ELECTRIC DIVISION EVALUATION REPORT

ELECTRIC UTILITY RESPONSE TO THE WINTER FREEZE

OF DECEMBER 21 to DECEMBER 23, 1989

An Evaluation of the Actions Taken by Texas Utilities to Correct Technical Plant Equipment Problems

November 1990

Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 400N
Austin, Texas 78757

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TABLE OF CONTENTS

ATTACHMENTS

This report and the ideas expressed in this report do not necessarily represent a concensus of position of the Public Utility Commission of Texas or of its Staff members.

Chester R. Oberg 11/15/90

Chester R. Oberg, Nuclear Projects

Section I

INTRODUCTION

Several major electric power generating utilities, within the State of Texas, were severely affected by the freezing weather conditions in December of 1989. In May of 1990 the utilities were requested to provide the PUC Staff information on the corrective actions taken by them to prevent recurrence of the technical problems experienced by plant equipment. A variety of corrective actions to the problems were reported by the utilities that were affected by the cold weather.

The intent of this Electric Division Evaluation Report is to compile the answers from the utilities and to assess the adequacy of the responses to the equipment problems. This report will not address changes to any PUC emergency notification measures nor will it consider ERCOT and utility emergency power curtailment procedures or steps that should be taken to manage consumer demand for electrical power prior to or during an extreme weather related emergency. These topics will be address elsewhere. This report is principally based on information provided by the utilities.

Section II

BACKGROUND

The winter freeze of December 21 through December 23, 1989, greatly strained the ability of the Texas electric utilities to provide reliable power to their customers. Record and near record low temperatures were felt throughout the state resulting in a significantly increased demand for electrical power. At the same time that demand was increasing, weather related equipment malfunctions were causing generating units to trip off the line. The combination of heavy demand and loss of generating units caused near loss of the entire ERCOT electric grid.

It should be noted that other states also experienced similar power shortages resulting in rolling blackouts. The State of Florida experienced depressed temperatures that ranged from 20 degrees F to 30 degrees F below normal for that time of year. Most Florida utilities resorted to "rolling blackouts" to prevent the State grid from collapsing. The actual Florida peak demand during the rolling blackout period was 15,929 MW. This exceeded the projected demand by 18% and the Florida State 1988-1989 winter peak of 12,897 MW by 23.5%.

Most of the Texas electric generating utilities met the increased electric demands during this emergency with a minimum of service interruptions. Using emergency plan procedures, ERCOT, the Electric Reliability Council of Texas, was able to lessen the load of those utilities hit hardest by transferring power from utilities with a generating surplus to those lacking generation capacity.

Early on December 23rd, the loss of generating units and rising customer demands caused Houston Lighting and Power Company (HL&P), Lower Colorado River Authority (LCRA), and the City Public Service Board of San Antonio (CPSB) to use their remaining spinning reserves. Next these three utilities requested available spinning reserve power from other utilities in ERCOT to maintain the integrity of their control areas.

The ERCOT Emergency Electric Curtailment Plan calls for individual utilities having difficulties meeting their load to do all they can before other utilities are asked to shed load to preserve the entire electric system. As loads continued to increase on December 23rd, and with all available spinning reserves in ERCOT having been already utilized, individual utilities with generating deficits were required to start shedding load. Firm load was shed by HL&P from 6:53 to 10:58 a.m., by CPSB from 7:08 to 10:48 a.m., and by LCRA from 8:33 to 11:02 a.m.

System-wide, pre-allocated on a percentage basis, firm load shedding is the last step in the ERCOT emergency operating procedures and requires all utilities to reduce demand by interrupting customer service. When an additional set of generating units were lost around 10:15 a.m. because of the freeze-up of instrumentation, all ERCOT utilities were ordered to shed additional firm load between 10:21 and 10:31 a.m. on December 23rd to halt and reverse the collapse of the electric grid.

A detailed sequence of events is presented in Attachment No. 1. This attachment also contains graphs illustrating the ERCOT capacity vs. load demand and a partial representation of the resultant changes in the system frequency on December 23, 1989. Changes in demand load and temperature variation are also shown for one utility.

SECTION III

UTILITY RESPONSES

A questionnaire was sent to those ERCOT utilities affected by the severe December weather. In general, the questionnaire solicited the actions taken by the utilities to prevent recurrence of the equipment problems under similar conditions and the cost of those actions. The following specific questions were asked for each affected unit:

(1) Unit Name and Unit MW Capacity

(2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

(3) List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

(4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

(5) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

(6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

(7) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

The extreme weather pointed out several weak areas in power plant operations. Inoperative or inadequate heat tracing systems and inadequate insulation on instrumentation sensing lines seemed to be the most common technical equipment problem encountered during the freeze. Some plant operators battled this type of problem with hand held propane torches to keep pipes from freezing during the emergency. Other problems encountered ranged from fish plugging cooling water intake screens to frozen grease that prevented fuel valves from freely operating. The causes of unit failures are summarized in Attachment No. 2.

Utility detailed responses have been included in this report in Attachment No. 3. The responses of the utilities varied. One utility instituted a comprehensive engineering review of their power plants. Others merely corrected the specific equipment failures. In some cases there was a lack of maintenance evident, although it would be difficult to state that if the maintenance had been accomplished the unit would not have shut-down.

Cogeneration plants also experienced problems during the freezing weather. The problems of the cogenerators were similar in nature to those experienced by the larger generating power plants. A summary of cogeneration data is included in Attachment No. 4.

Some of the most prevalent post emergency actions taken by the utilities to prevent future power plant shutdowns caused by cold weather included:

1. Improving heat tracing and insulation coverage on power plant instrumentation,
2. Upgrading instrumentation air supplies by removing excessive moisture with desiccant instrument air dryers,
3. Purchasing fish nets to be placed in front of intake water screens if fish begin running,
4. Developing plant procedures calling for inspections of plant equipment prior to the cold weather season, and
5. Installing wind breaks and enclosures around certain equipment exposed to the weather.

One of the critical areas is that of the unit/plant design temperature range. In general, the utilities reported design temperatures were pushed to their lower limits. The following design temperatures apply to those plants that were reported to have failed during the freeze:

Utility	Design Temperature Ranges(Pre-Dec. 1989)
CPL:	10 degrees F with 30 MPH winds

Utility	Design Temperature Ranges(Pre-Dec. 1989)
HL&P	10 to 105 degrees F, in general. STP was determined to be able to operate in a range of 3 to 105 degrees F. Limestone is protected to 5 degrees F with freeze protection equipment.
TUE	-10 degrees F with 35 MPH winds.
LCRA	1 to 110 degrees F (No design temperatures were available for Sim Gideon 2.)
TMPA	15 to 107 degrees F

When power plant equipment is exposed to weather conditions beyond its design limits, subsequent failures can be expected. At that time only the dedication and adaptability of plant operations and maintenance personnel to rapidly changing conditions is able to mitigate plant problems.

The specific design temperature ranges of reported units is contained in Attachment No. 5, Plant Design Temperatures.

SECTION IV

COSTS OF CORRECTIVE ACTIONS

As part of Attachment No. 2, the costs of the corrective actions are listed for each plant with the dates that the corrective action was taken. The expenses listed vary considerably for each plant, from a high of $ 109,266 for a significant amount of heat tracing and insulation installation on a single unit to nominal, or essentially no cost for many of the other units. The no cost corrective actions usually involved routine maintenance tasks such as the resetting of instrumentation, sealing equipment to prevent water intrusion or the replacement of frozen valves.

The cost to "fix" the freezing weather plant problems is about $ 2,773,253. The costs have been divided approximately equal between O & M ($ 1,194,553), maintenance cost allocation, and capital expense ($ 1,578,700). The majority of the expenses being funded from maintenance cost allocations. Since the rules for determining a capital expense vary from utility to utility, it is difficult to draw any conclusions regarding this type of cost division.

It should be noted that the cost of "fixing" the generating units is not confined only to those units that were shutdown as a result of the cold weather. The utilities are also taking measures to ensure that those generating units that were not affected will be able to continue to operate in any future adverse weather conditions.

The costs of corrective action for cogeneration units was not included in the total costs given above or in Attachment No. 2. Only a portion of the cogenerators reported a cost to correct identified plant problems. Based on the reporting cogeneration units, their estimated corrective action costs are approximately $ 650,000.

SECTION V

EVALUATION OF UTILITY RESPONSES

Whether the corrective actions being implemented by the utilities are sufficient to prevent future freeze related power plant failures, only direct experience with another deep freeze will ascertain.

The design temperatures for all of the reported power plants have a range from -10 degrees F to +110 degrees F. Because of the size of Texas and its varying climates, it is not feasible for the PUC to entertain implementation of a single required design temperature range. It is clearly the responsibility of each utility to ensure that the proper temperature range is selected by the Design Engineer when a power plant is being designed and that it is constructed in accordance with that design. The selection of the proper temperature range is the essential ingredient that will determine the reliability of a power plant to respond correctly to adverse weather conditions. Where necessary the utilities should supplement instrumentation and control systems with supplemental heat tracing systems and other forms of protective devices.

After a power plant has been constructed, it is necessary to maintain the plant to keep it functioning in accordance with its design. Each unit's active and passive equipment must be maintained. Insulation must retain its integrity in order to be effective. Heat tracing systems must be checked for correct operation on a regular basis. Control air systems should be drained of excess moisture. Cold weather operating procedures need periodic review for changing circumstances, and plant personnel need training in order to maintain their operating proficiency. The results of improper maintenance and training will be seen in increased O & M expenses for the repair of failed equipment as well as loss of plant reliability.

The near complete loss of the ERCOT grid brings an awareness that, even in Texas, plant operators must prepare for cold weather emergencies. This awareness of and attention to cold weather problems must be continued.

