Box 13
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(DRAFT)

CONDENSED REPORT

PGandE GEYSERS RETROFIT PROJECT

UNITS 1 - 12

S-79007

August 3, 1979

ROGERS
Engineering • San Francisco

DISCLAIMER

ROGERS ENGINEERING CO., INC.
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In reply refer to:

S-79007

6 August 1979

Mr. J. P. Finney
Pacific Gas and Electric Company
77 Beale Street, Room 1901
San Francisco, CA 94106

Subject: Draft Condensed Report
PGandE Geysers Retrofit Project Units 1-12

Dear John:

We are transmitting herewith eight copies of this Condensed Report.

As this is a Condensed Report, we are continuing to update the Final Report Technical Data, Volumes I and II. It has taken some time to make all of the comments and corrections which were marked in the previous report. We expect that within two weeks time we will have the original report corrected.

We do feel that this Condensed Report is much easier to read and assimilate, and will probably be the final report on this retrofit project, after corrections and completion of Sections 6 and 7.

Yours very truly,

Herb. Rogers

H. Rogers, Jr.
President

HR:ee

Encls. 8

cc: R. P. Wischow w/enc.

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CONDENSED REPORT

PGandE GEYSERS RETROFIT PROJECT

1.0 INTRODUCTION

The firm of Rogers Engineering Co., Inc. is submitting herewith a cost benefit analysis for Pacific Gas and Electric Company on the hydrogen sulfide abatement systems required at Units 1-12 of the Geysers.

1.1 Purpose

The purpose of this work is to demonstrate whether there is a cost benefit to Pacific Gas and Electric Company in replacing the present iron catalyst/caustic/peroxide system used in the direct contact condenser units versus an alternative approach using surface condensers and the Stretford System.

1.2 Scope of Study

This work is limited to consideration of Units 1 thru 12, and shall use as much as possible data already prepared by PGandE, and with

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concurrence and cooperation of the various departments of PGandE with respect to the design, construction, and operations of the Geysers Project.

To evaluate the cost and time involved in installing the alternative abatement system (surface condenser/Stretford Process), it was necessary to prepare new process flow sheets, physical arrangements of equipment, cost estimates and construction schedules. It is important to note that for this report the design is a concept. If this project proceeds to final design and purchase of equipment, it will be necessary to pursue the engineering details to a much greater extent than time would permit in preparing this report.

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2.0 SUMMARY AND RECOMMENDATIONS

This section is prepared as an executive summary of the whole report. It also has the recommendations in brief form. Details of all data follow in the body of the report. This conceptual report is to justify the method and approach to make a decision on Units 1 through 12.

2.1 General Economic Viewpoint

The overview of economic techniques, cost estimate method and economic design selection alternatives are presented. Generally the regular Pacific Gas and Electric GM estimate format has been followed. The accounts are the normal plant accounts used by plant accounting. The economic analysis must be done with equivalent alternatives and is performed using the level annual revenue requirement technique. The GM estimates are prepared in June 1979 dollars and also with estimated escalation to June 1982 the center of gravity of expenditures. General construction, engineering services, engineering, operating department and generation planning all contributed to various aspects of the costs and economics.

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2.2 Existing Abatement

The existing units with the iron catalyst, caustic, and peroxide H_2S abatement are presented so that a common base could be established for later comparison. Additional capital costs, operating and maintenance costs and capacity factors are addressed. It is understood that a fully implemented iron catalyst, caustic and peroxide system presently meets the air pollution board requirements. This existing abatement system is Alternative 1, the defender, and the retrofit with surface condensers and Stretford system vent gas treatment is Alternative 2, the challenger.

Analysis of the overall Geysers Power Plant capacity factor shows it to be decreasing. The highest calculated annual capacity factor was 81 percent and the lowest 65 percent to date. It is not possible to attribute all changes in capacity factor to abatement. Full time, complete abatement has only been on a relatively short time on a few units. The capacity factor can be stated for past plant operations and projections made from trends established. Recognizing the limitations of analyzing the total plant capacity factors versus those for analyzing individual units or groups of units, the calculated annual capacity factor range for the abated group and the unabated group is 62-76 percent and 68-84 percent respectively. The existing abatement system will be evaluated at both 60 and 70 percent capacity factors in the cost analysis. The long term mature unabated existing plants have demonstrated an ability to achieve 80 percent and even 85 percent. Data development is in Section 3.1.3.

The capital cost to implement the iron catalyst, caustic and peroxide abatement system fully on all units is estimated to be 8.9 million dollars over and above the 12.5 million already invested in the abatement facilities. See Table 3-9.

The costs for chemicals will amount to an estimated 10 million dollars per year and is included as part of the operating cost. Maintenance costs are estimated to be about double the unabated units.

Although this abatement method is very severe on the plant equipment it is estimated that continued high maintenance will keep the plants going. Replacement in kind is not envisioned.

2.3 Alternative Abatement

The alternative, considered in this report, to the iron catalyst, caustic and peroxide abatement is the retrofit of units 1 through 12 with surface condensers and the installation of various Stretford process plants to treat the vent gases and remove the sulfur. Various combinations of Stretford process plants are studied.

Recent tests at Unit 15 are not conclusive with respect to the Surface Condenser/Stretford abatement system meeting the air pollution requirements.

Each typical unit has been studied with regard to performance, equipment arrangement, and capital cost estimates. The typical units are:

Typical	Typical For
1	1 and 2
3	3 and 4
5	5, 6, 7, 8, 9 and 10
11	11 and 12

In a few cases individual units were addressed since there were arrangement or performance differences which affected costs.

The capacity factor for the retrofit is dependent on the natural long term capacity factor of the power plant unit in combination with the Stretford units capacity factor. In Sections 3.1.3 and 4.2

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the respective capacity factors are presented. Two overall capacity factors are used in the economic evaluation: 80 and 85 percent.

The total capital cost estimate is in the standard GM Form. This whole report is conceptual in nature as the final designs and drawings are not made. Telephone quotations of major equipment were obtained and field investigations by qualified persons developed the other costs. The GM 1979 is without escalation and GM with escalation is to June 1982.

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COST TO RETROFIT WITH SURFACE CONDENSERS AND STRETFORD PROCESS

Unit	GM 1979	GM With Escalation
1	$ 2,042,712	$ 2,631,912
2	2,042,712	2,631,912
3	3,899,308	4,010,633
4	3,899,308	4,010,633
5	6,002,573	7,742,017
6	6,002,573	7,742,017
7	6,002,573	7,742,017
8	6,002,573	7,742,017
9	6,002,573	7,742,017
10	6,002,573	7,742,017
11	12,116,789	15,576,132
12	12,116,789	15,576,132
Subtotal	$ 72,135,056	$ 90,889,456
Stretford Systems		
1-6	$ 17,572,146	$ 22,588,993
7, 8, 11	17,464,697	22,450,867
9, 10	5,569,904	7,160,112
12	5,825,350	7,488,487
Subtotal	$ 46,432,097	$ 59,688,459
Total	$118,565,153	$150,577,915

Engineering, Procurement and Construction critical path schedules have been developed to determine the length of time required to implement the retrofit on each typical unit. Also, of critical importance to the economic evaluation is the required unit outage time to implement the retrofit. Generally, each total project takes

30 months from the start of engineering to end of restart of the unit. Outage times range from 8 - 11 months for specific units.

2.4 Cost Benefit Analysis

This is a comparison of the existing iron catalyst, caustic and peroxide system with the retrofit of units with surface condenser/ Stretford Process. The retrofit units with the Stretford Process is considerably more economic. The closest the iron method comes is 1.5 times the retrofit evaluated cost. The level annual revenue requirement is about 36,742,000 dollars for the surface condenser/ Stretford Process retrofit and 56,667,000 dollars for the iron method. The estimated minimum benefit is 19,925,000 dollars per year.

The largest cost in the evaluation is the cost of energy due to the iron system's anticipated capacity factor. The second largest cost is cost of chemicals to keep the iron system operating and the third largest cost in the analysis is the capital to retrofit the units with surface condensers and install the Stretford units.

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2.5 Overall Recommendation

The overall recommendation is to proceed with a series of projects to retrofit all existing Units 1-12 with surface condensers and various combinations of Stretford processes.

A complete financial analysis to establish an approach and order for implementing the retrofit is being prepared but is not ready for this draft.

2.6 Engineering Services

The estimated engineering services costs are included in each individual unit's cost estimate under Account 365 Other Engineering. The engineering services total based upon the 1979 total construction cost of 118.5 million is 7.2 million dollars.

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3.0 EXISTING ABATEMENT

Methods to control the hydrogen sulfide emissions from the Geysers Power Plant were initiated in 1971. The addition of a metal catalyst (ferric iron) to the circulating cooling water was selected for large scale tests at Units No. 1 and 2. Currently, in addition to the metal catalyst, caustic soda and hydrogen peroxide are being introduced to maximize the abatement on Units 3, 4, 5, 6, 11 and 12. Additionally interim abatement on Units 8, 9, 10 is being used.

