with C_5+ naphtha about 88% by volume and the remainder butanes. Since n-butane is in short supply and there is excess isobutane in the feed, some isobutane is added to gasoline when needed for vapor pressure adjustment of finished gasoline.

Provision for an n-butane side-cut from the deisobutanizer is included in the HF Alkylation unit design. The alkylate product should be flexible in n-butane content to allow for a Reid vapor pressure (RVP) of total alkylate of about 5 to 6 psi for storage. When blending alkylate with naphtha for storage, a higher RVP is allowed; for instance, about 8 to 9 psi.

Since the feed contains excess isobutane, the overhead product from the deisobutanizer is exported for sales. The isobutane product is a high-purity stream with less than 0.5% by volume n-butane content. Alkylation unit feed and product stream compositions are presented in the following tables.

HF Alkylation Unit Feedstock

Component	lb mol/hr	mol%
Propene	0.01	-
Propane	1.92	0.07
Isobutane	933.70	34.11
1-Butene	119.29	4.36
n-Butane	291.43	10.64
Isopentane	1,016.53	37.14
1-Pentene	192.54	7.03
n-Pentane	107.88	3.94
Cyclopentane	11.03	0.40
2-Methylpentane	59.99	2.19
C_6+ Heavier	4.14	0.14
Total, lb mol/hr	2,738.45	100.00
Total, lb/hr	178,900	
Pressure, psia	45	
Temperature, °F	100	

Product Streams

Component	Isobutane Product (lb mol/hr)	(mol%)	n-Butane Product (lb mol/hr)	(mol%)	Alkylate Product (lb mol/hr)	(mol%)
Propene	-	-	-	-	-	-
Propane	1.92	0.35	-	-	-	-
Isobutane	552.13	99.22	12.20	4.42	-	-
1-Butene	-	-	-	-	-	-
n-Butane	2.41	.43	244.24	88.47	44.87	2.80
Isopentane	-	-	19.56	7.11	1,067.42	66.55
1-Pentene	-	-	-	-	-	-
n-Pentane	-	-	-	-	107.95	6.73
Cyclopentane	-	-	-	-	11.03	0.69
2-Methylpentane	-	-	-	-	59.97	3.74
C_6+ Heavier	-	-	-	-	0.54	0.04
Alkylate	-	-	-	-	312.00	19.45
Total, lb mol/hr	556.46	100.00	276.00	100.00	1,603.78	100.00
Total, lb/hr	32,315		16,310		130,196	
Pressure, psia	85		60		5-6	
Temperature, °F	110		110		110	

B. Process Selection Rationale

The Phillips HF Alkylation Process is a commercially proven technology. Phillips has about 80 plants operating successfully throughout the world. Its capital and operating costs are lower than for the other processes examined. Phillips experience with high-amylene feeds fits well with the present design, which contains about 60% by volume amylenes to total olefins in the feed. The process provides reliability with a good turndown ratio.

1. Operability. The HF Alkylation Unit can be operated at about 50% of design capacity. It can be brought to full-load operation within a few hours.

2. Reliability. The plant is designed with all pumps spared and with block valves and bypass valves installed around control and relief valves. The design will permit maintenance on such items without shutting down.

3. Onstream Time. The operating factor for HF alkylation will be better than that of a fluid catalytic cracking unit and is estimated at about 95% stream factor.

4. Maintenance Costs. The maintenance cost estimate for the HF Alkylation unit is 3.5% of unit capital cost.

5. Equipment Lead Time. With the exception of the HF regenerator, the Phillips alkylation plant is designed entirely of carbon steel. The acid regenerator can be of either Monel-clad or solid Monel construction. Monel construction is a major factor in determining the equipment lead time.

6. Commercial Experience. Table II-1.2.14-1 summarizes plants using Phillips HF Alkylation Process in operation and under construction.

Table II-1.2.14-1 - Recent Phillips HF Alkylation Licensees

Company	Refinery Location	Startup Year	Design (bpsd)	Capacity (mtpd)
Gulf Oil Corporation	Philadelphia, PA	1973	15,000	1,667
Marathon Oil Company	Texas City, TX	1974	11,000	1,222
Getty Oil Company	El Dorado, KS	1976	10,000	1,111
Texas City Refining	Texas City, TX	1979	6,000	667
Lindsey Oil Limited	Killingholme, England	1981	4,200	467
BP Trading Limited	Rotterdam, Holland	1982	5,000	556
BP Trading Limited	Grangemouth, UK	1981	4,200	467
Marathon Oil Company	Garyville, LA	1980	21,000	2,333
Texaco-Gulf	Pembroke, Wales	1982	18,000	2,067
Amoco-Murphy Limited	Milford Haven, Wales	1981	3,000	333
Mobil Oil Corporation	Croydon, England	1982	14,500	1,611
Mobil Oil Corporation	Durban, South Africa	1981	2,500	278
Gulf Oil Corporation	Cincinnati, OH	1980	2,000	222
BP Trading Limited	Kwinana, Australia	1981	3,000	333
CFR	LaMede, France	1981	3,000	333
Mobil Oil Corporation	Saudi Arabia	1984	14,500	1,611
Petrobras	Cubatao, Brazil	1984	3,000	333
Trintoc	Point Fortin, Trinidad	1984	5,500	611
NNPC	Warri, Nigeria	1983	3,000	333
Albatross Oil Processing	Antwerp, Belgium	1984	4,800	538
Saber Refining	Corpus Christi, TX	1983	7,700	859
Tenneco Oil	Chalmette, LA	1984	16,000	1,778

C. Process Description

Refer to Process Flow and Control Diagrams D-33-MP-1NP, -2NP, -3NP, and -4NP for equipment arrangement and material balance.

Depropanized hydrocarbon liquid from the Gas Fractionation Section flows to Feed Surge Tank 33-01-1205, which has an 8-hr holdup to ensure continuous hydrocarbon flow to the HF Alkylation Unit. The hydrocarbon feed composition is shown in the above table as a mixture consisting of butylene and amylene olefins.

The total hydrocarbon olefinic feed, along with recycle isobutane, is charged to the reactor section of the HF Alkylation unit. The combined feed is dispersed through spray nozzles and mixed with hydrofluoric acid before entering the reactor riser. The reactor operates by differential gravity flow and has no moving parts such as impellers or mixers; also, acid circulation pumps are not required. Total conversion of reactants to high-quality alkylate occurs almost instantly.

From the reaction zone, the hydrocarbon components and acid catalyst flow upward to the settling zone. Here, acid catalyst breaks out as a bottom phase and flows by gravity on a return cycle through the shell side of parallel Acid Coolers 33-01-1301 and -1302 to the reaction zone, where the reaction cycle is repeated. Heat of reaction is removed by heat exchange with a large volume of coolant flowing through the tubes. Cooling water used is available for further cooling elsewhere in the unit. The hydrocarbon phase from the settling zone, containing minute quantities of propane, recycle isobutane, normal butane, pentanes, cyclopentane, and alkylate, is charged to Main Fractionator 33-01-1101 for recovery of product streams.

The main fractionator overhead is charged to HF-Isobutane Stripper 33-01-1103 for HF acid removal overhead. The bottoms isobutane product is catalytically defluorinated, KOH treated, and yielded as isobutane product. Recycle isobutane, essential for favorable control of reaction mechanisms, is produced as a vapor overhead stream from the main fractionator

and also from the HF isobutane stripper bottoms. The condensed and cooled recycle isobutane is returned to the reaction zone.

The alkylate bottom product from the main fractionator containing about 2% n-butane is acceptable for motor fuel blending. An n-butane product of about 85% purity and suitable for motor fuel blending is taken as a vapor side-draw near the bottom of the main fractionator. This sidestream is condensed and sent to storage for vapor pressure blending in gasoline.

A small slipstream of acid is withdrawn from Acid Settler 33-01-1202 and fed to Acid Rerun Tower 33-01-1102 to remove dissolved water and polymerized hydrocarbons. The overhead product from the rerun column is clean hydrofluoric acid, which is condensed and returned to the system. The bottom product from the rerun tower is a mixture of acid-soluble oils and an HF water azeotrope. This stream is sent to Main Fractionator Heater 33-01-1401 to be disposed of by burning.

Auxiliary systems included within the battery limits include (1) Acid Relief Neutralizer 33-01-1201 to remove HF from relief gas leaving the battery limits, (2) Recycle Acid Rerun Tower 33-01-1102 to remove acid-soluble oils that occur in the reactor acid, (3) Acid Storage Tank 33-01-1203 for anhydrous HF acid during periods when the unit is shut down for turnaround, (4) HF Acid Neutralizer 33-01-4102 for surface drainage and sewer drainage in the acid area, and (5) a change room and storage room for cleaning and storing necessary protective clothing required on occasion by operating and maintenance personnel.

Process hydrocarbon vapors from the relief gas header containing HF acid are contacted in Acid Relief Neutralizer 33-01-1201 with dilute aqueous sodium hydroxide prior to entering the flare system. Calcium chloride is used to precipitate calcium fluoride from spent caustic in Calcium Fluoride Precipitator 33-01-4101. Insoluble calcium fluoride settles out to form an inert sludge, which has been successfully used as a sanitary landfill without known environmental problems.

From product streams that require KOH treaters, the spent KOH is processed through a spent caustic neutralizer using Na_2CO_3. Drainage from the spent caustic neutralizer flows to the plant wastewater treatment system.

Product streams such as LPG, are defluorinated over an activated alumina bed. After the bed is "spent," it is considered inert and can be disposed of in a sanitary landfill.

D. Risk Assessment

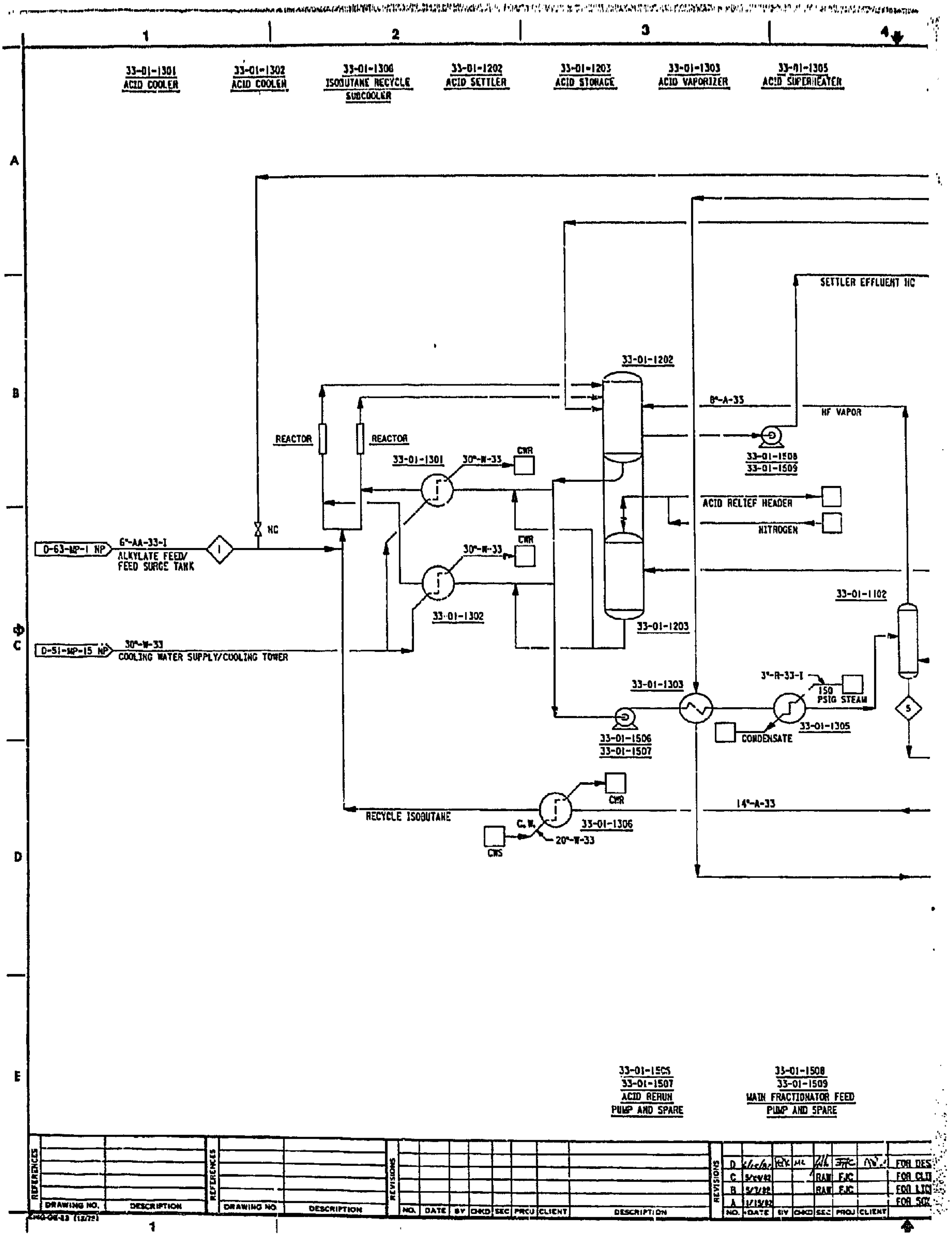
The hydrofluoric acid (HF) alkylation unit designed by Phillips Petroleum Company converts a mixture of butylenes, amylenes, and isobutane to produce alkylate as a blending component of finished gasoline.

The Phillips HF Alkylation Process is a commercially proven technology. Phillips has about 80 plants operating throughout the world. Phillips experience with high-amylene feeds fits well with the present design, which contains about 60% by volume amylenes to total olefins in the feed. The process provides reliability with a high-onstream factor. The plant is designed with all pumps spared and with block valves and bypass valves installed around control and relief valves. The design permits maintenance on such items without shutting down. Corrosion and equipment fouling are not expected to be problems. The technical risk is considered minimal.

E. Process Flow and Control Diagrams (Including Material Balance)

Process Flow and Control Diagrams for HF Alkylation Unit 33 are as follows:

Drawing No.	Title
D-33-MP-1NP	PFCD HF Alkylation - Acid System
D-33-MP-2NP	PFCD HF Alkylation - Fractionation
D-33-MP-3NP	Material Balance - HF Alkylation
D-33-MP-4NP	PFCD HF Alkylation - Waste Disposal



1
2
3
4
A
B
C
D
E
33-01-1301
ACID COOLER
33-01-1302
ACID COOLER
33-01-1306
ISOBUTANE RECYCLE
SUBCOOLER
33-01-1202
ACID SETTLER
33-01-1203
ACID STORAGE
33-01-1303
ACID VAPORIZER
33-01-1305
ACID SUPERHEATER
SETTLER EFFLUENT HC
33-01-1202
8"-A-33
HF VAPOR
REACTOR
REACTOR
33-01-1301
30"-W-33
CWR
33-01-1508
33-01-1509
ACID RELIEF HEADER
NITROGEN
D-63-MP-1 NP
6"-AA-33-1
ALKYLATE FEED/
FEED SURGE TANK
NC
30"-W-33
CWR
33-01-1302
33-01-1102
33-01-1203
D-51-MP-15 NP
30"-W-33
COOLING WATER SUPPLY/COOLING TOWER
3"-R-33-1
33-01-1303
150
PSIG STEAM
33-01-1506
33-01-1507
CONDENSATE
33-01-1305
CWR
14"-A-33
RECYCLE ISOBUTANE
C.W.
33-01-1306
CWS
20"-W-33
33-01-15C6
33-01-1507
ACID RERUN
PUMP AND SPARE
33-01-1508
33-01-1509
MAIN FRACTIONATOR FEED
PUMP AND SPARE
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
D
C
B
A
RAW
FJC
FOR DES
FOR CLI
FOR LIC
FOR SCO

33-01-1102 ACID RERUN TOWER

33-01-1304 STRIPPING ISOBUTANE HEATER

33-01-1307 ISOBUTANE RECYCLE CONDENSER

33-01-1308 MAIN FRACTIONATOR FEED RECYCLE EXCHANGER

33-01-1309 A,B MAIN FRACTIONATOR FEED [illegible] EXCHANGER

NOTES:
1. THE COOLING WATER FACILITY FOR THE H.F. ALKYLATION UNIT IS A SEGREGATED SYSTEM. SEE DRAWING D-51-MP-15 NP.
2. THE ISOBUTANE FLUSH LINE TIES INTO THE ISOBUTANE STORAGE FACILITY AT THE PUMP DISCHARGE LINE. (NORMALLY NO FLOW DURING UNIT OPERATION).

ISOBUTANE FLUSH/STORAGE (NOTE 2) — D-57-MP-4 NP

ALKYLATE/MAIN FRACTIONATOR — D-33-MP-2 NP

HF/MAIN FRACTIONATOR OVERHEAD ACCUMULATOR, ISOBUTANE STRIPPER — D-33-MP-2 NP

RECYCLE ISOBUTANE/ RECYCLE ISOBUTANE CONDENSER — D-33-MP-2 NP

[illegible]UENT HC

33-01-1308

16"-A-33-I — D-33-MP-2 NP

RECYCLE ISOBUTANE/MAIN FRACTIONATOR

33-01-1307

16"-A-33-I

14"-A-33- I

N.C.

SETTLER EFFUENT HC/ MAIN FRACTIONATOR — D-33-MP-2 NP

33-01-1309A
33-01-1[illegible]

MAKE-UP HYDROFLOUPIC ACID (ANHYDROUS/STORAGE)

[illegible]2

2"-R-33-1

150 PSIG STEAM

2"-A-33 RECYCLE ISOBUTANE

2"-R-33-I

33-01-1304

CONDENSATE

5

ACID SOLUBLE OILS (A.S.O.)/MAIN FRACTIONATOR HEATER — D-33-MP-2 NP

ALKYLATE/ MAIN FRACTIONATOR — D-33-MP-2 NP

6"-A-33 — D-33-MP-2 NP

ALKYLATE/ ALKYLATE COOLER

EQUIPMENT SHOWN ON THIS DRAWING

33-01-1102	33-01-1307
33-01-1202	33-01-1308
33-01-1203	33-01-1309A
33-01-1301	33-01-1309C
33-01-1302	33-01-1506
33-01-1303	33-01-1507
33-01-1304	33-01-1508
33-01-1305	33-01-1509
33-01-1306	

D33MP1NP.DGA

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

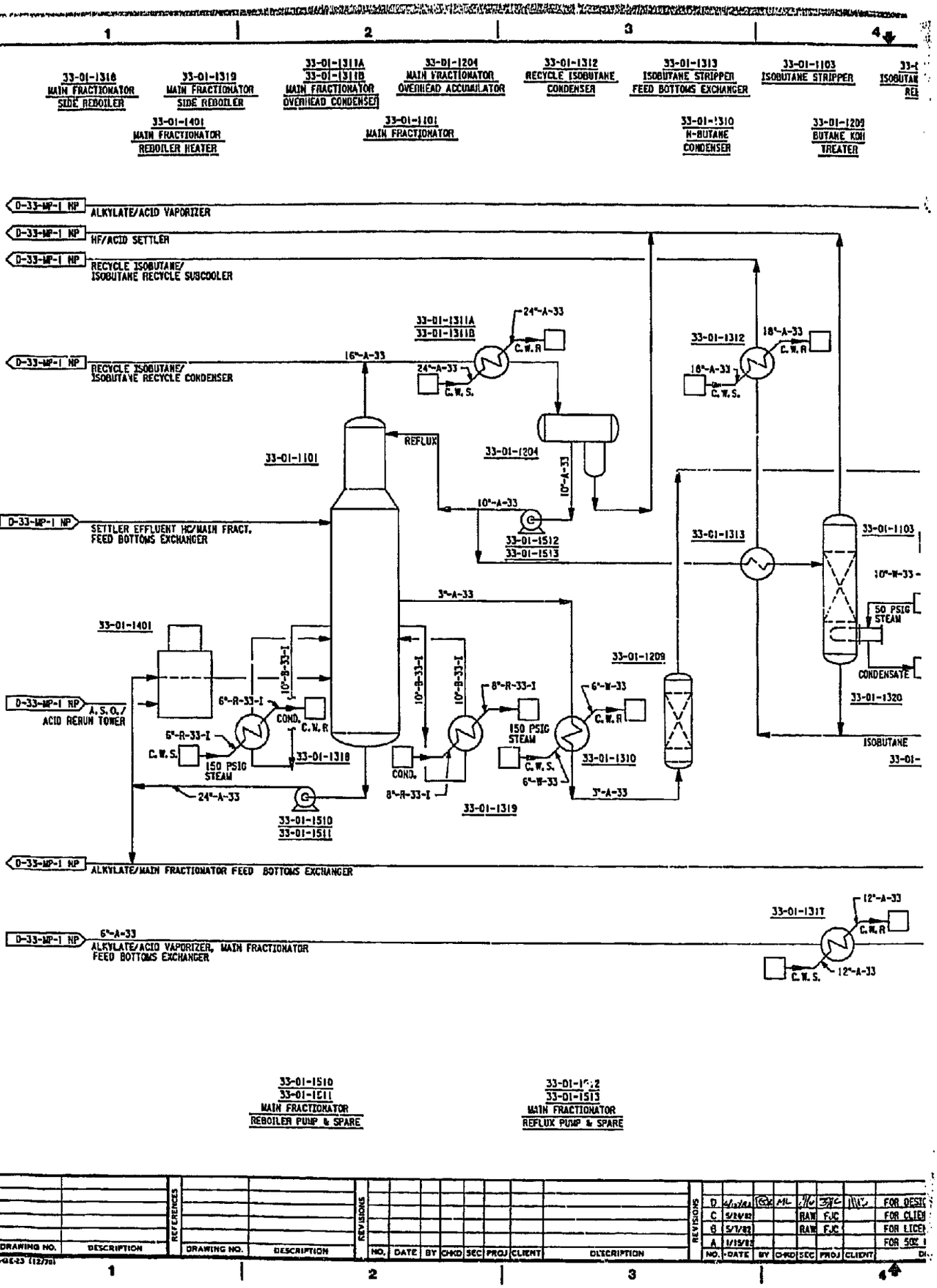
DRAWN			
CHECKED			
APVD DESIGN	REK	7/13/82	
APVD PROJ MGR	FJC	7/12/82	
APVD CLIENT			

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

TITLE: PROCESS FLOW AND CONTROL DIAGRAM HF ALKYLATION - UNIT 33 ACID SYSTEM

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182 | REVISION: 0

DOCUMENT NUMBER: D-33-MP-1 NP



REFERENCES			REFERENCES			REVISIONS								REVISIONS									
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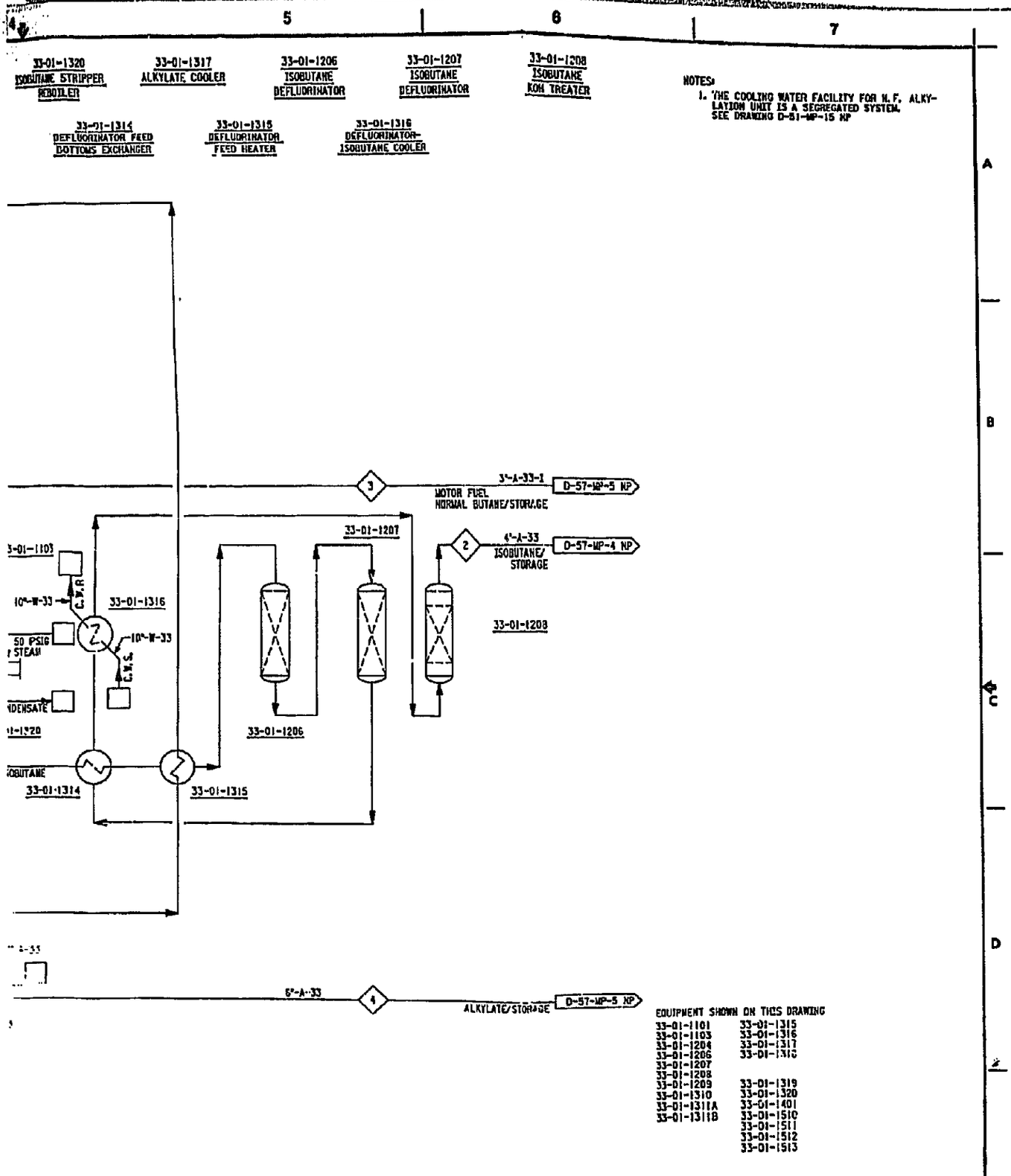
														D	4/26/82	[illegible]		ML	[illegible]	[illegible]	[illegible]	[illegible]	FOR DESIG
														C	9/24/82				RAW	FJC			FOR CLIEN
														B	5/1/82				RAW	FJC			FOR LICEN
														A	1/15/82								FOR 50%

ENG-GE-23 (12/79)


5
6
7
33-01-1320 ISOBUTANE STRIPPER REBOILER
33-01-1317 ALKYLATE COOLER
33-01-1206 ISOBUTANE DEFLUORINATOR
33-01-1207 ISOBUTANE DEFLUORINATOR
33-01-1208 KOH TREATER
33-01-1314 DEFLUORINATOR FEED BOTTOMS EXCHANGER
33-01-1315 DEFLUORINATOR FEED HEATER
33-01-1316 DEFLUORINATOR-ISOBUTANE COOLER
NOTES:
1. THE COOLING WATER FACILITY FOR N.F. ALKYLATION UNIT IS A SEGREGATED SYSTEM, SEE DRAWING D-81-MP-15 NP
A
B
C
D
E
3"-A-33-1
MOTOR FUEL NORMAL BUTANE/STORAGE
D-57-MP-5 NP
4"-A-33
ISOBUTANE/ STORAGE
D-57-MP-4 NP
33-01-1207
33-01-1208
33-01-1206
33-01-1316
33-01-1315
33-01-1314
33-01-1103
C.W.R.
C.W.S.
10"-W-33
50 PSIG STEAM
CONDENSATE
6"-A-33
ALKYLATE/STORAGE
D-57-MP-5 NP
EQUIPMENT SHOWN ON THIS DRAWING
33-01-1101
33-01-1103
33-01-1204
33-01-1206
33-01-1207
33-01-1208
33-01-1209
33-01-1310
33-01-1311A
33-01-1311B
33-01-1315
33-01-1316
33-01-1317
33-01-1318
33-01-1319
33-01-1320
33-01-1401
33-01-1510
33-01-1511
33-01-1512
33-01-1513
D33MP2NP.DGA
PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA
U.S. DEPARTMENT OF ENERGY
BASKETT
W.R. GRACE & CO.
50,000 B.P.D.
KENTUCKY
COAL - TO - METHANOL - TO - GASOLINE PLANT
PROCESS FLOW AND CONTROL DIAGRAM
HF ALKYLATION - UNIT 33
FRACTIONATION
SCALE: NONE
2000
6182
D-33-MP-2 NP
0
FOR DESIGN REPORT
FOR CLIENT APPROVAL
FOR LICENSOR APPROVAL
FOR 50% CLIENT REVIEW
DESCRIPTION
DRAWN
CHECKED
REK 1/12/82
FJC 1/12/82
THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

COMPONENT	MOL. WT.	① HYDROCARBON FEED	② ISOBUTANE PRODUCT	③ N-BUTANE PRODUCT	④ ALKYLATE PRODUCT	⑤ ASO
PROPENE	42.08	0.01				
PROPANE	44.09	1.92	1.92			
ISOBUTANE	58.12	933.70	552.13	12.20		
1-BUTENE	56.10	119.29				
N-BUTANE	58.12	291.43	2.41	244.24	44.87	
ISOPENTANE	72.15	1,016.53		19.56	1,067.42	
1-PENTENE	70.13	192.54				
N-PENTANE	72.15	107.88			107.95	
CYCLOPENTANE	70.13	11.03			11.03	
2-METHYLPENTANE	86.17	59.99			59.97	
C_6 + HEAVIER		4.14				
ALKYLATE	110.00	—			312.00	
TOTAL LB MOL/HR		2,738.45	556.46	276.00	1,603.78	—
TOTAL LBS/HR		178,898.6	32,315.0	16,309.6	130,195.0	76.6
BPSD		20,332	3,915.0	1,909	13,840	—
LBS/Bbl		211.28	198.10	205.05	225.8	—
MW		65.3	58.1	59.1	81.2	—

REFERENCES			
DRAWING NO.	DESCRIPTION	DRAWING NO	DESCRIPTION

REVISIONS								
NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	

REVISIONS								
NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT		
D	6/10/82	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		FOR DES
C	5/21/82			RAM	FJC			FOR CLI
B	5/7/82			RAM	FJC			FOR LIC
A	1/15/82							FOR SUB

ENG-GE-25 (12/79)

NOTES:

1. THE COOLING WATER FACILITY FOR H.F. ALKYLATION UNIT IS A SEGREGATED SYSTEM.
2. THE ISOBUTANE FLUSH LINE TIES INTO ISOBUTANE STORAGE FACILITY ON PUMP DISCHARGE LINE. (NORMALLY NO FLOW DURING UNIT OPERATION).

D33MP3NP.DGA

PHILLIPS PETROLEUM COMPANY
BARTLESVILLE, OKLAHOMA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

DESCRIPTION	FOR		
FOR DESIGN REPORT	DRAWN		
FOR CLIENT APPROVAL	CHECKED		
FOR LICENSOR APPROVAL	APVD SECT MGR	REK	9/12/82
FOR 50% CLIENT REVIEW	APVD PROJ MGR	FJC	9/12/82
	APVD CLIENT		

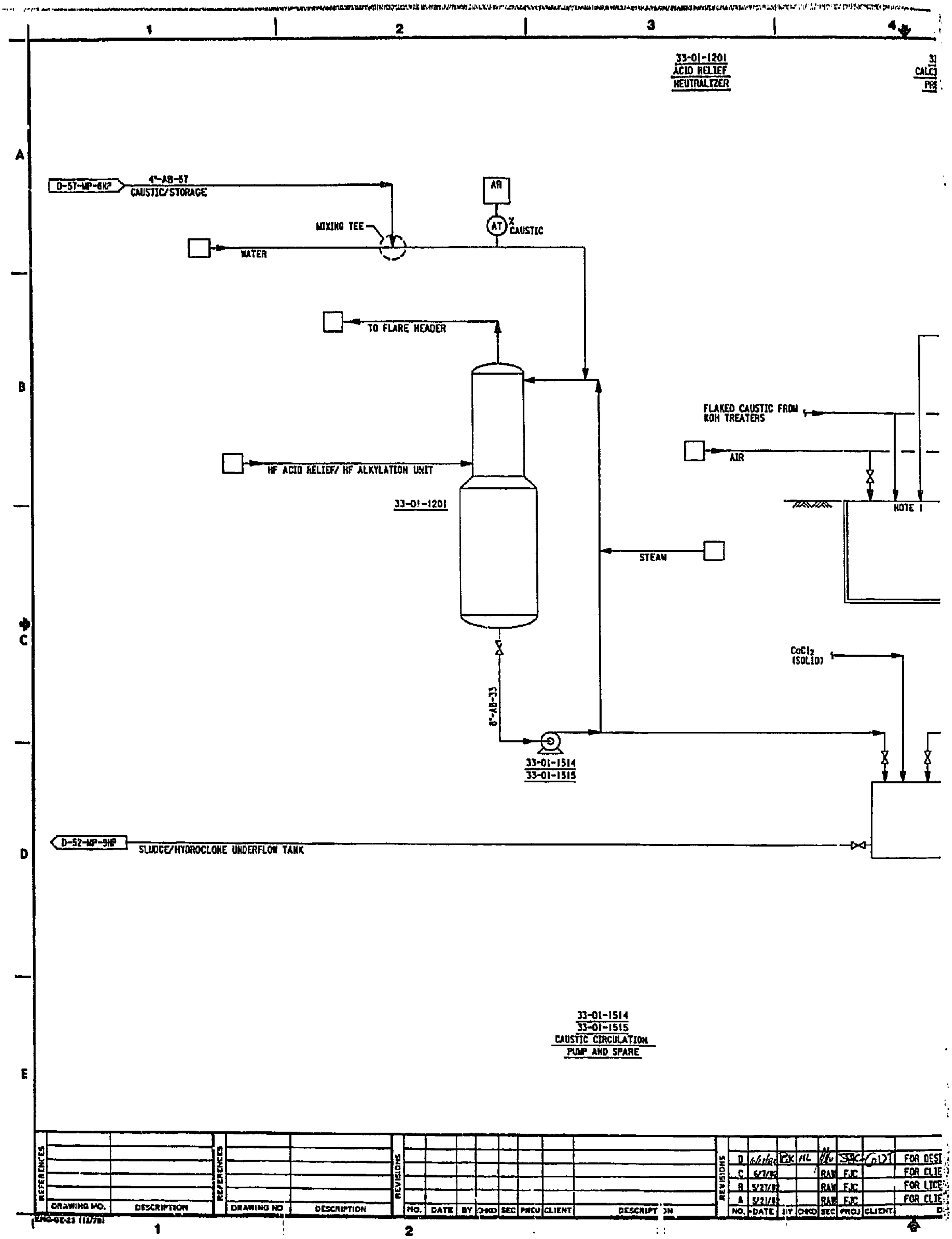
THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

TITLE: MATERIAL BALANCE
HF ALKYLATION - UNIT 33

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-33-MP-3 NP

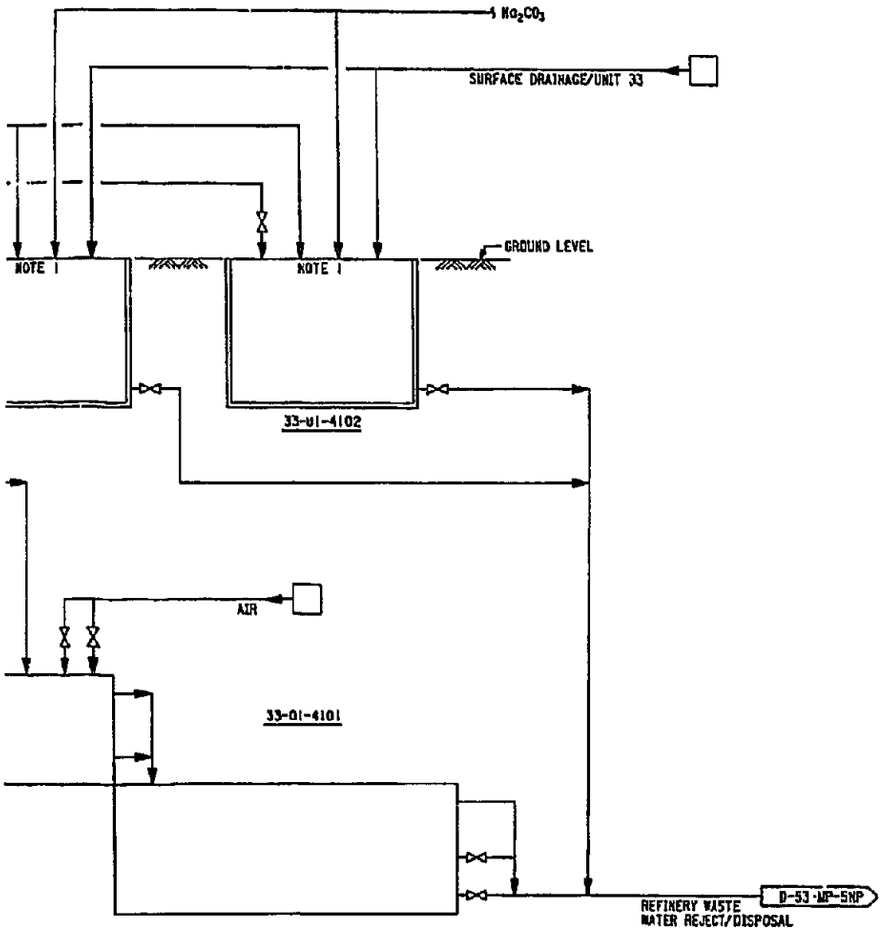
REVISION: 0


1
2
3
4
A
B
C
D
E
33-01-1201
ACID RELIEF
NEUTRALIZER
D-57-MP-8KP
4"-AB-57
CAUSTIC/STORAGE
AR
AT
% CAUSTIC
MIXING TEE
WATER
TO FLARE HEADER
FLAKED CAUSTIC FROM
KOH TREATERS
AIR
HF ACID RELIEF/ HF ALKYLATION UNIT
33-01-1201
NOTE 1
STEAM
$CoCl_2$
(SOLID)
8"-AB-33
33-01-1514
33-01-1515
D-52-MP-9HP
SLUDGE/HYDROCLONE UNDERFLOW TANK
33-01-1514
33-01-1515
CAUSTIC CIRCULATION
PUMP AND SPARE
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
DESCRIPTION
C
6/7/82
RAW
FJC
FOR CLIE
B
5/27/82
RAW
FJC
FOR LICE
A
5/21/82
RAW
FJC
FOR CLIE
D
FOR DESI

33-01-4101
CALCIUM FLUORIDE
PRECIPITATOR

33-01-4102
H.F. ACID NEUTRALIZER

NOTES:
1. REMOVABLE GRATING FOR Na_2CO_3 ADDITION.