A complete system blackout was prevented by timely implementation of the ERCOT emergency operating procedures and dedicated utility plant personnel working under adverse conditions to keep power plants generating.

SECTION VI

RECOMMENDATIONS

All utilities should ensure that they incorporate the lessons learned during December of 1989 into the design of new facilities in order to ensure their reliability in extreme weather conditions.

All utilities should implement procedures requiring a timely annual (each Fall) review of unit equipment and procedures to ensure readiness for cold weather operations.

All utilities should ensure that procedures are implemented to correct defective freeze protection equipment prior to the onset of cold weather.

All utilities should maintain insulation integrity and heat tracing systems in proper working order. Generating unit control systems and equipment essential to cold weather operations should be included in a correctly managed preventive maintenance program.

Additional training programs for plant personnel on the emergency cold weather procedures, including periodic drills, should be implemented by each responsible utility.

PUC Engineering Staff should modify procedures for power plant CCN reviews to include a specific review for plant reliability under adverse weather conditions. Of special interest would be the selection of proper design temperature ranges for the power plant site.

ATTACHMENT NO. 1

SEQUENCE OF MAJOR EVENTS DURING THE FREEZE

ATTACHMENT No. 1

SEQUENCE OF MAJOR EVENTS DURING THE FREEZE

December 21,1989

12:00 midnight	TMPP, TUE and WTU all curtailed by Lone Star Gas.
4:00 AM	ERCOT's North Texas Security Center declares a Severe Cold Weather Alert for North Texas.
12:00 noon	ERCOT's South Texas Security Center declares a Severe Cold Weather Alert for South Texas.

December 22,1989

12:00 midnight	Some South Texas utilities curtailed of spot market supplies of gas.
8:30 AM	ERCOT's operators observe system frequency drop to 59.95 hertz.
8:40 AM	ERCOT requests utilities to implement 1st step of Emergency Electric Curtailment Plan (EECP 2.3.1.1)
9:00 AM	ERCOT requests utilities to implement 2nd step of Emergency Electric Curtailment Plan (EECP 2.3.1.2).
12:00 noon	EECP canceled in North Texas
12:30 PM	EECP canceled in South Texas

December 23, 1989

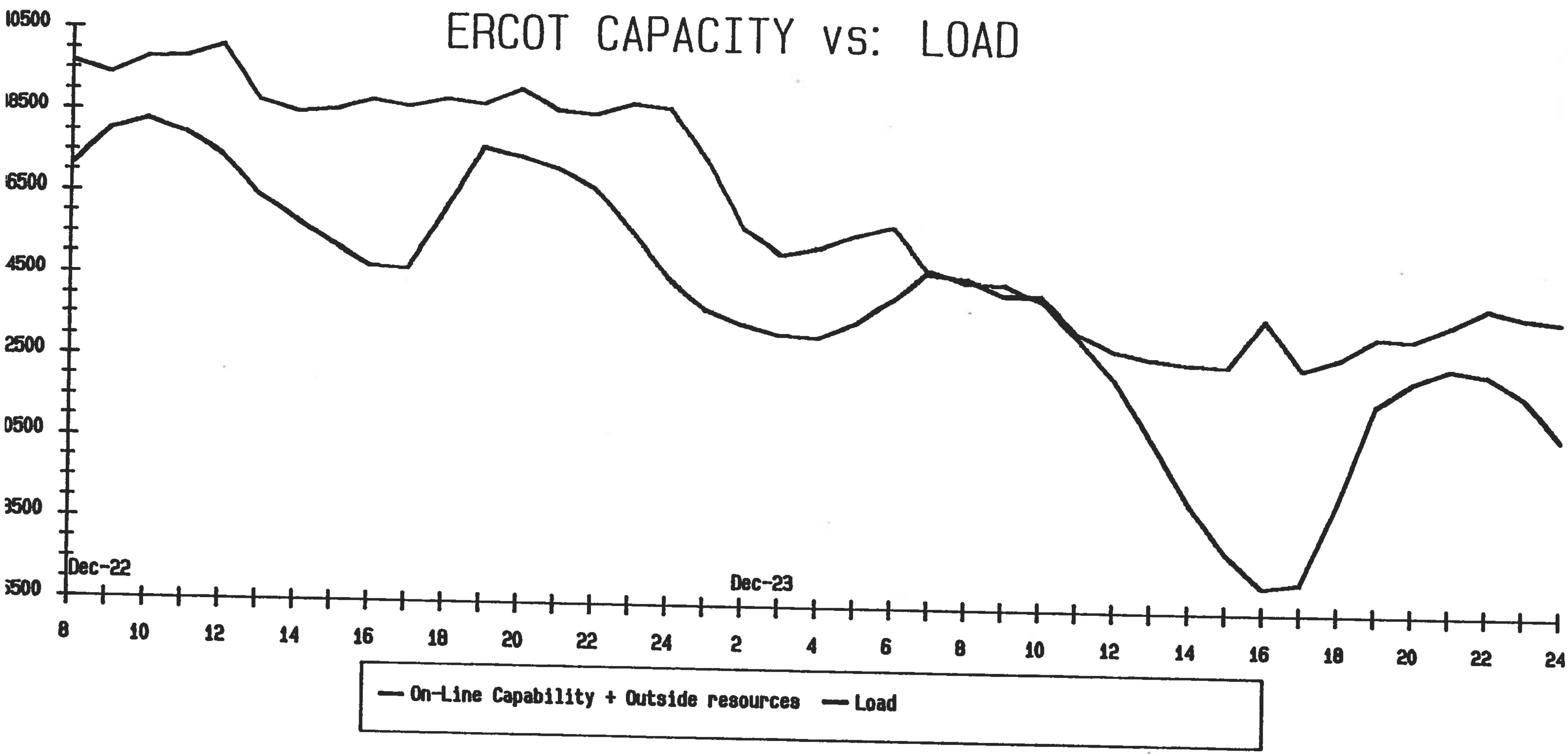
1:30 AM	WTU offers 220 MW of emergency power from Oklahoma DC tie.
3:50 AM	HL&P takes 220 MW of emergency power from WTU.
4:20 AM	WTU cancels emergency power from Oklahoma due to problems up there.

Attachment No. 1 Sequence of Major Events

5:30 AM	ERCOT prepares to declare EECP again. System operators preparing for possibility of shedding firm load.
5:36 AM	ERCOT system operators observe system frequency drop to 59.95 again.
6:00 AM	CPSB, LCRA and HL&P unable to maintain spinning reserve obligation.
6:04 AM	CPSB drops interruptible load.
6:07 AM	Frequency drops to 59.85 recovers to 59.92.
6:20 AM	TUE drops interruptible load.
6:38 AM	Frequency drops to 59.90.
6:40 AM	ERCOT declares EECP 2.3.1.2.
6:43 AM	Frequency drops to 59.87. ERCOT requests utilities to implement EECP 2.3.1.3.
6:53 AM	HL&P drops 300 MW of firm power.
6:56 AM	Frequency drops to 59.79.
6:59 AM	ERCOT requests utilities to implement EECP 2.4.1. CPL drops 85 MW of interruptible power transfers 11 MW to Mexico.
7:08 AM	CPSB drops 150 MW of firm power.
7:49 AM	ERCOT requests utilities implement EECP 2.4.2.
8:20 AM	HL&P begins rolling blackouts of 1000 MW.
8:33 AM	LCRA sheds 60 MW of firm load.
9:45 AM	HL&P receive emergency power from TUE(200 MW) and TMPP(50 MW). CPSB receives emergency power from WTU(50 MW).
10:20 AM	After recovery to 60.03, frequency drops back down to 59.65. ERCOT requests implementation of EECP 2.4.2.2 and 2.4.2.3.
10:21 AM	All ERCOT utilities drop firm load.

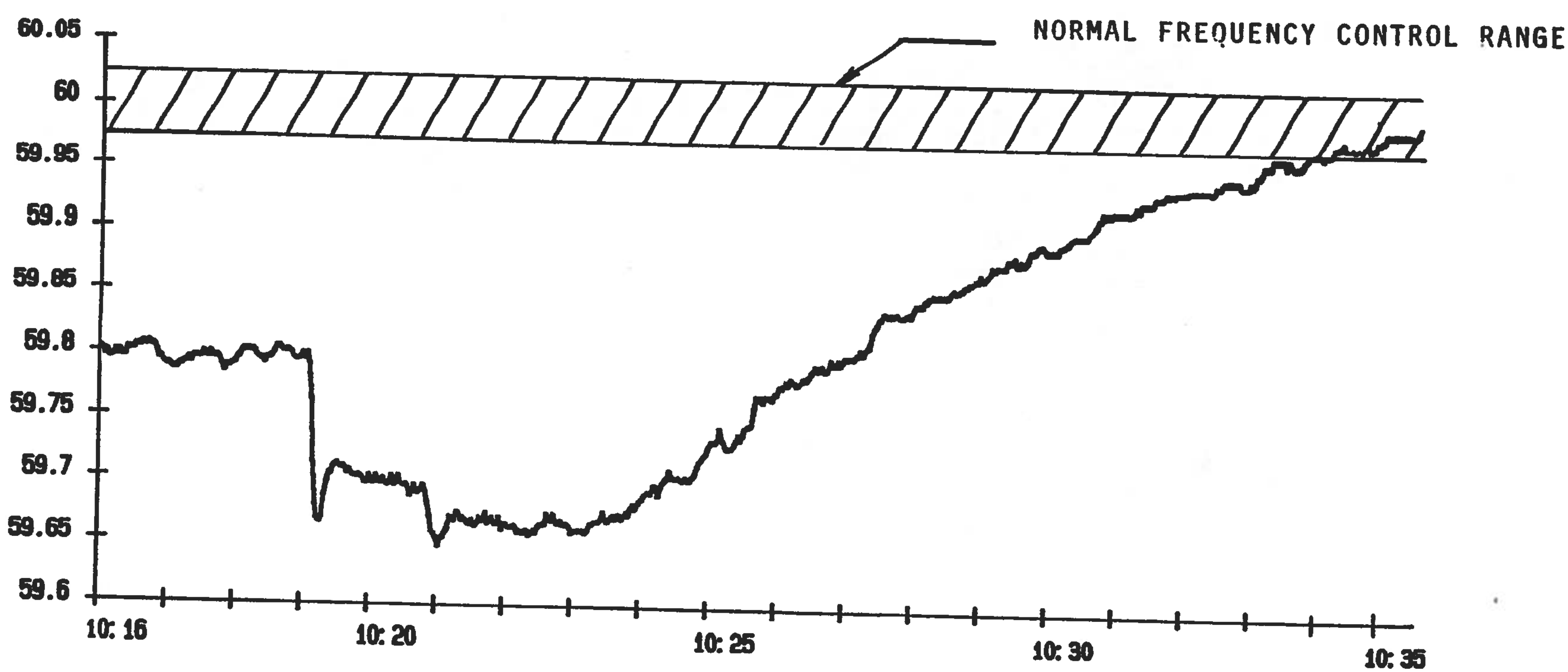
Attachment No. 1 Sequence of Major Events