3.1 Existing Conditions

It is our understanding, that Units 1 through 12 all operate under a variance to the air pollution standards, and the iron catalyst system with caustic and hydrogen peroxide will accomplish the required level of abatement required by the Air Pollution Board.

3.1.1 Historic Abatement

The historic data of time and type of abatement is important when evaluating the existing units. The abatement methods have affected the power plant unit operations and the equipment in each unit so treated. Table 3-1 summarizes by unit the abatement to date. Each unit has a varying amount of abatement, and it was put on at differing times in the useful life of the equipment. The units which are not on 100% of the time are only on when the air pollution officer requests they be on. Up to this point in the concept study, we could not determine how many hours per year Units' 2, 8, 9 and 10 abatement have actually been operating.

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TABLE 3-1

H_2S HISTORIC ABATEMENT

Unit	Commercial Operation	H_2S Abatement	Remarks
1	9/25/60	-	None
2	3/19/63	6/78	June-Oct. Interim Time Iron Catalyst
3	4/28/67	12/76 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
4	11/ 2/68	9/76 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
5	12/15/71	1/78 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
6	12/15/71	1/78 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst with Caustic and Hydrogen Peroxide
7	8/18/72	-	None
8	11/23/72	6/78	June-Oct Interim Time Iron Catalyst
9	10/15/73	6/78	June-Oct Interim Time Iron Catalyst Plus Caustic
10	11/30/73	6/78	June-Oct Interim Time Iron Catalyst Plus Caustic
11	5/31/75	1/77 1/79	100% Time Iron Catalyst 100% Time Iron Catalyst Caustic and Hydrogen Peroxide
12	3/1/79	3/79	100% Time Abatement Iron Catalyst and Caustic

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3.1.2 Existing Abatement

The existing units have the following abatement facilities installed as of June 1979:

Unit 1 - No permanent abatement equipment - only abatement testing program

Unit 2 - Operating intermittently using only ferric iron

Unit 3 - Using ferric iron, caustic and hydrogen peroxide-continuous abatement

Unit 4, 5 & 6 - Same as Unit 3

Unit 7 - Up stream EIC system - tests continuing

Unit 8 - Intermittent abatement only ferric iron

Unit 9 - Intermittent abatement only ferric iron with caustic

Unit 10 - Same as Unit 9

Unit 11 - Continuous abatement using ferric iron, caustic and hydrogen peroxide

Unit 12 - Same as Unit 11

3.1.3 Capacity Factor

Geysers power plant units are operated as a base load plant, that is they are on line all the time regardless of system load. Therefore, the capacity factor is indicative of how well a unit is performing. Many factors affect the capacity factor, and it is difficult to indicate the exact causes of a low capacity factor even though outage and curtailment records are kept.

Two questions are of greatest importance. What has been the highest capacity factor at which existing units have operated unabated? What has been the capacity factor of H_2S abated units since abatement has started? These are difficult questions, and it is not possible to attribute all changes in capacity factor to abatement. Full time complete abatement has been only on a relatively small number of units and for a short period of time. The capacity factor can only be "stated" for the past plant operations and what they are operating at today.

Available capacity factor data has been analyzed by statistical methods: least square mean, and median. It is essential to build confidence in a tool before it is used for predictions. The fol-

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lowing table illustrates the accuracy of the methods to approximate the annual capacity factor. The mean is the average value of capacity factor taking into account all the capacity factor values. The median is the statistically calculated capacity factor value at which an equal number of capacity factor values occur below and above the calculated value.

Many calculations and combinations of calculations have been made to study capacity factors of individual units and of the overall Geysers plant. Tables 3-2, 3-3 and 3-4 are summaries of part of the analysis. Trends have been statistically developed from Table 3-3 using 1975 through 1978 data and 1975 through April 1979 data. Table 3-5 (graph) indicates the capacity factor trend of the overall Geysers total plant and the subset of units with abatement. The capacity factor difference between existing units abated and unabated has been addressed by others and was not a part of this conceptual work. However based on the results in this report, the economic evaluations have been made at 60 and 70 percent capacity factor for abate units with the iron/caustic/peroxide abatement and 80 and 85 percent capacity factors for units with surface condenser/Stretford abatement.

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TABLE 3-2

COMPARISON OF METHODS

ANNUAL CAPACITY FACTOR ANALYSIS
(1977)

Unit	Actual[1] Annual Capacity Factor	-----Calculated----- Least Square	Mean	Median
1	67.7	67.7	67	65
2	86.3	86.3	85	85
3	57.2	57.4	57	60
4	76.1	76.1	75	78.3
5	87.5	87.5	87	95.7
6	78.0	77.7	77	85
7	83.8	83.8	83	90
8	82.4	82.5	82	88
9	92.0	92.0	92	92.9
10	95.2	95.2	94	95
11	74.0	74.0	74	77.5
A	-	-	84	80.0
B	-	-	84	89.6
C	-	80.0	79	85.8

[1]Annual capacity factor from Operating Dept.

A Combination of Units 3, 4, 5, 6, 11 (Existing Abatement)
B Combination of Units 1, 2, 7, 8, 9, 10 (Not Abated)
C All units combined

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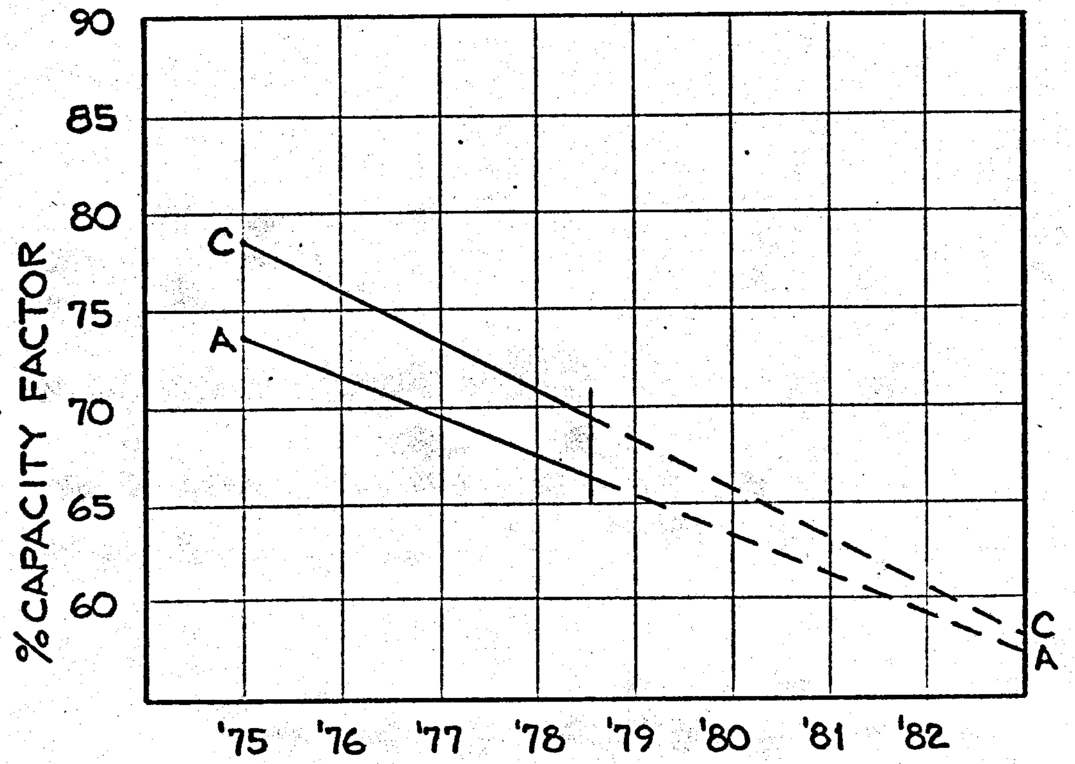
TABLE 3-3
ANNUAL CAPACITY FACTORS

Units	1975	1976	1977	1978	1979
1	76	78	67	50	68.3
2	53	76	85	67	58.3
3	74	70	57	38	44.5
4	53	65	75	52	48.3
5	84	86	87	82	62.0
6	82	90	77	84	59.5
7	79	88	83	78	62.0
8	77	90	82	59	82.0
9	90	87	92	78	90.8
10	95	86	94	77	97.8
11	47	71	74	54	68.3
A	68	76	74	62	56.5
B	78	84	84	68	76.4
C	74	81	79	65	67.3