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33-01-1514
33-01-1515
33-01-4101
33-01-4102

D33MP4NP.DGN

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW AND CONTROL DIAGRAM
HF ALKYLATION - UNIT 33
WASTE DISPOSAL

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-33-MP-4 NP

REVISION: D

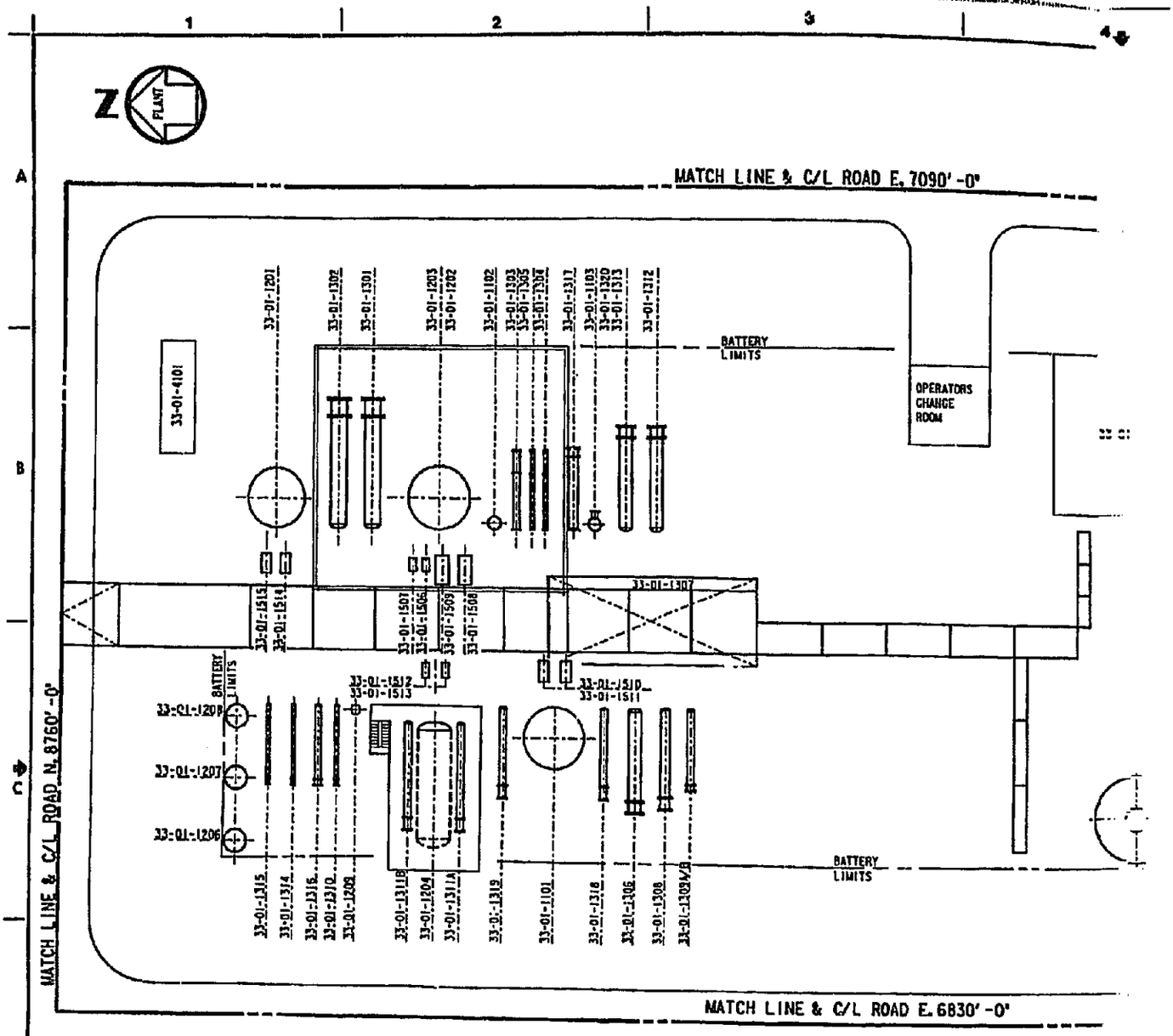
DESCRIPTION	BY	CHECKED	APVD PROJ MGR	APVD CLIENT
FOR DESIGN REPORT				
FOR CLIENT APPROVAL				
FOR LICENSOR APPROVAL				
FOR CLIENT 50% REVIEW				

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

F. Plot Plan/General Arrangement Drawings

Plot Plan and General Arrangement Drawings for HF Alkylation Unit 33 are as follows:

Drawing No.	Title
D-33-PD-1NP	Plot Plan - Unit 33 HF Alkylation
D-33-PD-2NP	Elevation - Unit 33 HF Alkylation



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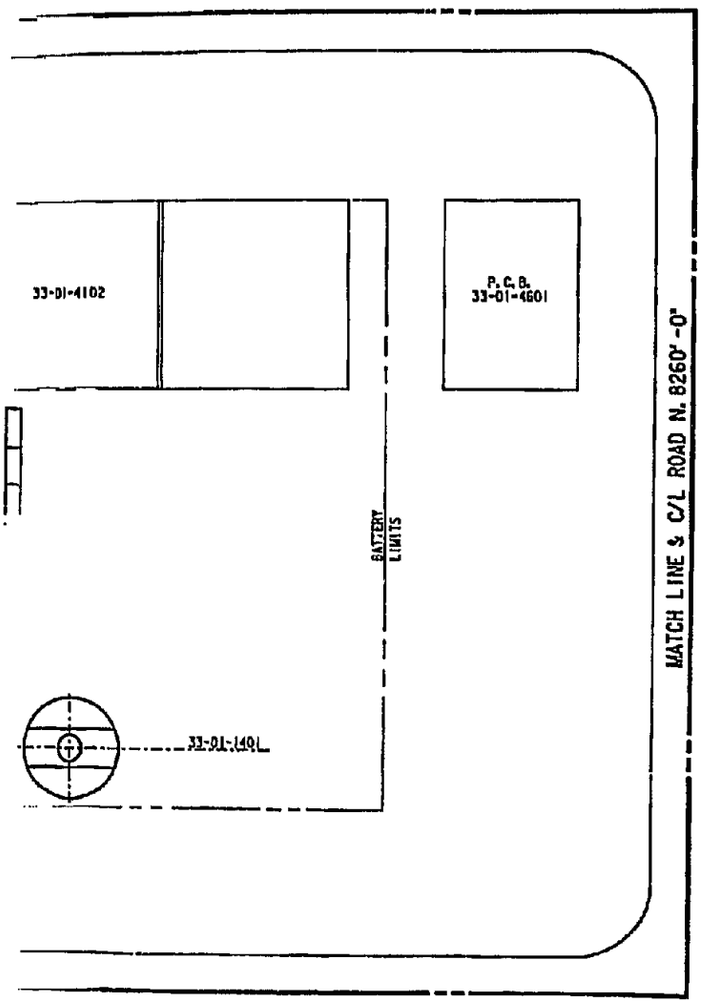
													C	3/18/82	RR			NH	FJC		
													B	3/9/82	RR			NH	FJC		
													A	1/15/82	RR			NH	FJC		

ENG-01-83 (12/79)



EQUIPMENT LIST

COLUMNS	
33-01-1101	MAIN FRACTIONATOR COLUMN
33-01-1102	ACID RERUN COLUMN
33-01-1103	ISOBUTANE STRIPPER COLUMN
VESSELS	
33-01-1201	ACID RELIEF NEUTRALIZER
33-01-1202	ACID SETTLER
33-01-1203	ACID STORAGE
33-01-1204	MAIN FRACTIONATOR OVERHEAD ACCUM.
33-01-1206	ISOBUTANE DEFLUORINATOR
33-01-1207	ISOBUTANE DEFLUORINATOR
33-01-1208	ISOBUTANE KOH TREATER
33-01-1209	BUTANE KOH TREATER
HEAT EXCHANGERS AND CONDENSERS	
33-01-1301	ACID COOLER
33-01-1302	ACID COOLER
33-01-1303	ACID VAPORIZER
33-01-1304	STRIPPING ISOBUTANE HEATER
33-01-1305	ACID SUPERHEATER
33-01-1306	ISOBUTANE RECYCLE SUBCOOLER
33-01-1307	ISOBUTANE RECYCLE CONDENSER
33-01-1308	MAIN FRACT. FD. RECYCLE EXCHANGER
33-01-1309A, B	MAIN FRACT. FD. BTMS. EXCHANGER
33-01-1310	N-BUTANE CONDENSER
33-01-1311A, B	MAIN FRACT. OVERHEAD COND.
33-01-1312	RECYCLE ISOBUTANE COND.
33-01-1313	ISOBUTANE STRIP. FD. BTMS. EXCH.
33-01-1314	DEFLUORINATOR FD. BTMS. EXCH.
33-01-1315	DEFLUORINATOR FD. HEATER
33-01-1316	DEFLUORINATOR ISOBUTANE CLR.
33-01-1317	ALKYLATE COOLER
33-01-1318	MAIN FRACT. SIDE REBOILER
33-01-1319	MAIN FRACT. SIDE REBOILER
33-01-1320	ISOBUTANE STRIPPER REBOILER
HEATER	
33-01-1401	MAIN FRACT. REBOILER HEATER
PUMPS	
33-01-1506	ACID RERUN PUMP
33-01-1507	ACID RERUN PUMP(SPARE)
33-01-1508	MAIN FRACT. FEED PUMP
33-01-1509	MAIN FRACT. FEED PUMP(SPARE)
33-01-1510	MAIN FRACT. REBOILER PUMP
33-01-1511	MAIN FRACT. REBOILER PUMP(SPARE)
33-01-1512	MAIN FRACT. REFLUX PUMP
33-01-1513	MAIN FRACT. REFLUX PUMP(SPARE)
33-01-1514	CAUSTIC CIRC. PUMP
33-01-1515	CAUSTIC CIRC. PUMP(SPARE)
MISCELLANEOUS	
33-01-4101	CALCIUM FLUORIDE PRECIPITATOR
33-01-4102	HF ACID NEUTRALIZER

0 10 20 40 60 80
SCALE 1" = 20'-0"

	FOR REPORT		
	ISSUED FOR APPROVAL		
	FOR LICENSOR APPROVAL		
	ISSUED CLIENT 50% REVIEW		
	DESCRIPTION		

FOR		
DRAWN	HY/CAD	
CHECKED		
APVD SECT NO	NH	
APVD PROJ MGR		
APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

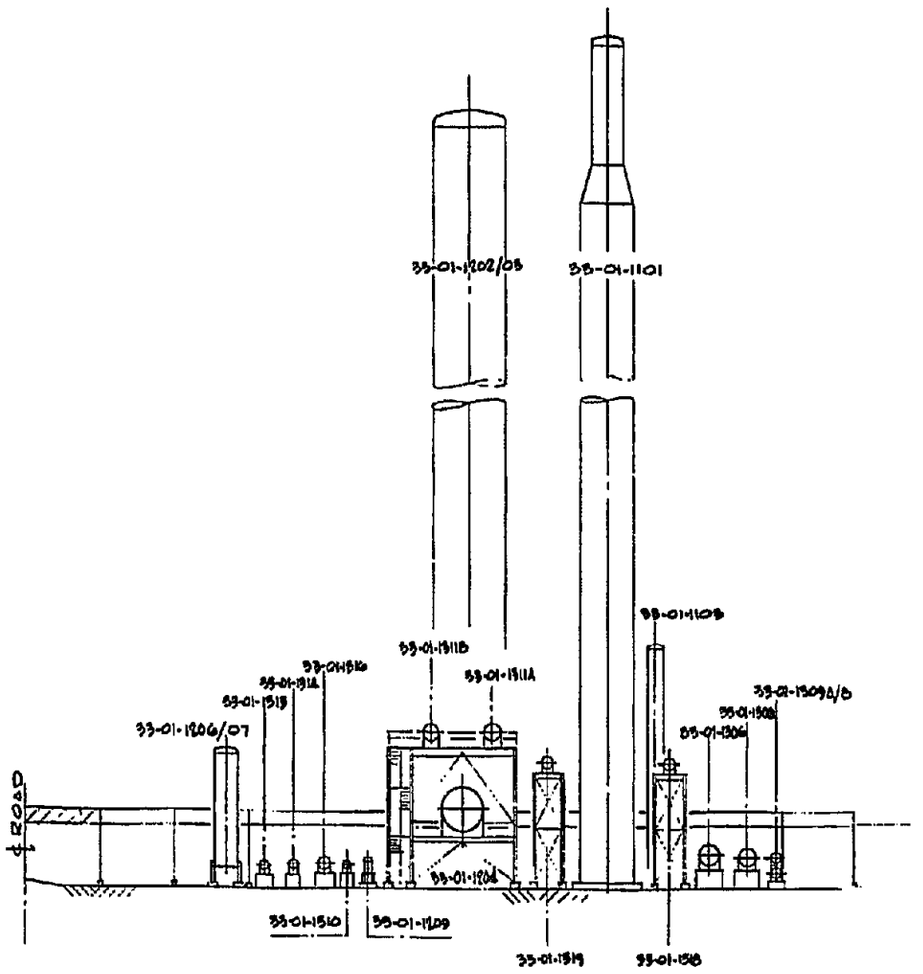
U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE	SCALE	ACCOUNT NUMBER	JOB NUMBER
PLOT PLAN UNIT 33 ALKYLATION	1"=20'-0"	7243	6182
	DOCUMENT NUMBER	D-33-PD-INP	REVISION D



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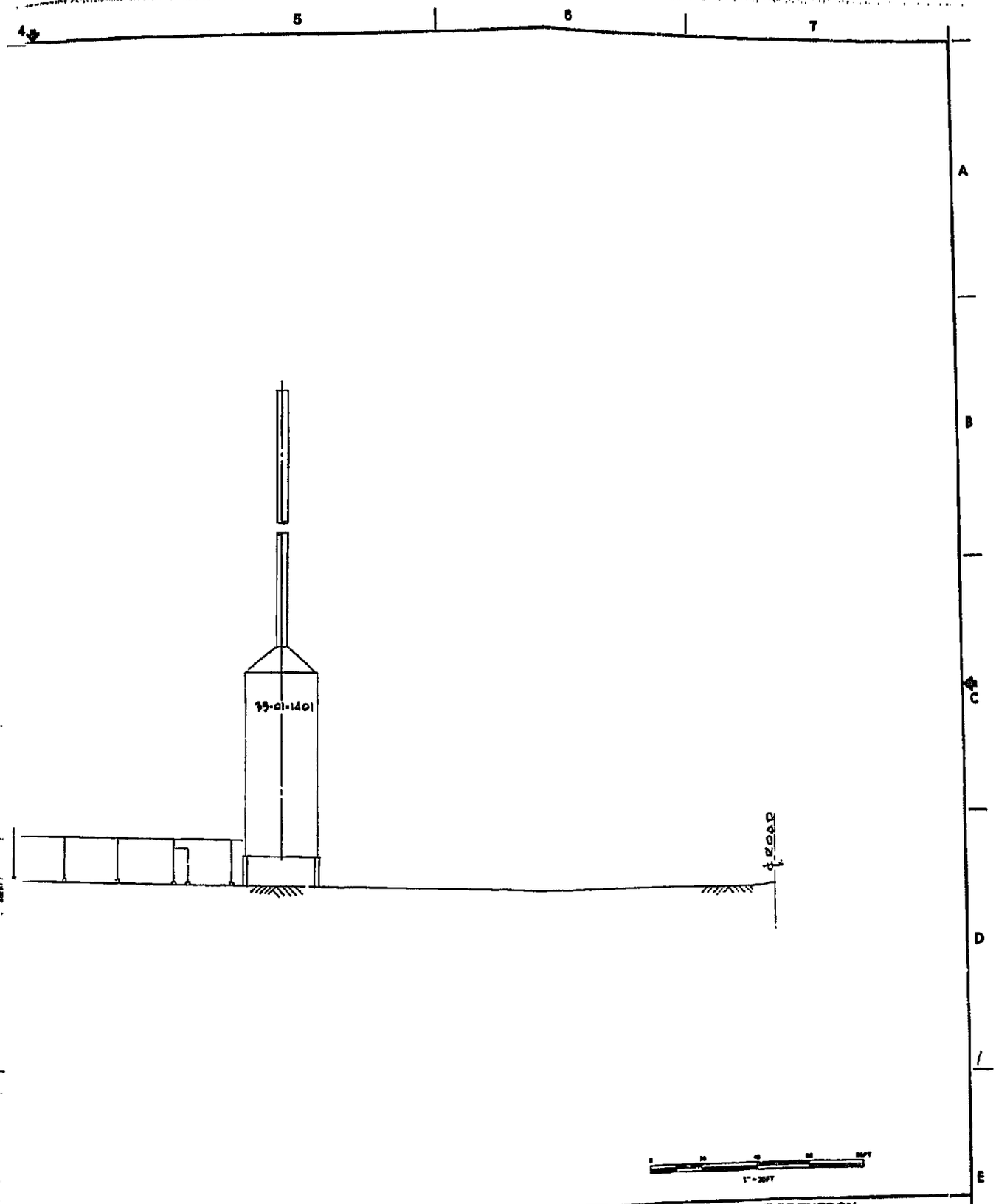
DRAWING NO.	DESCRIPTION	DRAWING NO.	DESCRIPTION									D	5-24-95	NC				
												C	5-8-95	RE				
												B	4-18-95	RE				
												A	4-6-95	RE				



FOR DESIGN REPORT	FOR		
FOR CLIENT APPROVAL	DRAWN	RR	
FOR LICENSOR APPROVAL	CHECKED		
HAVE CLIENT COMMENTS COMP	APVD DSCT MB		
DESCRIPTION	APVD PROJ MGR		
	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ELEVATION UNIT 33 ALKYLATION

SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISIONS
1" = 20'-0"	7249	6132	D

DOCUMENT NUMBER: D-33-PD-2NP

G. Single-Line Diagram

See Volume II, 1.2.12(G) for the Single-Line Diagram for HF Alkylation Unit 33.

1.2.15 ACID GAS REMOVAL - UNIT 34

A selective Rectisol process has been selected to remove sulfur compounds (H_2S/COS) and carbon dioxide (CO_2) from a coal derived synthesis gas. The process uses methanol for physical absorption of the acid gases. The licensor of the proprietary process selected for this project is the Lotepro Corporation. The shifted and unshifted feed gas streams are washed separately. In the regeneration of the methanol, sulfur-bearing gases are isolated and transferred to the sulfur recovery unit for the production of elemental sulfur.

The Acid Gas Removal unit product stream consists of purified synthesis gas that is compressed and used for methanol synthesis.

A. Basis of Design

In the selection of an acid gas removal process, the following design parameters had to be fulfilled for a candidate process to be considered:

(1) A treated product gas purity of less than 0.1 ppmv total sulfur and 3 to 6 volume percent CO_2 achieved by absorption of CO_2, H_2S, and COS from the feed gas.

(2) The CO_2 tail gas stream must contain less than 10 ppmv of total sulfur so that it can be vented to the atmosphere without thermal incineration.

(3) An H_2S-rich acid gas stream containing a minimum of 25% H_2S and suitable for a Claus unit feed must be produced.

(4) The technology must be commercially proven.

The following feed and product stream data summarize the normal operating conditions for the four-module Acid Gas Removal unit.

Feed Streams

Component	Shifted Feedgas (lb mol/hr)	Unshifted Feedgas (lb mol/hr)	Stripping Gas (lb mol/hr)
H_2	73,546.7	23,511.6	-
N_2	513.8	309.2	8,655.6
CO	12,820.3	28,463.3	-
Ar	172.4	103.8	-
CH_4	214.4	129.0	-
CO_2	53,771.4	11,567.3	-
H_2S	1,446.8	827.0	-
COS	12.1	51.0	-
O_2	-	-	-
Total Dry, lb mol/hr	142,497.9	64,962.2	8,655.6
H_2O	171.4	75.3	-
Total Wet, lb mol/hr	142,669.3	65,037.5	-
Total, lb/hr	2,951,690	1,401,320	242,500
Pressure, psia	790	790	33
Temperature, °F	100	100	68

Feed Streams (Contd)

Component	Air to Torvex (lb mol/hr)	Wash Water to Tail Gas Wash Column (lb mol/hr)
H_2	-	-
N_2	3,077.9	-
CO	-	-
Ar	39.5	-
CH_4	-	-
CO_2	-	-
H_2S	-	-
COS	-	-
O_2	828.7	-
Total Dry, lb mol/hr	3,946.1	-
H_2O	49.4	30,595.0
Total Wet, lb mol/hr	3,995.5	30,595.0
Total, lb/hr	87,810	551,200
Pressure, psia	63	16
Temperature, °F	82	100

Product Streams

Component	Shifted Syngas (lb mol/hr)	Unshifted Syngas (lb mol/hr)	Total Syngas (lb mol/hr)	Acid Gas to Claus (lb mol/hr)
H_2	73,392.8	23,359.5	96,752.3	0.6
N_2	508.2	304.8	813.0	119.7
CO	12,819.8	27,880.3	40,700.1	0.3
Ar	166.4	101.2	267.6	Trace
CH_4	196.6	122.7	319.2	Trace
CO_2	733.3	3,480.2	4,213.4	3,331.7
H_2S	Trace		Trace	2,273.7
COS	Trace	Trace	Trace	62.8
O_2				
Total Dry, lb mol/hr	87,817.1	55,248.7	143,065.6	5,788.8
H_2O	-	-	-	-
CH_3OH	4.3	3.0	7.3	6.0
Total Wet, lb mol/hr	87,821.4	55,251.7	143,072.9	5,794.8
Total, lb/hr	563,490	995,830	1,559,320	231,450
Pressure, psia	760	766	760	25
Temperature, °F	82	82	82	92

Product Streams (Contd)

Component	Total Tail Gas (lb mol/hr)	Waste-water (lb mol/hr)	Water from Wash Column (lb mol/hr)
H_2	5.0	-	-
N_2	11,624.0	-	-
CO	35.5	-	-
Ar	47.7	-	-
CH_4	5.6	-	-
CO_2	58,354.2	-	19.9
H_2S	0.1	-	-
COS	0.3	-	-
O_2	360.2	-	-
Total Dry, lb mol/hr	70,432.6	-	19.9
H_2O	3,511.4	327.7	27,480.9
CH_3OH	1.6	0.2	14.0
Total Wet, lb mol/hr	73,945.6	327.9	27,514.8
Total, lb/hr	2,971,680	5,910	496,420
Pressure, psia	16	46	17
Temperature, °F	145	279	65

B. Process Selection Rationale

The selective Rectisol process as offered by Lotepro Corporation is a commercially proven technology. Its capital and operating costs are lower than costs for other processes examined. For the Gasoline Plant, the process has been configured into four identical trains. The water/methanol separation is configured into two trains. This arrangement provides flexibility and a high turndown ratio. The licensor guarantees the process performance and utility consumptions.

1. Pressure. The higher partial pressure of CO_2 and H_2S in the feed gas results in increased absorption rates and solvent temperature rises in the absorption columns, reducing the solubility of acid gas components in the solvent and requiring a higher solvent circulation. A cold solvent presaturated with CO_2 minimizes the solvent circulation rate. There are a number of Rectisol plants that operate at higher pressures than this plant will require. No problems are anticipated related to system pressure.

2. Gas Impurities. Impurities enter the gas purification unit in the feed gas stream and are produced in the unit by side reactions with circulating solvent.

A sidestream of spent methanol is continuously distilled in a methanol fractionator that will remove all dirts and dissolved impurities via a bottom waste stream.

3. Maintenance and Operation Characteristics. In the Rectisol process, hydraulic turbines are not required to recover energy; it makes use of fewer rotary machines and vessels compared to competitive processes. Therefore, its maintenance cost will be lower than the maintenance cost required for other processes. Also, the Rectisol process should be somewhat easier to start up, operate, and shut down.

4. Variations in H_2S Concentration. The sulfur content of the coal may vary from 2.3 to 5.1 weight percent. The concentration of sulfur compounds (H_2S + COS) present in the feed to the gas purification system may vary from 1.3 to 3.3 volume percent. In order to avoid large variations in H_2S concentration of the feed going to sulfur recovery unit (which may vary from 25 to 40 volume percent if not controlled), the gas purification system must be flexible enough to separate the correct amount of CO_2 and produce a constant composition feed for the sulfur recovery unit.

The Rectisol process achieves this objective by adjusting the amount of CO_2 in the vent stream in a stripper/reabsorber column as discussed in the Rectisol process description.

5. Equipment Availability. Equipment availability is defined as the ratio of days each piece of equipment is available to operate, whether operating or not, to days in a fixed period of time (usually the period between two planned major overhauls).

The Rectisol acid gas removal process uses conventional equipment, simple in design. The availability of equipment in the systems is better than 97%.

6. Proven Technology. At least nine plants employing the Rectisol process have been successfully constructed and are being operated in the United States. Table II-1.2.15-1 shows the list of the plants, plant capacities, and other process variables. Many other plants that utilize the Rectisol process are operated outside the United States.

C. Process Description

Refer to Process Flow and Control Diagrams D-34-MP-1NP, -2NP, -3NP, -4NP, -5NP, and -6NP for the acid gas removal material balance. The equipment arrang ment is shown on Drawings D-34-PD-1NP and -2NP.

Table II-1.2.15-1 - List of Rectisol Units
Installed in the United States

Customer	Order	Feed Gas (MMSCFD)	Pressure (psig)	Components Removed (vol %)
Texaco Inc.[a] Wilmington, California	1965	80.0 (H_2 rich gas from P.O.)	460	CO_2, H_2S
Texaco Inc. Montebello, California	1966	0.90 (H_2 rich gas from P.O.)	1,100-2,500	CO_2, H_2S
Borden Chemical Co. Geismar, Louisiana	1966	17.0	300	CO_2
Rohm & Haas Co. Philadelphia, Pennsylvania	1966	13.0	340	CO_2
Brooklyn Union Gas Co. Brooklyn, New York	1968	12.0	340	CO_2
Long Island Lighting Co.[a] Holbrook, New York	1969	4.3	600	CO_2, H_2S
American Air Liquide for Monsanto Texas City, Texas	1969	53.0 (H_2 rich gas from steam reformer)	340	CO_2, 10.2% → 20 ppmv
Celanese Chemical Corp. Clear Lake, Texas	1975	(H_2 rich gas from P.O.)	425	CO_2, H_2S
Syngas (Dupont U.S.I.) Deer Park, Texas	1976	(H_2 rich gas from P.O.)	840	CO_2, H_2S (2 stages)

[a]Turnkey Project

1. H_2S/CO_2 Removal. The shifted and unshifted feed gases that are supplied to the Acid Gas Removal unit in separate streams are injected with methanol tc prevent the formation of ice and hydrates as the gas is cooled down in Heat Exchangers 34-01-1301 and 34-01-1308 against purified product gas and cold tail gas. After separation of the condensed methanol-water mixture in Knockout Drums 34-01-1201 and 34-01-1205, the shifted gas enters Shifted Gas Methanol Wash Column 34-01-1101. The unshifted feed gas enters Unshifted Gas Methanol Wash Column 34-01-1104. Both streams will be washed with methanol.

In the upper part of Shifted Gas Methanol Wash Column 34-01-1101, CO_2 is removed to the required level with cold lean methanol from the warm regeneration section. In the bottom section of Column 34-01-1101, H_2S + COS is absorbed down to 0.1 ppm. In order to minimize the temperature rise in the lower section caused by the heat of solution, a split-stream of CO_2-loaded methanol from the CO_2 wash section of the absorber is used for sulfur removal. The heat of solution for the CO_2 absorption is removed by temperature rise of the downstream flowing methanol and by cooling the methanol in Exchanger 34-01-1302 against vaporizing refrigerant.

As the solubility of CO_2 in methanol is less than the solubility of H_2S, the methanol flow of the CO_2 removal section of Wash Column 34-01-1101 must be greater than to the H_2S removal section. The methanol surplus from the CO_2 removal section of the tower is taken from the middle of the column.

The unshifted feed gas in Unshifted Gas Methanol Wash Column 34-01-1104 is washed with cold lean methanol. The purified gas leaving the top of the column is warmed in Unshifted Feed Gas Cooler 34-01-1308 and then combined with the purified shifted gas. The heat of solution is removed by warming the solvent and vaporizing external refrigerant in Methanol Chiller 34-01-1309.

The H_2S-loaded methanol from the s|he H_2S-loaded methanol from the s| 34-01-1101 is routed to Recycle Gas Flash Drum 34-01-1203,| Recycle Gas Flash Drum 34-01-1203, at an intermediate pressure to recover dissolved H_2 an|ressure to recover dissolved H_2 an from Drum 34-01-1203 is recycled by Recycle Gas Compressor s recycled by Recycle Gas Compressor feed gas.

The same procedure is used for the he same procedure is used for the from Column 34-01-1101, which is expanded into Drum 34|01, which is expanded into Drum 34 flashed gases recompressed by Compressor 34-01-1801. ssed by Compressor 34-01-1801.

The H_2S-loaded methanol from the|he H_2S-loaded methanol from the 34-01-1104 is flashed in Recycle Gas Flash Drum 34-0|ed in Recycle Gas Flash Drum 34-C dissolved H_2 and CO to be recycled via Compressor 34-0|p be recycled via Compressor 34-01 from Drum 34-01-1206 is flashed in the sump of CO Strippin|s flashed in the sump of CO Strippin to remove the bulk of dissolved CO. dissolved CO.

2. <u>CO-Rich Tail Gas</u>. To limit the CO |<u>O-Rich Tail Gas</u>. To limit the CO | gas, a CO-rich gas is generated by expanding separately t|generated by expanding separately t| from Flash Drums 34-01-1202, 34-01-1203, and 34-01|-01-1202, 34-01-1203, and 34-01 34-01-1106. The CO-rich tail gas leaves the top of CO|ich tail gas leaves the top of CO 34-01-1106. After warming in Exchanger 34-01-1301, it is|rming in Exchanger 34-01-1301, it is catalytic incineration before venting to the atmosphere. before venting to the atmosphere.

3. <u>H_2S Enrichment</u>. The methanol from t|<u>H_2S Enrichment</u>. The methanol from t| 34-01-1106 will be fed into H_2S Concentration Colum|d into H_2S Concentration Colum increase the H_2S concentration in the tail gas feed to|entration in the tail gas feed to removal process, CO_2 is stripped from the vent stream in| stripped from the vent stream in of the column, and H_2S is rewashed in the upper | H_2S is rewashed in the upper | sulfur-free methanol from Drum 34-01-1202 not used for re|om Drum 34-01-1202 not used for re 34-01-1104.

The tail gas from Column 34-01-1102|he tail gas from Column 34-01-1102 sulfur-free. The gas is warmed in Exchanger 34-01-1301, an| warmed in Exchanger 34-01-1301, an the methanol content is reduced in Water Wash Column 34-01-| reduced in Water Wash Column 34-01-

II-1.2.15-10

At an intermediate tray of Column 34-01-1102, cold methanol is withdrawn and used as refrigerant in Exchanger 34-01-1307. To provide the necessary head, Pumps 34-01-1503 and -1504 are used.

4. Warm Regeneration. The methanol from the sump of Column 34-01-1102, now enriched in H_2S, is pumped by Cold Stripper Bottoms Pump 34-01-1507 through Heat Exchangers 34-01-1310 and 34-01-1311 to Methanol Regenerator Column 34-01-1103. The complete desorption of H_2S and CO_2 from the loaded methanol will take place here by means of methanol vapors, generated in Regenerator Reboiler 34-01-1313.

The vapors from the top of Column 34-01-1103 will be cooled in Water Cooler 34-01-1312 and then in Exchangers 34-01-1314 and 34-01-1315 against the cold H_2S fraction and refrigerant. The condensate is separated in Separator 34-01-1208 and routed back via Cold Stripper Bottoms Pump 34-01-1507 to the regeneration column. The H_2S fraction leaving Drum 34-01-1208 will be warmed in Exchanger 34-01-1314 and will leave the unit as feedstock for a Claus sulfur recovery plant.

The regenerated methanol leaving the sump of Column 34-01-1103 is cooled in Regenerator Bottoms Exchanger 34-01-1311 to ambient temperature and buffered in Methanol Collection Vessel 34-01-1207 before being pumped to the methanol wash columns for shifted and unshifted gas. Its temperature is lowered in Exchangers 34-01-1310 and 34-01-1307 against cold loaded methanol. A small portion of the regenerated methanol is injected into the two feed gas streams.

5. Methanol-Water Separation. The condensate from Drums 34-01-1201 and 34-01-1205 that contains a mixture of methanol and water is heated in Reflux Cooler 34-01-1317 and fed to Methanol Fractionator 34-01-1105, where methanol and water are separated by distillation. The column is heated by means of medium-pressure steam in Methanol Fractionator Reboiler 34-01-1316. The methanol vapor from the top of Column 34-01-1105

will be routed to the hot regeneration, while the water is withdrawn as waste. The reflux supplied to Column 34-01-1105 is regenerated methanol from Column 34-01-1103, pumped by Pump 34-01-1509 and cooled in Exchanger 34-01-1317.

6. General. In order to reduce the methanol losses, a methanol slop system is provided. It consists of a buried main methanol header with branch connections to all pieces of equipment where leakages of methanol can occur.

The methanol header will collect such leakages into Methanol Slop Drum 34-01-1210, also buried. Vertical Pump 34-01-1511 is installed in order to recycle the solvent to the regeneration section of the unit.

Storage Tank 34-01-1211 is used to store methanol. A filling pump is provided. The tank is used to collect methanol streams during plant shutdowns. In such cases, when the methanol is not pure, it is made up through the regeneration section.

D. Risk Assessment

Shifted and unshifted raw feed gases are treated in the Rectisol unit for the removal of CO_2, H_2S, COS, higher hydrocarbons, gum formers, and other impurities that are produced in the coal gasifier.

Crude gas, saturated with water vapor, will be indirectly cooled by cold purified gas and external refrigeration. Icing will be prevented by the injection of methanol. The gas then enters the first absorber, where sulfur compounds and CO_2 will be removed to the required level by washing the raw feed gas with cold methanol. The overhead from the absorber column is routed to the methanol synthesis unit, and the rich methanol from the absorber bottoms, after flushing and heating, is regenerated completely in the H_2S regenerator.