10:31 AM	Frequency recovers to 60.05. ERCOT requests all utilities not in trouble to pick up firm load. All but HL&P, CPSB and LCRA comply.
10:48 AM	CPSB begins picking up shed firm load.
10:58 AM	HL&P begins picking up shed firm load.
11:02 AM	LCRA begins picking up shed firm load.
12:00 noon	ERCOT requests utilities back to EECP 2.3.1.2.
12:40 AM	EECP canceled.



ERCOT CAPACITY vs: LOAD
10500
8500
6500
4500
2500
0500
3500
5500
Dec-22
Dec-23
8
10
12
14
16
18
20
22
24
2
4
6
8
10
12
14
16
18
20
22
24
On-Line Capability + Outside resources
Load

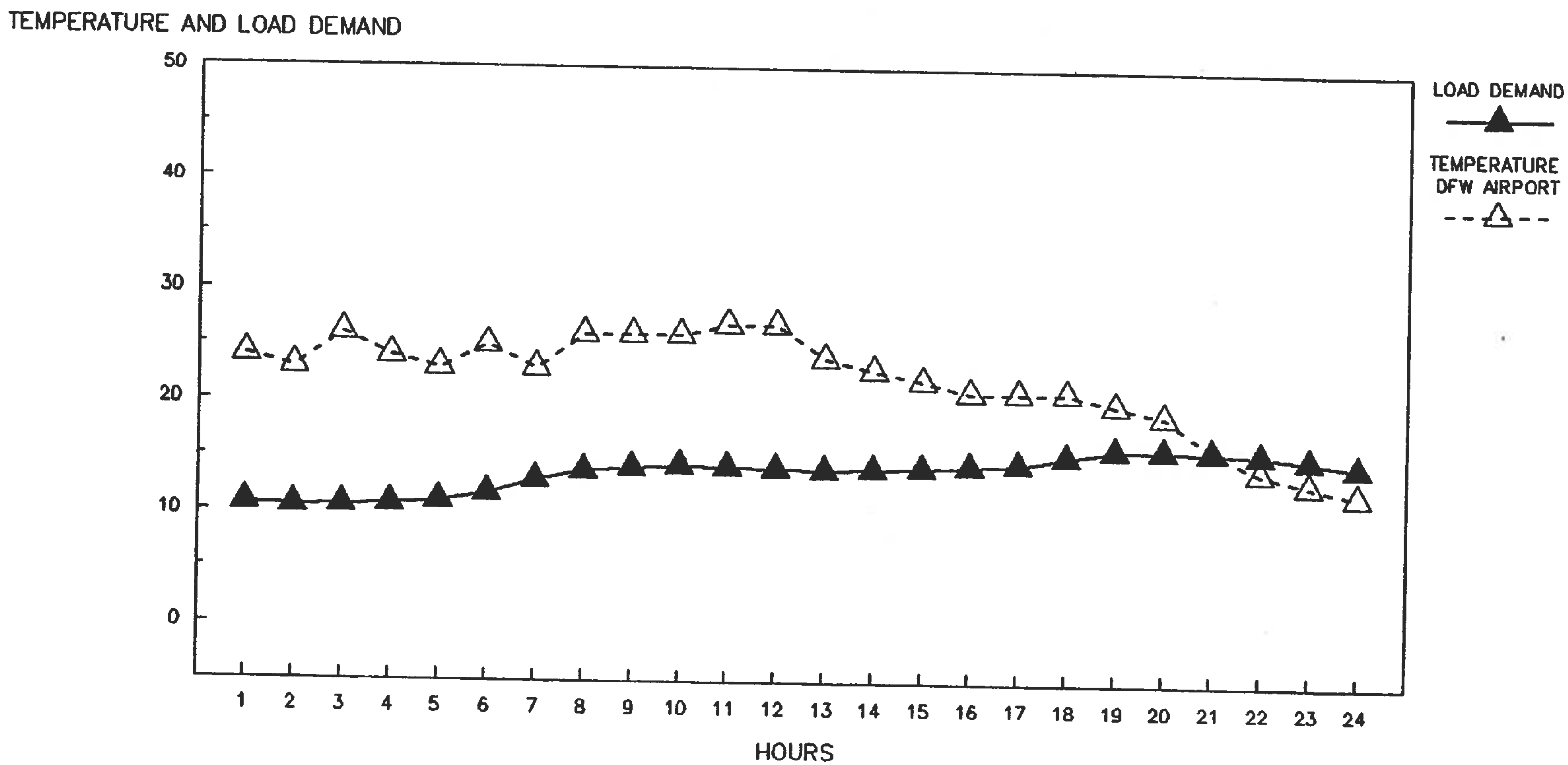
ERCOT FREQUENCY - Dec. 23, 1989



Temperature Variations December 1989
Texas Utilities Electric Company,
DFW Airport Temperatures

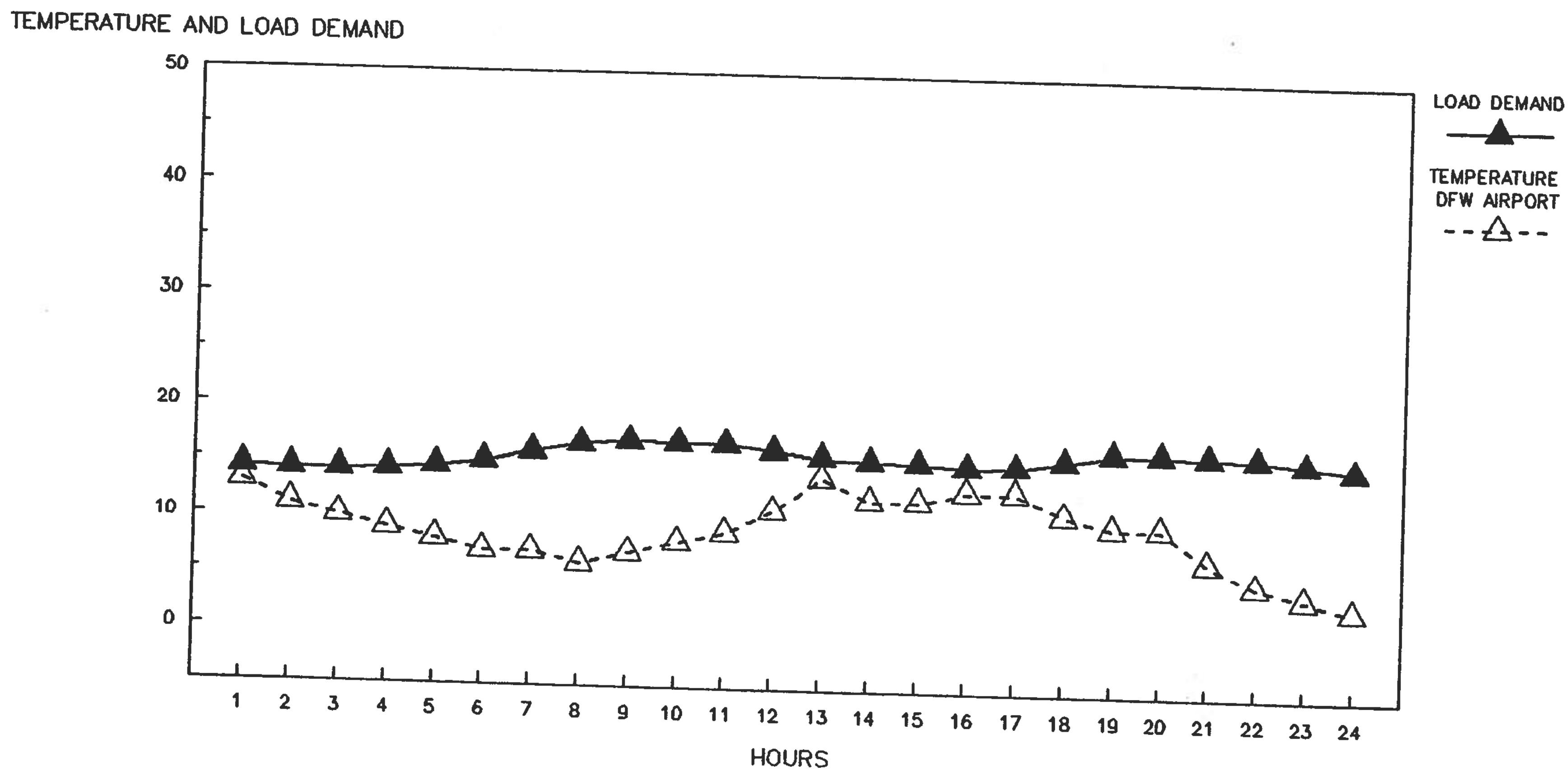
Date	Hour	Load	Temp Fdeg	Date	Hour	Load	Temp Fdeg
12/21/89	1	10658	24	12/23/90	1	15097	3
	2	10529	23		2	14913	3
	3	10586	26		3	14893	2
	4	10697	24		4	14935	2
	5	11029	23		5	15086	0
	6	11688	25		6	15316	0
	7	12966	23		7	15501	-1
	8	13814	26		8	15680	0
	9	14091	26		9	15713	5
	10	14307	26		10	15533	7
	11	14219	27		11	14869	10
	12	14114	27		12	14300	15
	13	14029	24		13	13520	17
	14	14105	23		14	12801	20
	15	14212	22		15	12240	21
	16	14419	21		16	11896	22
	17	14620	21		17	11946	20
	18	15297	21		18	12932	17
	19	15911	20		19	13916	17
	20	15922	19		20	14185	15
	21	15860	16		21	14373	15
	22	15666	14		22	14407	15
	23	15221	13		23	14162	16
	24	14602	12		24	13749	16
12/22/89	1	14271	13	12/24/89	1	13337	16
	2	14184	11		2	13199	16
	3	14246	10		3	13214	16
	4	14349	9		4	13087	17
	5	14622	8		5	12909	16
	6	15142	7		6	13259	16
	7	16029	7		7	13528	17
	8	16749	6		8	13895	17
	9	17063	7		9	14082	22
	10	16995	8		10	13706	25
	11	16937	9		11	12955	29
	12	16489	11		12	12087	33
	13	15906	14		13	11386	35
	14	15663	12		14	10663	38
	15	15505	12		15	10094	41
	16	15284	13		16	9719	41
	17	15286	13		17	9672	40
	18	15951	11		18	10386	37
	19	16649	10		19	11031	30
	20	16722	10		20	11117	31
	21	16613	7		21	11217	28
	22	16427	5		22	11314	29
	23	16011	4		23	11256	29
	24	15509	3		24	10969	28