TABLE 3-4
ANNUAL MEDIAN CAPACITY FACTORS

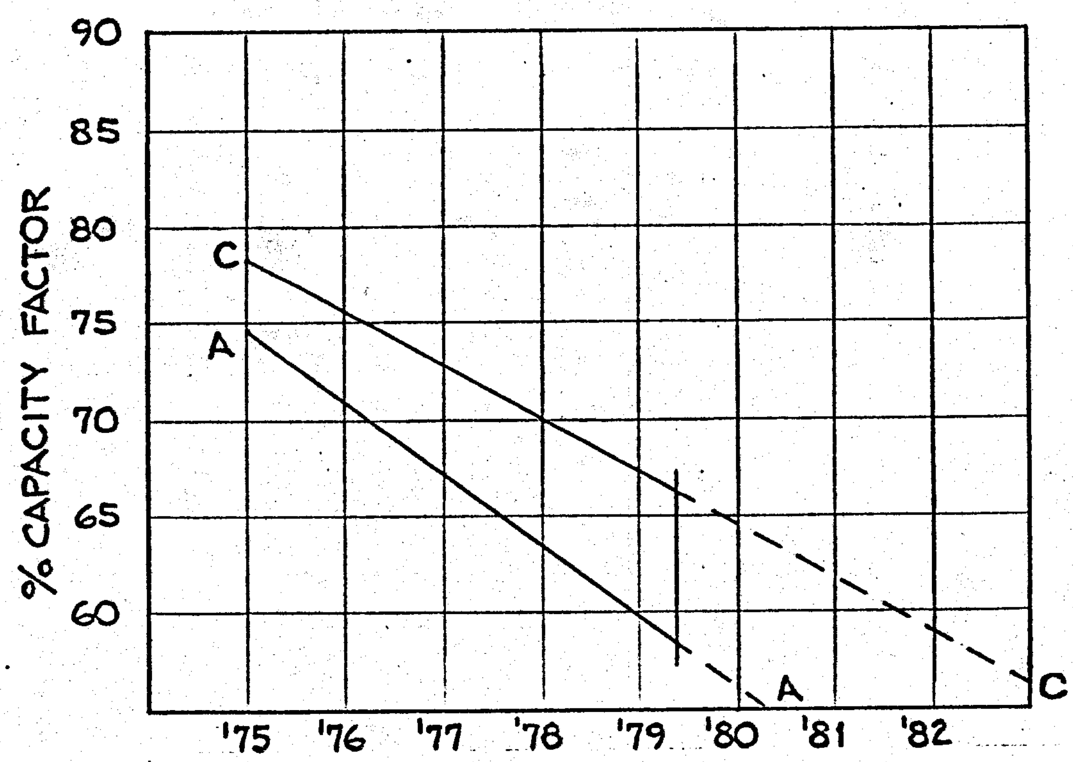
Units	1975	1976	1977	1978	1979
1	80.0	86.0	65.0	57.0	68.3
2	52.8	85.0	85.0	75.0	55.0
3	80.0	75.0	60.0	35.0	30.0
4	55.0	68.8	78.3	50.0	45.0
5	91.7	92.1	95.7	83.3	50.0
6	95.0	93.3	85.0	86.3	55.0
7	87.5	89.0	90.0	76.7	75.0
8	86.5	91.7	88.0	72.5	85.0
9	91.7	93.8	92.9	87.5	90.0
10	96.3	92.9	95.0	85.0	97.5
11	45.0	80.0	77.5	70.0	60.0
A	79.0	82.5	80.0	71.7	60.0
B	86.3	90.0	89.6	75.7	80.0
C	83.5	88.2	85.8	74.5	69.0



DATA 1975—1978

LEGEND

C-TOTAL PLANT
A-ABATED UNITS



DATA 1975-4/79

ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	CAPACITY FACTOR STATISTICAL TRENDS	DRAWING NO. TABLE 3-5	REV.
JOB NO. S-79007		SHEET OF	

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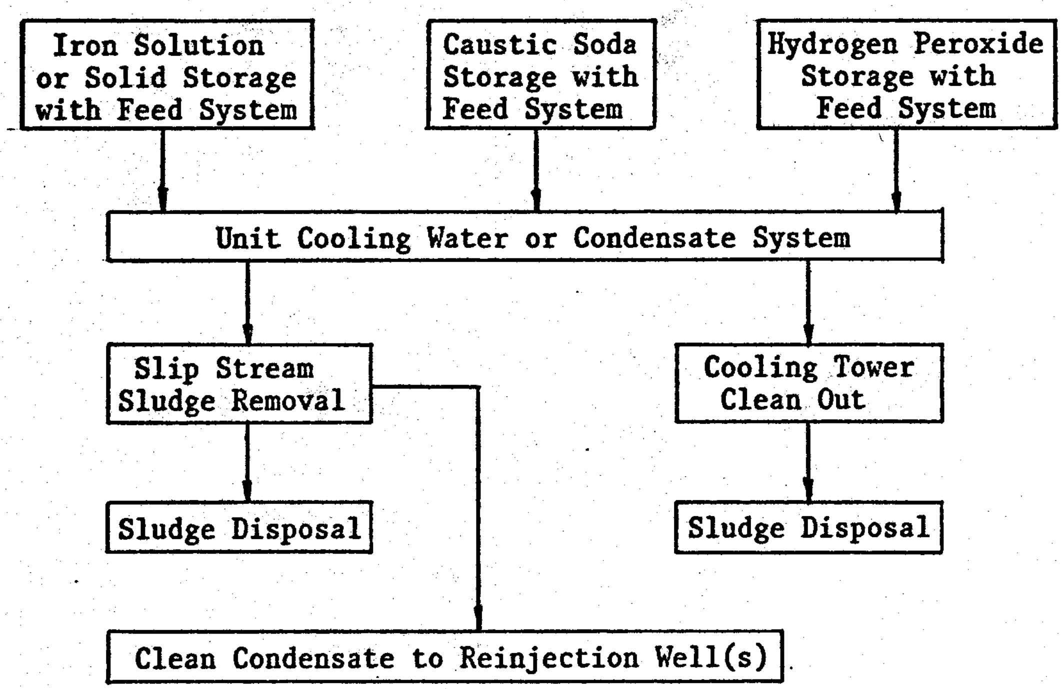
3.2 Overall Process

In order to compare the existing abatement system as applied to the direct contact condensers, the chemical feed (budget data) was examined for Units 3, 4, 5, 6, 11 and 12. The molar ratio of ferric iron, caustic soda and hydrogen peroxide were compared with the mols of hydrogen sulfide in the incoming steam and an average chemical input ratio was developed. For the purposes of this report, these chemical values can then be prorated for all Units 1 thru 12, so as to cost out the placement of a continuous abatement program onto each unit, which theoretically could provide the abatement necessary to meet the air quality standards.

The overall process for each of the first twelve units in block diagram is as follows:



The chemical requirements for each unit are summarized in Table 3-6 and 3-7. The chemical quantities required are dependent on the units' capacity factor. Two capacity factor levels are presented: the 60 percent which plants are now operating, and the 70 percent which is anticipated to be the long range best capacity factor obtainable with this abatement system.

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TABLE 3-6

IRON CATALYST ABATEMENT CHEMICALS
(60 Percent Capacity Factor)

Unit	Iron #/hr.	NaOH 100% #/hr.	H_2O_2 Gal./hr.	Sludge yd.^{3}/yr.
1	12.8	14.2	22.8	180
2	12.8	14.2	22.8	180
3	58.4	67.9	109.5	1,367
4	58.4	67.9	109.5	756
5	116.8	135.8	219	1,451
6	146.0	135.8	219	2,073
7	90.6	100.9	162.5	1,267
8	41.6	56.1	90.4	670
9	22.4	25.0	40.2	313
10	27.3	30.4	49.0	382
11	219.0	271.6	438	3,622
12	110.7	123.3	198.7	1,549
Total	916.8	1,043.1	1,681.4	13,810

TABLE 3-7

IRON CATALYST ABATEMENT CHEMICALS
(70 Percent Capacity Factor)

Unit	Iron #hr.	NaOH 100% #/hr.	H_2O_2 Gal/hr.	Sludge yd.^{3}/hr.
1	14.9	16.6	26.6	210
2	14.9	16.6	26.6	210
3	68.1	79.2	127.8	1,595
4	68.1	79.2	127.8	882
5	136.3	158.4	255.5	1,693
6	170.3	158.4	255.5	2,418
7	105.7	117.7	189.6	1,478
8	48.5	65.4	105.5	782
9	26.1	29.2	46.9	365
10	31.8	35.5	57.2	446
11	255.5	316.9	511.0	4,226
12	129.2	143.8	231.8	1,807
Total	1,067.4	1,216.9	1,961.8	16,112

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3.3 Operations

As described in 3.2 Overall Process above the chemical feed ratios between unit hydrogen sulfide feed input and chemicals, sludge made, etc. can be applied to the capacity factor (each unit separately) and thence calculate the related cost for operating chemicals, sludge disposal, et al. The capacity factor was estimated separately for each unit, by statistical evaluation of values from operating records.