Although methanol is classified as toxic and flammable, these potential hazards are controlled to acceptable levels of safety by application of standard methods for plant design and operational handling. This plant will be the largest installation of its kind in the world. Thus, it is important to examine some of its risk factors and evaluate the process reliability.

1. Capacity. The large capacity of the plant will not cause any processing problem. In order to avoid mechanical and installation problems, the system is designed in four parallel trains.

2. Integration With Other Processing Units. The Rectisol process has not been operated in conjuction with the Texaco Coal Gasification Process. However, it has been used in conjunction with a different coal gasification process producing gas of similar composition in a plant in South Africa. The operation of the African installation has been satisfactory, and there is no reason to believe that the performance would be different in the W.R. Grace & Co. project.

3. Equipment. The Rectisol process uses equipment of simple and conventional design. In certain parts of this system, spiral wound exchangers are used. Lotepro Corporation has used spiral wound exchangers of comparable size and duties in its other installations without mechanical or operational difficulties.

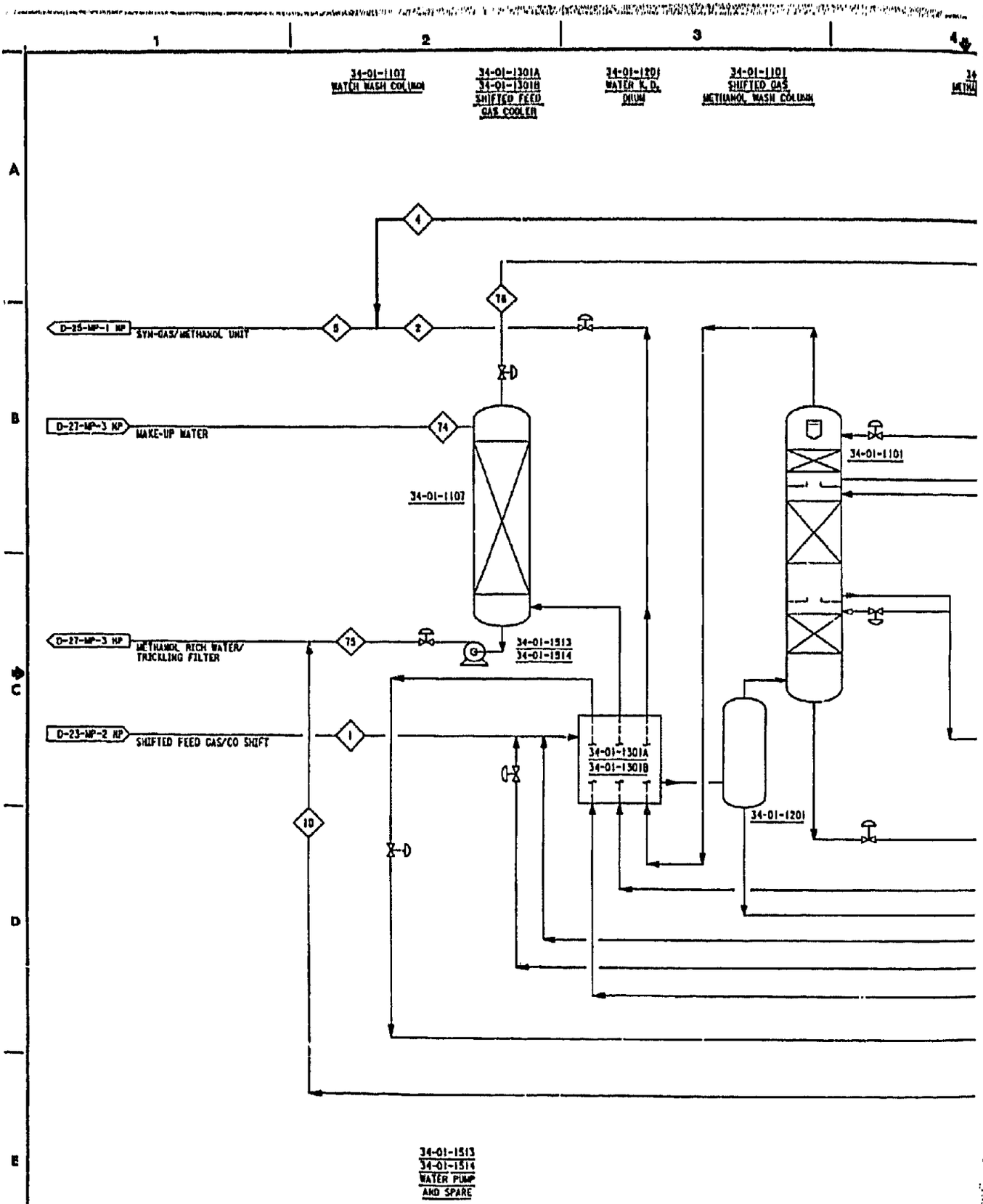
4. Pressure. There are several Rectisol acid gas removal installations that operate at higher pressures than the 790-psia pressure required for this project. Pertinent information accumulated from the experience with high-pressure installations is incorporated into the final design of this project.

The risk of designing a Rectisol acid gas removal process with a feed rate of 2 billion scfd at 790 psia has been reduced to a low level by attention to the detailed engineering design and accumulated know-how from other installations. The licensor guarantees a plant availability of better than 97% for the Rectisol section of the project.

E. Process Flow and Control Diagrams (Including Material Balance)

Process Flow and Control Diagrams for Acid Gas Removal Unit 34 are as follows:

Drawing No.	Title
D-34-MP-1NP	PFCD Acid Gas Removal - Methanol Wash
D-34-MP-2NP	PFCD Acid Gas Removal - Gas Separation
D-34-MP-3NP	PFCD Acid Gas Removal - Methanol Cooling
D-34-MP-4NP	PFCD Acid Gas Removal - Methanol Wash
D-34-MP-5NP	PFCD Methanol Storage - Methanol Storage
D-34-MP-6NP	Material Balance - Acid Gas Removal



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ENG-DC-83 (12/79)

34-01-1302
METHANOL CHILLER

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THERE ARE FOUR TRAINS IN THIS UNIT

UNSHIFTED SYN-GAS/34-01-1308 D-34-MP-4 NP

TAIL GAS/34-01-1401 D-34-MP-4 NP

TAIL GAS/34-01-1102 D-34-MP-2 NP

H_2S METHANOL/34-01-1203 D-34-MP-2 NP

LEAN METHANOL/34-01-1307 D-34-MP-2 NP

34-01-1302

REFRIGERANT GAS

REFRIGERANT LIQUID

CO_2 LOADED METHANOL/34-01-1305 D-34-MP-2 NP

METHANOL WATER/34-01-1317 D-34-MP-3 NP

RECYCLE GAS/34-01-1801 D-34-MP-2 NP

LEAN METHANOL/34-01-1501 D-34-MP-3 NP

CO RICH TAIL GAS/34-01-1106 D-34-MP-2 NP

CO RICH TAIL GAS/34-01-2501 D-34-MP-4 NP

D-34-MP-5 NP

EQUIPMENT SHOWN ON THIS DRAWING:
34-01-1101
34-01-1107
34-01-1201
34-01-1301A, B
34-01-1302
34-01-1513
34-01-1514

D34MP1NP.DGA

LOTEPRO CORPORATION
LOW TEMPERATURE PROCESSING AND EQUIPMENT
NEW YORK, N.Y.

U.S. DEPARTMENT OF ENERGY

BASKETT W.R. GRACE & CO. KENTUCKY
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT

DESCRIPTION	DRAWN	CHECKED	APVD SECT MGR	APVD PROJ MGR	APVD CLIENT
FOR DESIGN REPORT					
FOR CLIENT APPROVAL					
REVISED FOR LICENSOR APPROVAL					
FOR LICENSOR APPROVAL					
FOR CLIENT 50% REVIEW					

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

TITLE: PROCESS FLOW & CONTROL DIAGRAM ACID GAS REMOVAL - UNIT 34 METHANOL WASH

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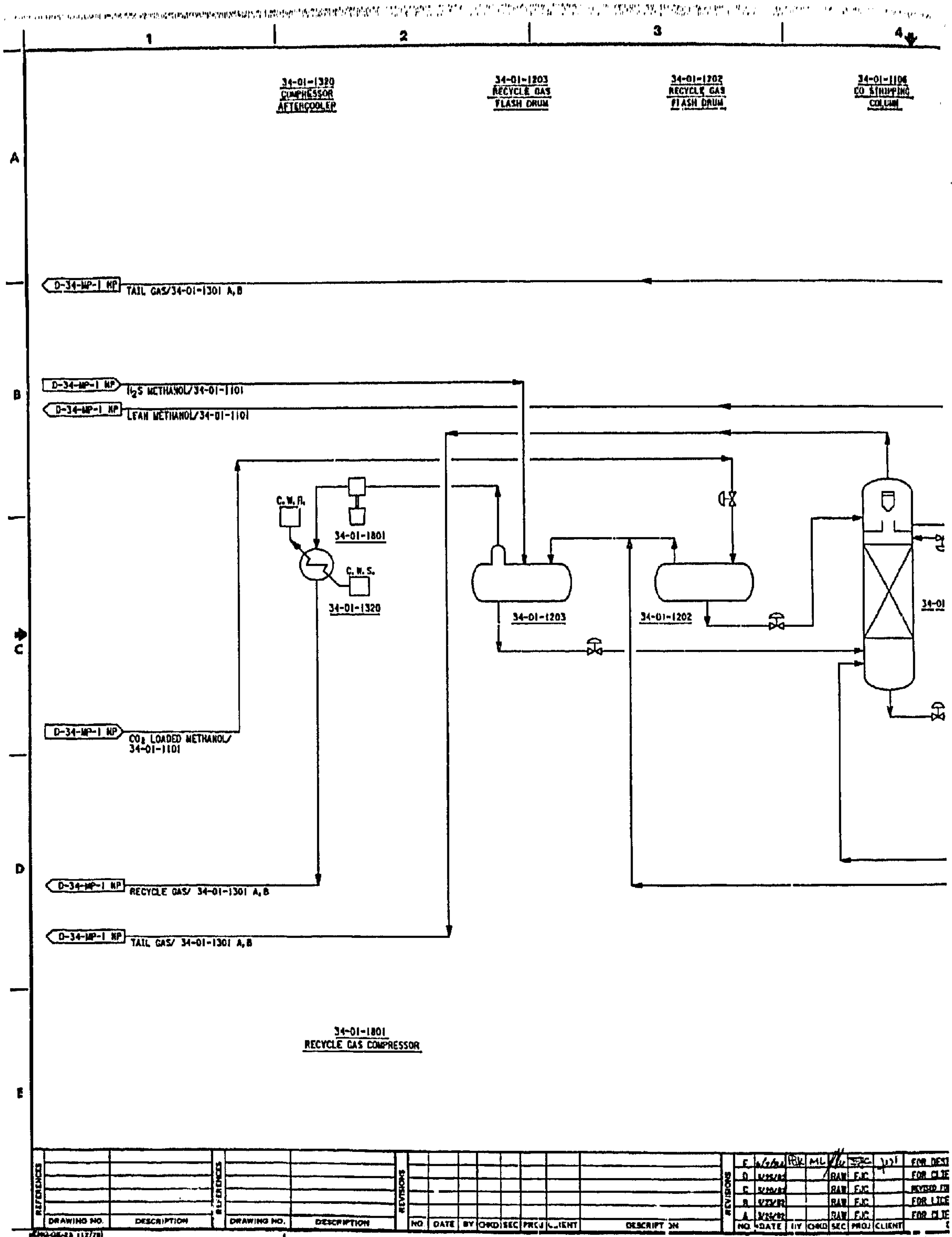
DOCUMENT NUMBER: D-34-MP-1-NP

REVISION: E



34-01-1320
COMPRESSOR AFTERCOOLER
34-01-1203
RECYCLE GAS FLASH DRUM
34-01-1202
RECYCLE GAS FLASH DRUM
34-01-1106
CO STRIPPING COLUMN
D-34-MP-1 MP
TAIL GAS/34-01-1301 A,B
D-34-MP-1 MP
H2S METHANOL/34-01-1101
D-34-MP-1 MP
LEAN METHANOL/34-01-1101
C.W.R.
C.W.S.
34-01-1801
34-01-1320
34-01-1203
34-01-1202
D-34-MP-1 MP
CO2 LOADED METHANOL/ 34-01-1101
D-34-MP-1 MP
RECYCLE GAS/ 34-01-1301 A,B
D-34-MP-1 MP
TAIL GAS/ 34-01-1301 A,B
34-01-1801
RECYCLE GAS COMPRESSOR
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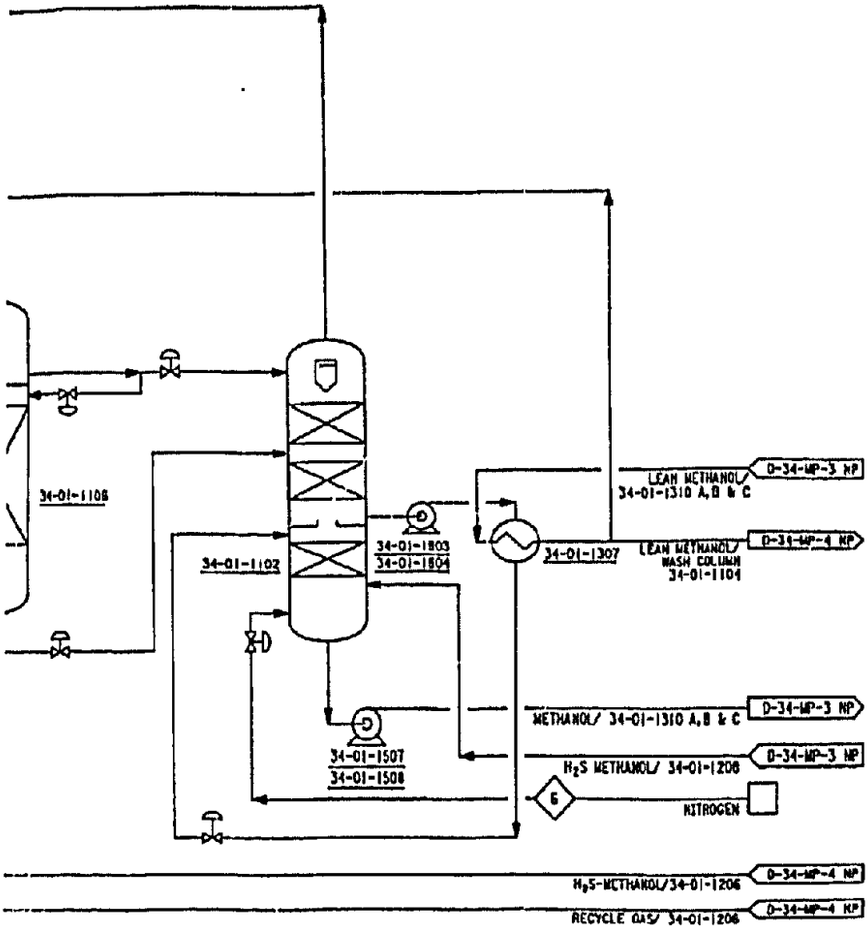
34-01-1102
H_2S CONCENTRATION
COLUMN

34-01-1307
LEAN
METHANOL COOLER

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING IS FOR ONE TRAIN. THERE ARE FOUR TRAINS IN THIS UNIT.



34-01-1507
34-01-1508
COLD STRIPPER
BOTTOMS PUMP & SPARE

34-01-1503
34-01-1504
FLASH SEPARATOR
FEED PUMP & SPARE

EQUIPMENT SHOWN ON THIS DRAWING:
34-01-1102
34-01-1106
34-01-1202
34-01-1203
34-01-1307
34-01-1320
34-01-1503
34-01-1504
34-01-1507
34-01-1508
34-01-1801

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LOTEPRO CORPORATION
LOW TEMPERATURE PROCESSING AND EQUIPMENT
NEW YORK, N.Y.

U.S. DEPARTMENT OF ENERGY
BASKETT — W.R. GRACE & CO. — KENTUCKY
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT

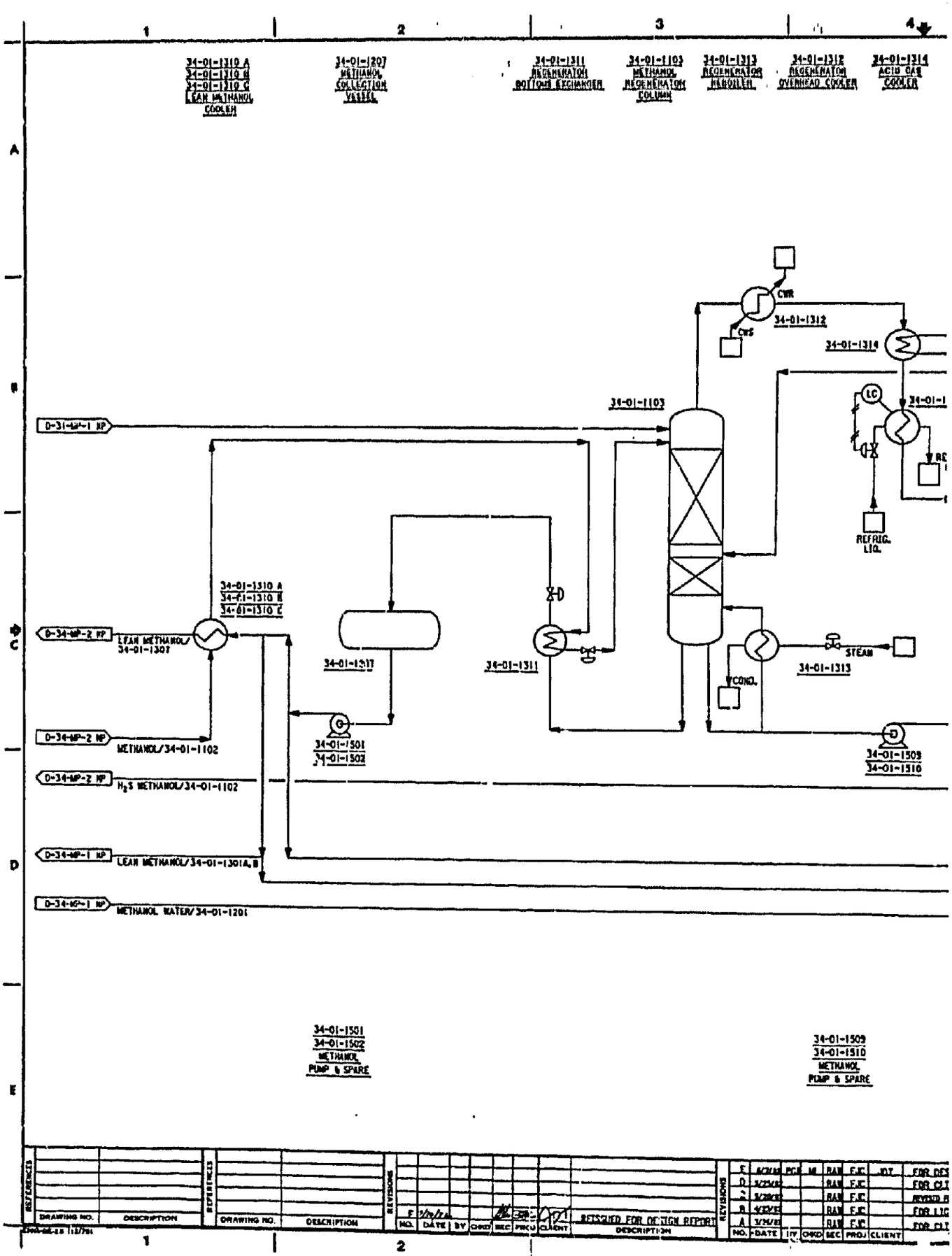
FOR DESIGN REPORT	DRAWN	
FOR CLIENT APPROVAL	CHECKED	
REVISED FOR LICENSOR APPROVAL	APPD DEPT MGR	
FOR LICENSOR APPROVAL	APPD PROJ MGR	
FOR CLIENT "GC" REVIEW	APPD CLIENT	
DESCRIPTION		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

TITLE: PROCESS FLOW & CONTROL DIAGRAM
ACID GAS REMOVAL - UNIT 34
GAS SEPARATION

SCALE: NONE | CONTRACT NUMBER: 2800 6182 | REVISION: E

D-34-MP-2 NP



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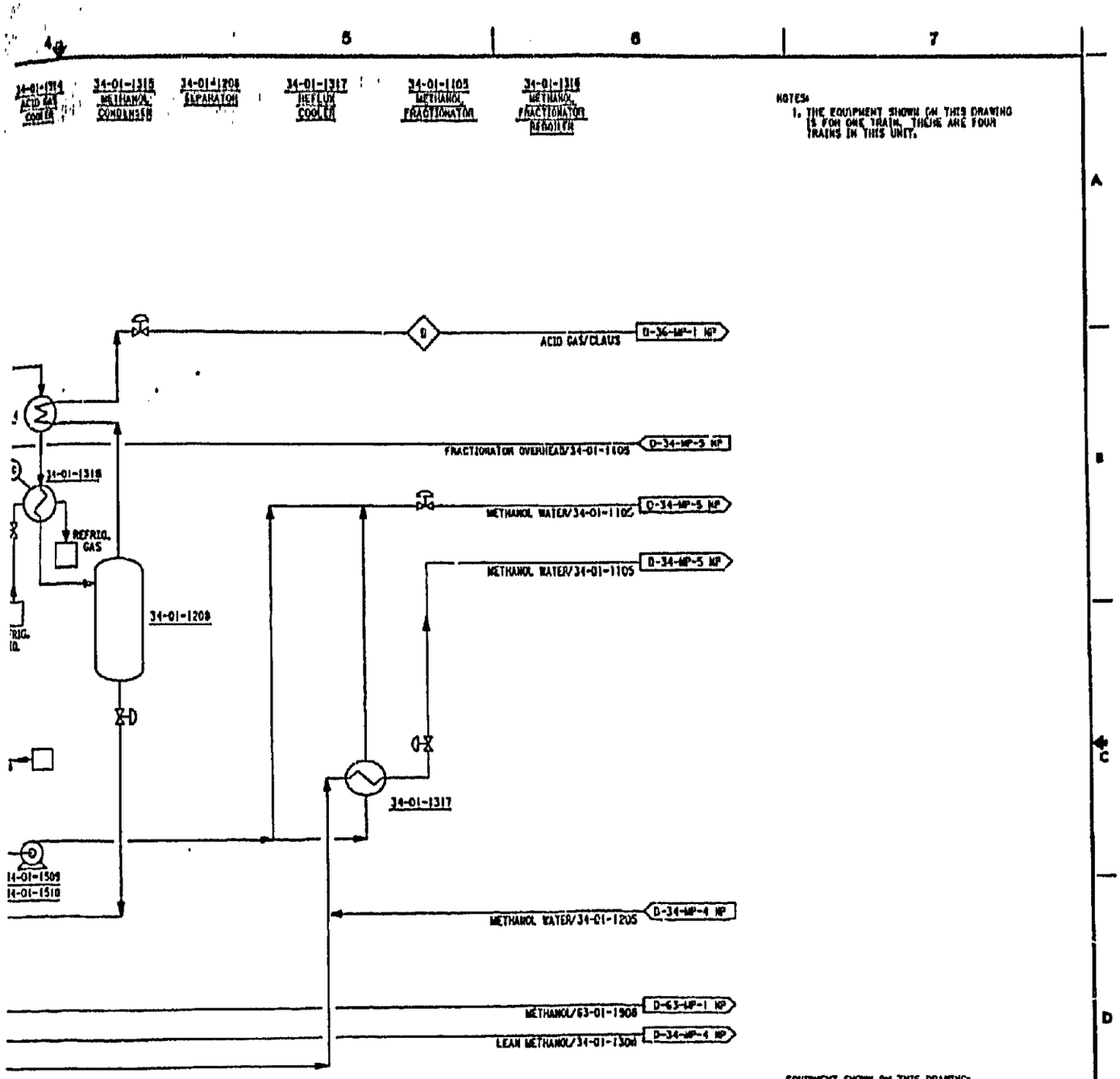

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LOTEPRO CORPORATION
LOW TEMPERATURE PROCESSING AND ENGINEERING
SITE VISIT, N.Y.

U.S. DEPARTMENT OF ENERGY

BASKETT — M.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

INT	DESCRIPTION	DRAWN	CHECKED	APVD DEPT MGR	APVD PROJ MGR	APVD CLIENT
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	FOR CLIENT APPROVAL					
	REVISED FOR LICENSOR APPROVAL					
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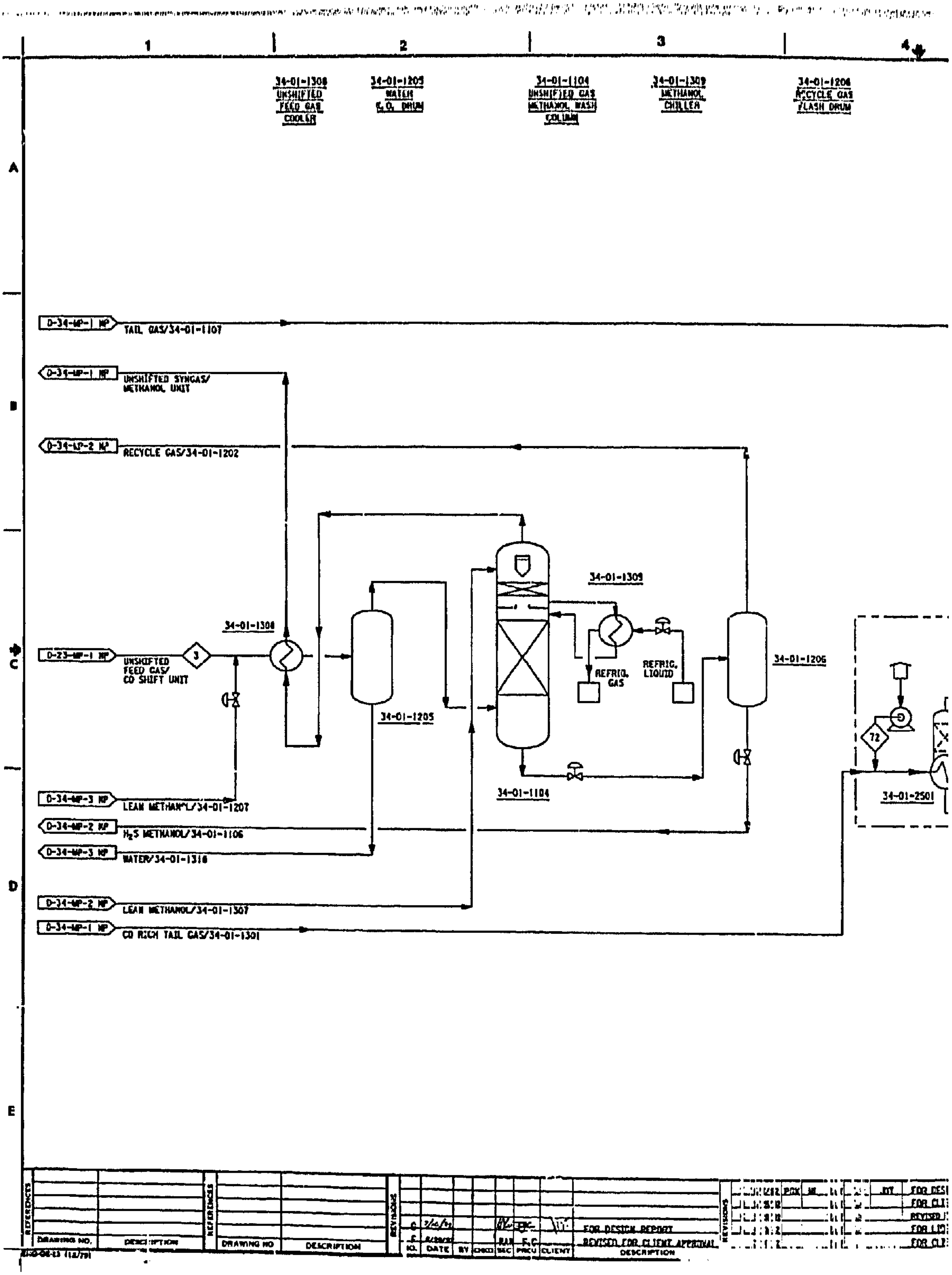
THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

VIEW: PROCESS FLOW & CONTROL DIAGRAM
ACID GAS REMOVAL - UNIT 34
METHANOL COOLING

SCALE: NONE | DRAWING NUMBER: 2600 | REVISION: 6182

D-34-MP-3-NP

REVISION: F



1
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A
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C
D
E
34-01-1308 UNSHIFTED FEED GAS COOLER
34-01-1205 WATER C.O. DRUM
34-01-1104 UNSHIFTED GAS METHANOL WASH COLUMN
34-01-1309 METHANOL CHILLER
34-01-1206 RECYCLE GAS FLASH DRUM
D-34-MP-1 MP
TAIL GAS/34-01-1107
D-34-MP-1 MP
UNSHIFTED SYNGAS/ METHANOL UNIT
D-34-MP-2 MP
RECYCLE GAS/34-01-1202
D-23-MP-1 MP
UNSHIFTED FEED GAS/ CO SHIFT UNIT
3
34-01-1308
34-01-1205
34-01-1309
REFRIG. GAS
REFRIG. LIQUID
34-01-1206
34-01-1104
72
34-01-2501
D-34-MP-3 MP
LEAN METHAN^L/34-01-1207
D-34-MP-2 MP
H2S METHANOL/34-01-1106
D-34-MP-3 MP
WATER/34-01-1316
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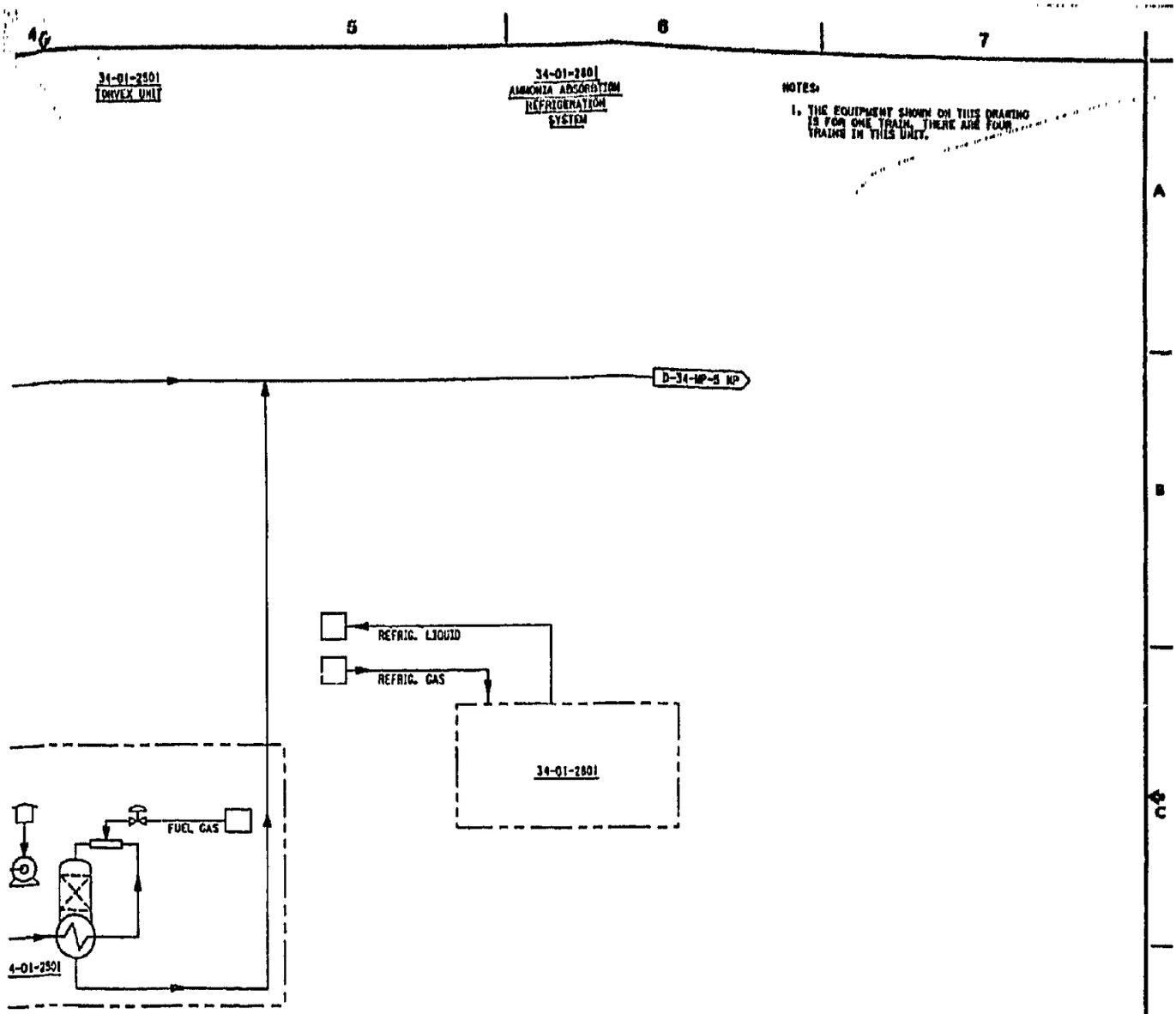

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34-01-1308
34-01-1309
34-01-2501
34-01-2801

D34MP4MP.DGA

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	FOR CLIENT APPROVAL
	REVISED FOR LICENSOR APPROVAL
	FOR LICENSOR APPROVAL
	FOR CLIENT 50% REVIEW

LOTEPRO CORPORATION
LOW TEMPERATURE PROCESSING AND DESIGNS
NEW YORK, N.Y.