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 21, 1989



LOAD DEMAND IS x 1000.

TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 22, 1989



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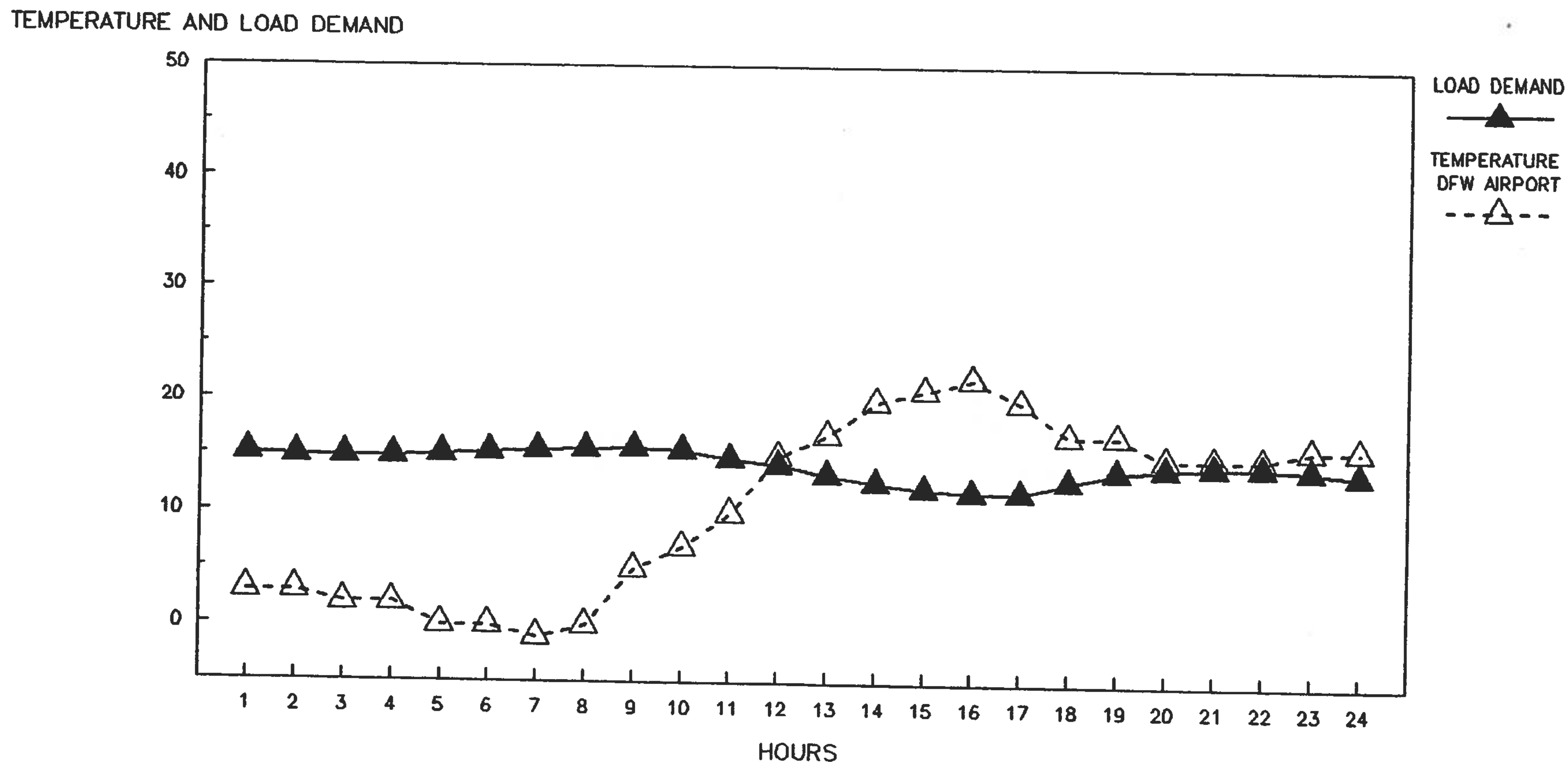
LOAD TEMPERATURE VARIATION
December 23, 1989



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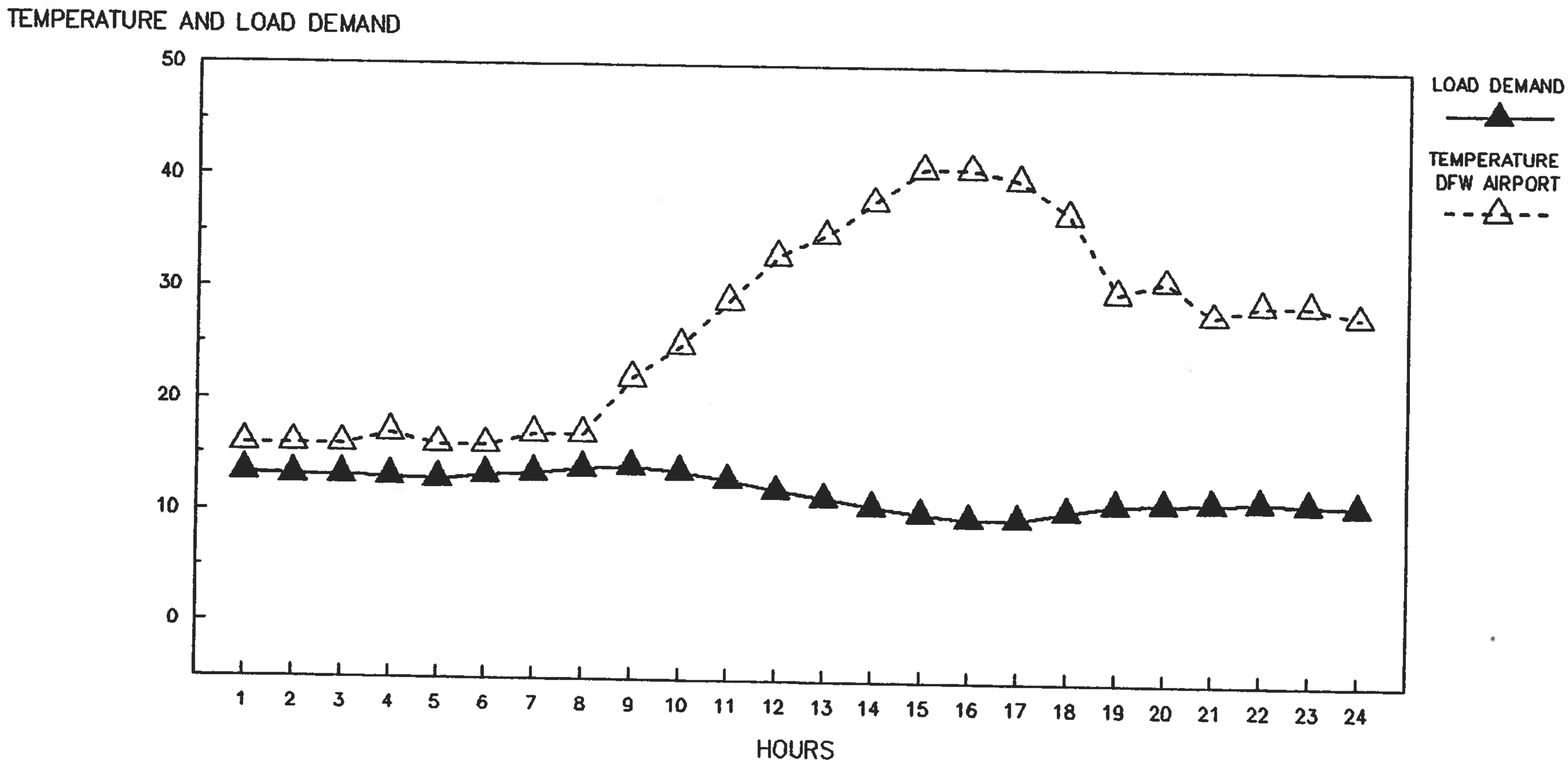
TEXAS UTILITIES ELECTRIC COMPANY
LOAD TEMPERATURE VARIATION
December 24, 1989