TABLE 3-8

IRON CATALYST/CAUSTIC/PEROXIDE CHEMICAL COSTS
(Dollars Per Year)

Units	60% Capacity Factor	70% Capacity Factor
1	$ 131,500	$ 153,400
2	131,500	153,400
3	632,200	737,600
4	627,000	731,500
5	1,214,400	1,416,800
6	1,256,400	1,465,800
7	882,500	1,029,600
8	490,900	572,700
9	216,100	252,100
10	272,100	317,400
11	2,432,400	2,837,800
12	1,076,800	1,256,300
Total	$9,363,800	$10,924,400

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3.4 Capital Cost

For the purpose of this report, the actual field installation costs were examined for the facilities considered to be necessary for developing the existing abatement system into a continuous and reliable system. (Units 3, 4, 5, 6, 11 and 12). These costs were then prorated and projected to a permanent facilities cost for each unit (1, 2, 7, 8, 9 and 10). The existing column was derived from GM Estimate 186422R2, and the Research and Development allocation for caustic and peroxide facilities, all except for Unit 12, which is based on Unit 11. The "additional capital" is the estimated additional required to bring all existing units up to a common level of abatement using the iron catalyst/caustic/ peroxide systems. These costs are estimated in June 1979 dollars.

Table 3-9 is a summary of the past and additionally required capital costs for the iron/caustic/peroxide abatement system.

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TABLE 3-9

EXISTING H_2S ABATEMENT CAPITAL COST
(Dollars x 1,000)

Unit	Existing	Additional Capital (1979)	Total
1 & 2	-	2,415	2,415
3 & 4	$ 4,950	-	4,950
5 & 6	2,415	-	2,415
7 & 8	-	2,869	2,869
9 & 10	-	2,869	2,869
11	5,794	-	5,794
12	5,794	-	5,794
Totals	$18,953	$8,153	$27,106

The estimated GM Estimate total for the additional is calculated as follows:

Item	Dollars x 1000
Direct Costs	$ 8,153
GM Factor @ 20.7%	1,688
Sub Total (GM 1979)	$ 9,841
Escalation @ 28.55%	2,810
Total GM Estimate	$10,651

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3.5 Remaining Life

Effect of Existing Abatement on Equipment Life

One problem developed by the existing abatement is that oxidation of the sulfur cannot be selectively stopped when free sulfur is produced. The reaction also produces some sulfites and sulfates. The existing equipment was originally specified to be constructed using 304 SS. The expected equipment life would probably have been over 50 years. The sulfites, sulfates and oxygen, however, corrode 304 SS in a manner described as "pit" corrosion.

Corrosion testing was initiated in about 1973, and the initial findings were reported by Dodd and Ham on 22 January 1975.

Tubular Type Heat Exchangers and Piping

The corrosion data without iron indicate very little loss of metal from 304 SS; measured value less than 0.0001 inch/year. With iron, the general corrosion increased to 0.0007 inch/year and the pitting action showed an unsensitized rate of 0.005 inch/year. Assuming that 22 gauge heat exchanger tubing is the thinnest construction material and that a 30% thickness loss is allowable prior to replacement, the following can be calculated:

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Normal life expectancy:

22 Ga. is 0.028 inch thick

0.028 x 0.30 = 0.0084 allowable loss

0.0084 ÷ 0.0001 inch/year = 84 years

With iron 0.0084 ÷ 0.0007 = 12 years

With iron and pitting 0.0084 ÷ 0.005 = < 2 years

Based on the above values, it might be necessary to replace some tubular type heat exchanger tubes on every unit turnaround (2 year interval), and some piping may require patching. For economic evaluation, it will be assumed that all 304L SS piping and equipment components will need replacement in twelve years. Since the corrosion test data indicates that carpenter alloy 20 cb 3 is not corroded by the sulfur acids, equipment replacement will be costed for this alloy, which will give an additional useful life of over fifty years in this type H_2S abatement services.

Cooling Tower

The effect of the sulfur acids and excess iron and sulfur sludge on the cooling tower is such that a complete reconditioning will be required every unit turnaround (2 year interval). During this 2 year run, it is estimated that the cold water temperature will increase 1°F. The result will be an increase in turbine exhaust hood pressure of 0.075 psi (0.15 in. Hg Abs.). The resulting loss in turbine heat drop will be 2.175 Btu/lb. steam flow. Assuming 77% overall turbo-generator efficiency, the power loss will be about 0.0005 kW/lb. steam flow. This figure will be used to calculate the generation capacity loss during the run.

Pumps

It is assumed that all pumping requirements for cooling water and auxiliary water will not be affected during the operation between turnaround.

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3.6 Existing Abatement System Summary

This section presents the parameters involved with retrofitting the existing Units 1-12 with the iron oxide/caustic/peroxide. As this is the condensed report only the results are presented of the most significant elements. See Table 3-10.

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TABLE 3-10

ALTERNATIVE 1: EXISTING ABATEMENT

Unit	Design Gross kW	Net kW	Annual MWh @ 60% x 1000	Annual MWh @ 70% x 100	GM Estimated Cost 1979	O & M Cost 1979 $/yr. @ 60%	O & M Cost 1979 $/yr. @ 70%	Schedule (Months)
1	12,500	12,098	63,587	74,185	2,415,000	155,300	172,700	-
2	12,500	12,115	63,676	74,289		155,300	172,700	-
3	27,500	26,500	139,284	162,498		747,800	831,400	-
4	27,500	26,500	139,284	162,498		740,900	823,800	-
5	55,000	53,020	278,673	325,119		1,435,400	1,595,900	-
6	55,000	53,020	278,673	325,119		1,484,200	1,650,200	
7	55,000	53,020	278,673	325,119	2,869,000	1,042,300	1,158,900	-
8	55,000	53,020	278,673	325,119		579,300	644,100	-
9	55,000	53,020	278,673	325,119	2,869,000	255,200	283,700	-
10	55,000	53,020	278,673	325,119		321,400	357,300	-
11	110,000	106,000	557,136	649,992		2,874,400	3,195,900	-
12	110,000	106,000	557,136	649,992		1,272,300	1,414,600	-
CT. DED.			(13,878)	(16,191)	-	-	-	
Total	630,000	607,333	3,178,263	3,707,977	8,153,000	11,063,800	12,301,200	

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4.0 ALTERNATIVE ABATEMENT

This section presents the parameters involved with retrofitting the existing Units 1-12 with surface condensers and installing various combinations of Stretford units to process the vent gases from the power plant units. As this is the condensed report only the results are presented of the most significant elements.

4.1 Design Conditions

Table 4-1 is the summary of the conceptual designs. All values are after retrofit is completed. It indicates the new design gross kilowatt output, the net kilowatt output and the annual net outputs at two capacity factors. The capital cost estimate total is presented in 1979 dollars. Operations and Maintenance cost differences from the existing design is tabulated. A schedule was created for each typical unit type in this study and the results are tabulated. The Total Project is the time in months to provide the engineering, procurement and construction. The total construction time and the unit outage time are indicated. The outage time was used in the calculation of construction outage energy.

The lower half of the Table 4-1 presents the summary information about Stretford Processes. It was determined there was an economic benefit for each of the combinations of Stretford units and their locations. The shorthand notation Stretford 1-6 means a single Stretford unit serving all Units 1-6 located near Unit 3 but not at the Unit 3 & 4 site. The shorthand notation Stretford 7, 8, 11 means a single Stretford unit serving units 7, 8 and 11 with it located at Unit 11. A single Stretford unit was economic for Unit 9 & 10 as was a single Stretford unit for Unit 12. All the Stretford costs are summarized in the table as well as the construction times.

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TABLE 4-1

ALTERNATIVE 2 - RETROFIT UNITS

Unit	Design Gross kW	Net kW After Retrofit	Annual MWh @ 80% x 1000	Annual MWh @ 85% x 1000	GM Estimate Cost 1979 $	Operation & Maintenance Cost LA $/yr. Difference	Schedule (Months) Total Project (Months)	Construction (Months)	Unit Outage (Months)
1	11,845	11,339	79,464	84,430	2,042,712		28.0	9.0	8.0
2	11,974	11,495	80,557	85,592	2,042,712				
3	26,817	25,661	179,832	191,072	3,899,308		28.0	9.0	8.0
4	26,817	25,661	179,832	191,072	3,899,308				
5	54,101	52,005	364,451	387,229	6,002,573		30.0	10.5	9.3
6	54,101	52,005	364,451	387,229	6,002,573				
7	54,101	51,988	364,332	387,103	6,002,573		30.0	10.5	9.3
8	54,101	51,988	364,332	387,103	6,002,573				
9	54,101	52,078	364,963	387,773	6,002,573		30.0	10.5	9.3
10	54,101	52,078	364,963	387,773	6,002,573				
11	108,147	103,729	726,933	772,366	12,116,789		32.0	12.0	11.3
12	108,147	102,801	720,429	765,456	12,116,789		32.0	12.0	11.3
Totals	618,353	592,828	4,154,539	4,414,198	72,133,056				
Stretford			(Minus)	(Minus)					
1-6	x	x	(9,329)	(9,329)	17,572,146	1,714,784	30.0	9.3	8.7
7, 8, 11	x	x	(9,592)	(9,592)	17,464,697	1,704,356	30.0	9.3	8.7
9, 10	x	x	(1,050)	(1,050)	5,569,904	543,634	28.0	8.3	7.7
12	x	x	(1,050)	(1,050)	5,825,350	570,839	28.0	8.3	7.7
Totals	618,353	592,828	(21,021)	(21,021)	46,432,097	4,533,613			
Grand Total	618,353	592,828	4,133,518	4,393,177	118,565,153	4,533,613			

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4.2 Power Plant Capacity Factor

The capacity factor of the retrofit power plant units with surface condensers is estimated to be the same as the long term mature unabated capacity factory of existing units. This factor has been demonstrated to be 80 percent overall and it is anticipated could reach 85 percent in the long term. Both of these values are used in the economic evaluations of Section 5. In Section 3.1.3 is a discussion of the existing plant capacity factors.