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

60,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PROCESS FLOW & CONTROL DIAGRAM
ACID GAS REMOVAL - UNIT 34
METHANOL WASH

JOB NO.	CONTRACT NO.	SHEET NO.	REVISION
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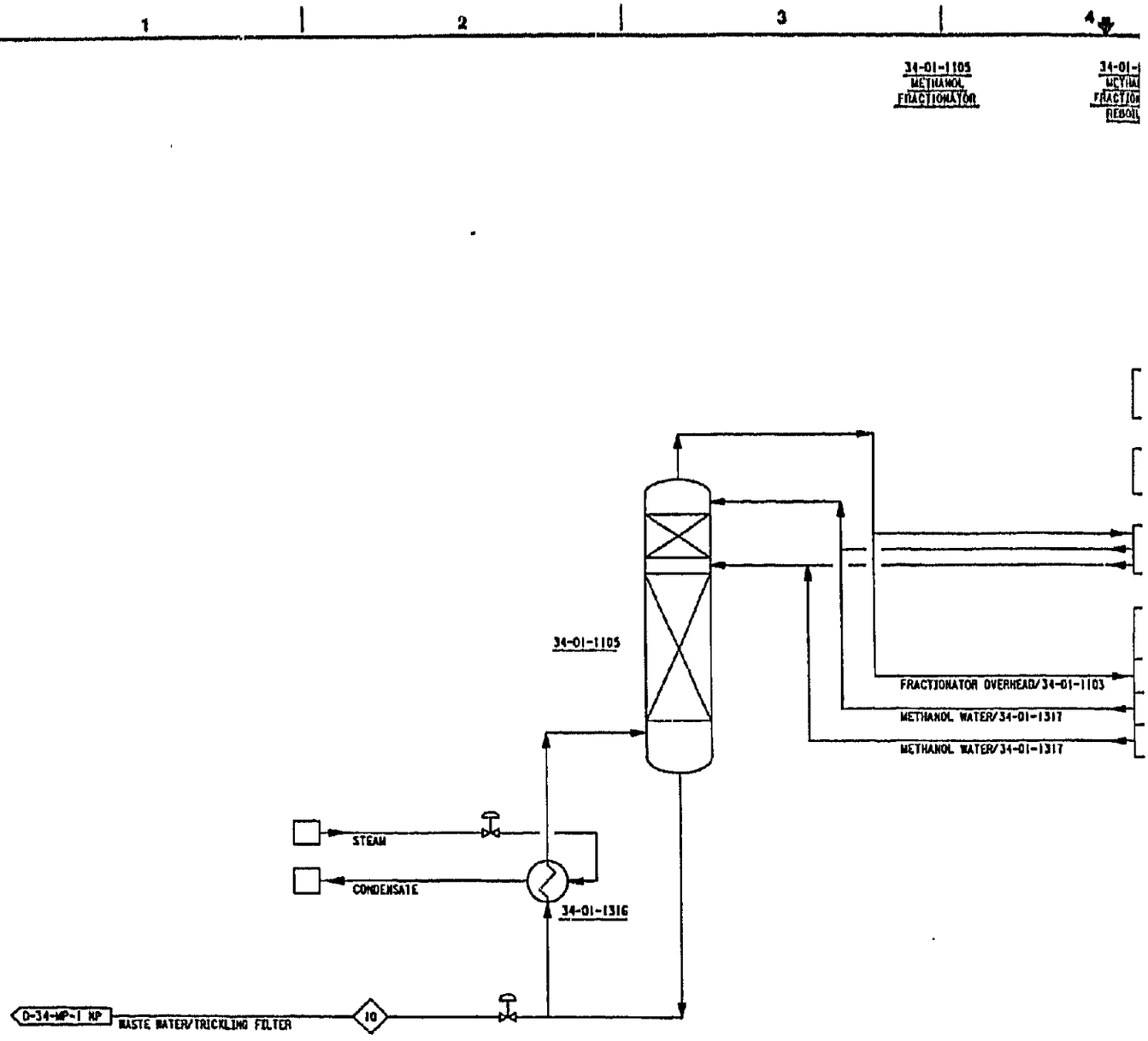
D-34-MP-4-NP



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REVISIONS

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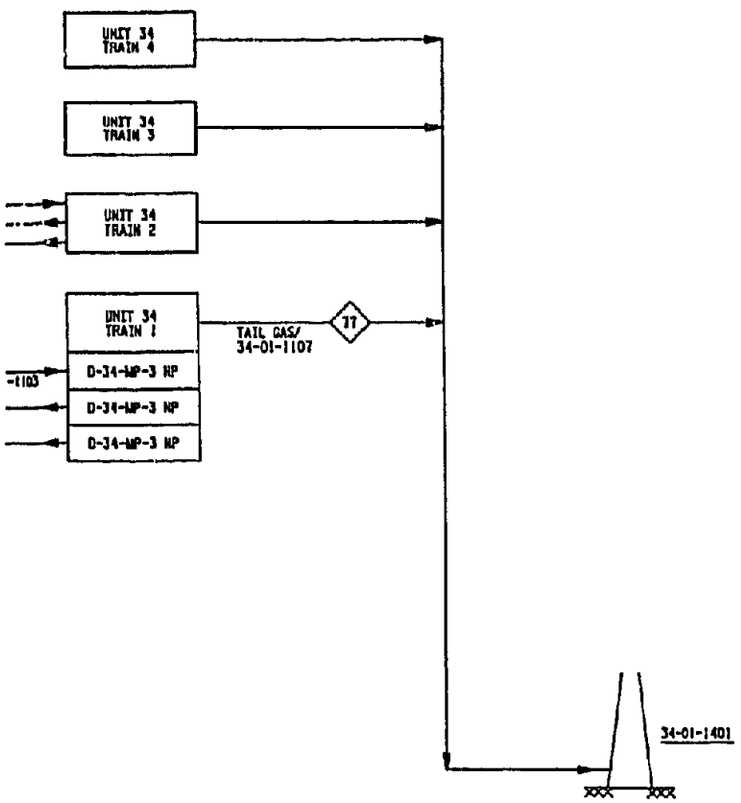
E	6/27/12	PCK	ML	RAW	FJC	IDT FOR DESI
D	5/25/12			RAW	FJC	FOR CLII
C	5/25/12			RAW	FJC	REVISED F
B	4/27/12			RAW	FJC	FOR CLII
A						NOT ISSU

34-01-1316
METHANOL FRACTIONATOR REBOILER

34-01-1401
STACK

NOTES:
1. THE METHANOL FRACTIONATOR AND REBOILER ARE COMMON TO TWO OF FOUR TRAINS. THE STACK IS COMMON TO ALL FOUR TRAINS.



EQUIPMENT SHOWN ON THIS DRAWING:
34-01-1105
34-01-1316
34-01-1401

D34MP5KP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PROCESS FLOW AND CONTROL DIAGRAM
ACID GAS REMOVAL - UNIT 34
METHANOL STORAGE

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-34-MP-5 NP

REVISION: G

NT	DESCRIPTION	DR	CH	APVD SECT MGR	APVD PROJ MGR	APVD CLIENT
	FOR DESIGN REPORT					
	FOR CLIENT APPROVAL					
	REVISED FOR LICENSOR APPROVAL					
	FOR LICENSOR APPROVAL					
	NOT ISSUED					

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

STREAM NUMBER		1		2		3		4		
STREAM NAME		SHIFTED FEEDGAS		SHIFTED SYNGAS		UNSHIFTED FEEDGAS		UNSHIFTED SYN-GAS		
COMPONENT	MOL. WT.	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-
H_2	2.016	18,367.0	51.61	18,348.2	83.57	5,878.0	36.19	5,839.4	42.28	24
N_2	28.016	128.5	0.36	127.1	0.58	77.3	0.48	77.5	0.55	
CO	28.010	3205.1	9.00	3205.0	14.60	7,116.0	43.81	6,970.1	50.46	10
Ar	39.949	43.1	0.12	41.6	0.19	26.0	0.16	25.3	0.19	
CH_4	16.042	53.6	0.15	49.2	0.22	32.3	0.20	30.7	0.22	
CO_2	44.010	13,443.1	37.73	183.3	0.84	2,891.9	17.81	870.1	6.30	1
H_2S	34.082	361.7	1.02	TRACE	<0.1 PPMV	206.8	1.27			
COS	60.076	3.0	0.01	TRACE		12.8	0.08	TRACE		
O_2	32.000									
SUBTOTAL		35,625.1	100.00	21,954.4	100.00	16,241.1	100.00	13,813.1	100.00	35
H_2O	18.016	53.2				24.3				
CH_3OH	32.04			1.1				0.8		
TOTAL		35,678.3		21,955.5		16,265.4		13,813.9		35
P, PSIA		790.0		760.0		790.0		765.8		
T, °F		100		82		100		82		

STREAM NUMBER		9		10		72		74		
STREAM NAME		ACID GAS TO CLAUS		WASTE WATER		AIR TO TORVEX		WATER TO TAIL GAS WASH COLUMN		
COMPONENT	MOL. WT.	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-MOL/HR	MOL %	LB-
H_2	2.016	0.2	0.01							
N_2	28.016	29.9	2.07			769.5	78.00			
CO	28.010	0.1	0.01							
Ar	39.949	TRACE	0.9 PPMV			9.9	1.00			
CH_4	16.042	TRACE	1.3 PPMV							
CO_2	44.010	832.9	57.55							
H_2S	34.082	568.4	39.28							
COS	60.076	15.7	1.08							
O_2	32.000					207.2	21.00			
SUBTOTAL		1,447.2	100.00			986.6	100.00			
H_2O	18.016			75.9	99.97	12.4		7648.8	100.00	6
CH_3OH	32.04	1.5		<0.1	0.03					
TOTAL		1,448.7		75.9	100.00	999.0		7648.8	100.00	6
P, PSIA		24.7		46.6		63.0		16.0		
T, °F		92		278		82		100		

REFERENCES			REFERENCES			REVISIONS									REVISIONS								
DRAWING NO.	DESCRIPTION		DRAWING NO	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	
															E	6/7/82	KDK	ML				FOR DESI	
															D	5/25/82			RAW	FJC		FOR 12,75	
															C	5/20/82			RAW	FJC		REVISED FOR	
															B	4/23/82			RAW	FJC		FOR USED	
															A							NOT ISSUE	

ENG-GE-23 (12/79)

1

NOTES:

1. THERE ARE A TOTAL OF FOUR MODULES IDENTICAL TO THIS MODULES.
2. HEAT AND MATERIAL BALANCES SHOWN ARE FOR ONE MODULE AT THE NORMAL OPERATING CONDITIONS.

	◇5		◇6	
	TOTAL SYN-GAS		STRIPPING GAS	
L % 42.28 0.55 50.46 0.19 0.22 6.30 00.00	LB-MOL/HR 24,188.1 203.3 18,175.0 66.9 79.8 1,053.4 TRACE TRACE 35,016.5	MOL % 67.63 0.57 28.45 0.19 0.22 2.94 <0.1 PPMV 100.00	LB-MOL/HR 2,163.8 2,163.8	MOL % 100.00 100.00
	1.8 35,018.3 760.0 82		 2,163.8 23.9 82	

	◇75		◇77	
L UM	LOADED WATER FROM WASH COLUMN		TOTAL TAIL GAS	
L % 00.00 00.00 	LB-MOL/HR 5.0 5.0 6,870.2 3.5 6,878.7 17.0 65	MOL % 0.07 99.88 0.05 100.00 	LB-MOL/HR 1.2 2,906.0 8.9 11.9 1.1 14,586.5 <0.1 <0.1 90.0 17,607.7 877.9 0.4 18,486.0 16.0 145	MOL % 0.01 16.49 0.05 0.07 0.01 82.86 1.5 PPMV 4.2 PPMV 0.51 100.00

D34MP6NP.DGA

LOTEPRO CORPORATION
LOW TEMPERATURE PROCESSING AND EQUIPMENT
NEW YORK, N.Y.

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

FOR DESIGN REPORT	DRAWN	DAR	
FOR CLIENT APPROVAL	CHECKED	RGB	3-4-82
REVISED FOR LICENSOR APPROVAL	APVD RELT MGR	REM	3-4-82
FOR LICENSOR APPROVAL	APVD PROJ MGR	FJC	3-4-82
NOT ISSUED	APVD CLIENT		
DESCRIPTION			

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

TITLE: MATERIAL BALANCE
ACID GAS REMOVAL - UNIT 34

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

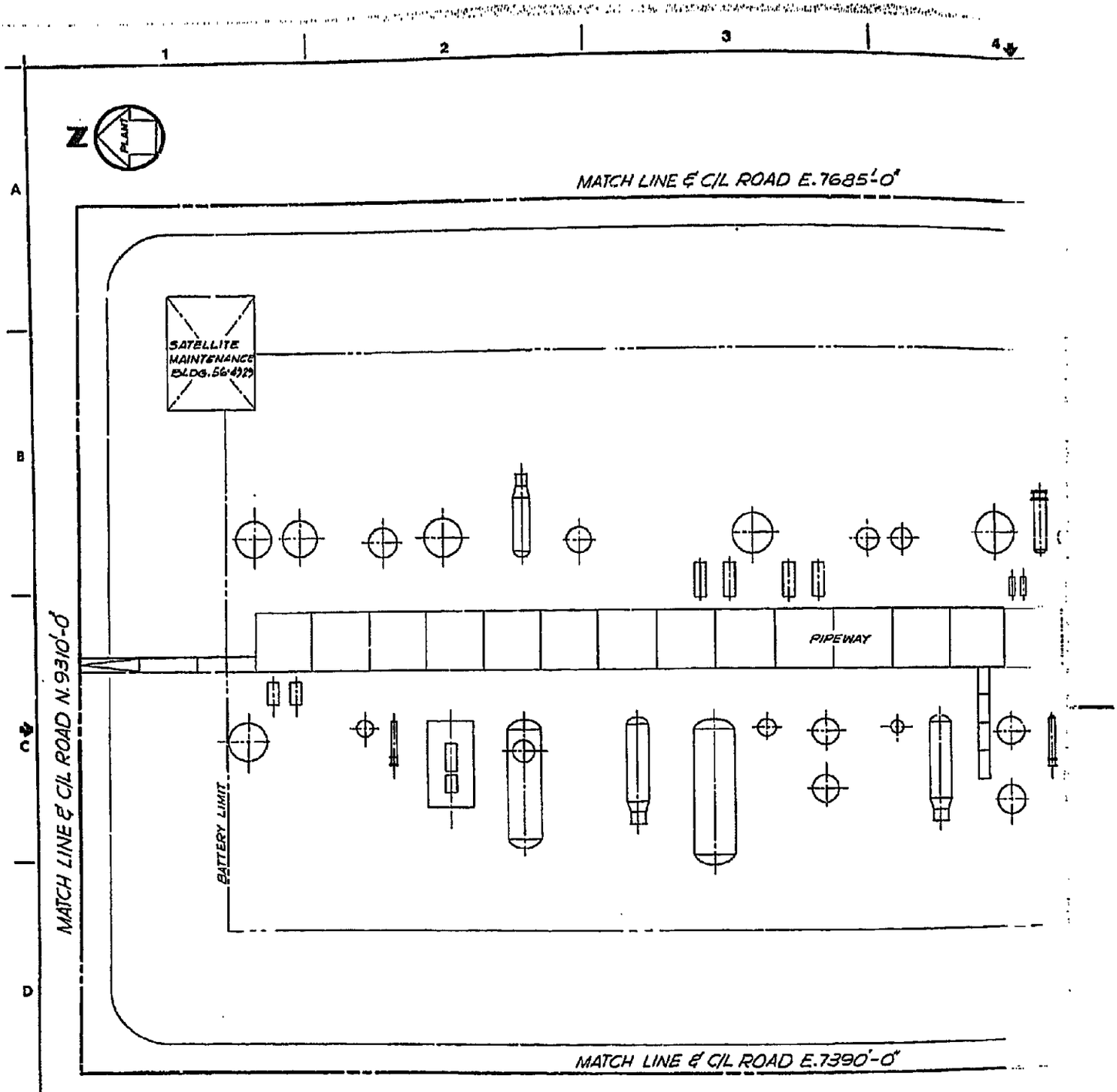
DOCUMENT NUMBER: D-34-MP-6 NP

REVISION: E

F. Plot Plan/General Arrangement Drawings

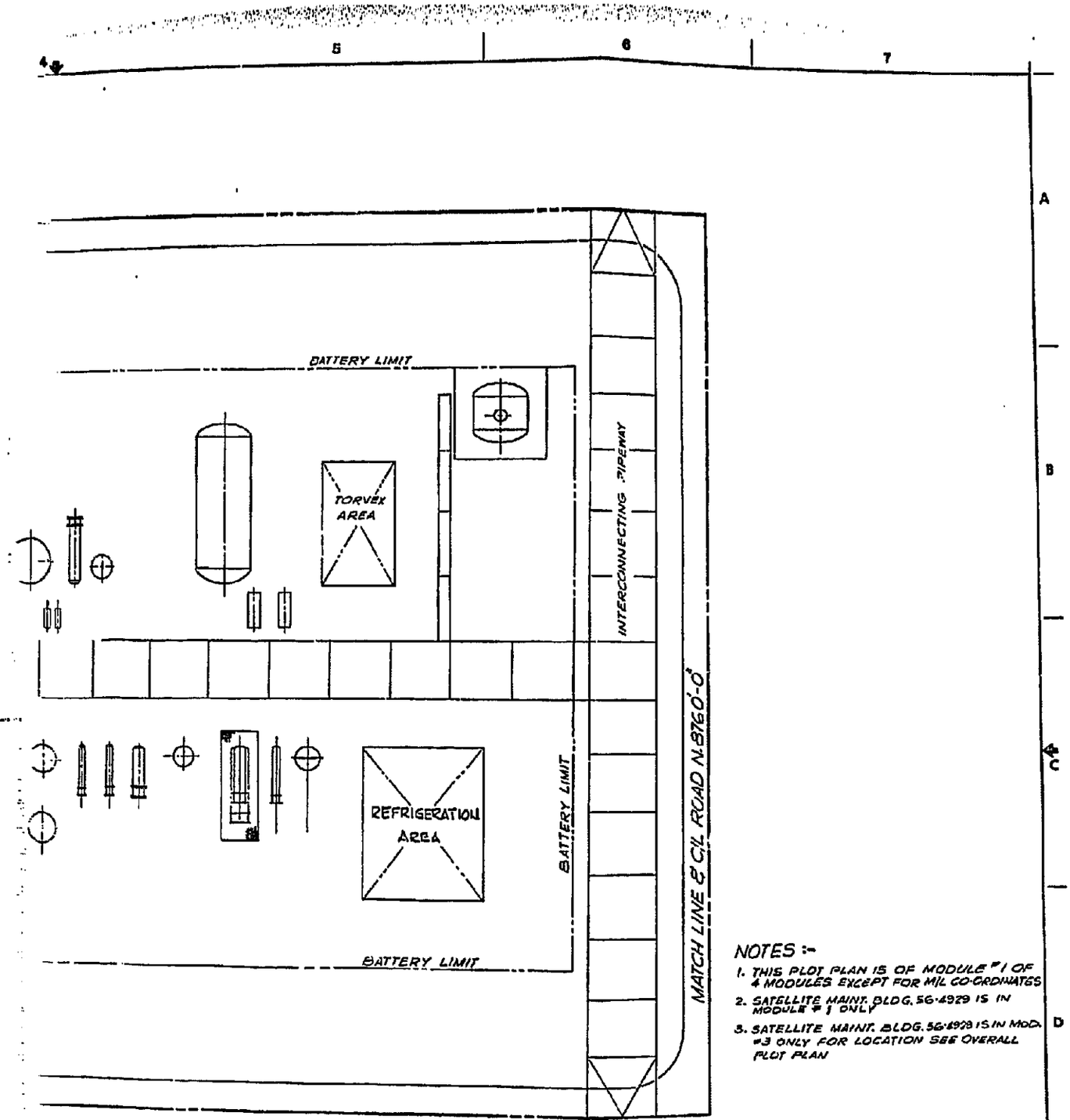
Plot Plan and General Arrangement Drawings for Acid Gas Removal Unit 34 are as follows:

Drawing No.	Title
D-34-PD-1NP	Plot Plan - Unit 34 Acid Gas Removal
D-34-PD-2NP	Elevation - Unit 34 Acid Gas Removal



REFERENCES			REFERENCES			REVISIONS								REVISIONS								
DRAWING NO.	DESCRIPTION		DRAWING NO	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT		
														A	6/29/82	EE					RAR	FOR
														C	4/21/82	EE						FUE
														B	4/2/82	RR						
														A	3/19/82	TSG						

ENGGE-23 (12/79)



NOTES :-

1. THIS PLOT PLAN IS OF MODULE # 1 OF 4 MODULES EXCEPT FOR M/L CO-ORDINATES
2. SATELLITE MAINT. BLDG. 56-4929 IS IN MODULE # 1 ONLY
3. SATELLITE MAINT. BLDG. 56-4928 IS IN MOD. #3 ONLY FOR LOCATION SEE OVERALL PLOT PLAN

1" = 20FT

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PLOT PLAN
UNIT-34
CID GAS REMOVAL

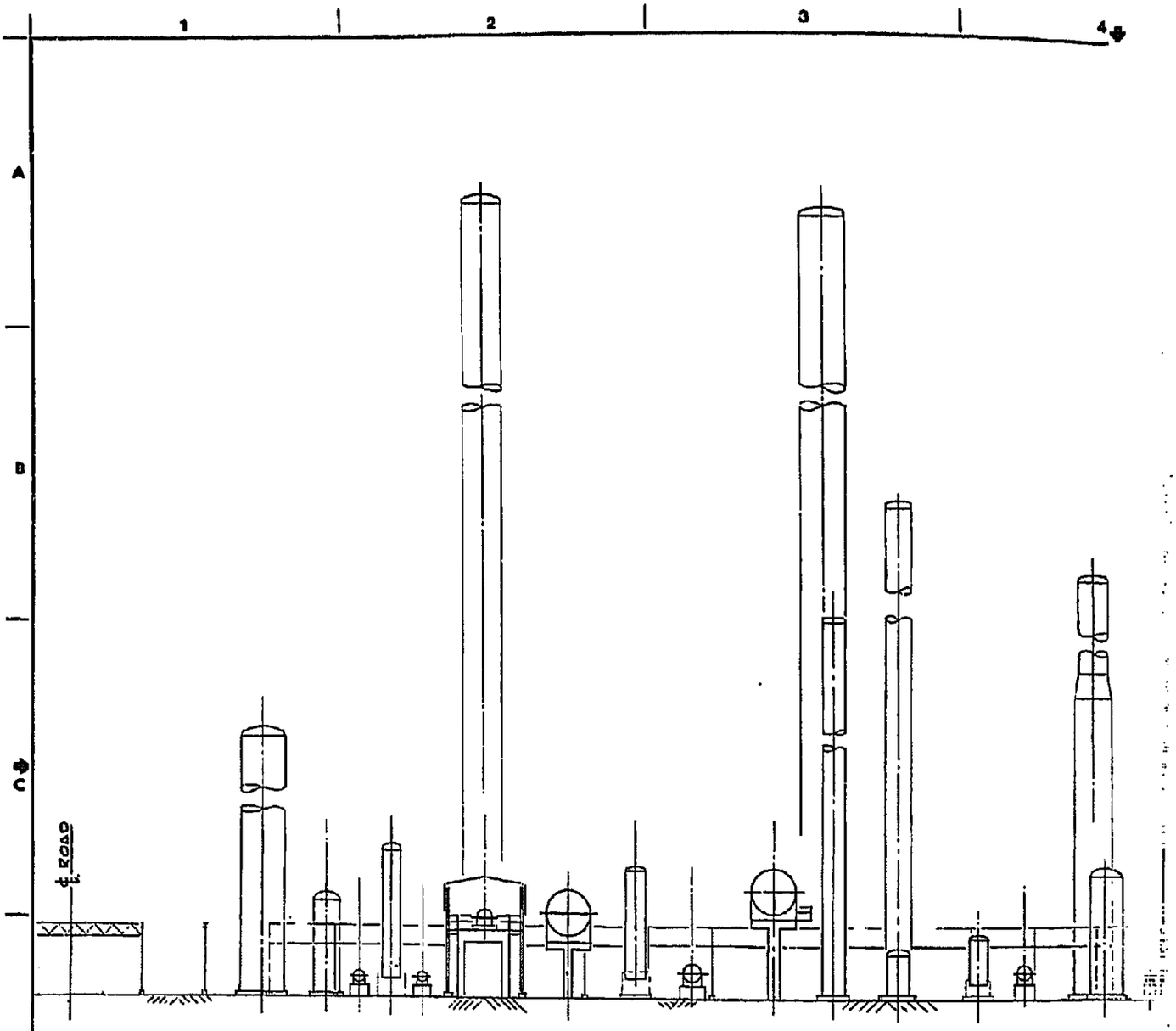
SCALE 1"=20'-0" | ACCOUNT NUMBER 7243 | JOB NUMBER 6182 | REVISION D

DOCUMENT NUMBER D-34-PD-INP

FOR DESIGN REPORT
FOR CLIENT APPROVAL
FOR LICENSOR APPROVAL
ISSUED FOR CLIENT 50% REVIEW
DESCRIPTION

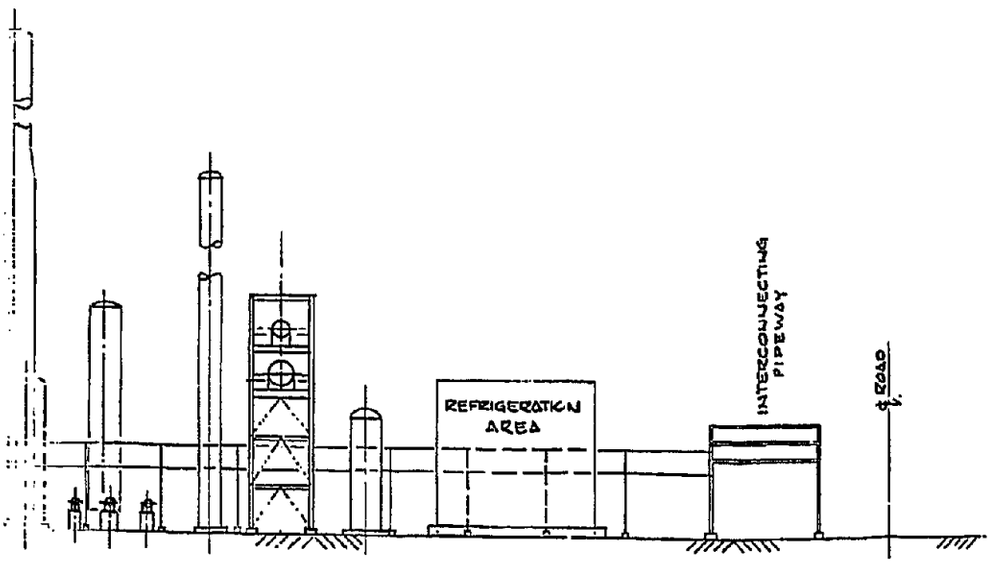
DRAWN	TSG/LL	
CHECKED		
APVD SECT HD		
APVD PROJ MGR		
APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA



REFERENCES			REFERENCES			REVISIONS									REVISIONS								
DRAWING NO.	DESCRIPTION		DRAWING NO.	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	
															D	5-25-82	RR						
															C	5/14/82	RR						
															B	4/22/82	RR						
															A	4-15-82	RR						

ENG-64-33 (12/78)



1" = 20FT

FOR DESIGN REPORT	
FOR CLIENT APPROVAL	
[illegible] APPROVAL	
[illegible] REVIEW FOR COMP.	
DESCRIPTION	

DRAWN	RZ
CHECKED	
APVD SECT MGR	
APVD PROJ MGR	
APVD CLIENT	

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — KENTUCKY

W.R. GRACE & CO.
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ELEVATION UNIT 34 ACID GAS REMOVAL

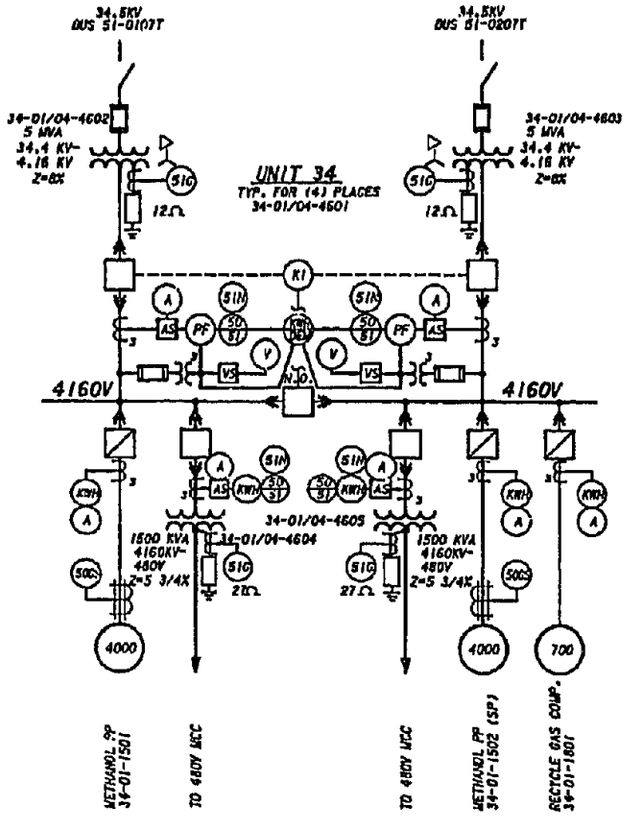
SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
1" = 20'-0"	7243	6182	2

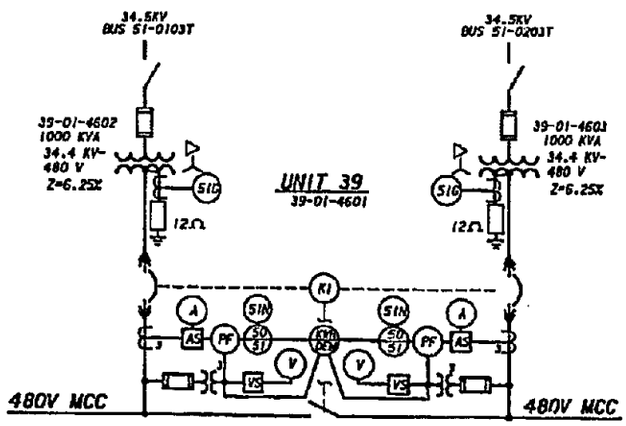
DOCUMENT NUMBER: D-34-PD-2NP

G. Single-Line Diagram

The Single-Line Diagram for Acid Gas Removal Unit 34 is as follows:

Drawing No.	Title
D-51-EE-7NP	One-Line Diagram - Units 34 and 39





SYMBOL LIST

- MEDIUM VOLTAGE STARTER, COMPLETE INCLUDING FUSES, 3STISOLID STATE TRIP), PL RTD AND DIFF. PROT. ON MOTORS OVER 500H
- 51 = TIME DELAY PHASE OVER CURRENT RELA
  50 = INSTANTANEOUS PHASE OVER CURRENT R
- 51N = TIME DELAY OVER CURRENT GROUND FA PROTECTION
- 50GS = INSTANTANEOUS OVER CURRENT GROUN PROTECTION
- GROUNDING RESISTANCE
- 86 HAND RESET AUXILIARY RELAY
- 87 DIFFERENTIAL CURRENT RELAY
- OUTDOOR POWER CIRCUIT BREAKER WITH DISCONNECTING SWITCHES
- 3 POSITION SWITCH, CENTER OFF
- SURGE ARRESTOR
- RECTIFIER
- CONDUCTOR CROSSING NOT CONNECTED
- CONDUCTOR CONNECTED
- 32 REVERSE POWER PROTECTION RELAY
- 40 LOSS OF FIELD PROTECTION RELAY
- 46 GENERATOR ROTOR OVERHEATING
- 49 OVER LOAD (THERMAL) FOR GEN. STATOR
- SYN SYNCHRO SCOPE
- GEN GENERATOR
- C.T. (DONUT TYPE)
- PF POWER FACTOR

REFERENCES DRAWING NO.	DESCRIPTION	REFERENCES DRAWING NO.	DESCRIPTION

REVISIONS NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPT
F	7-13-82	LS	RTB				REISSUED FOR DESIGN REPORT

REVISIONS NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	
F	8-6-82	VT	T.I.	RTB	F.J.C		ISSUED FI
D	4-26-82	VT	T.I.	RTB	F.J.C		REISSUED
C	5-7-82	VT	T.I.	RTB	F.J.C		FOR LICE
B	4-30-82	VT	T.I.	RTB	F.J.C		ISSUED FI
A	3-19-82	VT	T.I.	RTB	F.J.C		ISSUED FO

ENG-08-23 (12/78)

SYMBOLS

- BUS DUCT.
- BUS, POWER CONDUCTOR
- ELECTRICAL OR MECHANICAL INTERLOCK
- CONNECTOR DRAWOUT TYPE
- SWITCH
- FUSE
- POWER CIRCUIT BREAKER DRAWOUT TYPE
- AIR CIRCUIT BREAKER DRAWOUT TYPE
- 300/5 — PHASE CURRENT TRANSFORMER (CT) INDICATING TURNS RATIO & QUANTITY
- POTENTIAL TRANSF. (P.T)
- 3 Ø 1000/1150 KVA 34.5 KV-4160V 8%Z AT 55°C — POWER TRANSF. OA/FA KVA RATING SHOWN
- 3 Ø - 3 WINDING POWER TRANSF.
- GROUND CONNECTION
- (75) — 3 Ø MOTOR, NUMBER INDICATES HORSEPOWER
- LOW VOLTAGE COMBINATION MOTOR STARTER 20A INDICATES TRIP RATING OR CONTINOUS CURRENT RATING
- KI — MECHANICAL KEY INTERLOCK SYSTEM
- AS — CONTROL SWITCH
  - AS AMMETER SWITCH
  - VS VOLTMETER SWITCH
- (A) — METERS
  - A AMMETER
  - DEM DEMAND
  - PF POWER FACTOR
  - KWH KILOWATT HOUR
  - V VOLTMETER
- LP — PANEL BOARD
  - LP = LIGHTING PANEL

ABBREVIATIONS

A	AMPERE
V	VOLT
W	WATT
KV	KILOVOLT
KVA	KILOVOLTAMPERE
KW	KILOWATT
MVA	MEGAVOLTAMPERE
PF	POWER FACTOR
AS	AMMETER SELECTOR SWITCH
VS	VOLTMETER SELECTOR SWITCH
N.O.	NORMALLY OPEN
N.C.	NORMALLY CLOSE
MCC	MOTOR CONTROL CENTER
KWH	KILOWATT HOUR
DEM	DEMAND
Ω	OHM
LTC	LOAD TAP CHANGING
Ø	PHASE
Z %	IMPEDANCE PERCENT
SP	SPARE
LRA	LOCKED ROTOR AMPERES
FLA	FULL LOAD AMPERES
DIAG.	DIAGRAM
STR	STARTER
FDR	FEEDER
PP	PUMP
HP	HORSEPOWER
LOC.	LOCATION
SCHEM.	SCHEMATIC
QTY.	QUANTITY
TYP.	TYPICAL
U	UNIT
SHT.	SHEET
DWG.	DRAWING
CIRC.	CIRCULATING
BLWR.	BLOWER
APP'D	APPROVED
TR	TRAIN
COMP.	COMPRESSOR
CONN.	CONNECTED
WTR.	WATER
GEN.	GENERATOR
IND.	INDUCTION
THRU	THROUGH
ALKY	ALKYLATION
XFMR	TRANSFORMER

NT	DESCRIPTION
	ISSUED FOR DESIGN REPORT
	REISSUED FOR CLIENT APPROVAL
	FOR LICENSOR APPROVAL
	ISSUED FOR CLIENT APPROVAL
	ISSUED FOR CLIENT SDE REVIEW

APP'D		
DRAWN	HT	
CHECKED		
APP'D DEPT HD		
APP'D PROJ MGR		
APP'D CLIENT		

AMP
THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ONE LINE DIAGRAM
ACID GAS REMOVAL U-34
PROCESS WATER TREATMENT U-39

SCALE	ACCOUNT NUMBER	JOB NUMBER	DIVISION
NONE	4600	6182	E

DOCUMENT NUMBER: D-51-EE-7NP

1.2.16 SULFUR RECOVERY (CLAUS) - UNIT 36

The Sulfur Recovery Unit (SRU) is designed to convert the sulfur compounds in the acid gas from the Acid Gas Removal (Rectisol) Unit to elemental sulfur, which will be recovered as a salable product. The tail gas from the SRU is further treated for the removal of the remaining sulfur compounds in the Sulfur Removal Unit before being vented to the atmosphere. Two parallel, 50% SRU trains are provided.

A. Basis of Design

The quantity of acid gas from the Acid Gas Removal - Unit 34 requires that two parallel 50% SRU trains be installed. This arrangement requires less field fabrication and provides greater operational flexibility. The following feed and product stream data summarize the normal operating condition information for the two 50% plants.

Feed Streams

Component	Total Acid Gas (lb mol/hr)	(mol%)
H_2	0.59	0.01
CH_4	-	-
CO	0.34	60 ppmv
CO_2	3,331.73	57.55
N_2	119.67	2.07
A	-	-
H_2S	2,273.71	39.28
COS	62.80	1.08
Total Dry, lb mol/hr	5,788.84	100.00
Total, lb/hr	234,490	
Pressure, psia	25	
Temperature, °F	92	

Product Streams

Component	Tail Gas (end of run) (lb mol/hr)	(mol%)	Sulfur Product (end of run) (lb mol/hr)	(mol%)
H_2	67.14	0.88	-	
CH_4	-	-	-	
CO	130.90	1.71	-	
CO_2	3,199.96	41.75	-	
N_2	4,142.12	54.05	-	
O_2	-	-	-	
H_2S	79.32	1.03	-	
COS	2.28	0.03	-	
SO_2	39.74	0.52	-	
S_6	0.34	440 ppm	-	
S_8	2.10	0.03	274.54	100.00
Total Dry	7,663.90	100.00	274.54	100.00
H_2O	2,514.08		-	
Total Wet	10,177.98		274.54	
Total lb/hr	311,960		70,430	
Pressure, psia	18		65	
Temperature, °F	280		290	

B. Process Selection Rationale

The Claus sulfur recovery process is universally used throughout the world for bulk recovery of sulfur from acid gases containing hydrogen sulfide (H_2S).

An alternative method of recovering sulfur from such gases is to manufacture sulfuric acid. However, handling, storing, and shipping the quantities of sulfuric acid generated by this plant would be much more difficult than marketing the smaller quantity of sulfur.

Hydrogen sulfide could be converted directly in a Stretford unit but with considerably higher investment and operating cost. The largest Stretford unit in the United States has a design capacity of 52 ltpd compared with up to 1,200 ltpd in the acid gas from the Acid Gas Removal Unit.