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ATTACHMENT NO. 2

CAUSES OF PLANT SHUTDOWNS
and
CORRECTIVE ACTION COSTS (SUMMARY)

ATTACHMENT No. 2

CAUSES OF PLANT SHUTDOWNS AND CORRECTIVE ACTION COSTS (SUMMARY)

Unit Name	Cause	Date Compl.	Expenses O & M	Expenses Capital
		Central Power and Light (CPL)		
Barney Davis 1			3,500	50,000
Barney Davis 2			3,500	50,000
Caleto Creek 1			55,200	50,000
E. S. Joslin 1*	Frozen instrumts	11/90	92,500	50,000
J. L. Bates 1			18,400	50,000
J. L. Bates 2			1,500	50,000
La Palma 6			32,200	50,000
Laredo 1				50,000
Laredo 2			4,000	50,000
Laredo 3			34,400	50,000
Lon C. Hill 3*	Frozen instrumts	12/90	65,600	50,000
Lon C. Hill 4*	Boiler tube leak	12/89	47,600	50,000
Nueces Bay 6 *	Frozen instrumts	11/90	37,600	50,000
Nueces Bay 7			32,200	50,000
Victoria 6			52,400	50,000
Total CPL			$ 480,600	$ 750,000
Grand Total CPL			$ 1,230,600	

* Tripped off line during cold weather emergency

Preventive and corrective measures include the following:

Control Air Dryers (Capitalized)
DC Heater Enclosures (O & M)
Drum Enclosures (O & M)
Heat Tracing (O & M)
Drum Level Instrumentation (O & M)

Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)

Houston Lighting & Power Company (HL&P)

Unit Name	Cause	Date Compl.	Expenses O & M	Expenses Capital
Cedar Bayou 1	Frozen instrumts	2/90	$ 4,800	38,000
Cedar Bayou 2				
Cedar Bayou 3	Frozen instrumts	10/90	10,000	90,000
Greens Bayou 5	Frozen instrumts	9/90	15,800(4)	
Limestone 1	Frozen instrumts	9/90	57,700(2)	
Limestone 2	Frozen instrumts	9/90	57,300	
P H Robinson 1	Frozen instrumts	10/90	38,800	38,000
P H Robinson 2			38,800	
P H Robinson 3				38,000
P H Robinson 4			1,100	48,000(3)
S R Bertron 1		3/90	44,000	40,000
S R Bertron 2		9/90		76,000
S R Bertron 3	Frozen instrumts	10/90	3,700	
S R Bertron 4	Ice in boiler fan	12/89		
South Texas 1	Frozen instrumts	10/90	20,000(1)	140,700(5)
South Texas 2		6/90	20,000	213,000(5)
T H Wharton 2	Boiler motor failed	1/90	51,509	
T H Wharton 3	Frozen instrumts	10/90	65,140	
T H Wharton 4	Frozen instrumts	5/90	109,266	
T H Wharton GT21	Frozen instrumts	7/90	1,000	
T H Wharton GT54	Frozen fuel valve	12/89		
W A Parish 1		9/90	63,000(6)	
W A Parish 2				
W A Parish 3				
W A Parish 5	Frozen instrumts	7/90	74,918	57,000
W A Parish 6				
W A Parish 7				
W A Parish 8	Frozen instrumts	8/90	2,500	50,000
W A Parish GT21	Batteries frozen	5/90		
Webster GT	Frozen instrumts	2/90		
Total HL&P			$ 679,333	$ 828,700
Grand Total HL&P			$ 1,508,033	

Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)

Notes

(1) Additional Cost for seal water lines and instrumentation lines to be determined after engineering analysis.
(2) Maintenance costs for Bottom Ash Hopper and Sluice Gate Pistons included ($8,400).
(3) Costs for Aux Boiler Steam Drum End Enclosures.
(4) Costs for temporary burner deck enclosures not significant.
(5) Costs for additional freeze protection for auxiliary cooling surge tank and feedwater booster pumps.
(6) Cost for all Parish units combined.

Included in this list are anticipated cold weather modifications on various HL&P generating units that did not fail in service during the cold weather emergency (See Attachment B of HL&P letter dated June 15, 1990, that has been included in Attachment No. 4.)

Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)

Texas Utilities Electric Company (TUE)

Unit Name	Cause	Date Compl.	Expenses O & M	Expenses Capital
Eagle Mountain 3	Fish plugged intake	1/90		
Handley 5	Human error	1/90		
Martin Lake 2	Frozen instrumts	1/90	2,000	
Monticello 2	Frozen instrumts	1/90	2,000	
Monticello 3	Frozen instrumts	1/90	2,700	
Morgan Creek CT4	Frozen fuel valve	1/90		
Mountain Creek 2	Fish plugged intake	1/90		
Mountain Creek 7	Instrument error	1/90		
River Crest 1	Fish plugged intake	8/90	900	
Stryker Creek 1	Low gas pressure	1/90		
Tradinghouse 1	Frozen instrumts	1/90	500	
Valley 2	Frozen instrumts	1/90	300	
Total TUE			$ 8,400	

Attachment No. 2 Causes of Plant Shutdowns and Corrective Action Costs (Summary)

Lower Colorado River Authority (LCRA)

Unit Name	Cause	Date Compl.	Expenses O & M	Expenses Capital
Sim Gideon 2	Frozen instrumts	2/90	300	
Sam K Seymour 3	Frozen instrumts	5/90	420	
Total LCRA			$ 720	

Texas Municipal Power Agency (TMPA)

Unit Name	Cause	Date Compl.	Expenses O & M	Expenses Capital
Gibbons Creek 1	Frozen instrumts	10/90	25,500	
Total TMPA			$ 25,500	

GRAND TOTAL, ALL UTILITIES	$ 1,194,553	$ 1,578,700
Total	$ 2,773,253	

ATTACHMENT NO. 3

INDIVIDUAL UTILITY RESPONSES

Utility Responses:

Brazos Electric Power Cooperative, Inc.
Central Power and Light Company
Houston Lighting and Power Company
Lower Colorado River Authority
Texas Municipal Power Agency
Texas Utilities Electric Company

BRAZOS
ELECTRIC
COOPERATIVE

BRAZOS ELECTRIC POWER COOPERATIVE, INC.
2404 LaSalle Avenue • P.O. Box 2585
Waco, Texas 76702-2585
(817) 750-6500

June 11, 1990

Mr. Chester R. Oberg
Public Utility Commission of Texas
7800 Shoal Creek Boulevard Suite 400N
Austin, Texas 78757

Re: Cold Weather Operation
Your letter dated, May 10, 1990
PUC Project 9542

Dear Mr. Oberg:

Please recall that, with the exception of Miller 1 which was not designed for oil firing, all of our units were responsive and suffered no outages during the problem cold period.

The following actions have been taken on Miller 3 Unit:

The burner management system was tested making some minor fuel pressure trip adjustments.

Miller 1 unit was not equipped for oil firing because its gas fuel supply was very reliable, and Brazos builds its plants for the lowest first cost. We plan now to install the necessary equipment.

The following activity has been underway on Miller 1 Unit:

* Specifications have been prepared for the purchase of fuel oil pumps, and the purchasing process is now underway.

* Specifications are being prepared for the purchase of other associated equipment such as valves, strainers, etc.

* Specifications will be prepared for piping and installation labor.

* If new burner controls are needed we will attempt to delay this part of the project until they can be installed along with future replacement BTG controls.

It is hoped that this can be completed in December 1990.

We will make the usual preparations in November for cold weather operations. Such preparations include, but are not limited to, the following inspection and testing:

* Heating cable survey and inspection

* Equipment heaters

* Area Heating equipment

* Outdoor lube oil systems and oil inspection.

* Actual brief oil firing on at least one burner

* All fuel oil tanks full

Please call if we need to discuss this further.

Jack T. Ard

Jack T. Ard P.E.
Manager Power Production

Copy: J.D. Copeland

CENTRAL POWER AND LIGHT COMPANY / Home Office: P.O. Box 2121, Corpus Christi, Texas 78403 512-881-5300

October 8, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400n
Austin, Texas 78757

Subject: December 1989 Weather Problems

Dear Mr. Oberg

Central Power and Light had problems with its generating units just as many other utility company's did. The following information will address the seven question posed in your letter of May 10, 1990 concerning CPL generating units that were lost or unable to respond during the cold weather emergency of December 1989.

Question No. 1 - Unit name and unit MW capacity

Four (4) of CPL's generating units tripped off the line. The units and their capacity were as follows:

Unit	Capacity	Unit Tripped Date	Unit Tripped Time
E S Joslin 1	257-NMW	12-23-89	0150-Hrs
Nueces Bay 6	172-NMW	12-23-89	0536-Hrs
Lon C. Hill 3	162-NMW	12-23-89	0605-Hrs
Lon C. Hill 4	256-NMW	12-23-89	0656-Hrs

Question No.2 Unit general design temperature limitations (Maximum and minimum), in degrees F.

CPL's Generating Units are designed for a minimum ambient temperature of 10 degrees F with a wind velocity of 30-MPH. A specific maximum temperature is not specified as it is equipment dependant (eg. boiler tube metal may operate at temperatures as high as 1000 degrees F; furnace gas temperatures may be as high as 2300 degrees F). Other equipment such as electronic and digital control equipment may require a conditioned area where temperatures are controlled at or near 75 degrees F.