4.3 Cost Estimates

Cost estimates have been made for each typical power plant unit and each Stretford installation separately. The summaries are presented by account number. The cost estimates are typical for the units as follows:

Estimate Unit	Typical for Each Unit
1	1 and 2
3	3 and 4
5	5, 6, 7, 8, 9, 10
11	11 and 12

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4.3.1 Unit 1 Estimate Summary

TABLE 4-2

SUMMARY COST ESTIMATE - UNIT 1

Account	Description	Equip. & Mat'l	Labor	Total
54-20	Condensate System	$ 690,124	$282,354	$ 972,478
54-30	Circ. Water System	264,576	80,932	345,508
54-70	Instrumentation	16,790	18,171	34,961
55-30	Control & Power Conn.	3,943	17,472	21,415
55-60	Station Power System	19,716	16,214	35,930
365	Engineering & Other	281,120	0	282,120
	Subtotals	$1,277,269	$415,143	$1,692,412
	GM Factor (20.7%)			350,300
	Subtotal (GM 1979)			2,042,712
	Escalation (28.55%)			589,200
	Total GM Estimate			$2,631,912

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4.3.2 Unit 3 Estimate Summary

TABLE 4-3

SUMMARY COST ESTIMATE - UNIT 3

Account	Description	Equip. & Mat'l	Labor	Total
54-20	Condensate System	$1,392,331	$514,200	$1,906,532
54-30	Circ. Water System	521,138	167,253	688,392
54-70	Instrumentation	19,080	19,352	38,432
55-60	Station Power System	39,432	19,352	58,784
365	Engineering & Other	538,440	0	538,440
	Subtotals	$2,510,422	$720,157	$3,230,579
	GM Factor (20.7%)			668,730
	Subtotal (GM 1979)			3,899,308
	Escalation (28.55%)			111,325
	Total GM Estimate			$4,010,633

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4.3.3 Unit 5 Estimate Summary

TABLE 4-4

SUMMARY COST ESTIMATE UNITS 5 THROUGH 10
(Each Unit)

Account	Description	Equip. & Mat'l	Labor	Total
51-20	Building	$ 0	$ 14,910	14,910
54-20	Condensate System	2,241,646	969,926	3,211,572
54-30	Circ. Water System	224,508	318,696	543,204
54-70	Instrumentation	25,440	20,501	45,941
55-60	Station Power System	34,344	86,430	120,774
365	Engineering & Other	960,000	0	960,000
	Subtotals	$3,485,938	$1,410,463	$4,896,401
	GM Factor (23.9%)			1,126,172
	Subtotal (GM 1979)			6,022,573
	Escalation (28.55%)			1,719,444
	Total GM Estimate			$7,742,017

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4.3.4 Unit 11 Estimate Summary

There are two estimates for Unit 11 typical. The first is to install the condensers perpendicular to the centerline of the turbine. The second is to install the condenser parallel with the centerline of the turbine.

TABLE 4-5

SUMMARY COST ESTIMATE - UNIT 11

(Tube Bundle Perpendicular to Turbine Shaft)

Account	Description	Equip. & Mat'l	Labor	Total
51-20	Building	$ 11,448	$ 33,547	44,995
54-20	Condensate System	4,437,245	1,557,138	5,994,383
54-30	Circ. Water System	1,107,912	850,322	1,958,234
54-70	Instrumentation	34,471	41,937	76,405
55-60	Station Power System	67,416	37,274	104,690
56-10	Compressed Air System	2,544	27,956	30,500
365	Engineering & Other	1,641,841	0	1,641,841
	Subtotals	$7,302,877	$2,548,171	$9,851,048
	GM Factor (23.0%)			2,265,741
	Subtotal (GM 1979)			12,116,789
	Escalation (28.55%)			3,459,343
	Total GM Estimate			$15,576,132

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TABLE 4-6

SUMMARY COST ESTIMATE - UNIT 11

(Tube Bundle Parallel to Turbine Shaft)

Account	Description	Equip. & Mat'l	Labor	Total
51-20	Building	$ 19,080	$ 147,700	$ 166,780
54-20	Condensate System	4,437,245	1,557,138	5,994,383
54-30	Fire Water System	1,102,570	838,208	1,940,778
54-40	Lube Oil System	22,642	80,140	102,782
54-70	Instrumentation	35,107	46,593	81,700
55-60	Station Power System	70,087	47,059	117,146
56-10	Compressed Air System	10,812	67,560	78,372
365	Engineering & Other	1,696,320	0	1,696,320
	Subtotals	$7,393,862	$2,784,398	$10,178,260
	GM Factor (23.0%)			2,340,999
	Subtotal (GM 1979)			12,519,259
	Escalation (28.55%)			3,574,248
	Total GM Estimate			$16,093,507

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4.3.5 Stretford Unit 1-6 Estimate Summary

TABLE 4-7

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 1-6

Account	Description	Mat'l & Equip.	Labor	Total Dollars
54-29	H_2S Abatement 1-6	$11,872,723	$1,164,545	$13,037,269
365	Engineering & Other	1,394,520	0	1,394,520
	Subtotals	$13,267,243	$1,164,545	$14,431,789
	GM Factor (21.76%)			3,140,357
	Subtotal (GM 1979)			17,572,146
	Escalation (28.55%)			5,016,847
	Total GM Estimate			$22,588,993

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4.3.6 Stretford Unit 7, 8, 11 Estimate Summary

TABLE 4-8

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 7, 8 &11

Account	Description	Mat'l & Equip.	Labor	Total Dollars
54-29	H_2S Abatement	$11,789,716	$1,323,707	$13,113,423
365	Engineering & Other	1,230,120	0	1,230,120
	Subtotal	$13,019,836	$1,323,707	$14,343,543
	GM Factor (21.76%)			3,121,154
	Subtotal (GM 1979)			17,464,697
	Escalation (28.55%)			4,986,170
	Total GM Estimate			$22,450,867

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4.3.7 Stretford Units 9, 10 and 12 Estimate Summary

TABLE 4-9

SUMMARY COST ESTIMATE

STRETFORD UNIT FOR POWER PLANT UNITS 9 & 10, 12

Account	Description	Mat'l & Equip.	Labor	Total Dollars
54-29	H_2S Abatement	$ 8,108,503	$1,272,455	$ 9,380,958
365	Engineering & Other	1,017,960	0	1,017,960
	Subtotal	$ 8,108,503	$1,272,455	$ 9,380,958
	GM Factor (21.76%)			2,041,296
	Subtotal (GM 1979)			11,422,254
	Escalation (28.55%)			3,261,053
	Total GM Estimate			$14,683,307

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5.0 GENERAL ECONOMICS AND COST BENEFIT ANALYSIS

The economic techniques, cost estimate methods and design selection parameters which apply in general to work performed in this report. Each area of costs or economics has assumptions and ground rules in order for the results to be consistent. These will be explained as applicable to this report. The cost benefit analysis follows the general economic conditions. The results of each system to be compared are analyzed on the Level Annual Revenue Requirement (LARR) basis. This method and factors are discussed in Appendix A.

The cost benefit analysis is where the alternatives are compared. At this point the alternatives are required to be equivalent and if they are not, then factors are used to create equality so comparisons can be made between equals. The benefits are defined as the difference in cost between the alternatives. The existing direct contact condenser system with the iron catalyst, caustic and peroxide is Alternative 1 and defender. The retrofit of units with surface condensers and the addition of Stretford units to process the vent gases is Alternative 2 or the challenger. The study is to show the economics of continuing with the existing defender or to convert and implement the challenger system in terms of 1979 dollars.