C. Process Description

The purpose of the sulfur recovery unit is to convert the bulk of the sulfur compounds in the acid gas from the Acid Gas Removal Unit to elemental sulfur. This conversion is accomplished by oxidizing (burning) one-third of the H_2S in the acid gas to SO_2 with air. The SO_2 will then combine with the remaining two-thirds of the H_2S to form elemental sulfur and water vapor in accordance with the following reactions:

$$H_2S + 3/2\ O_2 \longrightarrow SO_2 + H_2O$$
$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O$$
$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O \text{ (Overall reaction)}$$

These reactions create temperatures high enough to sustain the reaction thermally, and they will continue to equilibrium. The thermal reactions are followed by three catalytic reaction stages to complete the reaction to practical limits.

The acid gas enters the plant through Acid Gas Knockout Drum 36-01-1201 to trap entrained liquid. The feed stream is metered after passing through the knockout drum. Airflow from Combustion Air Blower 36-01-1801 is controlled to maintain a 2:1 H_2S to SO_2 ratio in Reaction Furnace 36-01-1401. The acid gas feed to the reaction furnace is preheated with 600-psig steam and is burned with the combustion air.

The hot gases from the reaction furnace are cooled first by generating 250-psig steam in Reaction Cooler 36-01-1301 and then further cooled by generating 50-psig steam in No. 1 Sulfur Condenser 36-01-1302. Most of the sulfur formed in the reaction furnace is condensed in the No. 1 condenser from which it flows through a sulfur seal into a sulfur pit. The cooled gases pass through a wire mesh coalescer for removal of entrained sulfur and flow to No. 1 Reheater 36-01-1307. In the reheater, the process gas is heated to reaction temperature with 600-psig steam. The process gas then enters the first converter, where the reaction to form sulfur from H_2S and SO_2 will continue. The reaction is exothermic and heat is generated in proportion to the amount of sulfur produced. The hot process gas is cooled in the No. 2 condenser by generating 50-psig steam. The condensed sulfur passes through a sulfur seal and into the sulfur pit. The cooled process gas passes through a coalescer for the removal of entrained sulfur.

The second and third stages are similar to the first stage (each comprising a reheater, converter, and condenser/coalescer). The final condenser produces 15-psig steam to cool the process gas as low as is practical. The other condensers produce 50-psig steam.

The tail gas from the final condenser is sent to Sulfur Removal Unit 37 to remove the remaining sulfur components. The sulfur recovered is collected in a rundown pit. From there it is pumped periodically to sulfur storage tanks. The sulfur in the sulfur pit contains H_2S and polysulfides so the pit vapor space must be swept with air to prevent the evolved H_2S from building up to a potentially explosive concentration.

The sulfur pit vent gas then is treated in the Sulfur Removal Unit for removal of the H_2S.

1. Flexibility and Turndown. Turndown of each plant to one-third of design capacity is possible with standard instrumentation. Features provided to give turndown flexibility are:

(a) Metering and control valve rangeability; dual transmitters or other facilities are provided for turndown to 20% of design capacity.

(b) The air blower is vented to the atmosphere to prevent surging. Automatic antisurge control is provided.

Turndown normally will not affect sulfur recovery to any measurable extent.

2. Startup. The SRU is started up by burning fuel gas with excess air on a cold startup with either fresh catalyst or catalyst that has previously been stripped of sulfur. This procedure allows the plant and catalyst beds to dry out and attain normal operating temperatures before introduction of acid gas feed to avoid corrosive conditions. When an acid gas flame is established, the fuel gas is shut off.

Startup on a warm plant or catalyst that has not been stripped of sulfur is accomplished by burning fuel gas substoichiometrically as described under "Shutdown."

3. Shutdown. Fuel gas will be burned substoichiometrically with steam to strip sulfur from the sulfur-laden catalyst beds and to sweep out acid gas reaction products.

D. Risk Assessment

Unscheduled emergency shutdown of the sulfur recovery unit can occur because of loss of the air blower, loss of flame in the reaction furnace, loss of boiler feedwater, or high-liquid level in the acid gas knockout drum. Unscheduled shutdown also can occur because of excessive condenser or converter fouling or a blocked sulfur drain line that builds up pressure drop over a period of time.

In this design, two nominal trains are provided as well as spare air blowers. Each train handles 73% of the gas flow for the normal operating condition case. High-liquid level in the knockout drum can be prevented by proper operation of upstream areas. Many of these Claus units have been operated successfully for years without unscheduled shutdown.

The modified Claus process is proven technology, with hundreds of units in commercial operation. This process meets the Best Available Control Technology (BACT) Standards. The prime criterion for selecting a sulfur recovery system is to meet the environmental restriction imposed by BACT. With the BSRP sulfur removal unit, it also meets the Lowest Achievable Emission Rate (LAER) Standards necessary for nonattainment areas.

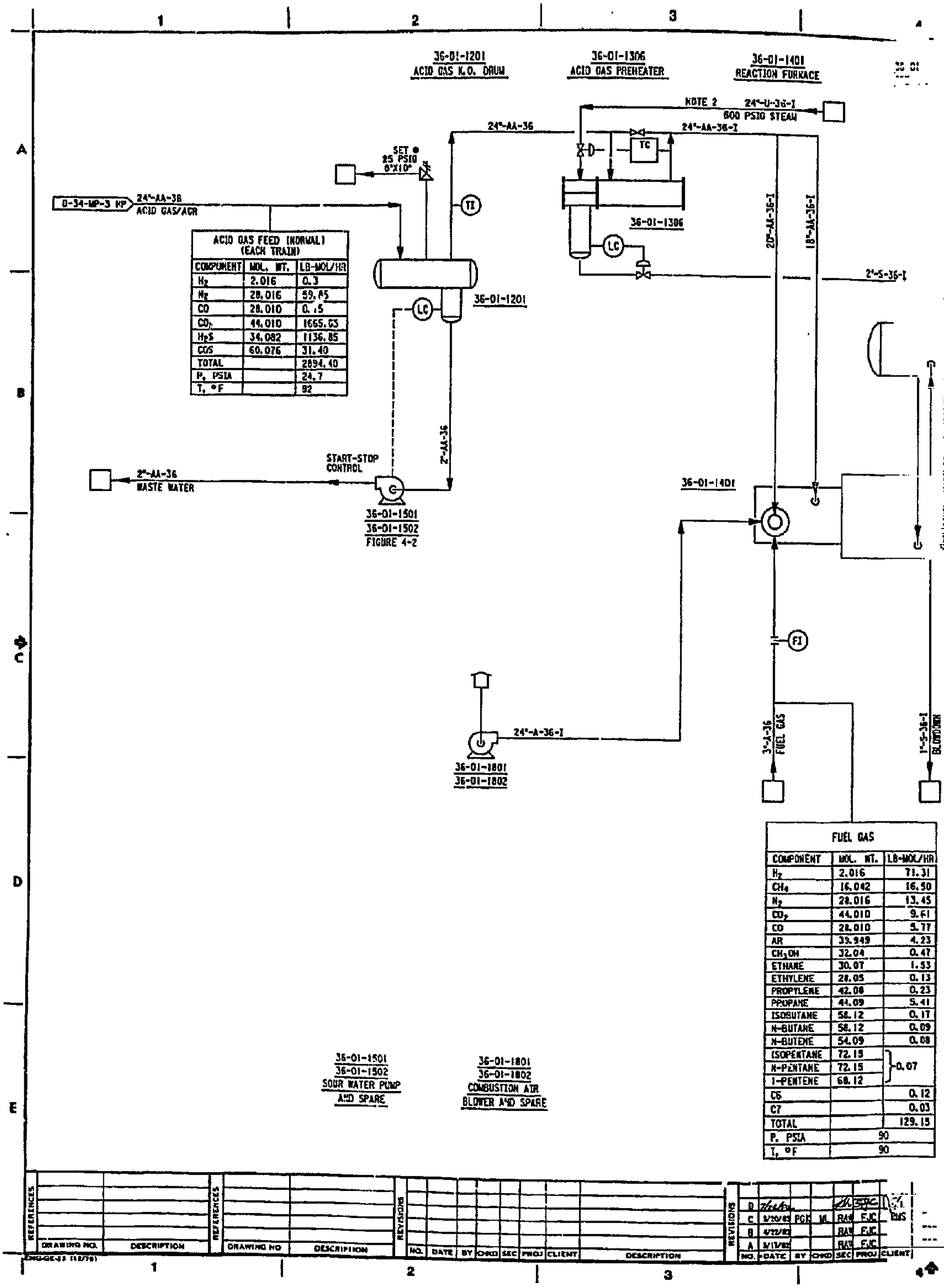
The construction material is primarily carbon steel. From many years of engineering, procurement, and construction of these units, select vendors and fabricators are to be used that have proved their equipment for reliability with a minimum of maintenance. The availability of equipment for this unit requires a minimum of lead time.

Sulfur recovery units are considered highly reliable operating units with a minimum of maintenance required.

E. Process Flow and Control Diagrams (Including Material Balance)

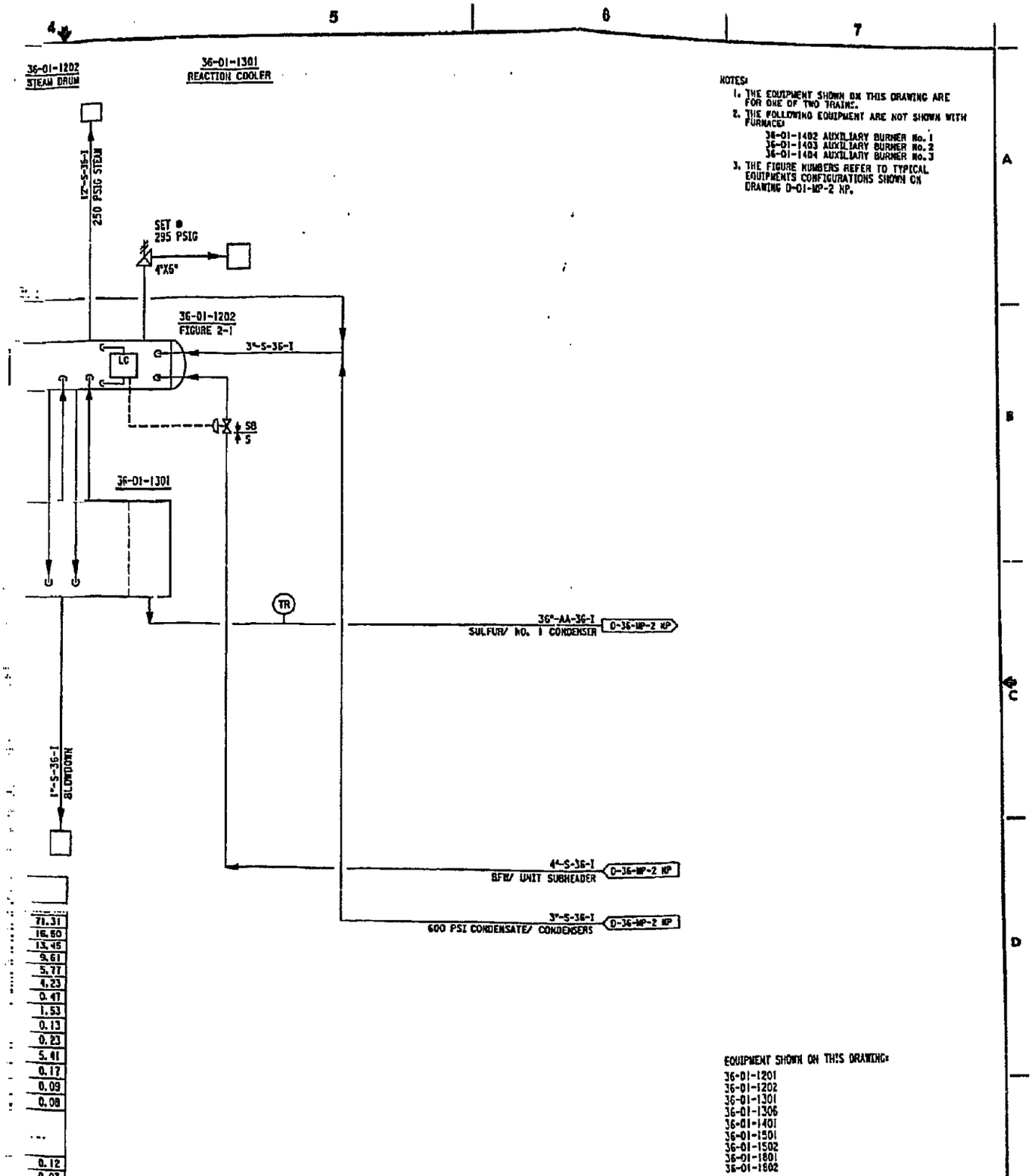
Process Flow and Control Diagrams for Sulfur Recovery (Claus) Unit 36 are as follows:

Drawing No.	Title
D-36-MP-1NP	PFCD Sulfur Recovery (Claus) - Reactor
D-36-MP-2NP	PFCD Sulfur Recovery (Claus) - Recovery
D-36-MP-3NP	PFCD Sulfur Recovery (Claus) - Recovery



ACID GAS FEED (NORMAL) (EACH TRAIN)		
COMPONENT	MOL. WT.	LB-MOL/HR
H_2	2.016	0.3
N_2	28.016	59.85
CO	28.010	0..5
CO_2	44.010	1665.65
H_2S	34.082	1136.85
COS	60.076	31.40
TOTAL		2894.40
P, PSIA		24.7
T, °F		92

FUEL GAS		
COMPONENT	MOL. WT.	LB-MOL/HR
H_2	2.016	71.31
CH_4	16.042	16.50
N_2	28.016	13.45
CO_2	44.010	9.61
CO	28.010	5.77
AR	39.949	4.23
CH_3OH	32.04	0.47
ETHANE	30.07	1.53
ETHYLENE	28.05	0.13
PROPYLENE	42.08	0.23
PROPANE	44.09	5.41
ISOBUTANE	58.12	0.17
N-BUTANE	58.12	0.09
N-BUTENE	54.09	0.08
ISOPENTANE	72.15	0.07 (ISOPENTANE, N-PENTANE, 1-PENTENE combined)
N-PENTANE	72.15	
1-PENTENE	68.12	
C6		0.12
C7		0.03
TOTAL		129.15
P, PSIA	90	
T, °F	90	



NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FOLLOWING EQUIPMENT ARE NOT SHOWN WITH FURNACE:
   36-01-1402 AUXILIARY BURNER No. 1
   36-01-1403 AUXILIARY BURNER No. 2
   36-01-1404 AUXILIARY BURNER No. 3
3. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENTS CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2 NP.

71.31
16.60
13.45
9.61
5.77
4.23
0.47
1.53
0.13
0.23
5.41
0.17
0.09
0.08
...
0.12
0.03
129.15

EQUIPMENT SHOWN ON THIS DRAWING:
36-01-1201
36-01-1202
36-01-1301
36-01-1306
36-01-1401
36-01-1501
36-01-1502
36-01-1801
36-01-1802

NO.	DESCRIPTION	DRAWN	CHECKED	APVD SECT MGR	APVD PROJ MGR	APVD CLIENT	DATE
1	REVISED FOR DESIGN REPORT			PCC	FJC		12-31-8
0	FOR DESIGN REPORT			PCC	FJC		12-31-8
	FOR CLIENT APPROVAL						
	FOR CLIENT 50% REVIEW						

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

D36MP1NP.DGN

U.S. DEPARTMENT OF ENERGY

BASKETT — M.R. GRACE & CO. — KENTUCKY

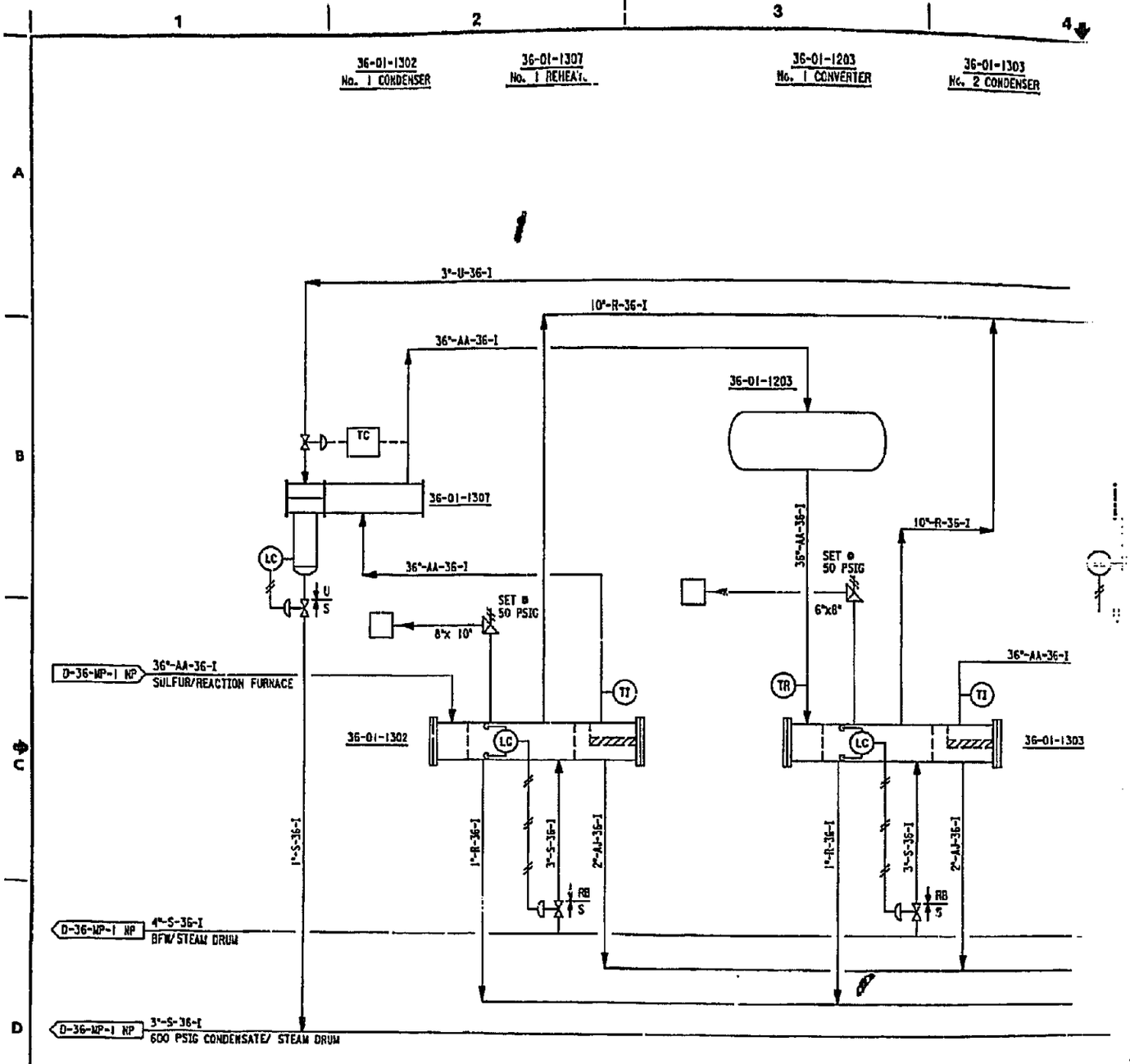
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW & CONTROL DIAGRAM SULFUR RECOVERY (CLAUS)-UNIT 36 REACTION SECTION

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

DOCUMENT NUMBER: D-36-MP-1 NP

REVISION: 0



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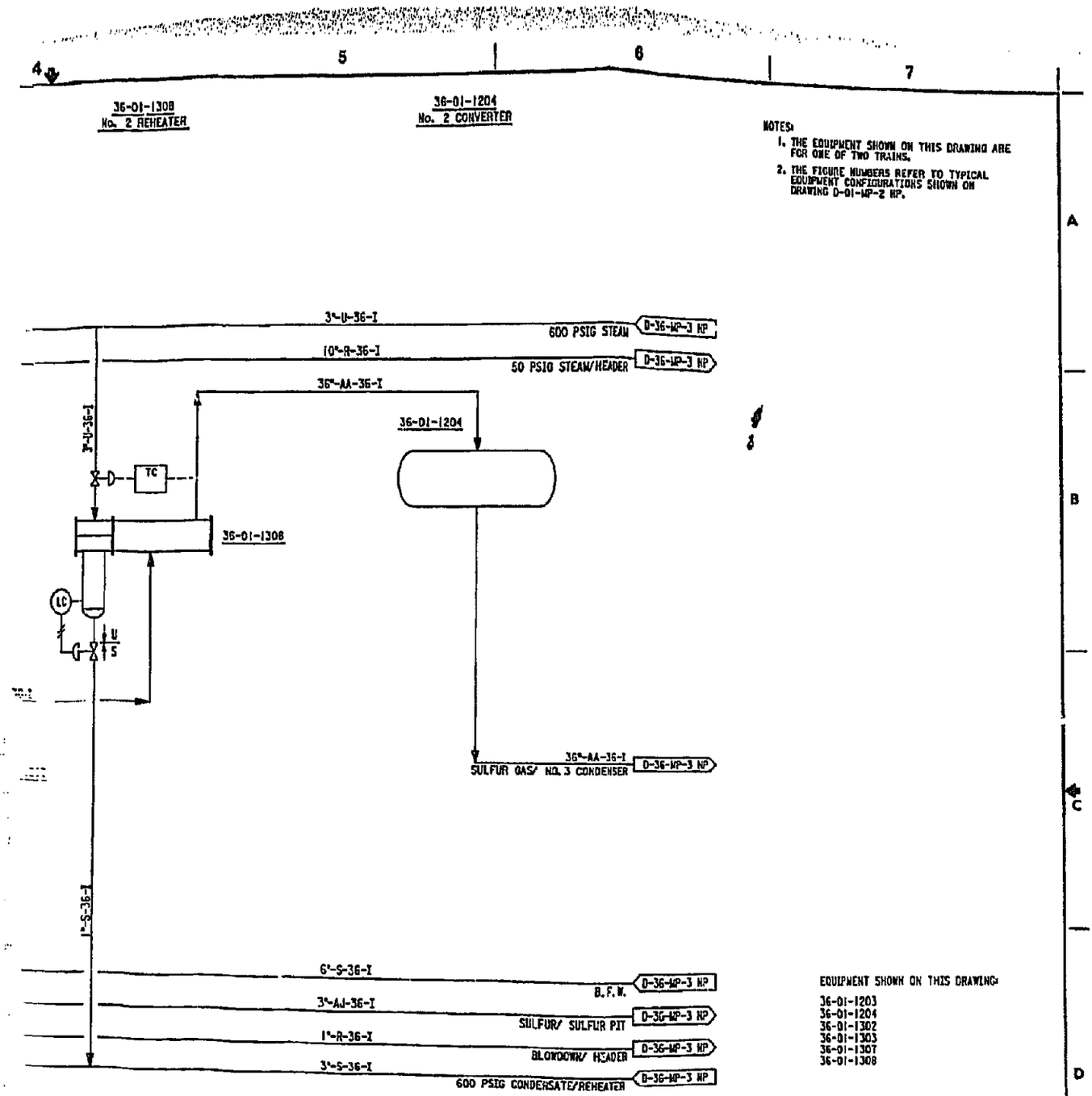
														C	5/6/82	KCK	MIL		3MC	KMS		
														B	4/22/82			RAW	FJC			
														A	3/17/82			RAW	FJC			

ENG-GE-83 (12/78)



NOTES:

1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2 NP.

EQUIPMENT SHOWN ON THIS DRAWING:

36-01-1203
36-01-1204
36-01-1302
36-01-1303
36-01-1307
36-01-1308

FOR DESIGN REPORT	APVD		
FOR CLIENT APPROVAL	DRAWN		
FOR CLIENT 90% REVIEW	CHECKED		
DESCRIPTION	APVD SECT MGR	PCC	12-31-8
	APVD PROJ MGR	EJC	12-31-8
	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

D36MP2NP.DGA

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BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW & CONTROL DIAGRAM SULFUR RECOVERY (CLAUS)-UNIT 36 RECOVERY SECTION

SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
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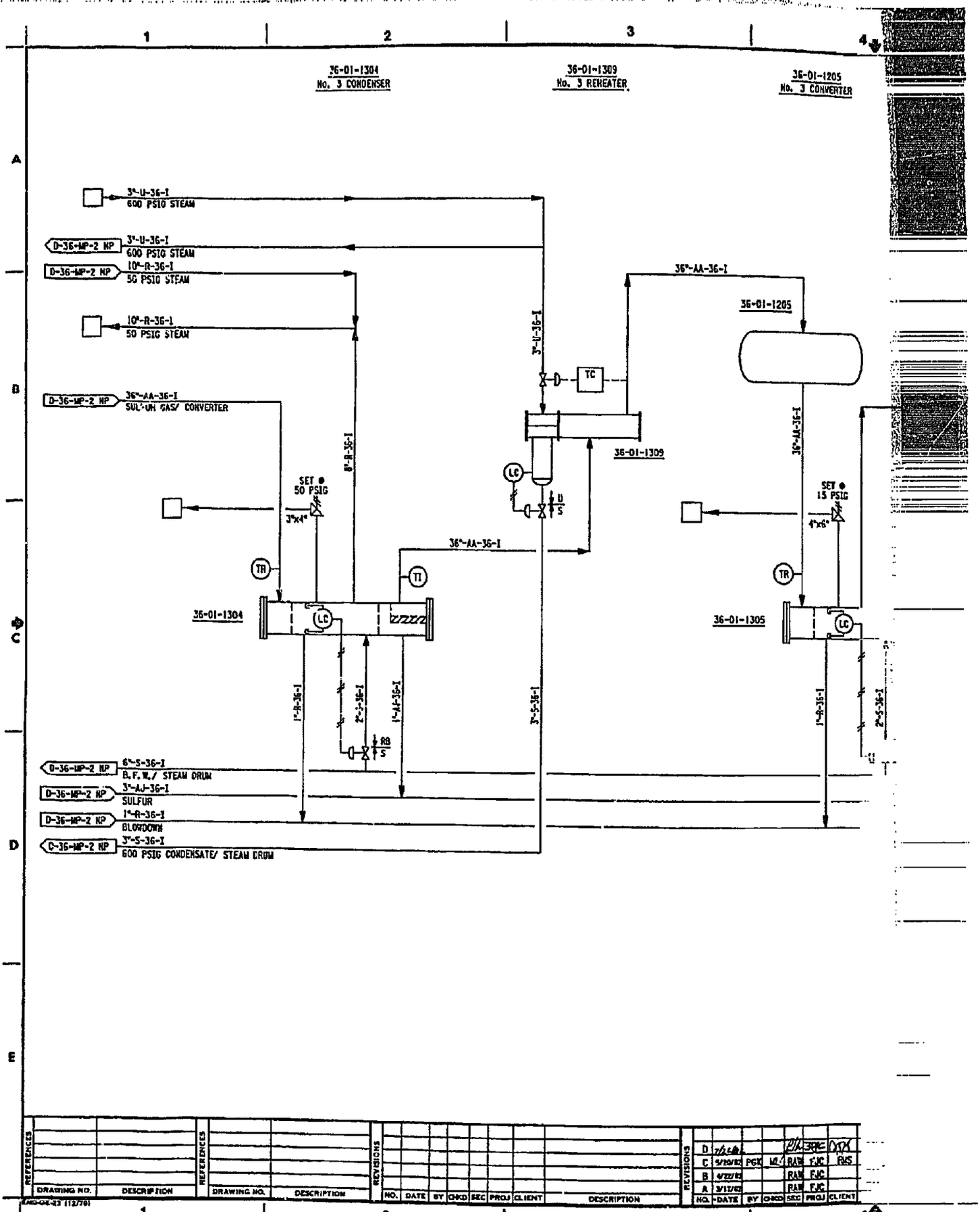
DOCUMENT NUMBER: D-36-MP-2 NP



REFERENCES			REFERENCES			REVISIONS									REVISIONS								
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															C	5/20/82	PGK	MJ	RAM	FJC		RMS	
															B	4/22/82			RAM	FJC			
															A	3/11/82			RAM	FJC			

FMD-GE-23 (12/79)

36-01-1305
No. 4 CONDENSER

36-01-4101
SULFUR PIT

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2 NP.

10"-R-36-I
15 PSIG STEAM HEADER

36"-AA-38-I
TAIL GAS/ REDUCING GAS GENERATOR
D-37-MP-1 NP

COMPONENT	MW	TAIL GAS MOLE/HR
H_2S	35.056	35.66
SO_2	64.013	19.87
N_2	28.016	2,071.05
S_2	192.384	0.17
S_3	256.512	1.05
CO_2	44.01	1,599.95
Ar	2.016	33.57
CO	28.01	65.45
COS	60.07	1.14
TOTAL DRY		3,831.35
H_2O	18.016	1,257.84
TOTAL WET		5,089.19
LB/HR		155,992
MW	30.65	30.65
MSCFH		1,931.22
TEMP °F		280
PRESS PSIA		17.50
ACFS		641.26

TI

2"-S-36-I

1"-AJ-36-I

PC

6"-R-52-I
B. F. W. HEADER

1"-R-36-I
BLOWDOWN HEADER

D-37-MP-3 NP

36-01-1803
36-01-1804

2"-AA-36-I
SWEEP GAS/BSNP
D-37-MP-2 NP

36-01-1503
36-01-1504

4"-AJ-36-I
SULFUR
D-57-MP-2 NP

M

36-01-4101

COMPONENT	SULFUR
LB/HR	108,000
MW	256
TEMP °F	280
PRESS PSIA	65

36-01-1803
36-01-1804
SULFUR PIT VENT
BLOWER AND SPARE

36-01-1503
36-01-1504
SULFUR PUMPS

EQUIPMENT SHOWN ON THIS DRAWING:
36-01-1205
36-01-1304
36-01-1305
36-01-1309
36-01-1503
36-01-1504
36-01-1803
36-01-1804
36-01-4101

D36MP3NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY
50,000 B.P.D.
COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW & CONTROL DIAGRAM SULFUR RECOVERY (CLAUS)-UNIT 36 RECOVERY SECTION

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182 | REVISION: 0

DOCUMENT NUMBER: D-36-MP-3 NP

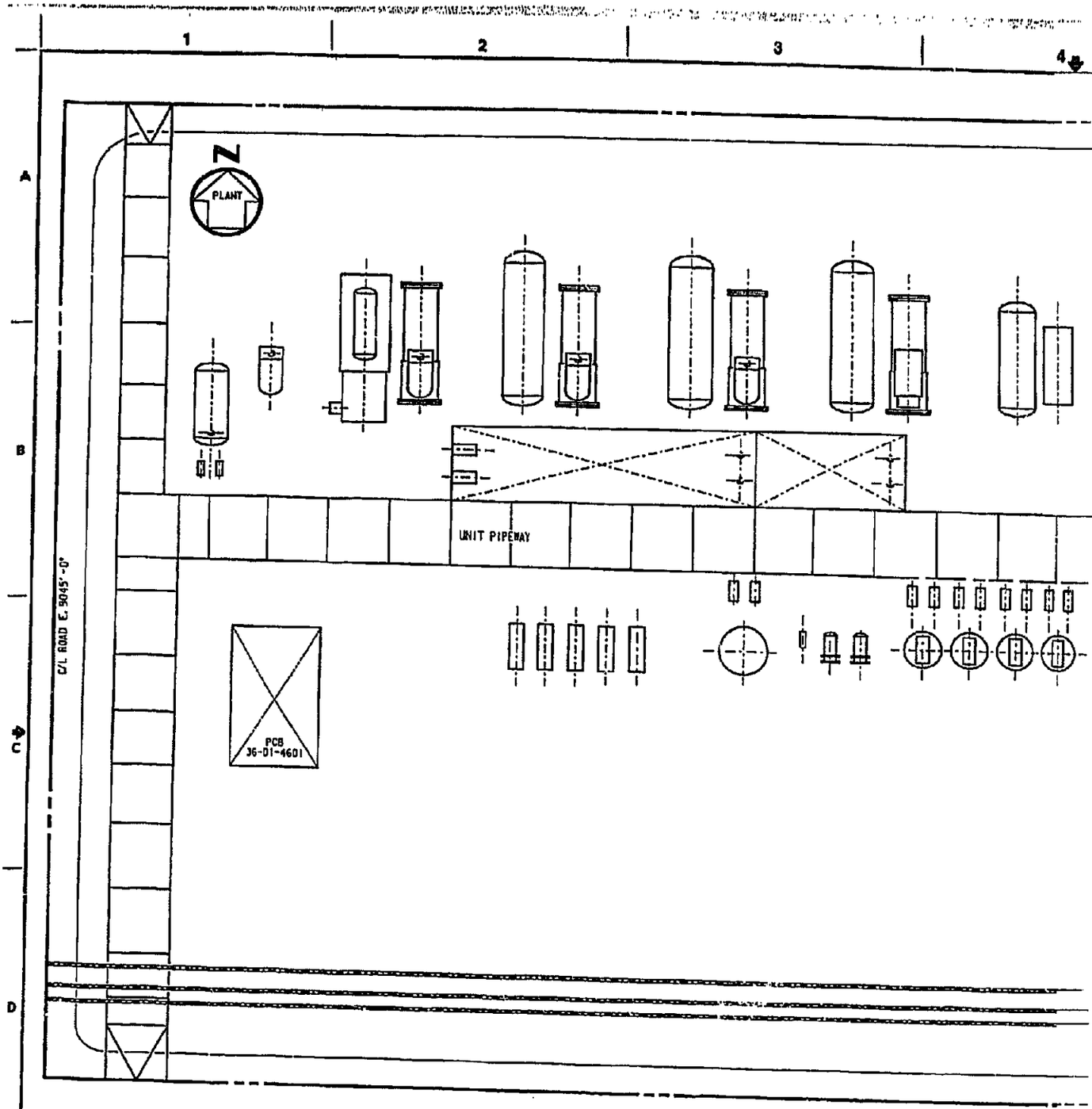
DESCRIPTION	DRAWN	CHECKED	APVD PROJ MGR	APVD CLIENT
R DESIGN REPORT				
FOR CLIENT APPROVAL	PDC	FJC	PDC 12-31-8	FJC 12-31-8
FOR CLIENT SOC REVIEW				

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

F. Plot Plan/General Arrangement Drawings

Plot Plan and General Arrangement Drawings for Sulfur Recovery (Claus) Unit 36 are as follows:

Drawing No.	Title
D-36-PD-1NP	Plot Plan - Unit 36 and Unit 37 SRU and BSRP
D-36-PD-2NP	Elevation - Unit 36 and Unit 37 SRU and BSRP



REFERENCES		REFERENCES		REVISIONS								REVISIONS							
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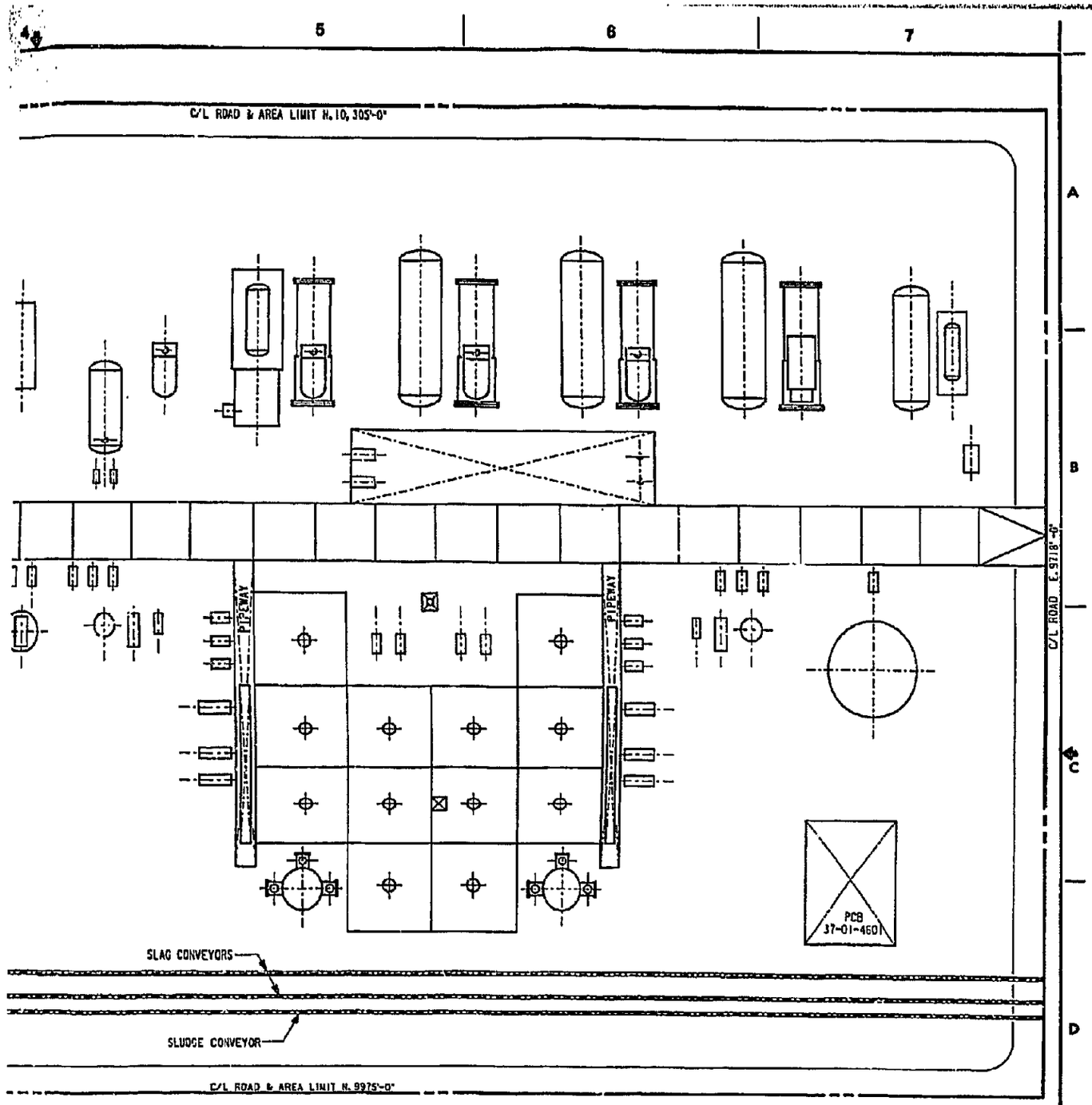
												A	5-7-82	MF		NH			FOR
												A	4-8-82	JC		NH		JC	FOR
												A	3-15-82	JC		NH			FOR