Question No. 3 - List of equipment(s) or plant systems that were adversely affected by the cold weather.

Question No. 4 - For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

The following equipment/plant systems were affected by the cold weather at the Power Stations noted above:

Unit Name	No.	(3) Affected Equip.	(4) Failure Mode	(4) Failure Cause	(4) How did failure contribute to overall probs.
E S Joslin	1	Boiler	(A)	(C)	(E)
Nueces Bay	6	Boiler	(A)	(C)	(F)
Lon C Hill	3	Boiler	(A)	(C)	(F)
Lon C Hill	4	Boiler	(B)	(D)	(G)

(A) Boiler Tripped as a result of low drum level
(B) Furnace over pressure protection tripped the boiler
(C) Frozen drum level sensing lines and instrumentation
(D) Boiler tube failure caused furnace over pressure
(E) The failure of the drum level instrumentation provided a false signal to the feed water control system which resulted in a reduction in feedwater to the boiler leading to a low water event in the boiler. The low water event caused the failure of several water wall tubes. The failed water wall tubes damaged the radiant section of the reheater. The unit was rendered unable to return to service until extensive NDT was performed and repairs were made.
(F) The units were tripped by the operator. The instrument problems were corrected and the units were returned to service
(G) A boiler tube leak caused the furnace over pressure. The tube leak was repaired and the unit returned to service.

Question No. 5 For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

In order to prevent recurrence of the system and equipment failure during future adverse weather conditions a complete post critique of power station operation was necessary. The Director of Generation Operation, Mr. Perry A. Beaty, appointed a taskforce to review the operation at each of CPL's Power Stations. The taskforce was charged with identifying all weather related problems and recommending action steps needed to prevent recurrence of weather related problems. The taskforce inspected records, logs, and interviewed the staff at each power station. The following actions were recommended:

(1) Engineering review of CPL's low temperature design requirements.
(2) The addition of desiccant type air dryers to the power station control air systems.
(3) Review power station heat tracing practices.
(4) Review power station boiler protection systems.
(5) Review power station boiler drum level instrumentation.
(6) Review boiler drum enclosures and D C heater instrumentation enclosures.

Stone and Webster Engineering was retained to perform the required design and specification for control air drying. Bath and Assoc. was retained to perform the required design review and specification for the drum enclosures and the DC heater enclosures.

Question No. 6 For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

See attached Tables 1, 2, 3, 4, & 5

Question No. 7 For each piece of equipment or system identified above report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

See attached Tables 1, 2, 3, 4, & 5

Thank you for your patience. If you have questions concerning the information provided please feel free to call us.

Very truly yours,

Ronald R. Earley
Manager Technical Services
Generation Operations Dept.

RRE:(rre10590)
Attachments
xc: Perry A. Beaty, Jr.
File:998-275.10.00-002

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO. 1 CONTROL AIR DRYERS

POWER STATION	UNIT NO.	COMPLETION DATE PROJECTED	COMPLETION DATE ACTUAL	COST PROJECTED	COST ACTUAL	MAINT/ CAPITAL
NBPS	6	11/15/91		$50,000.00		CAPITAL
Nueces Bay	7	11/15/91		$50,000.00		CAPITAL
LAPPS La Palma	6	11/15/92		$50,000.00		CAPITAL
LARPS	1	11/15/92		$50,000.00		CAPITAL
Laredo	2	11/15/92		$50,000.00		CAPITAL
	3	11/15/92		$50,000.00		CAPITAL
LCHPS	3	11/15/91		$50,000.00		CAPITAL
Lon C. Hill	4	11/15/91		$50,000.00		CAPITAL
VICPS Victoria	6	12/14/90		$50,000.00		CAPITAL
JLBPS	1	11/15/92		$50,000.00		CAPITAL
J.L. Bate	2	11/15/92		$50,000.00		CAPITAL
ESJPS E.S. Joslin	1	12/14/90		$50,000.00		CAPITAL
BMDPS	1	11/15/91		$50,000.00		CAPITAL
Barney Davis	2	11/15/91		$50,000.00		CAPITAL
COCPS Coleto Creek	1	12/14/90		$50,000.00		CAPITAL
				$750,000.00		

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.2 DC Htr ENCLOSURES

POWER STATION	UNIT NO.	COMPLETION DATE PROJECTED	COMPLETION DATE ACTUAL	COST PROJECTED	COST ACTUAL	MAINT/ CAPITAL
NBPS	6 1	11/15/90		$7,500.00		MAINT
	7 2	11/15/90		$1,500.00		MAINT
LAPPS	6 3	11/01/90		$7,500.00		MAINT
LARPS	1 4	NONE REQUIRED				
	2 5	NONE REQUIRED				
	3 6	12/15/90		$2,500.00		MAINT
LCHPS	3 7	11/01/90		$5,000.00		MAINT
	4 8	11/01/90		$5,000.00		MAINT
VICPS	6 9	11/15/90		$7,500.00		MAINT
JLBPS	1 10	NONE REQUIRED				
	2 11	NONE REQUIRED				
ESJPS	1 12	11/01/90		$7,500.00		MAINT
BMDPS	1 13	11/01/90		$1,000.00		MAINT
	2 14	11/01/90		$1,000.00		MAINT
COCPS	1 15	11/15/90		$9,000.00		MAINT
				$55,000.00		

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.5 DRUM LEVEL INSTRUMENT

POWER STATION	UNIT NO.	COMPLETION DATE PROJECTED	ACTUAL	COST PROJECTED	ACTUAL	MAINT/ CAPITAL
NBPS	6	10/19/90		$19,900.00		MAINT
	7	12/07/90		$19,900.00		MAINT
LAPPS	6	11/23/90		$19,900.00		MAINT
LARPS	1	NONE REQUIRED				
	2	NONE REQUIRED				
	3	11/30/90		$19,900.00		MAINT
LCHPS	3	12/07/90		$19,900.00		MAINT
	4	12/07/90		$19,900.00		MAINT
VICPS	6	11/30/90		$19,900.00		MAINT
JLBPS	1	12/14/90		$15,900.00		MAINT
	2	NONE REQUIRED				
ESJPS	1	NONE REQUIRED				
BMDPS	1	NONE REQUIRED				
	2	NONE REQUIRED				
COCPS	1	NONE REQUIRED				
				$155,200.00		

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO. 4 HEAT TRACING

POWER STATION	UNIT NO.	COMPLETION DATE PROJECTED	COMPLETION DATE ACTUAL	COST PROJECTED	COST ACTUAL	MAINT/ CAPITAL
NBPS	6	11/15/90		$6,700.00		MAINT
	7	11/15/90		$8,300.00		MAINT
LAPPS	6	11/30/90		$3,000.00		MAINT
LARPS	1	NONE REQUIRED				MAINT
	2	12/01/90		$500.00		MAINT
	3	11/30/90		$2,000.00		MAINT
LCHPS	3	11/15/90		$37,200.00		MAINT
	4	11/15/90		$7,700.00		MAINT
VICPS	6	12/01/90		$20,000.00		MAINT
JLBPS	1	12/14/90		$1,500.00		MAINT
	2	12/14/90		$1,500.00		MAINT
ESJPS	1	11/17/90		$70,000.00		MAINT
BMDPS	1	11/30/90		$1,500.00		MAINT
	2	11/30/90		$1,500.00		MAINT
COCPS	1	12/01/90		$28,200.00		MAINT
				$189,600.00		

FREEZE PROTECTION
PREVENTATIVE AND CORRECTIVE MEASURES

TABLE NO.3 DRUM ENCLOSURERS

POWER STATION	UNIT NO.	COMPLETION DATE PROJECTED	COMPLETION DATE ACTUAL	COST PROJECTED	COST ACTUAL	MAINT/ CAPITAL
NBPS	6	11/15/90		$3,500.00		MAINT
	7	11/30/90		$2,500.00		MAINT
LAPPS	6	11/01/90		$15,000.00		MAINT
LARPS	1	NONE REQUIRED				
	2	12/15/90		$3,500.00		MAINT
	3	12/15/90		$10,000.00		MAINT
LCHPS	3	11/01/90		$3,500.00		MAINT
	4	11/01/90		$15,000.00		MAINT
VICPS	6	11/15/90		$5,000.00		MAINT
JLBPS	1	12/10/90		$1,000.00		MAINT
	2	NONE REQUIRED				
ESJPS	1	11/01/90		$15,000.00		MAINT
BMDPS	1	11/01/90		$1,000.00		MAINT
	2	11/01/90		$1,000.00		MAINT
COCPS	1	11/15/90		$18,000.00		MAINT
				$94,000.00		

The Light company
Houston Lighting & Power

P.O. Box 1700 Houston, Texas 77251 (713) 228-9211

June 15, 1990

PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
JUN 15 1990
BY ______
ELECTRIC

Chester R. Oberg
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

Dear Mr. Oberg:

Your letter of May 10, 1990 requested that Houston Lighting & Power provide information regarding generating units which were lost or were otherwise unable to respond to the cold weather emergency which occurred throughout Texas in December of 1989.

Attachment A to this letter contains a response for each of the generating units which was adversely affected by the cold weather. General design temperature ranges are indicated for each unit. Plants built since the 1970's have included freeze protection design criteria which are indicated in Attachment A for Limestone and the South Texas Project. Although other plants do not have specific freeze protection design criteria established, freeze protection was provided in accordance with operating experience for Houston area plants. The following is offered to further supplement and clarify the information provided in Attachment A.