5.1 Economic Evaluation

There are two periods of time in which economic evaluations take place in this report. The first evaluation is early in the process and affects the basic design parameters and conditions. These could be called design trade-offs or design selection analyses. These tend to be very rough approximations to eliminate unnecessary alternatives to be addressed in detail. The second economic evaluation is the final comparison (cost benefit analysis) which includes all the details of each alternative.

The Engineering Planning Department, Generation Planning Section was consulted in the preparation and the determination of techniques and factors used in economic evaluations of different generation plans. The overall method is a level annual revenue requirement (LARR) technique. All economic quantities must be converted to LARR before comparison. LARR takes into account escalation, cost of capital, and other items. In generation planning, single life values for LARR are utilized rather than perpetual values.

The following areas each have levelizing factors which were provided by Generation Planning.

- -Account 314 Capital, Single Life, 30 Years
- -Operation & Maintenance, 30 Years
- -Power Values, 30 Years and Single
- -Geysers Steam, 30 Years

Appendix "A" explains these factors in more detail.

5.2 Cost Estimate Accounts

The cost estimates have been prepared by categories, and are the same accounts used by Pacific Gas and Electric for GM estimates. Only the following accounts are included by the nature of this project work.

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Account	Description
51-20	Structures and Improvements
52-50	Main Steam Piping
54-20	Turbine-Generator - Condensate System
54-29	H_2S Abatement Facilities
54-30	Turbine-Generator - Circulating Water System
54-40	Lube Oil System
54-70	Turbine-Generator - Instrumentation
55-30	Control and Power Connection
55-60	Auxiliary Electrical Equipment - Station Power
56-10	Compressed Air System
365	Engineering and Other Cost Allocations

The detailed cost figures are in June 1979 dollars. These are modified, due to escalation and project timing as a result of the schedule prepared. Separate subtotals are established for the total of direct costs, the total with GM overheads and indirects, and the total with escalation.

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5.3 Cost Estimates

The cost estimates include equipment and material; installation labor with overheads, profit and indirects; Account 365-Engineering and other allocatable costs; escalation; and the GM factor. Each will be briefly discussed as they apply to the detailed estimates which follow.

5.3.1 Major Equipment

Suppliers of the major equipment, condensers, pumps, and Stretford licensors were contacted by telephone and followed up by transmittal of pertinent equipment data sheets. In the majority of cases, vendors were contacted who have had some experience in the special problems associated with geothermal plants.

The following items in the detailed cost estimate are adjusted quoted figures:

- Condensers and Ejectors
- Condensate Pumps
- Circulating Water Pump
- Stretford Equipment

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The Material and Equipment column is a combination of adjusted quoted costs, estimated bulk materials, six percent use tax, and twenty percent for unestimated items since this is a conceptual cost estimate. The estimate assumes that Pacific Gas and Electric will purchase all major equipment and supply it to the contractor for installation, as has been the practice at the Geysers Plant. The costs in the estimate for each piece of major equipment reflect our best judgment as to the eventual bid on the "selected" equipment data sheets.

5.3.2 Installation Cost

The estimated installation cost is the cost anticipated to be charged by an outside contractor to perform the removal of the old and installation of the new equipment. Most of the larger project construction work at the Geysers has been done by outside contractors and this guide has been used in preparation of this estimate. This decision affects the labor overheads and labor efficiency as well as the general overheads of a GM factor.

The estimated materials and labor shown on the detailed estimates are based upon the conceptual layout drawings and field investigations at the site for each installation. There is judgment used

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whenever making such an estimate, and this estimate has been prepared by people who have been a part of other geothermal plant construction. The construction department has assisted with suggestions on various factors included in the estimates.

In consultation with General Construction about contractor performance and costs at the Geysers certain figures were developed for use in this conceptual report. The current labor direct rates show a $15 per hour to be an overall good concept estimate direct labor cost. The labor efficiency has been estimated to be 60 percent and has been used in the estimate. The contractor overhead includes his profit, overheads and all indirect expenses. It has been estimated that 55 percent is a good value from past Geysers' experience in contractor bidding.

In addition to the above basic parameter discussions a twenty percent contingency has been included in the direct man-hours for this conceptual estimate. The labor man-hours shown in detailed estimates are derived as follows:

Man-hours	= Basic Estimate	x One Divided By Efficiency	x Contingency
2.0	= 1.0	x 1.67	x 1.2

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5.3.3 Account 365

The costs shown in Account 365 are the direct allocatable costs to a given project such as field construction activities, general office engineering and other engineering. All the costs have been lumped into the three above subdivisions. Also, previous Geyser GM's were studied both as estimates and as final plant accounting to determine the appropriate numbers. The past range is from 14 to 18 percent of the total direct charges. Since these cost estimates developed in this report are for fairly complex project modifications, a twenty percent figure is considered appropriate for the conceptual estimates.

5.3.4 GM Factor

The GM Estimate preparation is the last step in the cost estimate process. The GM estimate is used to get funds approved for the project. Engineering Services in consultation with Engineering and General Construction puts the final GM numbers together. Engineering Services has been consulted in the methods and factors used in preparation of GM estimates.

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The GM factor is a function of whomever does the construction. The estimates prepared here are based upon an outside contractor doing the construction. The following factor is applied to the direct costs.

Factor Development

Item	Percent of Direct Cost
Indirects:	
Indirects	0.0
General Overheads:	
General Engineering & Administration	16.0
Allowance for Funds During Construction	3.7 - 5.0
Ad Valorem Taxes	1.0 - 2.0
Total GM Factor	20.7 - 23.0%

The allowance for funds during construction is a function of the construction period; the general engineering and administration; and the direct costs. The Ad Valorem is a function of the direct dollar cost of the project. Pacific Gas and Electric S. P. 112.6-1, Appendix A, effective 10/16/78 has been used in determining the factor. Each estimate summary indicates the percentage used for the GM factor.

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5.3.5 Escalation

The GM estimate total includes escalation, and it is separated out as a definable item. The rate of escalation was derived from Economics and Statistics Department escalation report for Autumn 1978. All the detailed cost estimates are June 1979 dollars. The escalation time assumes one year or June 1980 to start engineering and procurement, and two additional years to the center of gravity of dollar disbursements for a project (3 years of escalation). The escalation was calculated at the stated compound percent applied to the sum of the direct costs plus the GM factor costs.

5.3.6 Project Differential Cost

It is often helpful to have a magnitude feeling for the GM estimated cost total in terms of level annual revenue requirement. This figure in mills per kilowatthour is presented with each cost estimate summary.

5.4 Design Selection Evaluation

Certain economic evaluations were made at the very beginning and apply in general so they are presented here.

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5.4.1 Cooling Tower and Circulating Water Flow

It is assumed that no additional major investment is required to return the cooling tower capability to design condition beyond regular maintenance. Thus, the only design trade-off to maximize power is to increase circulating water flow until pumping costs or size of the circulating water piping limit the retrofit space considerations. This forced an examination of field cooling tower test data, along with pumping and piping considerations to set the estimated capability for operating vacuum after retrofit.

5.4.2 Condensing and Gas Cooling Limitations

Once the cooling tower return water and off tower temperature have been assigned preliminary values as shown by para. 5.4.1, the specification of the surface type heat exchangers must then consider two factors:

(a) The terminal temperature difference (TTD) which is the steam inlet temperature minus the condenser outlet water temperature and

(b) the cold gas outlet temperature minus the condenser inlet water temperature.

As the specified TTD is lowered, the turbine operating back pressure is also lowered and the condenser size and cost rises. For surface type exchangers, the Standards of the Heat Exchanger Institute recommends a lower TTD limit of 5°F. Table 5.1 (study for Unit 1) shows that the increased power output will more than offset the condenser cost. However, the specification for TTD was increased to 7.8°F (Unit 1) in order to reduce the exchanger to a size suited to the available installation space. A similar methodology was used for all units in the retrofit study.

As the gas cooling temperature is lowered (assuming turbine back pressure is held constant), two conditions influence vacuum system specification.

(a) A colder temperature will decrease the inlet pressure available to the vacuum system steam jet ejectors, and

(b) at the same time the steam vapor entrainment carried by the noncondensable gas flow is reduced.

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The combination of these two factors results in an overall increase in motive steam requirement as the cold gas temperature is allowed to rise. Table 5.2 (Study for Unit 1) shows that when a cost of steam is assigned to the motive steam it is desirable to specify lower cold gas temperatures. Throughout the study, cold gas temperatures were adjusted to avoid oversizing the condensers.

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TABLE 5.1

TYPICAL ECONOMIC ANALYSIS

MAIN CONDENSER - UNIT 1

STEAM END APPROACH (TTD)

Study Case Item	A	B
TTD °F	7.8	5
Condenser Cost (1)	0	$376,800
Calc. Power Output Increase	0	190 kW
Steam Input	0	0
ECONOMIC EVALUATION		
Difference in Capital (2) (Cost)	0	54,700 $/yr.
Difference in Energy (3) (Revenue)	0	86,500 $/yr.
Differences in Difference		$31,800 $/yr.