ENG-GE-23 (12/78)



0 10 20 40 60 80

SCALE: 1" = 20'-0"

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50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

DESCRIPTION			
FOR DESIGN REPORT	DRAWN	MY/CAD	
FOR DESIGN REPORT	CHECKED		
FOR CLIENT APPROVAL	APVD DEPT MG	NH	3-15-8
FOR CLIENT SOX REVIEW	APVD PROJ MGR	FJC	3-15-8
	APVD CLIENT		

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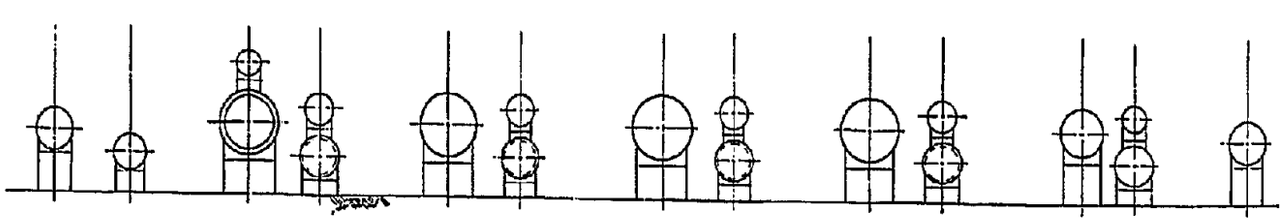
TITLE: PLOT PLAN
UNIT 36 AND UNIT 37
SRU AND BSRP

SCALE: 1" = 20'-0" | ACCOUNT NUMBER: 7243 | JOB NUMBER: 6182 | REVISION: D

DOCUMENT NUMBER: D-36-PD-INP



REFERENCES			REFERENCES			REVISIONS			REVISIONS			
DRAWING NO.	DESCRIPTION		DRAWING NO.	DESCRIPTION		NO.	DATE	BY	NO.	DATE	BY	
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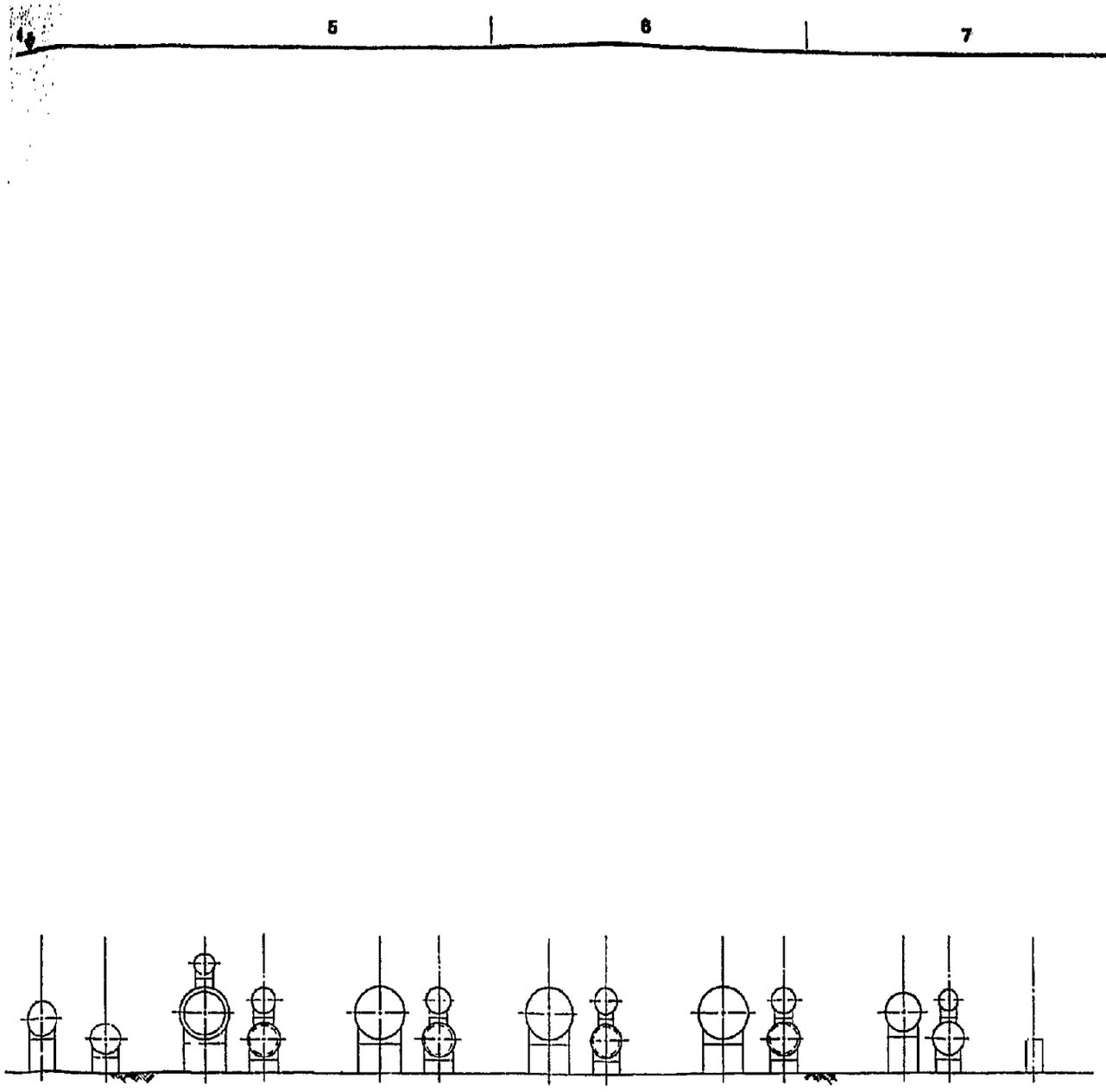
									B	4-29-82		FOR CLIEN
									A	4/16/82		FOR CLIEN



1"=20FT

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50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ELEVATIONS UNIT 56 AND UNIT 57 ERU AND BSRP

SCALE: 1"=20'-0" | ACCOUNT NUMBER: 7245 | JOB NUMBER: 6162

DOCUMENT NUMBER: D-36-PD-2NP

REVISION: E

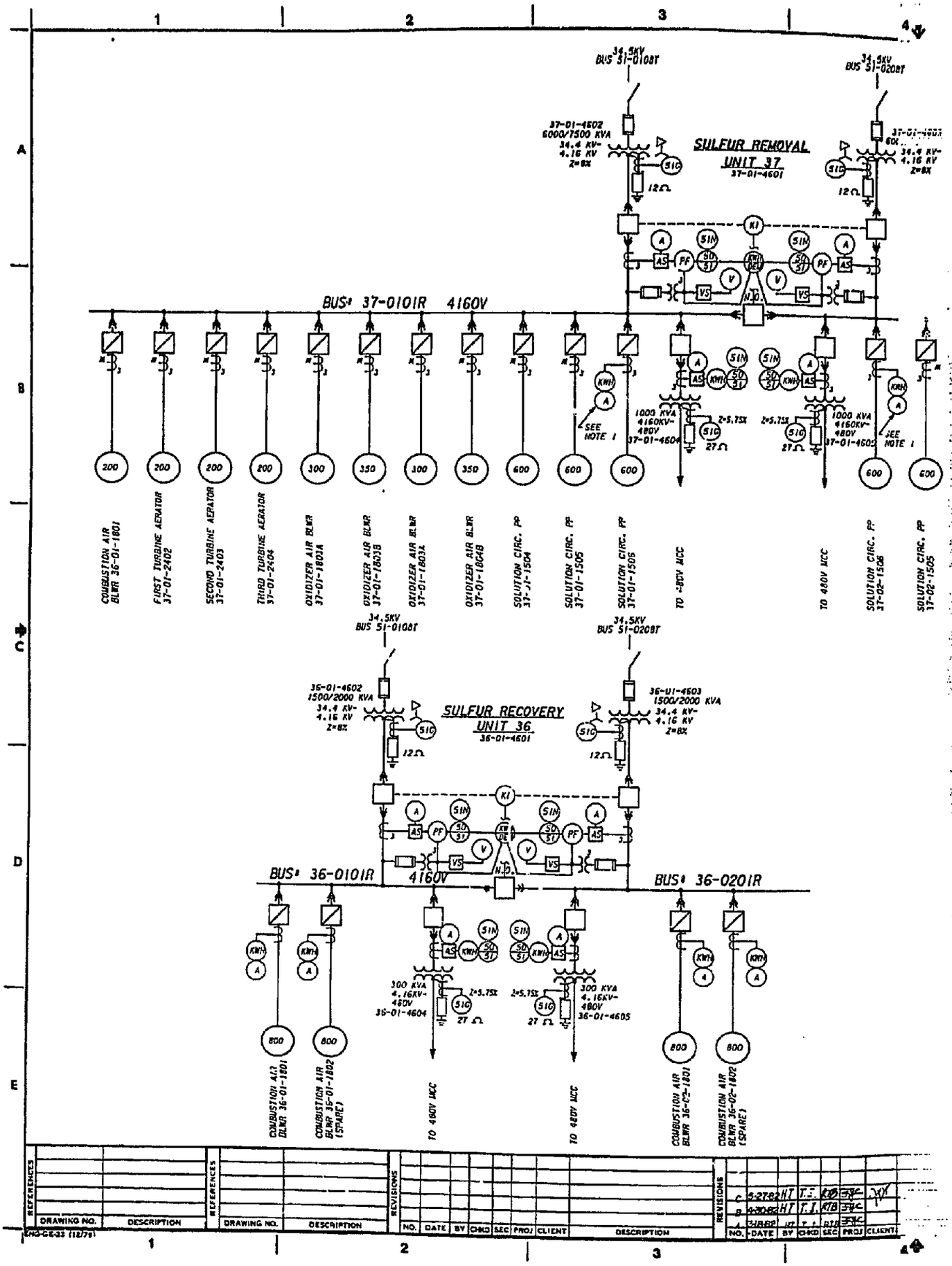
DESCRIPTION	BY	CHK	APVD
FOR DESIGN REPORT	MIL		
FOR CLIENT APPROVAL			
FOR CLIENT 50% REVIEW			

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

G. Single-Line Diagram

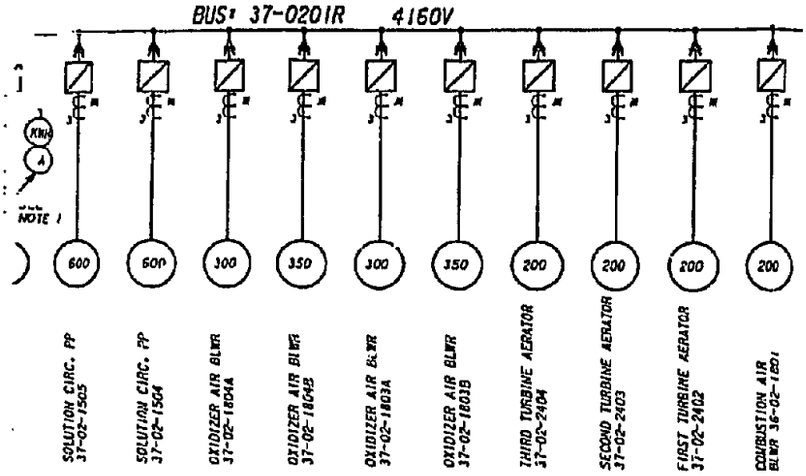
The Single-Line Diagram for Sulfur Recovery (Cleus) Unit 36 is as follows:

Drawing No.	Title
D-51-EE-8NP	One-Line Diagram - Units 36 and 37



REFERENCES			REFERENCES			REVISIONS								REVISIONS								
DRAWING NO.	DESCRIPTION		DRAWING NO.	DESCRIPTION		NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION	
														C	5-27-82	HT	T.J.	KTB	SWC			
														B	4-30-82	HT	T.J.	KTB	SWC			
														A	CHRIS	HT	T.J.	KTB	SWC			

CNG-GE-33 (12/79)



NOTES:

1. PROVIDE AM, KWH, METERS AT ALL LOCATIONS MARKED A

ISSUED FOR DESIGN REPORT	FOR		
ISSUED FOR CLIENT APPROVAL	DRAWN	HT	
ISSUED FOR CLIENT SDW REVIEW	CHECKED		
DESCRIPTION	APVD DEPT MG		
	APVD PROJ MGR		
	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: ONE LINE DIAGRAM SULFUR RECOVERY UNIT U-36 BEAVON SULFUR REMOVAL PLANT U-37

SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
NONE	4600	6182	4

DOCUMENT NUMBER: D-51-EE-8NP

1.2.17 SULFUR REMOVAL (BSRP) - UNIT 37

The Beavon Sulfur Removal Process (BSRP) has been selected to remove sulfur compounds (H_2S, SO_2, COS, CS_2, and sulfur) from the tail gas of the Claus sulfur recovery plant - Unit 36. The Beavon Sulfur Removal Process is a proprietary process licensed by The Ralph M. Parsons Company and the Union Oil Company of California.

The size of the two Claus sulfur recovery units requires that two parallel trains of BSRP be provided. The major gas stream to be treated is the tail gas stream from each Claus sulfur recovery unit, but a smaller stream of sweep gas from each sulfur storage pit also is treated.

The treated gas is discharged to the atmosphere from the top of the absorber. The gas will contain less than 10 ppmv of H_2S and less than 100 ppmv of total sulfur compounds measured as SO_2.

A. Basis of Design

The large amount of tail gas from each Claus unit requires a separate hydrogenation train for each stream. With this arrangement, the operator has the advantage of being able to tell from the H_2S and H_2 analyzers in the tail gas unit how each Claus unit is operating and maintain better control of the operation. Two trains allow the desuperheater/contact condenser and the absorber column diameter to be within Parsons previous experience. Two trains of Stretford regeneration provide turndown flexibility with considerable power savings under turndown conditions.

The total design capacity of both tail gas trains is 71.81 ltpd of sulfur from 135 million scfd of tail gas. The hydrogenation and gas scrubbing sections operate at less than 3 psig pressure.

The materials of construction are carbon steel and sulfur-resistant concrete, with stainless steel being used in areas of high turbulent Stretford solution flow and elevated temperature sulfur melting.

The size of the equipment is within the range of Parsons expertise.

Some undesirable side reactions take place in the Stretford solution. These reactions result in the formation of sodium thiosulfate ($Na_2S_2O_3$) and sodium sulfate (Na_2SO_4) instead of sulfur. These salts are quite soluble and can be allowed to build up to about 25% total dissolved salts. If allowed to build up beyond that, corrosion rates increase, regeneration rates decrease, and crystallization of $Na_2SO_4 \cdot 10H_2O$ (Glauber's salt) may occur in colder sections of the unit. The formation of these salts requires that the sodium associated with them be replaced. This is done by the continuous addition of a small stream of caustic.

The decanter overhead stream contains a small amount of solution to remove salts from the system as fast as they are being formed. The 2,7 anthraquinone disulfonic acid (ADA) and vanadium lost in discarding this stream must be replaced periodically to maintain the recommended concentrations in the solution. This is done by dissolving the powdered chemicals in Stretford solution in an agitated chemical mix sump and pumping the solution to the balance basin.

Feed Stream

Component	Tail Gas From Claus (lb mol/hr)	Tail Gas From Claus (mol%)	Sweep Gas From Claus Sulfur Storage Pit (lb mol/hr)	Sweep Gas From Claus Sulfur Storage Pit (mol%)
H_2	67.14	0.88	-	-
CH_4	-	-	-	-
CO	130.90	1.71	-	-
CO_2	3,199.96	41.75	-	-
N_2	4,142.12	54.05	194.30	78.79
O_2	-	-	51.66	20.95
H_2S	79.32	1.03	0.64	0.26
COS	2.28	0.03	-	-
SO_2	39.74	0.52	-	-
S_6	0.34	440 ppmv	-	-
S_8	2.10	0.03	-	-
Total dry, lb mol/hr	7,663.90	100.00	246.60	100.00
H_2O	2,514.08		7.62	
Total wet, lb mol/hr	10,177.98		254.22	
Total, lb/hr	311,960		7,250	
Pressure, psia	18		16	
Temperature, °F	280		280	

Treated Streams

Component	Treated Gas to Atmosphere (lb mol/hr)	(mol%)
H_2	103.04	1.16
CO	8.60	0.10
CO_2	3,506.06	39.47
N_2	5,212.10	58.68
O_2	51.66	0.58
H_2S	0.09	10 ppmv
COS	0.42	50 ppmv
Total dry, lb mol/hr	8,881.97	100.00
H_2O	1,010.74	
Total wet, lb mol/hr	9,892.71	
Total, lb/hr	320,660	
Pressure psia	15	
Temperature, °F	117	

Component	Molten Sulfur Product (lb mol/hr)	(mol%)
Sulfur (S_1)	139.80	100.00
Total dry	139.80	100.00
H_2O	-	
Total wet	139.80	
Total, lb/hr	4,480	
Pressure, psia	18	
Temperature, °F	280	

Component	Solution Purge Stream (lb/day)	(wt%)
ADA (2,7 anthraquinone disulfonic acid)	24	0.034
Vanadium	48	0.067
$NaHCO_3$	292	0.407
Na_2SO_4	1,128	1.570
$Na_2S_2O_3$	2,510	3.497
Water	67,770	94.425
Total	71,772	100.00

B. Process Selection Rationale

The Beavon Sulfur Removal Process was developed in 1970 and 1971 by The Ralph M. Parsons Company with the cooperation of the Union Oil Company of California. The first commercial units were started up in 1973. Since that time, more than 50 units have been built or are being built. Most of the operating units achieve an onstream factor of over 95% and at least one was onstream continuously for more than 2 years between turnarounds. The units have met and exceeded environmental requirements virtually all the time even during upsets of upstream units. At the present time, it is considered not only Best Available Control Technology (BACT) but also Lowest Achievable Emission Rate (LAER). It is effective for both strong and weak acid gas.

The BSRP is capable of handling 2-1/2 times the normal operating condition rate of H_2S for short periods (2 to 3 hours) if the composition of the solution is maintained within recommended ranges.

Turndown is usually limited by metering and control valve rangeability on the air and gas to the tail gas heater (reducing gas generator). This is about 20% of design. Since there are two trains, the overall turndown is about 10%. The use of two trains is advantageous in reducing power requirements on turndown to less than 50% to 60%. Having one hydrogenation section for each Claus unit allows operators to monitor the operation of each unit through the H_2S and H_2 analysis of the reduced gas of the appropriate BSRP and thereby obtain much smoother and efficient operation of the Claus unit. Each tail gas unit is started up and shut down in conjunction with the sulfur recovery unit preceding it. Essentially no sulfur compounds will be released to the atmosphere at any time.

All pumps and blowers are spared and maintenance requiring plant downtime will be rare.

No unusual lead time for equipment or material procurement is required.

C. Process Description

Refer to Process Flow and Control Diagrams D-37-MP-1NP, -2NP, -3NP, and -4NP for material balance.

The Beavon Sulfur Removal Process consists of two basic sections. The first section catalytically converts essentially all of the sulfur compounds in the Claus unit tail gas to hydrogen sulfide. This is called the hydrogenation section. This is followed by the Stretford section where the H_2S is absorbed in an alkaline solution and converted to elemental sulfur particles.

1. Hydrogenation Section. The sulfur recovery unit tail gas is heated to reaction temperature by mixing it in Reducing Gas Generator 37-01-1401 with the products of combustion of fuel gas (normally natural gas)

and air. The fuel gas is proportioned to the air rate so that combustion takes place with only 80% to 90% of the air necessary for complete combustion. The air rate is controlled by the temperature of the mixed gas going to the reactor. Steam is added to the flame to promote clean burning and to prevent carbon formation. The steam flow is proportioned to the fuel gas flow. Some hydrogen and carbon monoxide are formed to supplement that already in the tail gas. This provides an excess of reducing gas to ensure conversion of the sulfur compounds in the tail gas to hydrogen sulfide over the cobalt molybdate hydrogenation catalyst.

Water vapor normally present hydrolyzes COS, CS_2, and CO to H_2S and hydrogen in Reactor 37-01-1201 according to the following reactions:

$$COS + H_2O \longrightarrow H_2S + CO_2 \quad (1)$$

$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2 \quad (2)$$

$$CO + H_2O \longrightarrow H_2 + CO_2 \quad (3)$$

Hydrogen will react with SO_2 and sulfur to form H_2S according to the following reactions:

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O \quad (4)$$

$$S + H_2 \longrightarrow H_2S \quad (5)$$

All of the above reactions are exothermic, causing a temperature rise through the catalyst bed.

The gas from Reactor 37-01-1201 is cooled by exchange with boiling water in a water tube boiler, Reactor Effluent Cooler 37-01-1301. Steam is generated at 50 psig and the gas cooled from 725°F to about 330°F. The gas enters Contact Condenser/Desuperheater 37-01-1101, which is separated into two sections; the bottom section is called a desuperheater section. The gas is contacted with an alkaline solution descending through

disc and donut baffle trays. The alkaline solution absorbs any SO_2 that may be in the gas caused by upsets in the Claus unit operation. The sensible heat in the gas evaporates water from the alkaline solution and cools it adiabatically to its dew point of about 170°F. The alkaline solution is circulated over the baffle trays by centrifugal pumps 37-01-1501 and -1502. The pH of the solution is measured continuously and an alarm warns of a low pH. If the solution pH falls below 5 because of SO_2 in the tail gas, the desuperheater circulating solution and the condensate in the contact condenser section become very corrosive and can damage the equipment in a short time. The liquid level in the desuperheater is maintained by the automatic addition of condensate from the upper section of the column, the contact condenser section. Caustic is added whenever the pH gets low.

The contact condenser section is separated from the desuperheater section of the column by a chimney tray. Two bubble cap trays in the desuperheater section prevent entrainment of alkali from the desuperheater. The bubble cap trays receive the condensate makeup that maintains the desuperheater level.

Most of the water in the gas is condensed in the contact condenser section by direct contact with cooled condensate in a bed of 2-inch stainless steel pall rings. The condensate is cooled by circulating it through Solution Heater 37-01-1302 against a stream of Stretford solution and then through Contact Condenser Cooler 37-01-1303 against cooling water. The gas is cooled to 95°F. The condensed water is routed to battery limits. It will contain some absorbed H_2S.

2. Stretford Section. The Stretford process is based on the ability of vanadium when in the five-valent state to react with H_2S that has been absorbed in an alkaline solution, forming elemental sulfur. In this reaction, the vanadium is reduced to the four-valent state. Oxidation of the Stretford solution with air returns the vanadium to the five-valent state. Vanadium compounds are incapable of reacting directly with the oxygen

in the air. For this reason, ADA is used as an oxygen carrier to transfer oxygen from the air to the tetravalent vanadium.

The cooled reduced tail gas from Contact Condenser 37-01-1101 contacts with Stretford solution in a venturi scrubber that discharges into Absorber Evaporator 37-01-1102. There are three 36-inch venturi scrubbers in parallel discharging into one absorber for each train. Each venturi has a 20-foot-long by 36-inch-diameter tail pipe; 4,434 gpm of Stretford solution is circulated to each venturi for contact with one-third of the gas. The liquid and gas separate in the bottom of the absorber. The gas is further contacted with 3,326 gpm of lean Stretford solution in two packed beds of 3-inch stainless steel pall rings in the absorber. The gas, which contains less than 10 ppmv of H_2S and less than 100 ppmv of total sulfur (mainly COS) measured as SO_2, is discharged from the top of the absorber to the atmosphere.

The upper bed of pall rings in the absorber is used as an evaporative section to evaporate water from the Stretford solution to maintain the system water balance. The Stretford solution going to the top bed is heated by exchange with the circulating condensate of Contact Condenser Desuperheater 37-01-1101 as mentioned previously or in steam-jacketed sections of the circulating piping. This hotter solution heats the gas and saturates it with water. The water made in the reaction and used to replace the solution from the centrifuge cake is removed in this manner.

The reduced Stretford solution flows from the absorber by gravity to Reaction Basin 37-01-4101, which ensures enough time for the elemental sulfur to form as particulates; from there, it passes through a series of three oxidizer basins. In the oxidizer basins, air from Oxidizer Air Blowers 37-01-1802/1803 is sparged through a proprietary turboaerator, which disperses fine air bubbles throughout each basin. The reoxidized solution flows to a pump basin called Balance Basin 37-01-4105, from where it is pumped to Venturi Scrubbers 37-01-2201 and Absorber 37-01-1102. The air in the oxidizers not only reoxidizes the solution but also causes the sulfur

particles to float to the surface. From there, they are skimmed to a slurry basin as a 5% to 15% by weight sulfur slurry.

The sulfur slurry is concentrated to a 50% to 60% sulfur cake in a solid bowl scroll discharge 1st Centrifuge 37-01-2202. This cake is repulped with process water to about 25% sulfur slurry in Agitated Repulp Tank 37-01-1901. The diluted slurry is centrifuged to a 50% to 60% sulfur cake, which again is repulped in a 2nd Repulp Tank 37-01-1902. This time the water is a cooled stream from the Decanter Overhead Tank 37-01-1903. The resultant slurry (about 40% sulfur) is pumped into Sulfur Melter/Decanter 37-01-1304 equipped with a U-tube steam exchanger bundle. The vessel operates under about 55-psig pressure and is heated by 50-psig steam. The slurry is heated to above the melting point of sulfur and the molten sulfur and water separate. The sulfur is drawn off the bottom under interface level control to Storage Basin 37-01-4108; from there, it is sent periodically to loading or is mixed with sulfur from Claus Unit 36. The water phase is mixed with a cooled stream of decanter overhead water to prevent flashing and is routed through a backpressure control valve that will maintain the system pressure to a surge tank. Decanter Overhead Pump 37-01-1513 circulates the decanter overheads through Decanter Overhead Cooler 37-01-1306 for cooling against cooling water and then to the second repulp tank to quench the decanter overhead stream or to the purge stream discharge.

D. Risk Assessment

At recommended concentrations of chemicals, the Stretford solution used to absorb H_2S from the tail gas is capable of absorbing up to two-and-a-half times the design rate of H_2S for 2 to 3 hours without releasing dangerous concentrations to the atmosphere. More than 30 Beavon Sulfur Removal Units are in operation removing sulfur from the tail gas of Claus units to below 100 ppm.

Loss of combustion air to the reducing gas generator does not require an immediate shutdown of the unit. The residual heat in the

refractory and catalyst bed allows several hours for relighting the unit. Oxidizer air failure does not require an immediate shutdown of the unit. The large inventory of solution allows 1 to 2 hours to correct the problem. Both the combustion and oxidizer air blowers for each train are spared by a common spare blower.

Loss of circulation in the desuperheater does not require an immediate shutdown. Some units operate continuously without a desuperheater. Loss of circulation in the contact condenser circuit does not require an immediate shutdown. The lack of heat removal will gradually heat up the Stretford solution, but this can be tolerated for several hours while the problem is being corrected. The desuperheater pump and the contact condenser pump for each train are spared by a common circulating pump.

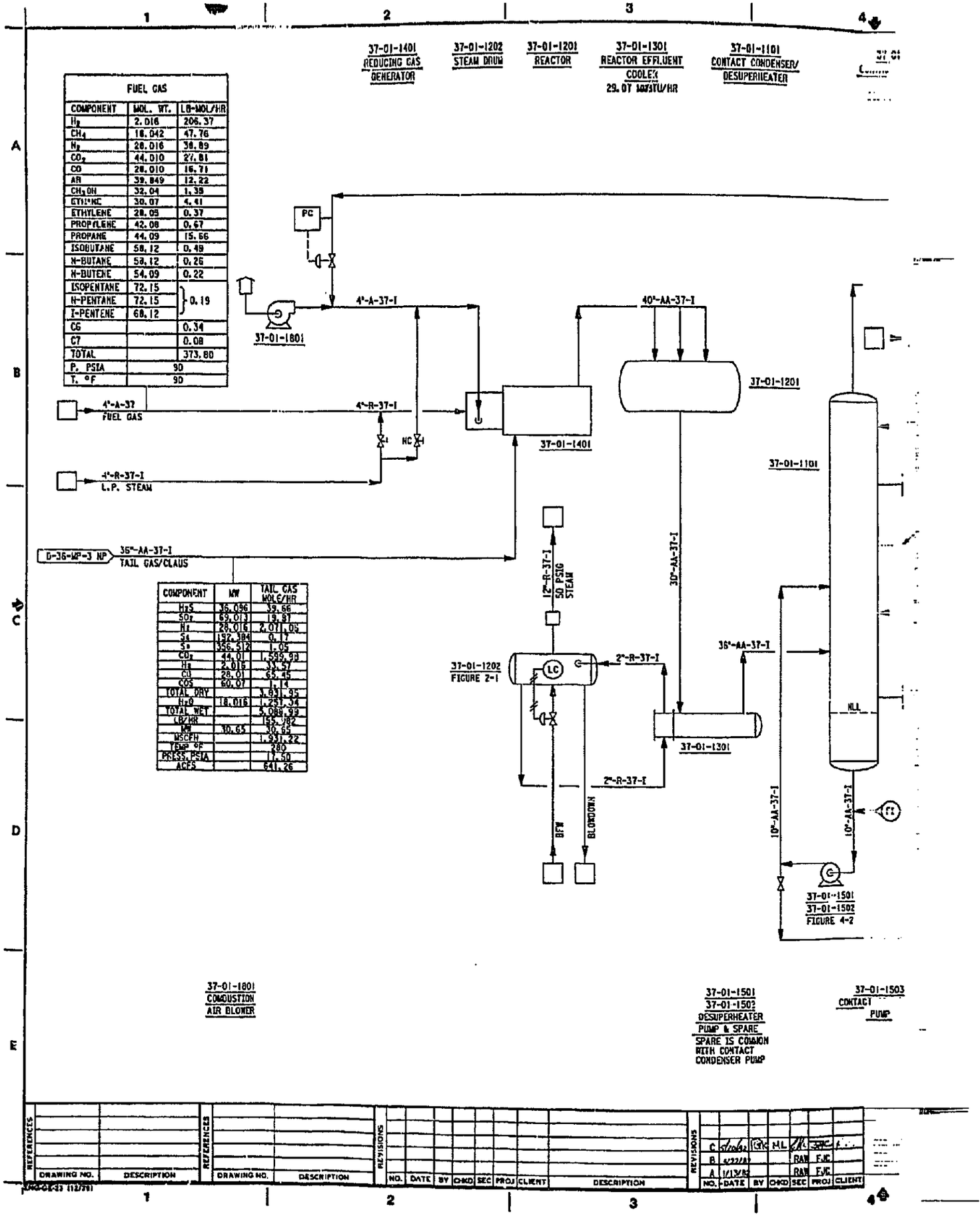
A large sulfur slurry basin is provided for each train so that any problems with the slurry handling, concentration, and melting equipment can be corrected without a shutdown of the tail gas unit. All slurry pumps are 100% spared.

Loss of Stretford solution to the venturis and absorber for each train requires an immediate shutdown of both the Claus sulfur removal unit and the tail gas unit. There are two circulating pumps and a 50% spare for each train. There is one BSRP train for each Claus sulfur recovery train; each is designed to remove 36 ltpd of sulfur from the tail gas of that train.

E. Process Flow and Control Diagrams
(Including Material Balance)

Process Flow and Control Diagrams for Sulfur Removal (BSRP) Unit 37 are as follows:

Drawing No.	Title
D-37-MP-1NP	PFCD Sulfur Removal (BSRP) - Reactor
D-37-MP-2NP	PFCD Sulfur Removal (BSRP) - Recovery
D-37-MP-3NP	PFCD Sulfur Removal (BSRP) - Regeneration
D-37-MP-4NP	PFCD Sulfur Removal (BSRP) - Common Equipment

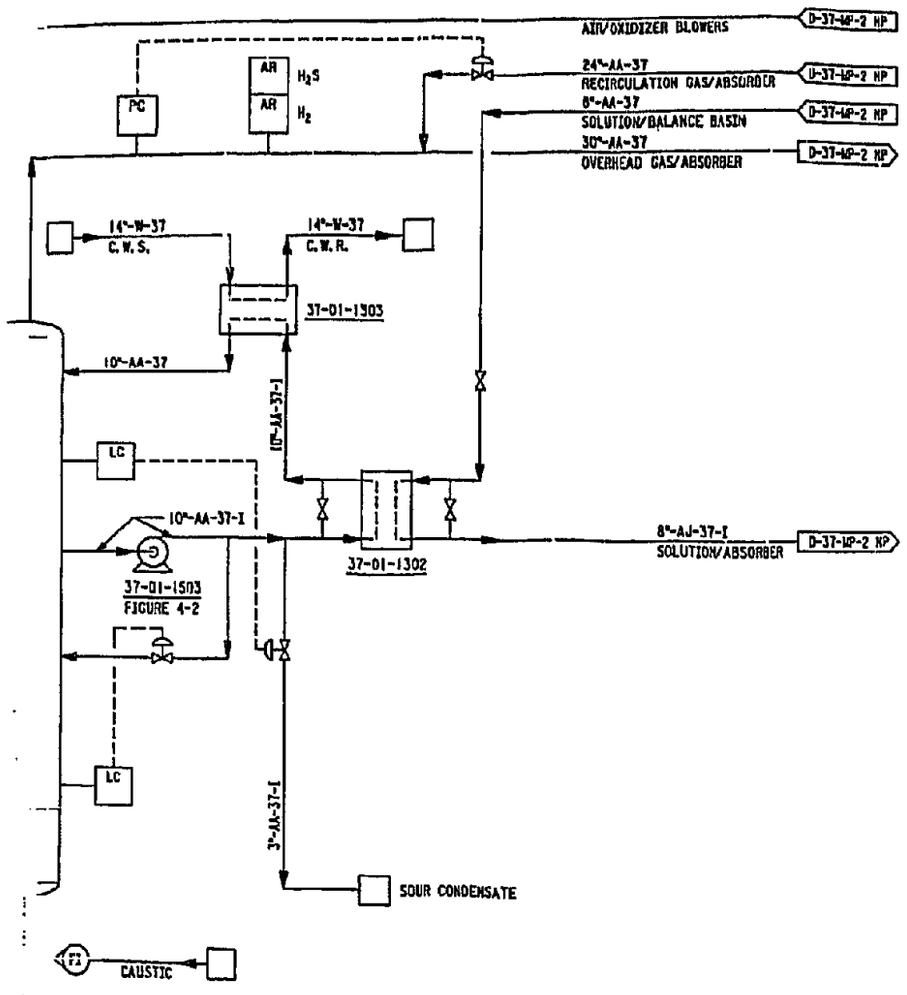

37-01-1401
REDUCING GAS GENERATOR
37-01-1202
STEAM DRUM
37-01-1201
REACTOR
37-01-1301
REACTOR EFFLUENT COOLER
29.07 MMBTU/HR
37-01-1101
CONTACT CONDENSER/ DESUPERHEATER
FUEL GAS
COMPONENT | MOL. WT. | LB-MOL/HR
H2 | 2.016 | 206.37
CH4 | 16.042 | 47.76
N2 | 28.016 | 36.89
CO2 | 44.010 | 27.81
CO | 28.010 | 16.71
AR | 39.949 | 12.22
CH3OH | 32.04 | 1.38
ETHANE | 30.07 | 4.41
ETHYLENE | 28.05 | 0.37
PROPYLENE | 42.08 | 0.67
PROPANE | 44.09 | 15.66
ISOBUTANE | 58.12 | 0.49
N-BUTANE | 58.12 | 0.26
N-BUTENE | 54.09 | 0.22
ISOPENTANE | 72.15 | 0.19
N-PENTANE | 72.15 | 0.19
T-PENTENE | 68.12 | 0.19
C6 | | 0.34
C7 | | 0.08
TOTAL | | 373.80
P, PSIA | 90
T, °F | 90
PC
37-01-1801
4"-A-37-I
40"-AA-37-I
37-01-1201
4"-A-37
FUEL GAS
4"-R-37-I
HC
37-01-1401
4"-R-37-I
L.P. STEAM
37-01-1101
D-36-WP-3 NP
36"-AA-37-I
TAIL GAS/CLAUS
COMPONENT | MW | TAIL GAS MOLE/HR
H2S | 36.096 | 39.66
SO2 | 64.063 | 19.81
N2 | 28.016 | 2,011.04
S4 | 128.384 | 0.17
S6 | 256.512 | 1.05
CO2 | 44.01 | 1,589.98
H2 | 2.016 | 22.57
CO | 28.01 | 55.45
COS | 60.07 | 1.14
TOTAL DRY | | 3,631.95
H2O | 18.016 | 1,257.04
TOTAL WET | | 5,088.99
LB/HR | | 155,382
MW | 30.65 | 30.65
MSCFH | | 1,931.22
TEMP °F | | 280
PRESS, PSIA | | 17.50
ACFS | | 641.26
12"-R-37-I
50 PSIG STEAM
30"-AA-37-I
36"-AA-37-I
37-01-1202
FIGURE 2-1
LC
2"-R-37-I
37-01-1301
2"-R-37-I
BFW
BLOWDOWN
NLL
10"-AA-37-I
10"-AA-37-I
FE
37-01-1501
37-01-1502
FIGURE 4-2
37-01-1801
COMBUSTION AIR BLOWER
37-01-1501
37-01-1502
DESUPERHEATER PUMP & SPARE
SPARE IS COMMON WITH CONTACT CONDENSER PUMP
37-01-1503
CONTACT PUMP
REFERENCES
DRAWING NO. | DESCRIPTION
REVISIONS
NO. | DATE | BY | CHKD | SEC | PROJ | CLIENT | DESCRIPTION
C 5/10/82 GK ML RAN FJC
B 4/22/82 RAN FJC
A 1/13/82 RAN FJC

37-01-1303
CONTACT CONDENSER
COOLER
50.14 MMBTU/HR

37-01-1302
SOLUTION
HEATER
9.13 MMBTU/HR

37-01-1307
STEAM SOLUTION
HEATER
9.13 MMBTU/HR

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON DRAWING D-01-MP-2 NP.