The Company is taking several administrative measures as a result of the experience gained during the 1989 cold weather emergency. The temperatures experienced were the coldest on record since the Company began building outside generating plants. The Company is re-evaluating its cold weather emergency procedures with regard to all of its plants to insure that they will operate at the weather extremes experienced in December of 1989. This response is consistent with the Company's commitment to the regular review of plans and procedures to insure that they remain current in light of experience. The Company is reviewing guidelines used by operators at the Company's generating plants when cold weather is imminent to insure that freeze protection measures are implemented. The guidelines are being revised to include improved freeze protection measures for equipment which experienced cold weather related problems during the 1989 cold weather emergency. Critical equipment lists are being reviewed and re-evaluated in light of the experience gained during the emergency. The Company is reviewing its cold weather emergency maintenance staffing levels and may increase crew size during such emergencies. Maintenance crews already provide twenty-four hour coverage during such emergencies. Maintenance crews monitor and activate freeze protection equipment and take necessary corrective action if and when problems arise.

The Company is taking corrective action with respect to equipment which failed and affected unit operation as a result of the 1989 cold weather emergency. Those actions are described in Attachment A. Each failure is being reviewed to determine the failure mode. If the failure resulted from an equipment malfunction, such as heat tracing circuit failure, maintenance is planned or has been undertaken to correct the situation. Most unit failures were of this type and resulted from frozen instrumentation sensing lines or transmitters. If the failure mode indicates the need for design modifications, an engineered modification is being developed. This engineering review has been extended to encompass similar units that did not experience failures during the 1989 cold weather emergency and engineering enhancements are being provided. Examples of modifications resulting from this review include drum-end enclosures to protect water-level sensing lines and moisture-removal devices for instrument air systems. Attachment B summarizes the modifications to generating units which did not experience failures in December 1989.

The Company is attempting to anticipate problems which it might experience in the event that even more extreme weather conditions occur and to take reasonable administrative and corrective actions to prepare for such conditions. The Company does not consider the administrative actions which it is implementing and the corrective steps which it is taking to necessarily be the ultimate answer to extreme cold weather conditions. The Company learns from each weather extreme how better to protect its generating equipment. The Company must emphasize, however, that it would not be prudent to plan for or implement steps which are beyond those needed given the historical weather patterns, including the occasional period of extreme cold weather, to which the Greater Houston area is subject. Generating plants in Amarillo, for example, are built with a level of freeze protection greater than would be reasonable or prudent in Houston.

The Company has surveyed the larger cogenerators in its service area including those under firm contract. The responses received are included in Attachment C.

The Company hopes that the information provided in this response is useful to the Commission in its review of procedures established by the electric utilities of the state to deal with cold weather emergencies. Should you have any questions regarding this response, please contact the undersigned at (713) 220 5387.

Sincerely,

John C. Houston

John C. Houston
Manager, Regulatory Activities

JCH/MGB/bg
3861
Encl.

ATTACHMENT A

Generating Plant Reports
December 21-24, 1989

<u>Index</u>

The generating unit reports are formatted to respond to the following questions:

1. Unit Name and Unit MW Capacity

2. Unit general design temperature limitations (Maximum and Minimum), in degrees F.

3. List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

7. For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

1. W A Parish Unit 5 : 670 MW

2. Design Temperature Range : 10°F - 105°F

3. a. High Secondary Air Duct Pressure Switch
   b. Seal Water to Vacuum Pumps

4. a. Failure Mode - False indication of high secondary air duct pressure.

      Cause of Failure -Condensation collected in low point of sensing line; condensate froze, causing false indication of high duct pressure.

      Contribution to overall failure of unit - High secondary air duct pressure indication that lasts 2 minutes results in a main fuel trip.

   b. Failure Mode - Low condenser vacuum.

      Cause of Failure - Seal water to vacuum pump froze, during outage caused by High Secondary Air Duct Pressure indication. Vacuum pumps require seal water to operate.

      Contribution to overall failure of unit - Low condenser vacuum results in automatic trip of unit.

5. a. Pressure sensing line will be re-sloped, heat traced and insulated.

   b. Low-point drains will be installed to drain seal water line when unit is off-line during freezing conditions. Temporary windbreaks and heaters will be used to protect seal water line during operation in freezing weather.

6. a. Corrective action will be completed by 7/31/90.

   b. Corrective action will be completed by 7/31/90.

7. a. $3668 - Maintenance

   b. $1250 - Maintenance

1. W A Parish Unit 8 : 570 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Superheat and Reheat Spray Regulator Instrument Lines

   b. Boiler Water Circulating Pump Differential Pressure Transmitter

4. a. <u>Failure Mode</u> - Superheat and reheat spray valves failed to close.

   <u>Cause of Failure</u> - Moisture in instrument air lines to Superheat and Reheat Spray regulators froze, resulting in loss of control of regulators.

   <u>Contribution to overall failure of unit</u> - There was no overall failure of unit. Load was reduced to 416 MW to control Superheat and Reheat temperatures. Condition was cleared within three hours.

   b. <u>Failure Mode</u> - False indication of low Boiler Water Circulating Pump pressure differential.

   <u>Cause of Failure</u> - Transmitter sensing lines froze due to failure of freeze protection equipment.

   <u>Contribution to overall failure of unit</u> - There was no overall failure of unit. Unit was derated to 420 MW. Condition was cleared within 35 minutes.

5. a. Instrument air system will be modified to allow collected moisture to be drained.

   b. Heat tracing and insulation will be updated on BWCP pressure transmitter sensing lines.

6. a. Corrective action will be completed by 8/31/90.

   b. Corrective action was completed on 5/14/90.

7. a. $50,000 - Capital

   b. $2500 - Maintenance

1. W A Parish Gas Turbine Unit 21 : 13 MW

2. Design Temperature Range : 10°F to 105°F

3. Starting motor battery

4. <u>Failure Mode</u> - Battery was not able to start cranking motor.

   <u>Cause of Failure</u> - Battery was weakened by exposure to low temperature.

   <u>Contribution to overall failure of unit</u> - Gas turbine cannot be started without use of cranking motor.

5. Space heaters will be used in the gas turbine enclosure to maintain temperature of starting motor batteries.

6. Corrective action completed - 5/29/90

7. Negligible cost

1. Limestone Unit 1 : 780 MW

2. Design Temperature Range : 10°F to 110°F
Freeze Protection : 5°F

3. Feedwater Flow Transmitter

4. Failure Mode - Loss of boiler feedwater flow

   Cause of Failure - Transmitter sensing lines froze, causing an incorrect control signal to slow boiler feed pumps to zero speed. This caused loss of feedwater flow.

   Contribution to overall failure of unit - Loss of feedwater flow resulted in a drop in drum water level. This ultimately caused a main fuel trip on boiler.

5. Heat Tracing and insulation on sensing lines will be upgraded.

6. Corrective action will be completed 9/15/90.

7. $300 - Maintenance

1. Limestone Unit 2 : 780 MW

2. Design Temperature Range : 10°F to 110°F
   Freeze Protection : 5°F

3. a. Boiler Drum Level Instrumentation
   b. Boiler Water Circulating Pump Differential Pressure Transmitter
   c. Superheat Spray Flow Transmitter
   d. Ignitor Gas Valve Actuator
   e. Circulating Water Pump Seal Water Piping

4. a. <u>Failure Mode</u> - Drum water level sensing lines froze, resulting in incorrect signal on drum water level.

   <u>Cause of Failure</u> - Heat tracing and/or insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - Drum level indication out of limits caused Main Fuel trip.

   b. <u>Failure Mode</u> - BWCP sensing lines froze, causing false indication of low pressure differential.

   <u>Cause of Failure</u> - Heat tracing and insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - False indication of low BWCP flow initiated a Main Fuel Trip.

   c. <u>Failure Mode</u> - Sensing lines to Superheat Spray Flow transmitter froze, causing indication of low spray flow.

   <u>Cause of Failure</u> - Heat tracing and insulation on sensing lines failed.

   <u>Contribution to overall failure of unit</u> - This did not contribute to unit failure.

   d. <u>Failure Mode</u> - Ice on valve prevented valve operation.

   <u>Cause of Failure</u> - Moisture collected from prior washdown, froze.

   <u>Contribution to overall failure of unit</u> - Caused delay in unit restart following unit trip for other reasons.

e. <u>Failure Mode</u> - Unprotected seal water piping froze and ruptured.

<u>Cause of Failure</u> - Isolation valves to circulating water pump leaked, making it impossible to drain the seal water piping while unit off line.

<u>Contribution to overall failure of unit</u> - This did not contribute to unit failure. Unit was off line for other reasons. Could have prevented unit restart.

5. a. Heat tracing and insulation on sensing lines will be upgraded. Also, Drum End Enclosures will be installed to protect from wind and rain.

   b. Heat tracing and insulation have been replaced.

   c. Heat tracing and insulation have been replaced.

   d. Ice was removed from valves. Administrative procedure was instituted to prevent recurrence.

   e. Seal water piping will be freeze protected.

6. a. Corrective action will be completed 9/15/90.
   b. Corrective action will be completed 9/15/90.
   c. Corrective action was completed 2/13/90.
   d. Corrective action was completed 1/2/90.
   e. Corrective action will be completed 9/15/90.

7. a. $50,400 - Maintenance
   b. $ 4,500 - Maintenance
   c. $ 500 - Maintenance
   d. $ 400 - Maintenance
   e. $ 1,500 - Maintenance

1. P H Robinson Unit 1 : 490 MW

2. Design Temperature Range : 10°F to 105°F

3. Boiler Feed Pump Suction Flow Transmitter

4. <u>Failure Mode</u> - Sensing lines to transmitter froze, causing a false signal of Low Feed Pump Flow.

   <u>Cause of Failure</u> - Heat tracing and insulation failed to protect sensing lines.

   <u>Contribution to overall failure of unit</u> - Unit tripped off line from 325 MW, due to automatic initiation of pump recirculation caused by false signal of low flow thru pump. Result was loss of feedwater flow to boiler and unit trip.