(1) Capital Installed

(2) Annualized Capital Installed per Year Value

(3) System Level Annualized Power per Year Value

This table indicates that it is economic to buy a better condenser lower TTD °F to get more electrical energy generated from the plant. The advantage is 31,800 level annual dollars per year.

TABLE 5.2

TYPICAL ECONOMIC ANALYSIS

MAIN CONDENSER - UNIT 1

NONCONDENSABLE GAS END APPROACH

Study Case Item	A	B	C	D
Noncondensable Gas Outlet °F	95	105	115	119
Difference in Heat Exch. Cost (1)	$17,700	$ 9,300	$ 2,700	0
Steam to Jet Difference (2)	0	$14,400	$47,200	$67,500
TOTAL DIFFERENCES (3)	$17,700	$23.700	$49,900	$67,500

(1) Annualize Capital Installed
(2) Steam Fuel Level Annualized Value
(3) Annualized Basis

This table indicates that by looking at the cooling of the noncondensable gases it is "economic" to cool it as case A; however, in real life, the jet steam is not a cost factor although more steam is required in case D. The case D capital cost is less and the designs reflect this relationship.

5.5 Installation Labor Cost Sensitivity

As all recognize in the construction industry, the labor productivity, the labor pay rate and the contractor overhead and profit vary depending on time of bid, overall conditions and the specific project requirements. Since this is a conceptual design report, some knowledge of what difference these variations of parameters can make in total project cost is worth studying. Cost sensitivity analysis was performed on the Unit 1 estimate to demonstrate the total cost vulnerability to parameter variation. This vulnerability is also a function of the labor to equipment and material ratio. The labor material ratio, excluding Account 365, vary from 0.365 to 0.558. Using a value of about 0.42, the following sensitivities to total project cost are observed:

Labor Efficiency %	Total Project Cost (per unit)
50	1.058
60	1.000
70	0.957

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Labor Rate $/hr.	Total Project Cost (per unit)
13.50	0.971
15.00	1.000
16.50	1.030

Labor Overhead %	Total Project Cost (Per Unit)
45	0.981
55	1.000
65	1.019

As observed these changes in total cost are small as compared with:

Escalation	1.285
Contingency	1.20

5.6 Capacity Factor (Cost Benefit Analysis)

Capacity factors of the units are being used to analyze the annual electrical output from a unit. The first discussions of capacity factor were presented in Section 3.1.3.

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5.6.1 Alternative 1 (Iron/Caustic/Peroxide System)

This system has indicated a decrease in capacity factor. There are many reasons for changes; however, at this time it appears that the iron, caustic, and peroxide system with direct contact condensers will operate at a 60 percent capacity factor. With continued operating experience and improvements to the system it appears a 70 percent capacity factor can eventually be achieved for the mature system. Both 60 and 70 percent will be used in comparisons.

5.6.2 Alternative 2 (Surface Condensed/Stretford System

This system should have the power plants capable of operating at their intrinsic or natural capacity factor. This was indicated by experience to be 80 percent and with a mature system to be 85 percent. Both figures will be used in the economic analysis.

The capacity factors of the vent gas processing equipment (Stretford) affects the Units capacity factor. As discussed in Section 5.4 of the technical data, Volume 1, the Stretford unit cost has been increased from the normal to provide a design that has zero forced outages in the case of combined units and for individual ones such

TABLE 5-3

ANNUAL ENERGY OUTPUT

	Alternative 1		Alternative 2	
Capacity Factor	60%	70%	80%	85%
Unit MWh/yr.				
1	63,587	74,185	74,464	84,430
2	63,676	74,289	80,557	85,592
3	139,284	162,498	179,832	191,072
4	139,284	162,498	179,832	191,072
5	278,673	325,119	364,451	387,229
6	278,673	325,119	364,451	387,229
7	278,673	325,119	364,332	387,103
8	278,673	325,119	364,332	387,103
9	278,673	325,119	364,332	387,103
10	278,673	325,119	364,332	387,103
11	557,136	649,992	726,933	772,366
12	557,992	649,992	720,429	765,456
Cooling Tower	-13,878	-16,191	0	0
Stretford	0	0	-21,021	-21,021
Total MWh/hr.	3,178,263	3,707,977	4,132,256	4,391,837

Alternative 1 has the lowest energy output when compared to Alternative 2. Therefore, Alternative 1 for economic comparisons must have a replacement energy cost element. This replacement energy need continued for the life of the facility and is represented by a level annual cost. Since the replacement energy is a function of the capacity factor of the alternative, four cases are developed. Table 5-4, Alternative 1 - Replacement Energy and Cost, summarizes the replacement energy costs by case.

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that they are available all the time a separate unit is available. Therefore, the Stretford units (the vent gas processing) are not anticipated to impact plant capacity factors.

5.7 Unit Energy (Cost Benefit Analysis)

The net kilowatt hours available for the bulk power system is of paramount importance when making comparisons. The design base reference point net kWh for each unit is used for this calculation. Alternative 1 energy is the base net times the hours indicated by the capacity factors. Alternative 2 energy is reduced from the base due to the retrofit and was presented earlier in the report. This new output times the hours indicated by capacity factor is the energy from the retrofit units. The Stretford energy is indicated at the bottom separately. Alternative 1 has a cooling tower deduct based upon Section 3.5. The alternative which generates the least energy has to make up the difference for economic evaluation purposes. The bulk power system supplies this energy and at its 100 percent capacity factor energy cost.

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TABLE 5-4

ALTERNATIVE 1 - REPLACEMENT ENERGY AND COSTS

Case	Alt. #1 Capacity Factor	Alt. #2 Capacity Factor	MWh/yr.	Level Annual $/yr.
1	60%	80%	953,993	62,009,000
2	60%	85%	1,213,574	78,882,000
3	70%	80%	424,279	27,578,000
4	70%	85%	628,860	44,450,000

5.8 Operations and Maintenance

The operations and maintenance cost must be estimated for each alternative to form a basis for comparison. The difference between alternatives is presented.

5.8.1 Alternative 1 (Defender)

The maintenance is estimated to be twice that of the base unabated plant. The maintenance is assumed for this study to be constant for both capacity factors. From historic data projected (FPC Form 1 year ending 1978 escalated one year), the unabated plant maintenance difference for Alternative 1 is estimated to be:

Level Annual Maintenance $/yr. 3,723,000

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This alternative also has a direct operating expense for the chemicals required for the system. The level annual dollars per year are estimated for the capacity factors:

Capacity Factor	Level Annual $/yr.
60%	20,506,700
70%	23,924,400

5.8.2 Alternative 2 (Challenger)

The power plant itself is estimated to require the same operations and maintenance as the unabated base plant; however, this alternative has the vent gas processing facilities (Stretford Units). These operations and maintenance costs are estimated to be:

TABLE 5-5

STRETFORD OPERATIONS AND MAINTENANCE
(Level Annual $/yr.)

Maintenance	$1,217,160
Chemicals	1,563,971
Steam	120,711
Electricity	1,632,227
Total	$4,534,069 $/yr.

5.9 Capital Cost

The capital costs have been estimated in Sections 3.4 and 4.3 for the respective alternatives 1 and 2. For economic evaluations in 1979 dollars, the level annual dollars per year are segregated by alternative.

5.9.1 Alternative 1 (Defender)

Not all the existing units have the full abatement. For comparison they are all brought up to full abatement. The estimated capital cost was presented in Section 3.4 and in terms of 1979 dollars the level annual $/year are estimated to be:

Capital	1,441,700 $/year

5.9.2 Alternative 2 (Challenger)

The required capital expenditures are in two areas for this alternative. The first is retrofitting the power plants with surface condensers, and the second is the Stretford process. These capital

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costs are summarized in Section 4.3. The following is the 1979 level annual dollars per year required:

Retrofit	10,566,000 $/yr.
Stretford	6,802,300
Total Capital	17,368,300 $/yr.

5.10 Replacement Energy During Construction

Schedules for the work of Alternative 2 have been presented in Section 4.1. This summary table is from this data. The Unit down time is required in the economic evaluation to account for all cost. If a plant has two units, both are out at the same time and the total time is the out of service time.

TABLE 5-6

ALTERNATIVE 2 - SUMMARY
REPLACEMENT ENERGY DURING CONSTRUCTION

Units	Construction Outage Months	Level Annual Replacement Cost $/yr.
1- 2	8.0	$ 481,338
3- 4	8.0	1,053,606
5- 6	9.3	2,450,558
7- 8	9.3	2,450,558
9-10	9.3	2,450,558
11	11.3	2,976,437
12	11.3	2,976,437
Total		$14,839,492

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5.11 Economic Evaluation

This evaluation is the summary of all the costs developed in this report. It is done by the level annual revenue requirement method. The dollar amounts in the table are thousands of dollars per year on a level annual basis, and are from the report sections indicated by the numbers in parenthesis. This evaluation is in 1979 dollars.