EQUIPMENT SHOWN ON THIS DRAWING:

37-01-1101	37-01-1307
37-01-1201	37-01-1401
37-01-1202	37-01-1501
37-01-1301	37-01-1502
37-01-1302	37-01-1503
37-01-1303	

10"-AA-37-I
EFFLUENT/ABSORBER
D-37-MP-2 NP

37-01-1503
COMPRESSOR
PUMP

D37MP1NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW AND CONTROL DIAGRAM SULFUR REMOVAL (SSRP)-UNIT 37 TAIL GAS REACTOR

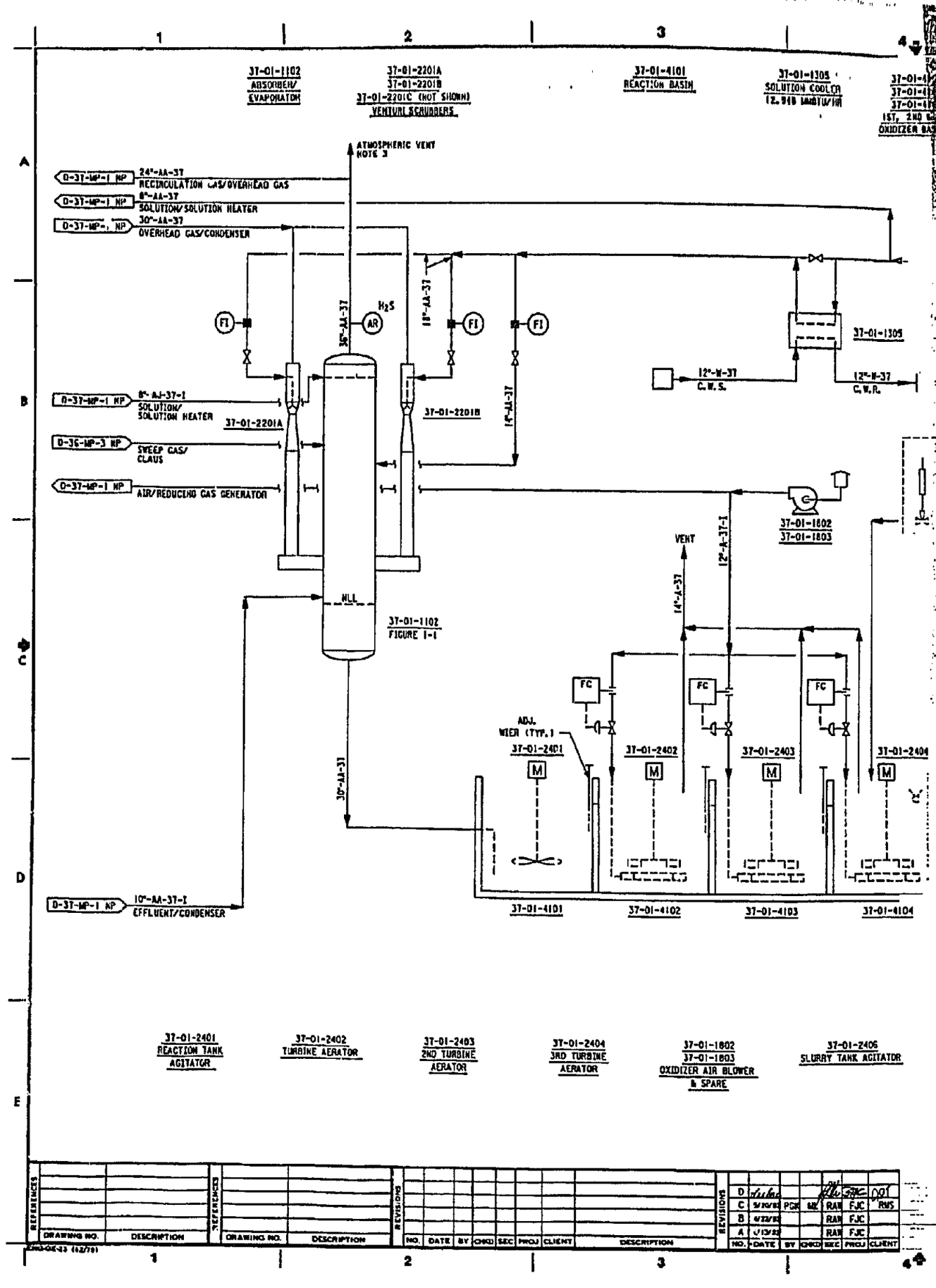
SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182

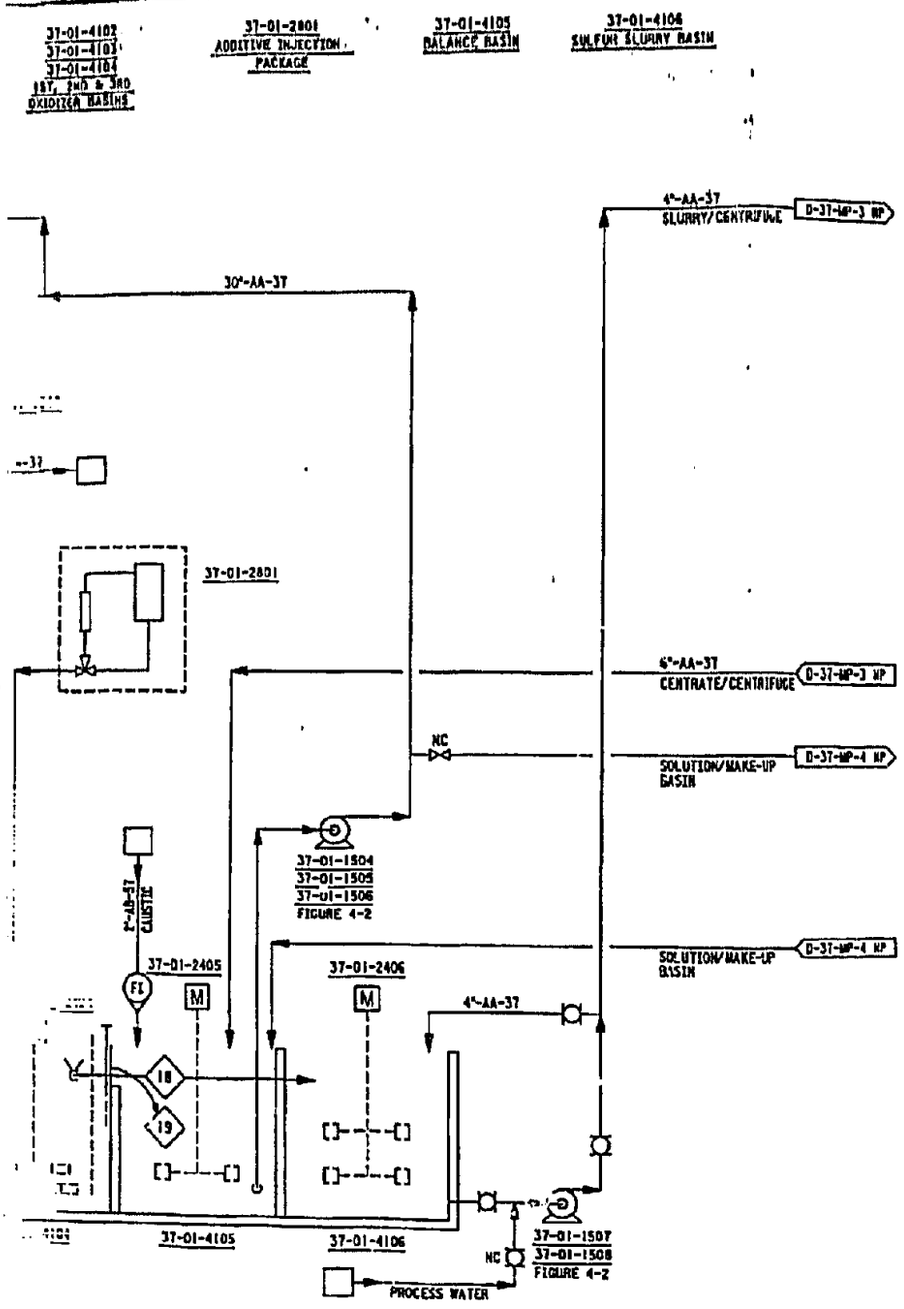
DOCUMENT NUMBER: D-37-MP-1 NP

REVISION: C

DESCRIPTION	FOR
FOR DESIGN REPORT	DRAWN
FOR CLIENT APPROVAL	CHECKED
FOR CLIENT 50% REVIEW	APVD MECY MD — HKC — 12-31-8
	APVD PROJ MGR — F.K. — 12-31-8
	APVD CLIENT

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA


37-01-1102
ABSORBER/
EVAPORATOR
37-01-2201A
37-01-2201B
37-01-2201C (NOT SHOWN)
VENTURI SCRUBBERS
37-01-4101
REACTION BASIN
37-01-1305
SOLUTION COOLER
ATMOSPHERIC VENT
NOTE 3
D-37-MP-1 NP
24"-AA-37
RECIRCULATION GAS/OVERHEAD GAS
D-37-MP-1 NP
8"-AA-37
SOLUTION/SOLUTION HEATER
D-37-MP-1 NP
30"-AA-37
OVERHEAD GAS/CONDENSER
30"-AA-37
H2S
AR
FI
18"-AA-37
FI
FI
37-01-1305
12"-W-37
C.W.S.
12"-W-37
C.W.R.
D-37-MP-1 NP
8"-AA-37-1
SOLUTION/
SOLUTION HEATER
37-01-2201A
37-01-2201B
14"-AA-37
D-36-MP-3 NP
SWEEP GAS/
CLAUS
D-37-MP-1 NP
AIR/REDUCING GAS GENERATOR
37-01-1602
37-01-1603
VENT
12"-A-37-1
14"-AA-37
NLL
37-01-1102
FIGURE 1-1
FC
FC
FC
ADJ.
WEIR (TYP.)
37-01-2401
37-01-2402
37-01-2403
37-01-2404
M
M
M
M
30"-AA-37
D-37-MP-1 NP
10"-AA-37-1
EFFLUENT/CONDENSER
37-01-4101
37-01-4102
37-01-4103
37-01-4104
37-01-2401
REACTION TANK
AGITATOR
37-01-2402
TURBINE AERATOR
37-01-2403
2ND TURBINE
AERATOR
37-01-2404
3RD TURBINE
AERATOR
37-01-1602
37-01-1603
OXIDIZER AIR BLOWER
& SPARE
37-01-2406
SLURRY TANK AGITATOR
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
DESCRIPTION
D
C
B
A
RAM
FJC
RMS
1
2
3
4



NOTES:

1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON D-01-MP-2 NP.
3. VENT COMPOSITION.

ATMOSPHERIC VENT

COMPONENT	MOL. WT.	MOLES/HR
H_2	2.016	51.53
CO	28.01	4.30
N_2	28.016	3,606.05
O_2	32.00	35.83
CO_2	44.01	1,753.03
COS	60.07	0.2
TOTAL DRY		5,440.94
WATER	18.016	505.37
TOTAL WET		4,946.31
MOLECULAR WEIGHT		32.47
LB/HR		160,310.
MSCFH		1,877.58
TEMPERATURE °F		116.
PRESSURE PSIA		14.50
ACFS		595.93

EQUIPMENT SHOWN ON THIS DRAWING:

37-01-1102	37-01-2403
37-01-1305	37-01-2404
37-01-1504	37-01-2405
37-01-1505	37-01-2406
37-01-1506	37-01-2801
37-01-1507	37-01-4101
37-01-1508	37-01-4102
37-01-1802	37-01-4103
37-01-1803	37-01-4104
37-01-2201A	37-01-4105
37-01-2201B	37-01-4106
37-01-2201C	
37-01-2401	
37-01-2402	

37-01-1507
37-01-1508
1ST CENTRIFUGE FEED PUMP & SPARE

37-01-1504
37-01-1505
37-01-1506
SOLUTION CIRCULATING PUMP & SPARE

37-01-2405
BALANCE TANK AGITATOR

D37MP2NP.DGN

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PROCESS FLOW AND CONTROL DIAGRAM
SULFUR REMOVAL (BSRP)-UNIT 37
SULFUR RECOVERY

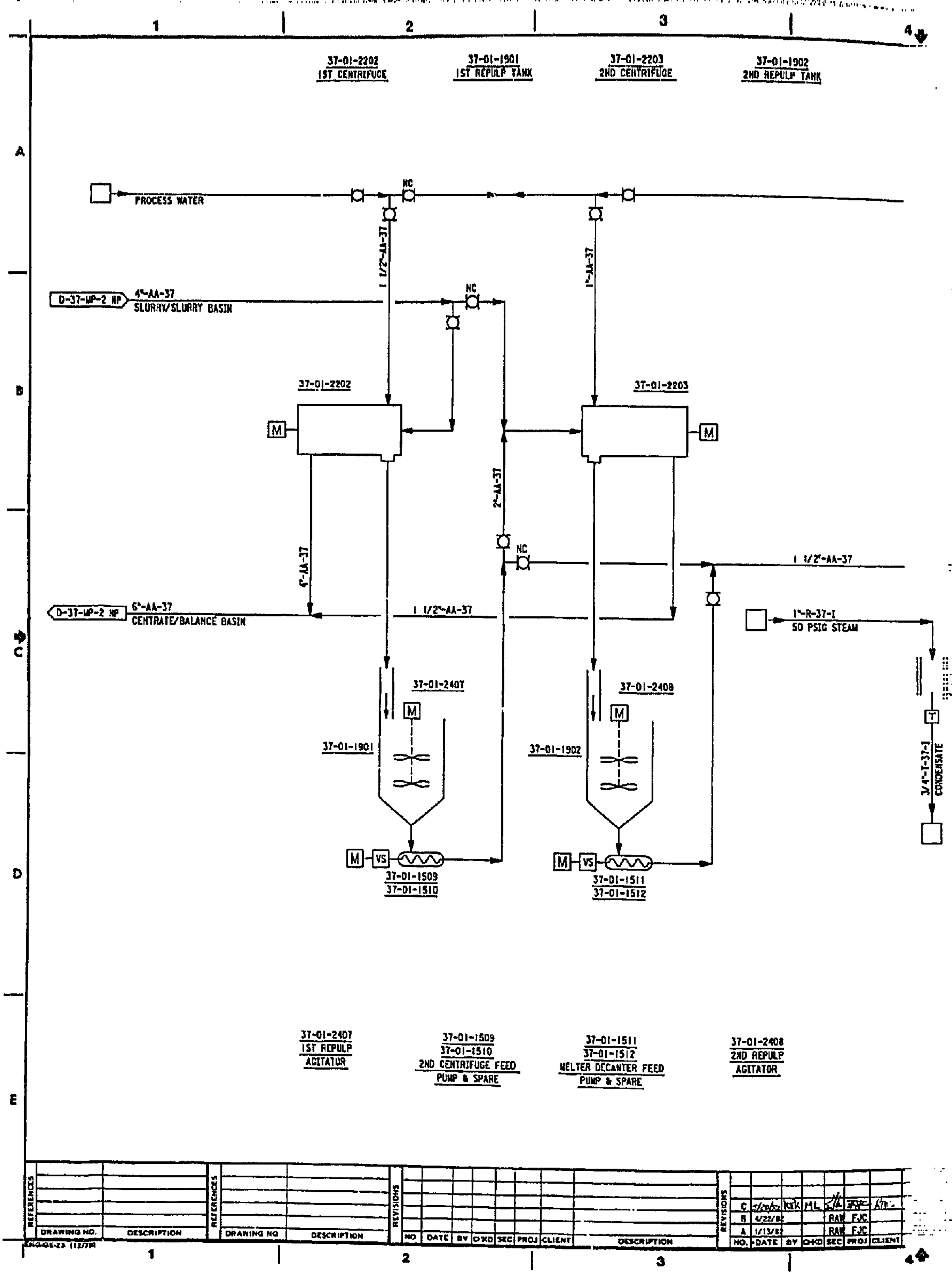
SCALE: NONE | PROJECT NUMBER: 2400 | CONTRACT NUMBER: 6182

DOCUMENT NUMBER: D-37-MP-2 NP

REVISIONS: 0

REVISIONS	DESCRIPTION	DRAWN	CHECKED	APVD DESIGN MGR	APVD PROJ MGR	APVD CLIENT
RMS	REVISED FOR DESIGN REPORT			HKC	FJC	
	FOR DESIGN REPORT			12-31-8	12-31-8	
	FOR CLIENT APPROVAL					
	FOR CLIENT SOX REVIEW					

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

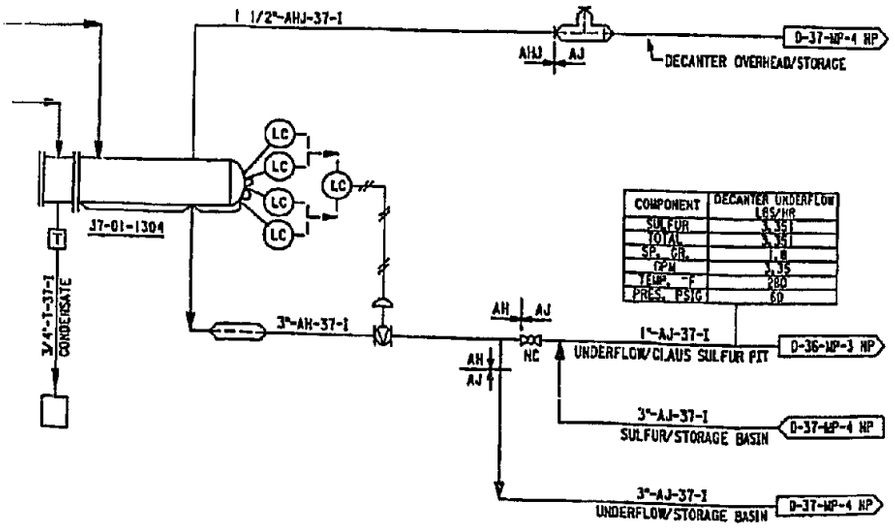


37-01-2202
1ST CENTRIFUGE
37-01-1901
1ST REPULP TANK
37-01-2203
2ND CENTRIFUGE
37-01-1902
2ND REPULP TANK
PROCESS WATER
NC
1 1/2"-AA-37
1"-AA-37
D-37-WP-2 NP
4"-AA-37
SLURRY/SLURRY BASIN
37-01-2202
37-01-2203
2"-AA-37
4"-AA-37
1 1/2"-AA-37
D-37-WP-2 NP
6"-AA-37
CENTRATE/BALANCE BASIN
1 1/2"-AA-37
1"-R-37-I
50 PSIG STEAM
3/4"-T-37-I
CONDENSATE
37-01-2407
37-01-1901
37-01-2408
37-01-1902
37-01-1509
37-01-1510
37-01-1511
37-01-1512
37-01-2407
1ST REPULP
AGITATOR
37-01-1509
37-01-1510
2ND CENTRIFUGE FEED
PUMP & SPARE
37-01-1511
37-01-1512
MELTER DECANTER FEED
PUMP & SPARE
37-01-2408
2ND REPULP
AGITATOR
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
DESCRIPTION
C
B 4/22/82 RAW FJC
A 1/13/82 RAW FJC
ENG-GE-23 (12/78)

37-01-1304
SULFUR MELTER/
DECANTER
2.5 MM BTU/HR

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING ARE FOR ONE OF TWO TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON D-01-MP-2 NP.

DECANTER OVERHEAD/STORAGE D-37-MP-4 NP



COMPONENT	DECANTER UNDERFLOW LBS/HR
SULFUR	5,351
TOTAL	5,351
SP. GR.	1.8
GPM	5.35
TEMP. °F	280
PRES. PSIG	60

EQUIPMENT SHOWN ON THIS DRAWING:

37-01-1304	37-01-1902
37-01-1509	37-01-2202
37-01-1510	37-01-2203
37-01-1511	37-01-2407
37-01-1512	37-01-2408
37-01-1901	

	FOR		
	DRAWN		
FOR DESIGN REPORT	CHECKED		
FOR CLIENT APPROVAL	APVD SECT HD	MEC	12-31-8
FOR CLIENT SOK REVIEW	APVD PROJ MGR	FJC	12-31-8
DESCRIPTION	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

037MP3NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

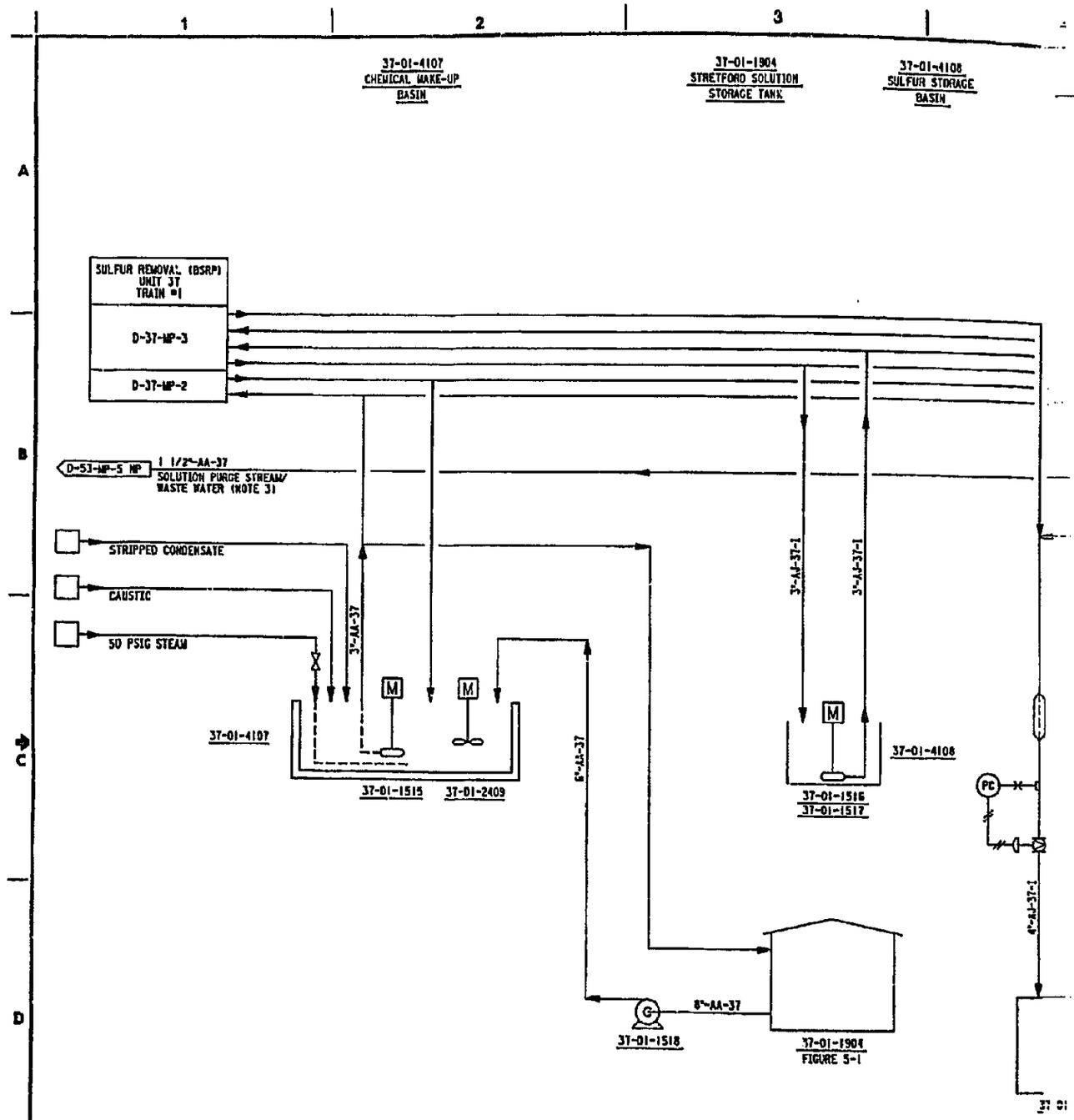
50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PROCESS FLOW AND CONTROL DIAGRAM SULFUR REMOVAL (RSRP)-UNIT 37 SOLUTION REGENERATION

SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
NONE	2800	6182	C

DOCUMENT NUMBER: D-37-MP-3 NP


37-01-4107
CHEMICAL MAKE-UP
BASIN
37-01-1904
STRETFORD SOLUTION
STORAGE TANK
37-01-4108
SULFUR STORAGE
BASIN
SULFUR REMOVAL (BSRP)
UNIT 37
TRAIN #1
D-37-MP-3
D-37-MP-2
D-53-MP-5 MP
1 1/2"-AA-37
SOLUTION PURGE STREAM/
WASTE WATER (NOTE 3)
STRIPPED CONDENSATE
CAUSTIC
50 PSIG STEAM
3"-AA-37
3"-AJ-37-1
3"-AJ-37-1
6"-AA-37
8"-AA-37
8"-AJ-37-1
37-01-4107
37-01-1515
37-01-2409
37-01-4108
37-01-1516
37-01-1517
37-01-1518
37-01-1904
FIGURE 5-1
37-01-1515
MAKE-UP SUMP PUMP
COMMON TO BOTH TRAINS
37-01-2409
CHEMICAL MAKE-UP
BASIN AGITATOR
COMMON TO BOTH TRAINS
37-01-1518
STRETFORD SOLUTION
STORAGE PUMP
37-01-1516
37-01-1517
SULFUR TRANSFER
PUMP & SPARE

37-01-1903
DECANTER OVERHEAD
TANK

37-01-1306
DECANTER OVERHEAD
COOLER
4.57 MMBTU/HR

NOTES:
1. THE EQUIPMENT SHOWN ON THIS DRAWING IS COMMON TO BOTH TRAINS.
2. THE FIGURE NUMBERS REFER TO TYPICAL EQUIPMENT CONFIGURATIONS SHOWN ON D-01-MP-2 NP
3. SOLUTION PURGE STREAM COMPOSITION.

SOLUTION PURGE STREAM

COMPONENT	MOL/WT	WEIGHT %	LB/DAY
ADA		0.034	24
VANADIUM	50.95	0.367	48
$NaHCO_3$	84.01	0.407	292
Na_2SO_4	142.05	1.570	1,128
$Na_2S_2O_3$	158.11	3.497	2,510
WATER	18.01	94.425	67,770
TOTAL		100.00	71,772

UNIT 37
TRAIN #2

4"-AA-37

AJ AA

4"-W-37
C.W.S.

37-01-1306

4"-W-37
C.W.R.

4"-AA-37-1

LC

6"-AA-37-1

37-01-1903

37-01-1513
37-01-1514
FIGURE 4-2

37-01-1513
37-01-1514
DECANTER OVERHEAD
PUMP & SPARE

EQUIPMENT SHOWN ON THIS DRAWING:

37-01-1306	37-01-1903
37-01-1513	37-01-1904
37-01-1514	37-01-2409
37-01-1515	37-01-4107
37-01-1516	37-01-4109
37-01-1517	
37-01-1518	

D3TMP4MP.DGA

REVISED FOR DESIGN REPORT			
FOR DESIGN REPORT			
FOR CLIENT APPROVAL	APVD PROJ MGR	HKC	12-31-84
NOT ISSUED	APVD FROM MGR	EJC	12-31-84
DESCRIPTION	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PROCESS FLOW AND CONTROL DIAGRAM
SULFUR REMOVAL (BSRP) - UNIT 37
COMMON EQUIPMENT

SCALE	CONTRACT NUMBER	JOB NUMBER	REVISION
NONE	2800	6182	1

DOCUMENT NUMBER: D-37-MP-4 NP

F. Plot Plan/General Arrangement Drawings

See Volume II, 1.2.16(F) for Plot Plan and General Arrangement Drawings for Sulfur Removal (BSRP) Unit 37.

C. Single-Line Diagram

See Volume II, 1.2.16(C) for the Single-Line Diagram for Sulfur Removal (BSRP) Unit 37.

1.2.18 HEAVY GASOLINE TREATING - UNIT 38

The gasoline produced in the methanol conversion reaction contains durene, a gasoline-range compound with a 175°F freeze point. Durene (1, 2, 4, 5 tetramethylbenzene) is reduced in a Heavy Gasoline Treating unit to meet finished gasoline quality requirements. Gases produced during heavy gasoline treating are stripped out of the gasoline stream and sent to the fuel gas system. The treated gasoline product is sent to product blending. Treated heavy gasoline is blended with light gasoline from the Gas Fractionation unit to produce a finished gasoline with about 2 wt% durene.

A. Basis of Design

The HGT unit feed from the Gas Fractionation Unit will be a heavy gasoline fraction containing durene (1, 2, 4, 5 tetramethylbenzene), which is reduced to a finished gasoline containing about 2 wt% durene. The feed and product stream compositions are indicated in the following tables.

Feed Streams

Component	HGT Feed (lb mol/hr)	Makeup Hydrogen (lb mol/hr)
Hydrogen	-	316.32
C_6 + Heavier	545.80	-
Total Dry, lb mol/hr	545.80	316.32
H_2O	-	-
Total Wet, lb mol/hr	545.80	316.32
Total, lb/hr	72,610.00	640.00
Pressure, psia	590.0	650.0
Temperature, °F	322	110

Product Streams

Component	Heavy Gasoline (lb mol/hr)	Fuel Gas (lb mol/hr)
Fuel Gas	-	81.84
C_6 + Heavier	589.97	-
Total Dry, lb mol/hr	589.97	81.84
H_2O	-	-
Total Wet, lb mol/hr	589.97	81.84
Total, lb/hr	71,110.00	2,140.00
Pressure, psia	145	115
Temperature, °F	100	110

B. Process Selection Rationale

The process selection of the Heavy Gasoline Treating (HGT) unit was made by Mobil Research and Development Corporation for the purpose of reducing durene to meet finished gasoline quality requirements. This unit is an integral part of MRDC's MTG process package.

C. Process Description

The arrangement of equipment and material balance for this unit are presented on Process Flow and Control Diagrams D-38-MP-1NP and -2NP.

1. Normal Operation. The HGT unit is similar to the mild catalytic hydrotreating processes used in petroleum refineries. The heavy gasoline feed from the Gas Fractionation unit is combined with a hydrogen-rich recycle stream, preheated in the reactor effluent/feed exchanger, and enters the reactor. The reactor effluent stream is cooled with process streams and air before entering the separator. The treated heavy gasoline stream from the separator is stabilized in the product stripper and

pumped to storage. The hydrogen rich vapor stream from the separator is recycled by the recycle compressor with a small purge flowing to the fuel gas system.

2. Catalyst Regeneration. Coke accumulates gradually on the catalyst during operation, causing catalyst deactivation. The HGT unit must shut down for catalyst regeneration. Catalyst activity is restored by removing the coke. Regeneration consists of burning off the coke with a controlled oxygen burn. After catalyst regeneration is completed, the HGT unit is returned to normal operation.

3. Catalyst. The catalyst required for the HGT unit is described below:

Type:	Mobil
Size: inch	3/32
Volume: ft^3	3,377
Loading Density: No./ft^3	42

4. Environmental Data. When the HGT catalyst is regenerated, the regeneration gases are scrubbed by a recirculating caustic solution to remove any sulfur dioxide. There are no noxious emissions, but there is a small discharge of liquid effluent after scrubbing. No emissions other than minor process losses at pump valves and flanges occur during normal operation.

D. Risk Assessment

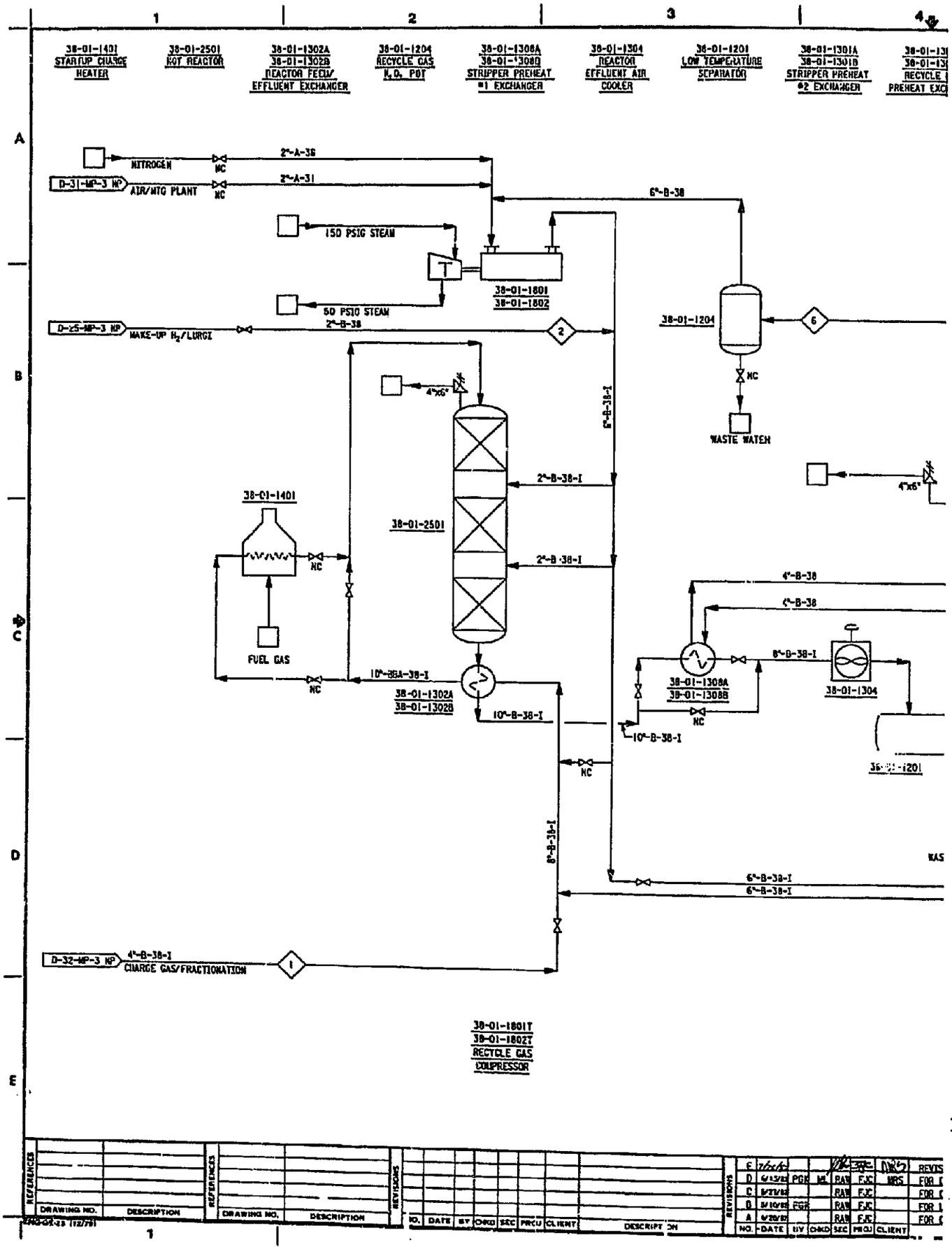
The HGT unit contains conventional petroleum-type equipment that has a high reliability from the standpoint of onstream time. The HGT unit is typical of petroleum hydrotreating units in operation today. The plant is designed with all pumps spared and with block valves and bypass valves installed around control and relief valves. The design permits maintenance on such items without shutdown. The operational aspect of the unit is similar to petroleum refining facilities in present-day operation.