There are four comparisons to be made based on the capacity factors.

The capacity factors over the long term are the most significant factor as they affect the two biggest cost items-replacement energy and treatment chemicals. Evaluation "A" compares Alternative 2 (surface condenser/ Stretford) at 80 percent capacity factor with Alternative 1 (iron/caustic/ peroxide) at both 60 and 70 percent capacity factors. Evaluation "B" compares Alternative 2 at 85 percent capacity factor with Alternative 1 at both 60 and 70 percent capacity factors.

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TABLE 5-7

ECONOMIC EVALUATION "A"
(thousands of $/yr. Level Annual)

Alternative:		1	1	2
(5.6)	Capacity Factor	60%	70%	80%
(5.7)	Energy (Replacement)	$62,009	$27,578	-
(5.10)	Energy (Replacement During Construction)	-	-	$14,840
(5.8)	Operation & Maintenance	24,230	27,647	4,534
(5.9)	Capital	1,442	1,442	17,368
	Total $1,000/yr.	$ 87,681	$56,667	$36,742
	Comparison Per Unit	2.39	1.54	1.00

TABLE 5-8

ECONOMIC EVALUATION "B"
(thousands of $/yr. Level Annual)

Alternative:		1	1	2
(5.6)	Capacity Factor	60%	70%	85%
(5.7)	Energy (Replacement)	$ 78,882	$44,450	-
(5.10)	Energy (Replacement During Construction	-	-	$14,840
(5.8)	Operation & Maintenance	24,230	27,647	4,534
(5.9)	Capital	1,442	1,442	17,368
	Total $1,000/yr.	$104,554	$73,539	$36,742
	Comparison Per Unit	2.84	2.00	1.00

Alternative 2 is observed to be the lowest level annual cost in all four cases. The conditions and the per unit multiple cases are summarized below. The per unit multiple is defined as the total of Alternative 2 divided into the total cost of Alternative 1, that is Alternative 2 is the per unit multiple times more economical than that of Alternative 1 for those conditions.

TABLE 5-9

SUMMARY COMPARISON

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Per Unit Multiple
1	60	80	2.39
2	60	85	2.84
3	70	80	1.54
4	70	85	2.00

TABLE 5-10

CASE DIFFERENCE SUMMARY (L.A.)

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Difference in $/yr. L.A.
1	60	80	50,939,000
2	60	85	67,812,000
3	70	80	19,925,000
4	70	85	36,797,000

There is a very large difference between Alternative 2 and Alternative 1. The smallest of the differences occurs in Case 3, 19,925,000 $/yr. level annual. It is worthwhile to look at the sensitivity to some assumptions to get a magnitude of how great the 19,925,000 $/yr. is. The largest component in the evaluation is replacement energy.

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Per Unit Replacement Energy Cost	Level Annual	Difference
1.0	27,500,000	0
0.85	23,300,000	-4,200,000
0.69	19,000,000	-8,500,000

Decreases in replacement energy by significant amounts only change the difference slightly. They would decrease the difference by the amount shown. 19.9 million is needed to make the alternatives equal cost.

The second largest cost is chemical requirements of the iron/caustic/peroxide system. Both a 20 percent increase and decrease are presented. A negative number decreases the difference.

Per Unit Chemical Cost	Level Annual	Difference
1.0	27,647,000	0
0.8	22,117,000	-5,530,000
1.2	33,177,000	+5,530,000

The third largest cost is the capital to install the surface condenser and the Stretford units. A 20 percent change in the capital cost only created a difference of 3.4 million dollars for evaluation purposes.

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Per Unit Capital Cost	Level Annual $/yr.	Difference
1.0	17,368,000	0
0.8	13,894,400	-3,473,600
1.2	20,841,600	+3,473,600

If one were to take all the three major cost elements and add the differences stated above in the greatest way against Alternative 2 the total would amount to 17,500,000 million dollars per year. The difference between Alternative 2 and 1 is 19,925,000 million dollars per year. Therefore, Alternative 2 is solidly the most economic.

To make comparisons with some previous work done by others it has been requested to present the present values of the cases and the elements. The results are the same; however, the units of the quantities are different. The present values are the 1979 dollars with all future expenditures converted to 1979 dollars. All dollar values are thousands of dollars.

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TABLE 5-11

PRESENT VALUE ECONOMIC EVALUATION "A"

Alternative:	1	1	2
Capacity Factor %	60	70	80
Energy Replacement $	539,208	239,808	-
Energy Replacement During Construction $	-	-	129,043
Operation & Maintenance $	210,695	240,408	39,426
Capital $	12,539	12,539	151,026
Total	762,442	492,755	319,495

TABLE 5-12

PRESENT VALUE ECONOMIC EVALUATION "B"

Alternative	1	1	2
Capacity Factor %	60	70	85
Energy Replacement $	685,930	386,521	-
Energy Replacement During Construction $	-	-	129,043
Operation & Maintenance $	210,695	240,408	39,426
Capital $	12,539	12,539	151,026
Total $	909,164	639,468	319,495

TABLE 5-13

CASE DIFFERENCE SUMMARY (PV)

Case	Alt. 1 Cap. Fac.	Alt. 2 Cap. Fac.	Difference in PV
1	60	80	$442,947,000
2	60	85	589,669,000
3	70	80	173,260,000
4	70	85	319,973,000

COST OF CAPITAL: 11 Percent

CAPITAL: The single life 30 year level annual revenue requirement (LARR) factor for generation planning is 0.1465.

OPERATION AND MAINTENANCE: The 30 year level annual factor for generation planning is 2.19.

STEAM AT GEYSERS: The 30 year level annual steam cost in mills per kWh is 24.4.

POWER VALUES: (for base loaded units in mills per kilowatt hour)

Year	30 Year Level	Single Value
1979	61	33
*1980	65	37
1981	68	39
1982	72	50
1083	75	55

*Data used in Report

CONSTRUCTION COST:

Direct Labor Rate: 15.00 dollars per hour
Efficiency: 60 percent of hours
Indirects and Profit: 55 percent of direct labor cost
Contingency: 20 percent on direct labor hours

Major Equipment: Evaluated manufacturer cost
Materials and Rentals: Estimated
Contingency: 20 percent on equipment and materials

Engineering and Other Allocatable Costs: 20 percent on labor and equipment

GM FACTOR:

Item	Percent of Direct Cost
Indirects:	
Indirects	0.0
General Overheads:	
General Engineering & Administration	16.0
Allowance for Funds During Construction	3.7 - 5.0
Ad Valorem Taxes	1.0 - 2.0
Total GM Factor	20.7 - 23.0%

No.	Date	Description	Ck	R.App	C.App
3	8/3/79	Revised for Final Draft "Condensed Report"			
1	6/29/79	Revised for Milestone Report #2			
0	6/13/79	Data Used in Milestone Report #1			

ROGERS ENGINEERING CO., INC. 111 PINE STREET SAN FRANCISCO, CALIF. 94111	ECONOMIC FACTORS AND METHODS DATA SHEET APPENDIX "A"	SPECIFICATION S-00-001	REV. 3
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METHODS:

1. For alternative comparison, the alternatives must be equal. All costs and their differences are compared to make a selection.

2. The costs of an installation is only the capital cost which must be authorized in a GM.

CALCULATIONS:

1.0 LEVEL ANNUAL STEAM

Level Annual Steam Factor (LASF) = 0.0244 $/kWh
Steam #/hr. x 0.049 kW/# x Capacity Factor x hrs./yr. x LASF = Level Annual $/yr.

2.0 LEVEL ANNUAL OPERATIONS AND MAINTENANCE

Note exclude electrical energy use factor of Section 3.0.
Level Annual Operations and Maintenance Factor (LAOMF) = 2.19
Operation and Maintenance Cost/yr. x LAOMF = Level Annual $/yr.

3.0 LEVEL ANNUAL ELECTRICAL ENERGY (Continuous)

Level Annual Power Value Factor (LAPVF) = 0.065 $/kWh
kWh/yr. x LAPVF = Level Annual $/yr.

4.0 LEVEL ANNUAL ELECTRICAL ENERGY (Construction)

Single Power Value (SPV) = 0.037 $/kWh
CRF (30, 11) Capital Recovery Factor Uniform Series 30 Years at 11 Percent
kWh/yr. x SPV x CRF (30, 11) = Level Annual $/yr.

5.0 LEVEL ANNUAL CAPITAL COST

Level Annual Capital Factor (LACF) = 0.1465
(Account 314 Only)
Capital Cost $ x LACF = Level Annual $/yr.

6.0 CAPITAL COST

Construction Cost x GM Factor = Capital Cost

7.0 CONVERT LEVEL ANNUAL $ PER YEAR TO PRESENT VALUE

$$\text{Present Value} = \frac{\text{Level Annual \$/yr.}}{\text{Uniform Series Capital Recovery Factor}}$$