Corrosion should not be a problem and equipment fouling is not expected to occur. The technical risk is considered minimal.

E. Process Flow and Control Diagrams (Including Material Balance)

Process Flow and Control Diagrams for Heavy Gasoline Treating Unit 38 are as follows:

Drawing No.	Title
D-38-MP-1NP	PFCD Heavy Gasoline Treating
D-38-MP-2NP	Material Balance - Heavy Gasoline Treating


1
2
3
4
38-01-1401 STARTUP CHARGE HEATER
38-01-2501 HOT REACTOR
38-01-1302A 38-01-1302B REACTOR FEED/ EFFLUENT EXCHANGER
38-01-1204 RECYCLE GAS K.O. POT
38-01-1308A 38-01-1308B STRIPPER PREHEAT #1 EXCHANGER
38-01-1304 REACTOR EFFLUENT AIR COOLER
38-01-1201 LOW TEMPERATURE SEPARATOR
38-01-1301A 38-01-1301B STRIPPER PREHEAT #2 EXCHANGER
38-01-13 38-01-13 RECYCLE PREHEAT EXC
A
B
C
D
E
NITROGEN
2"-A-36
NC
D-3-MP-3 NP
AIR/MTG PLANT
2"-A-31
6"-B-38
150 PSIG STEAM
38-01-1801
38-01-1802
60 PSIG STEAM
D-25-MP-3 NP
MAKE-UP H2/LURGI
2"-B-38
2
38-01-1204
6
NC
WASTE WATER
4"x6"
6"-B-38-I
38-01-1401
38-01-2501
2"-B-38-I
2"-B-38-I
4"-B-38
6"-B-38
FUEL GAS
NC
10"-36A-38-I
38-01-1302A
38-01-1302B
10"-B-38-I
38-01-1308A
38-01-1308B
6"-B-38-I
38-01-1304
NC
10"-B-38-I
NC
38-01-1201
8"-B-38-I
6"-B-38-I
6"-B-38-I
D-32-MP-3 NP
4"-B-38-I
CHARGE GAS/FRACTIONATION
1
38-01-1801T
38-01-1802T
RECYCLE GAS
COMPRESSOR
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO.
DATE
BY
CHKD
SEC
PROJ
CLIENT
DESCRIPTION
E
D
C
B
A
RAW
FJC
MRS
FOR

38-01-1303A
38-01-1303B
RECYCLE GAS
PREHEAT EXCHANGER

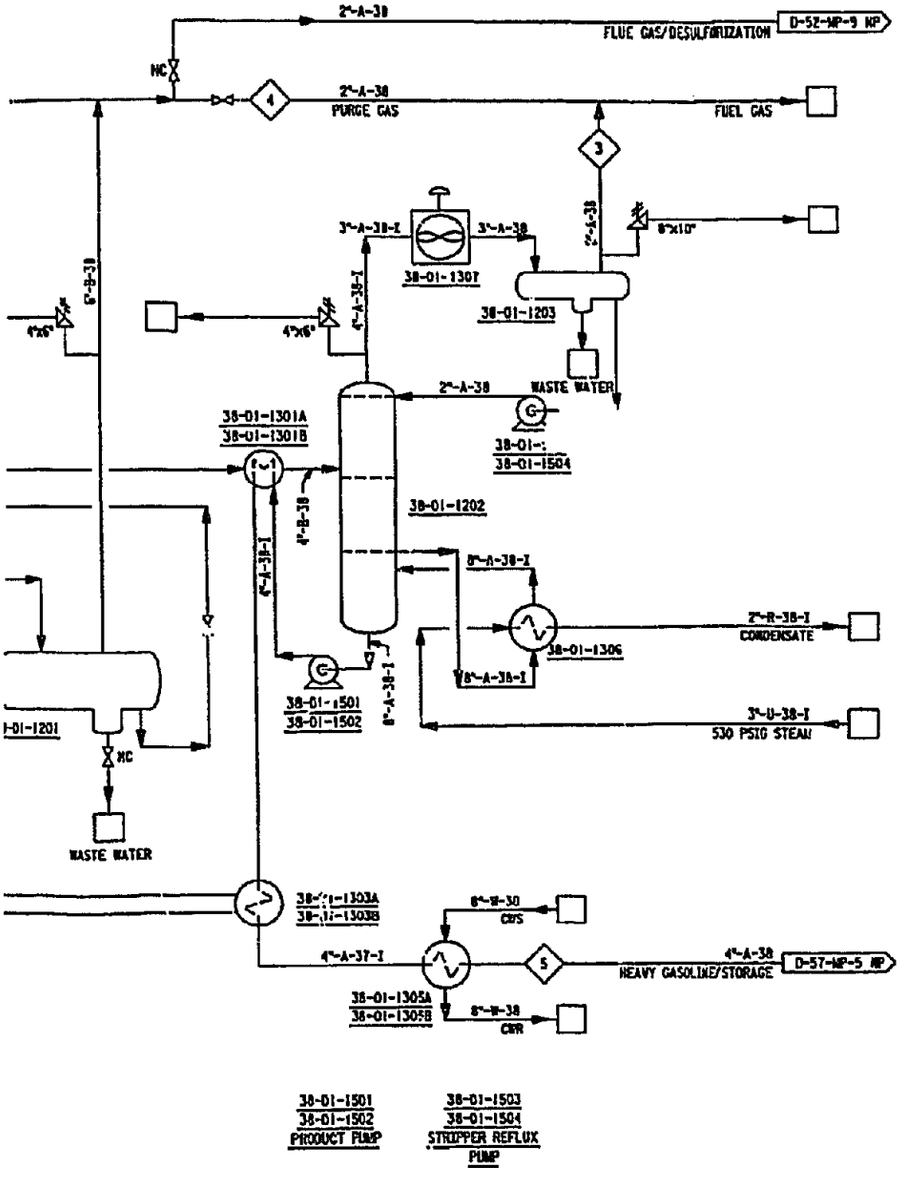
38-01-1307
STRIPPER
CONDENSER

38-01-1202
HOT STRIPPER

38-01-1305A
38-01-1305B
PRODUCT COOLER

38-01-1203
STRIPPER
REFLUX
ACCUMULATOR

38-01-1306
STRIPPER
REBOILER



38-01-1501
38-01-1502
PRODUCT PUMP

38-01-1503
38-01-1504
STRIPPER REFLUX
PUMP

EQUIPMENT SHOWN ON THIS DRAWING

38-01-1201	38-01-1306
38-01-1202	38-01-1307
38-01-1203	38-01-1308A
38-01-1204	38-01-1308B
38-01-1301A	38-01-1401
38-01-1301B	38-01-1501
38-01-1302A	38-01-1502
38-01-1302B	38-01-1503
38-01-1303A	38-01-1504
38-01-1303B	38-01-1801T
38-01-1304	38-01-1802T
38-01-1305A	38-01-2531
38-01-1305B	

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Mobil Research and Development Corporation

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE	PROCESS FLOW AND CONTROL DIAGRAM UNIT 38 HEAVY GASOLINE TREATING
SCALE	NONE
ACCOUNT NUMBER	2800
JOB NUMBER	6182
DRAWING NUMBER	D-38-MP-1 NP
REVISION	F

MFS	DESCRIPTION	DES	DRAWN	CHECKED	APVD DSGT MB	APVD PROJ MGR	APVD CLIENT
	REVISED FOR DESIGN REPORT						
	FOR DESIGN REPORT						
	FOR CLIENT APPROVAL						
	FOR LICENSOR APPROVAL						
	FOR CLIENT 50% REVIEW						

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

STREAM	◇1 HGT FEED	◇2 MAKE-UP H_2	◇3 OFF GAS	◇4 PURGE GAS	◇5 PROD…
BPSD	5,605				
MSCFD		2,885	450	296	
LB/HR	72,610	640	2,010	130	
API OR SG @ 60°F	0.89				
MW	133.04	2.02	40.72	4.12	
GPM	189				
CFM		51	35	7	
COMPONENT — MW					
HYDROGEN — 2.02	0.0	316.31	9.19	30.88	
ETHANE — 38.07	0.0	0.0	4.77	0.50	
PROPANE — 44.10	0.0	0.0	17.93	0.67	
ISOBUTANE — 58.12	0.0	0.0	9.54	0.22	
N-BUTANE — 58.12	0.0	0.0	5.11	0.10	
ISOPENTANE — 72.15	0.0	0.0	2.54	0.07	
N-PENTENE — 72.15	0.0	0.0	0.17	0.01	
2-METHYLPENTANE — 86.18	0.0	0.0	0.09	0.01	
C6+HEAVIER	545.80	0.0	0.03	0.01	
TOTAL MPH	545.80	316.31	49.37	32.47	

REFERENCES: DRAWING NO. | DESCRIPTION

REFERENCES: DRAWING NO | DESCRIPTION

REVISIONS: NO. | DATE | BY | CHKD | SEC | PROJ | CLIENT | DESCRIPTION

NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION
D	[illegible]	RK	ML	[illegible]	[illegible]	[illegible]	FOR DESIG…
C	5/27/81			RAM	FJC		FOR CLIEN…
B	5/11/81	FGK		RAM	FJC		FOR LICEN…
A	5/10/81	FGK		RAM	FJC		FOR CLIEN…

ENG-GE-23 (12/79)

1 2 3 4

A B C D E

	5 PRODUCT	6 REGENERATIVE RECYCLE GAS
	5,815	
		22,481
30	71,110	72,840
	0.84	
12	120.53	29.55
	173	
7		1,284
88	0.0	
50	0.36	
	6.03	
	8.03	
	6.64	
	15.46	
	1.71	
	7.96	
	543.78	
	589.97	2,465.0

D38MP2NP.DGN

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U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: MATERIAL BALANCE
UNIT 38
HEAVY GASOLINE TREATING

SCALE: NONE | ACCOUNT NUMBER: 2800 | JOB NUMBER: 6182 | REVISION: D

DOCUMENT NUMBER: D-38-MP-2 NP

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

DESCRIPTION	BY	CHK	APVD
PORT	DRAWN		
PROVAL	CHECKED		
APPROVAL	APVD DEPT MGR		
50% REVIEW	APVD PROJ MGR		
	APVD CLIENT		

F. Plot Plan/General Arrangement Drawings

See Volume II, 1.2.13(F) for Plot Plan and General Arrangement Drawings for Heavy Gasoline Treating Unit 38.

G. Single-Line Diagram

See Volume II, 1.2.12(G) for the Single-Line Diagram for Heavy Gasoline Treating Unit 38.

1.2.19 PROCESS WATER TREATMENT - UNIT 39

A. Basis of Design

The feed to the MTG plant contains water, and additional stoichiometric volumes of water are produced during the conversion of methanol to gasoline. In the conversion reaction, about 0.6 pound of water is produced per pound of methanol in the feed. The process water is separated from the hydrocarbon products and obtained as liquid at about 178 psig and 100°F. Consideration has been given to recycling this water to other plants in the overall Gasoline Plant to reduce the need for makeup water and wastewater treatment. The MTG water, at a pH of 3.5 to 4.0, contains traces of methanol, organic acids, hydrocarbons, and related oxygenates. The oxygenates are removed by an activated sludge treating unit.

Since this water treatment process is well suited to handling sanitary wastes, the wastewater generated from domestic use of potable water and process area surface runoff pretreated by the oily water treatment system are sent to the Mobil water treatment system.

B. Process Selection Rationale

The process selection of aerobic biotreatment of the MTG process water available through Mobil Research and Development Corporation was made by Parsons. This process has shown that the contaminants are biodegradable by conventional treatment using a trickling filter and an activated sludge basin. Results have demonstrated that the Chemical Oxygen Demand (COD) and Biochemical Oxygen Demand (BOD) are reduced to acceptable environmental limits. However, in the overall wastewater all effluent from this system is recycled.

C. Process Description

The wastewater stream from the MTG plant results from the water present in the methanol feed as well as water formed in converting

methanol to gasoline. The water produced in the conversion reaction is about 0.6 pound per pound of methanol in feed.

The wastewater contains minor quantities of dissolved organic chemical contaminants totaling less than 0.2% by weight. These contaminants are primarily oxygenated organic compounds, such as organic acids, alcohols, and ketones, in addition to the methanol resulting from breakthrough just prior to conversion catalyst regeneration. These are essentially removed in a wastewater treating facility.

Pilot plant studies on the aerobic biotreatment of MTG process wastewater have shown that the contaminants are biodegradable by conventional treatment using a trickling filter and an activated sludge basin. Results have demonstrated that COD and BOD are reduced to acceptable environmental limits.

Treatment steps for MTG wastewater involve routing the wastewater stream to a degasser where the pressure is lowered to atmospheric. The gases are routed to a flare system. The wastewater then is sent to a neutralization tank where pH is adjusted with sodium hydroxide solution. Nutrients for biological growth (ammonia and phosphoric acid) are added after the neutralization basin. Following neutralization, the wastewater is pumped to a trickling filter. The trickling filter effluent flows to an activated sludge extended aeration unit.

The waste activated sludge from the treatment process is conventional aerobic biological sludge, which is dewatered in the inert solids treatment system and then stored in the nonhazardous landfill. The organic content is high since there is little or no inert material in the raw MTG process water.

In addition to the process water discussed above, there are 25 gpm of spent caustic containing 6% of sodium sulfite and sodium bicarbonate developed during HGT section catalyst regeneration, 25 gpm of domestic sanitary wastewater, and 740 gpm of pretreated surface water runoff termed oily water.

In the integrated complex producing gasoline from coal-derived synthesis gas, about 40 volume percent of the biotreated water from the Process Water Treatment Unit is sent to a deaerator to remove gases and then to the gasification unit as makeup water. The remainder of the water treated in this system is routed to clean process water makeup.

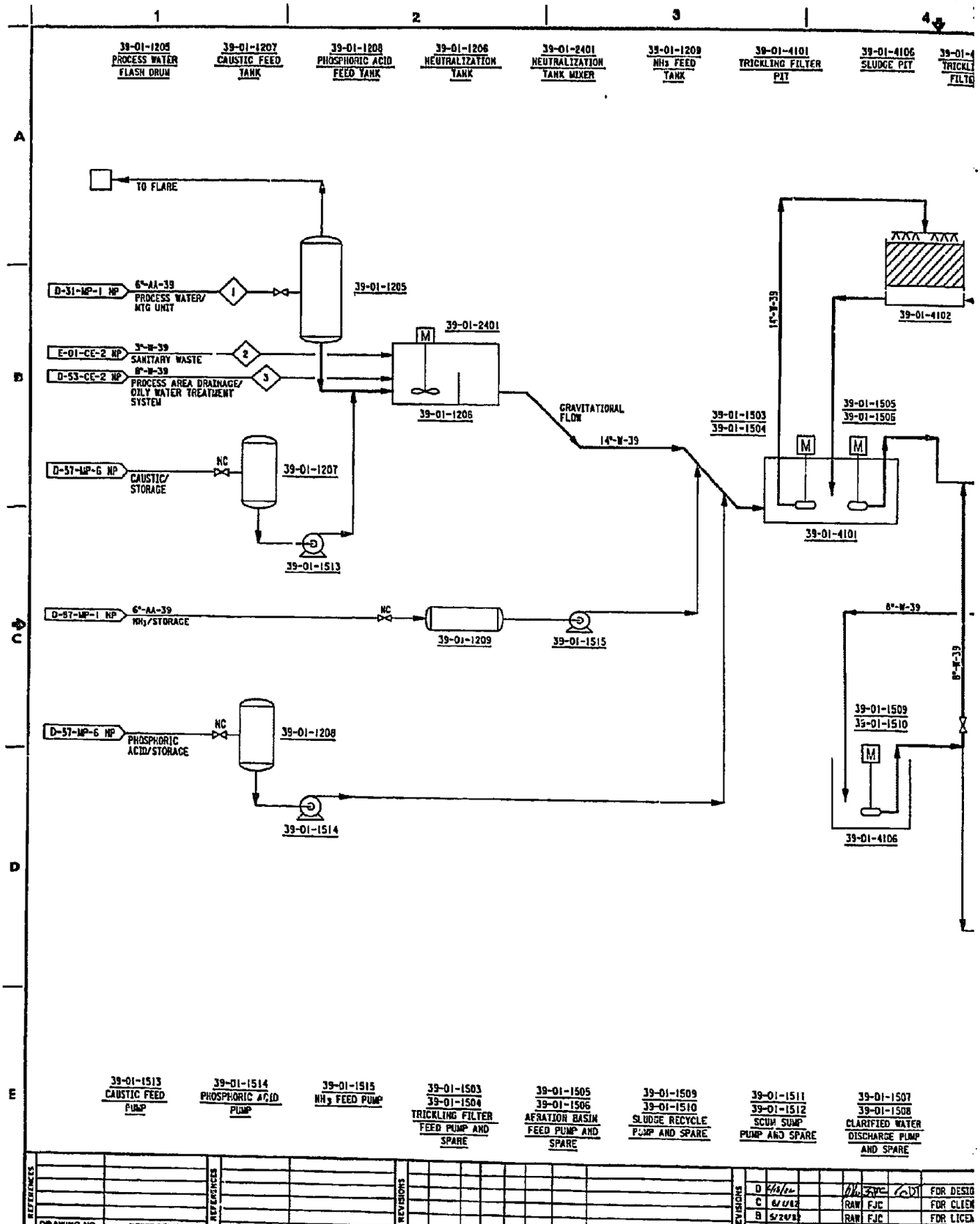
D. Risk Assessment

The Process Water Treatment unit contains conventional biotreatment-type equipment that is in general use throughout the petroleum and chemical industries. The technical risk is minimal.

E. Process Flow and Control Diagrams (Including Material Balance)

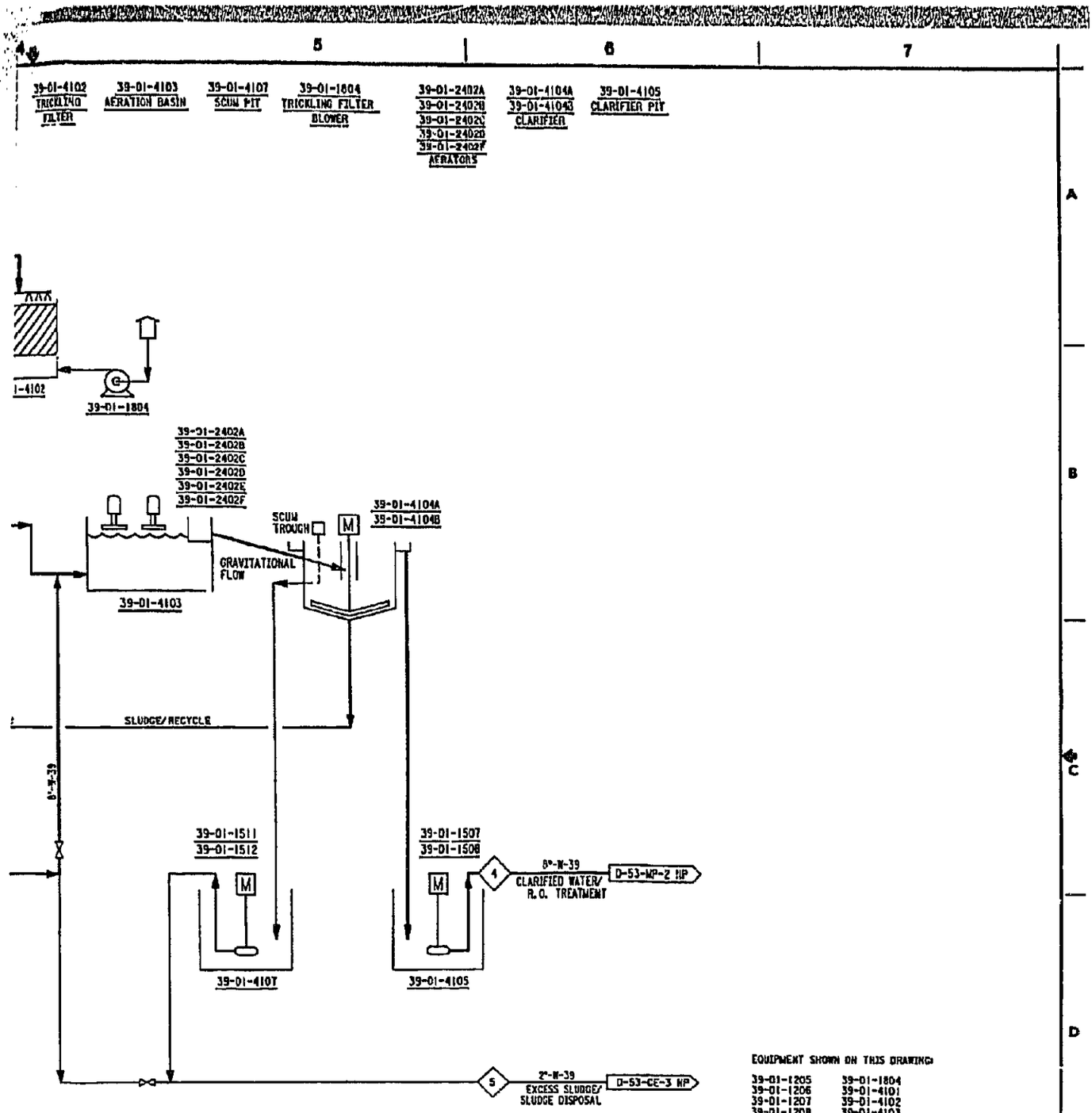
Process Flow and Control Diagrams for Process Water Treatment Unit 39 are as follows:

Drawing No.	Title
D-39-MP-1NP	PFCD Process Water Treating
D-39-MP-2NP	Material Balance - Process Water Treating



REFERENCES			REFERENCES			REVISIONS										REVISIONS								
DRAWING NO.	DESCRIPTION		DRAWING NO	DESCRIPTION		NO.	DATE	BY	CHKD	REC	PROJ	CLIENT	DESCRIPTION			NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT		
																D	6/15/82						FOR DESIG	
																C	6/1/82			RAW	FJC		FOR CLIEN	
																B	5/24/82			RAW	FJC		FOR LICEN	
																A	4/21/82			RAW	FJC		FOR CLIEN	

END-GE-23 (12/78)



EQUIPMENT SHOWN ON THIS DRAWING

39-01-1205	39-01-1804
39-01-1206	39-01-4101
39-01-1207	39-01-4102
39-01-1208	39-01-4103
39-01-1209	39-01-4104A
39-01-1503	39-01-4104B
39-01-1504	39-01-4105
39-01-1505	39-01-4106
39-01-1506	39-01-4107
39-01-1507	39-01-2401
39-01-1508	39-01-2402A
39-01-1509	39-01-2402B
39-01-1510	39-01-2402C
39-01-1511	39-01-2402D
39-01-1512	39-01-2402E
39-01-1513	39-01-2402F
39-01-1514	
39-01-1515	

D39MP1NP.DGA

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U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

PROCESS FLOW AND CONTROL DIAGRAM
PROCESS WATER TREATMENT (MOBIL)
UNIT 39

SCALE: NONE | ACCOUNT NUMBER: 2800 | DATE RELEASED: 6182

DRAWING NUMBER: D-39-MP-1 NP

REVISION: D

	DES	DRAWN	CHECKED	APVD SCAY NO	APVD PROJ MGR	APVD CLIENT
FOR DESIGN REPORT						
FOR CLIENT APPROVAL						
FOR LICENSOR APPROVAL						
FOR CLIENT SOX REVIEW						
DESCRIPTION						

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

COMPONENT	1 PROCESS WATER	2 SANITARY WASTE	3 OILY WATER	4 CLARIFIER WATER	5 EXCES[S] SLUDG[E]
WATER (GPM)	1750	25	737	2487	
BOD (MG/L)	1800	230		30 TO 50	
COD (MG/L)	2800			100 TO 150	
TSS (MG/L)		230	8 TO 15	8 TO 15	
CHLORIDES (MG/L)			10 TO 20	10 TO 20	
TEMPERATURE (°F)	100	AMB		100	
PRESSURE (PSIG)	178	ATM	ATM	77	

REFERENCES DRAWING NO.	DESCRIPTION

REFERENCES DRAWING NO.	DESCRIPTION

NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION

NO.	DATE	BY	CHKD	SEC	PROJ	CLIENT	DESCRIPTION
D	[illegible]			[illegible]			FOR DES[I...]
C	[illegible]			RAW	EJC		FOR CLIE[...]
B	5/27/8[?]			RAW	EJC		FOR LICE[...]
A	5/24/8[?]			RAW	EJC		FOR CLIE[...]

E10-GE-23 (12/73)

NOTE:
MATERIAL BALANCE SHOWN IS FOR NORMAL OPERATING CONDITION.

5 EXCESS SLUDGE
25
100
75

	FOR DESIGN REPORT		
	FOR CLIENT APPROVAL		
	FOR LICENSOR APPROVAL		
	FOR CLIENT 50% REVIEW		
	DESCRIPTION		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

D38MP2NP.DGA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: MATERIAL BALANCE FOR UNIT 39

SCALE: NONE | DOCUMENT NUMBER: 2809 | JOB NUMBER: 6182

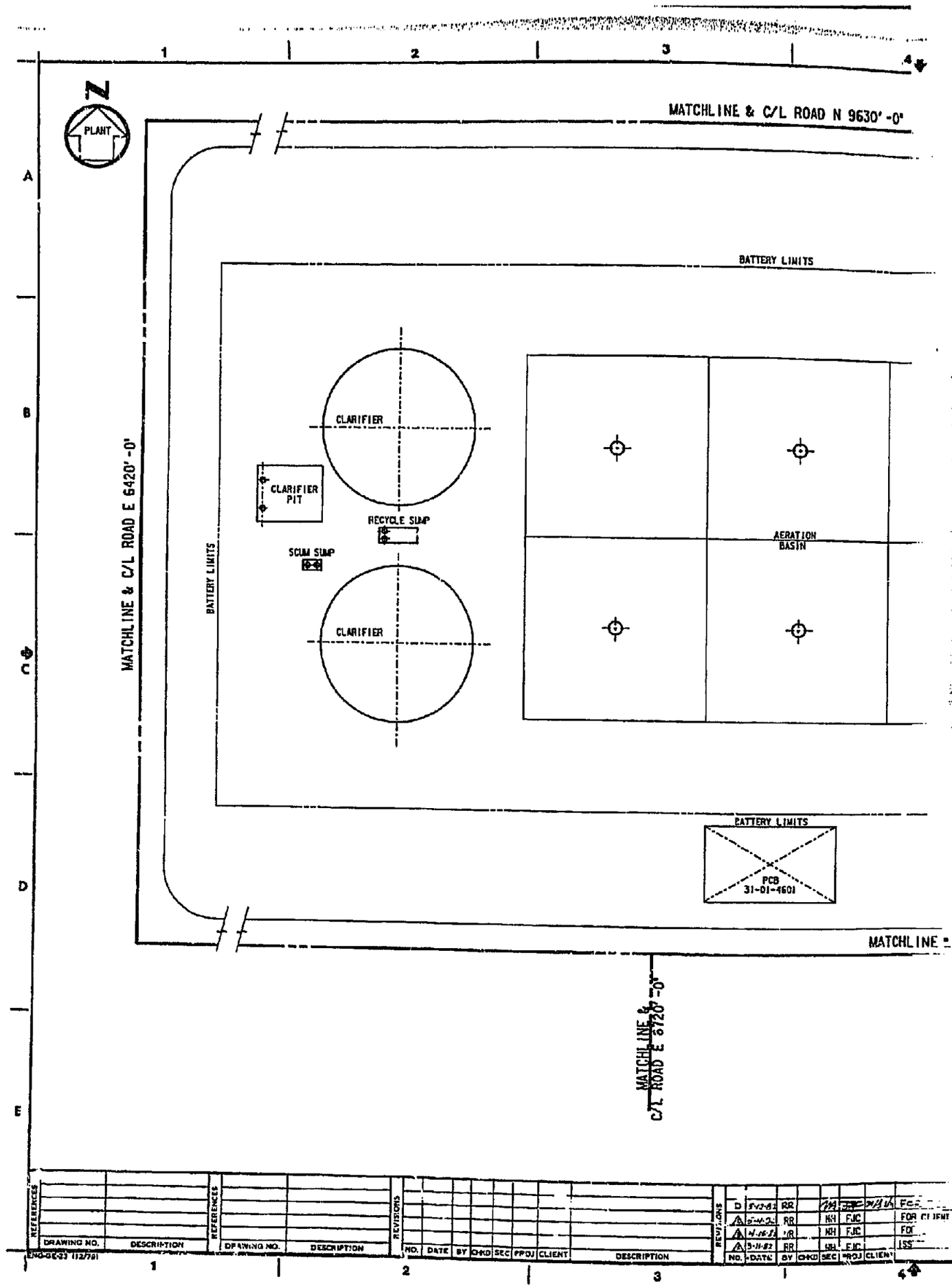
DOCUMENT NUMBER: D-39-MP-2 NP

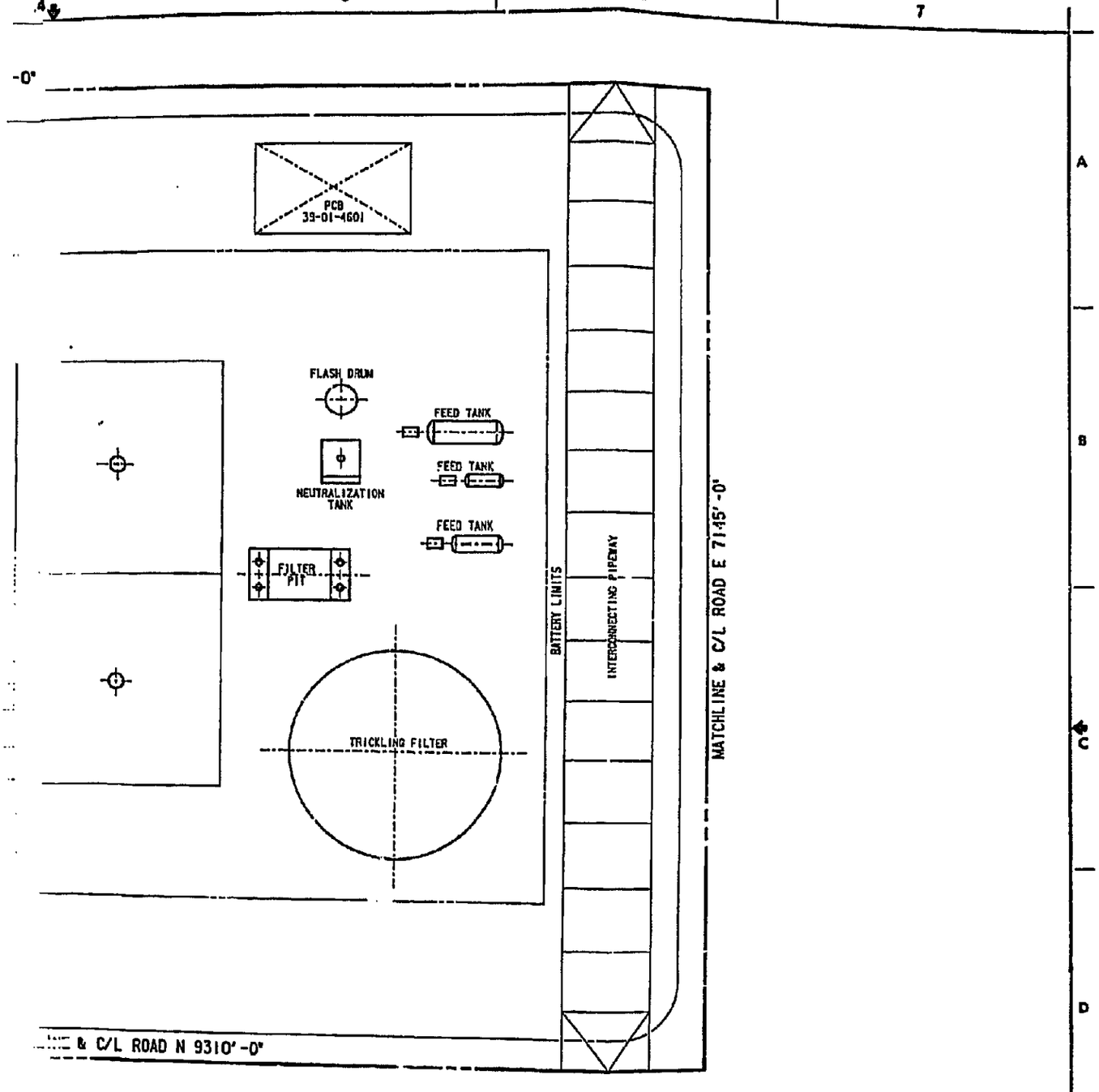
REVISION: 1

F. Plot Plan/General Arrangement Drawing

The Plot Plan and General Arrangement Drawing for Process Water Treatment Unit 39 is as follows:

Drawing No.	Title
D-39-PD-1NP	Plot Plan - Unit 39 Process Water Treatment


1
2
3
4
A
B
C
D
E
N
PLANT
MATCHLINE & C/L ROAD N 9630'-0"
MATCHLINE & C/L ROAD E 6420'-0"
BATTERY LIMITS
CLARIFIER
CLARIFIER PIT
RECYCLE SUMP
SCUM SUMP
CLARIFIER
AERATION BASIN
BATTERY LIMITS
BATTERY LIMITS
PCB 31-01-4601
MATCHLINE
MATCHLINE & C/L ROAD E 8720'-0"
REFERENCES
DRAWING NO.
DESCRIPTION
REFERENCES
DRAWING NO.
DESCRIPTION
REVISIONS
NO. DATE BY CHKD SEC PROJ CLIENT DESCRIPTION
REVISIONS
D 5-13-82 RR
5-14-82 RR
4-16-82 RR
3-11-82 RR
NH FJC
NH FJC
NH FJC
FOR CLIENT
FOR
ISS



FOR CLIENT APPROVAL	DRAWN	JW/CAD	
FOR LICENSOR APPROVAL	CHECKED		
ISSUED CLIENT REVIEW 50% COMP	APVD SECT HD	NH	
DESCRIPTION	APVD PROJ MGR		
	APVD CLIENT		

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

U.S. DEPARTMENT OF ENERGY

BASKETT — W.R. GRACE & CO. — KENTUCKY

50,000 B.P.D.

COAL - TO - METHANOL - TO - GASOLINE PLANT

TITLE: PLOT PLAN
UNIT 39
PROCESS WATER TREATMENT

SCALE	ACCOUNT NUMBER	JOB NUMBER	REVISION
1"=20'-0"	7243	6182	D

DOCUMENT NUMBER: D-39-PD-1NP

G. Single-Line Diagram

See Volume II, 1.2.15(G) for the Single-Line Diagram for Process Water Treatment Unit 39.