5. Heat tracing and insulation will be upgraded.

6. Corrective action to be completed 10/1/90.

7. $38,800 - Maintenance

1. Cedar Bayou Unit 1 : 740 MW

2. Design Temperature Range : 10°F to 105°F

3. Boiler Feedwater Flow Transmitter

4. <u>Failure Mode</u> - Loss of feedwater flow signal to feed pump control due to freezing of sensing line.

   <u>Cause of Failure</u> - Heat tracing and insulation failed to protect sensing line to transmitter.

   <u>Contribution to overall failure of unit</u> - Unit tripped on Low Feedwater Flow signal.

5. Heat tracing and insulation were upgraded.

6. Corrective action was completed 2/15/90.

7. $4800 - Maintenance

1. Cedar Bayou Unit 3 : 770 MW

2. Design Temperature Range : 10°F to 105°F

3. Fuel Oil Forwarding Pump Recirculation Valve

4. Failure Mode - Recirculation valve failed open on loss of instrument air pressure. This put fuel oil pump in recirculation, reducing fuel oil pressure at unit.

   Cause of Failure - Moisture in instrument air supply froze, reducing air pressure at valve.

   Contribution to overall failure of unit - Unit was derated 300 MW due to loss of fuel oil supply pressure, for a period of 19 minutes.

5. Install upsized instrument air dryer. Add moisture removal traps in instrument air system.

6. Corrective measures will be designed by 10/1/90. Completion date undetermined.

7. $90,000 - Capital

1. S R Bertron Unit 3 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Boiler Water Circulating Pump Differential Pressure Transmitter

   b. Frozen Gas Valves

   c. Low Condenser Vacuum

4. a. <u>Failure Mode</u> - False BWCP flow signal initiated a fuel trip.

   <u>Cause of Failure</u> - Correct BWCP flow signal lost because sensing lines to BWCP differential pressure transmitter froze.

   <u>Contribution to overall failure of unit</u> - Unit tripped on false signal of low BWCP flow.

   b. <u>Failure Mode</u> - Gas valve could not be operated, which caused fuel supply to be tripped.

   <u>Cause of Failure</u> - Lubricant in valve became very stiff at low temperature.

   <u>Contribution to overall failure of unit</u> - Unit tripped on loss of fuel supply.

   c. <u>Failure Mode</u> - Drip pump vent line to condenser froze and broke, causing loss of condenser vacuum.

   <u>Cause of Failure</u> - Vent line was not insulated.

   <u>Contribution to overall failure of unit</u> - Broken vent line caused unit to trip on loss of condenser vacuum.

5. a. Heat tracing and insulation on BWCP sensing lines will be upgraded.

   b. Gas valves will be lubricated when freezing conditions are imminent.

   c. Drip pump vent line and regulator were insulated.

(S R Bertron Unit 3 cont'd)

6. a. Corrective action will be completed by 10-01-90.
   b. N/A
   c. Corrective action was completed on 04-27-90.

7. a. $3,000 - Maintenance
   b. N/A
   c. $700 - Maintenance

1. S R Bertron Unit 4 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. Forced Draft Fan

4. Failure Mode - Ice formed in fan outlet ducts, fell and blocked fan rotation. Also broke damper.

   Cause of Failure - Water leaked into outlet ducts and formed large chunk of ice.

   Contribution to overall failure of unit - Unit tripped on loss of forced draft fans.

5. Maintenance action has been taken to prevent water intrusion into ducts.

6. Corrective action has been completed.

7. Negligible cost

1. Greens Bayou Unit 5 : 420 MW

2. Design Temperature Range : 10°F to 105°F

3. a. High-Pressure Turbine Pressure Switch

   b. Condensate Flow Control

4. a. <u>Failure Mode</u> - Frozen sensing lines caused false signal for throttle control valve position. This initiated turbine and fuel trips.

   <u>Cause of Failure</u> - Heat tracing and insulation failed to protect sensing lines.

   <u>Contribution to overall failure of unit</u> - Unit was tripped by turbine and burner controls upon signal that throttle valves were closed.

   b. <u>Failure Mode</u> - Instrument sensing lines froze, resulting in the loss of intelligence needed to open the polishing demineralizer bypass valve.

   <u>Cause of Failure</u> - Instrument lines were not insulated because the demineralizer is inside a building. The temperature inside the building dropped below freezing.

   <u>Contribution to overall failure of unit</u> - Unit tripped on low feedwater flow, resulting from reduced condensate flow.

5. a. Replace heat tracing and insulation on turbine pressure switch sensing lines.

   b. Replace heat tracing and insulation on condensate bypass valve. Temporary windbreak to be in use during freezing weather.

6. a. Corrective action scheduled for outage in Fall, 1990.

   b. Corrective action to be completed by 9/11/90.

7. a. $1050 - Maintenance

   b. $ 650 - Maintenance

1. Webster Gas Turbine : 13 MW

2. Design Temperature Range : 10°F to 105°F

3. Lubricating Oil Bypass Valve to Cooler

4. Failure Mode - Lubricating oil temperature was too low to start gas turbine.

   Cause of Failure - Moisture in instrument air piping froze, preventing air pressure sufficient to close bypass valve. Oil was bypassed to cooler, negating attempts to warm oil to proper temperature.

   Contribution to overall failure of unit - Gas turbine controls will not permit turbine to be started when lube oil temperature is out of range.

5. Add enclosure space heaters to maintain instrument air piping above freezing temperature.

6. Corrective action completed 2/15/90.

7. Negligible cost

1. T H Wharton Gas Turbine Unit 21 : 13 MW

2. Design Temperature Range : 10°F to 105°F

3. Lubricating Oil Cooler Fans

4. <u>Failure Mode</u> - Lubricating oil cooler fans would not start, due to false lube oil temperature signal.

   <u>Cause of Failure</u> - Moisture in instrument air line froze, blocking the signal from lube oil temperature transmitter.

   <u>Contribution to overall failure of unit</u> - Control system shut down the gas turbine because of high lube oil temperature.

5. Moisture trap will be installed in instrument air line.

6. Corrective action will be completed by 7/1/90.

7. $1000 - Maintenance

1. T H Wharton Unit 2 : 240 MW

2. Design Temperature Range : 10°F to 105°F

3. Loss of Cooling Air to Boiler Feed Pump Motor

4. <u>Failure Mode</u> - Boiler Feed Pump motor overheated and failed.

   <u>Cause of Failure</u> - Feed pump safety valve vent pipe leaked at a union, and water was blown onto motor. Ice formed, and obstructed cooling air intake on motor.

   <u>Contribution to overall failure of the unit</u> - When affected feed pump tripped, unit load was reduced 100 MW and unit operated on remaining boiler feed pumps.

5. Vent line was repaired.

6. Repair was completed 1/18/90.

7. $25,009 - Maintenance

1. T H Wharton Unit 3 : 285 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Drum Water Level Sensing Lines

   b. Feed Water Flow Transmitter

4. a. <u>Failure Mode</u> - One Heat Recovery Steam Generator was taken out of service by the control system, due to a false low drum level signal.

   <u>Cause of Failure</u> - Drum level sensing lines froze, due to failure of freeze protection measures.

   <u>Contribution to overall failure of unit</u> - The unit consists of 4 HRSGs, and 3 remained in operation. Unit was derated 23 MW.

   b. <u>Failure Mode</u> - Feedwater flow transmitter received a false low feedwater flow signal.

   <u>Cause of Failure</u> - Sensing lines to feedwater flow transmitter froze, which produced an errant signal to be generated by the transmitter. The control system tripped the boiler feed pump to protect the pump.

   <u>Contribution to overall failure of unit</u> - Loss of boiler feed pump caused the unit to be derated 85 MW.

5. a. Sensing lines heat tracing and insulation were upgraded. Wind breaks were added.

   b. Sensing lines heat tracing and insulation were upgraded.

6. a&b. Wind breaks were completed 2/15/90. Heat tracing and insulation on 2 HRSGs were upgraded by 5/2/90. Remaining heat tracing and insulation work will be completed during outage in Fall, 1990.

7. Wind Breaks - $6516 to install - Maintenance

   Heat Tracing and Insulation - $58,624 - Maintenance

1. T H Wharton Unit 4 : 285 MW

2. Design Temperature Range : 10°F to 105°F

3. a. Drum Water Level Sensing Lines

   b. Steam Flow Transmitter

4. a. <u>Failure Mode</u> - One Heat Recovery Steam Generator was taken out of service by the control system, due to a false low drum level signal.

   <u>Cause of Failure</u> - Drum level sensing lines froze, due to failure of freeze protection measures.

   <u>Contribution to overall failure of unit</u> - The unit consists of 4 HRSGs, and 3 remained in service. Unit was derated 23 MW.

   b. <u>Failure Mode</u> - False signal of low steam flow resulted in loss of drum water level.

   <u>Cause of Failure</u> - Sensing lines to steam flow transmitter froze, causing false low steam flow signal. Boiler feed pump flow was reduced by the control system.

   <u>Contribution to overall failure of unit</u> - Unit was tripped by the control system, on low drum level. Unit was derated 85 MW.

5. a. Sensing lines heat tracing and insulation were upgraded. Wind breaks were added.

   b. Sensing lines heat tracing and insulation were upgraded.

6. a&b. Wind Breaks were completed 2/15/90.
   Heat Tracing and Insulation were upgraded 5/2/90.

7. Wind Breaks - $6516 installed - Maintenance

   Heat Tracing and Insulation - $102,750 - Maintenance

1. T H Wharton Gas Turbine Unit 54 : 58 MW

2. Design Temperature Range : 10°F to 105°F

3. Loss of Fuel Oil Supply

4. Failure Mode - Fuel oil valve could not be operated.

   Cause of Failure - Ice formed in and immobilized fuel oil supply valve operator.

   Contribution to overall failure of unit - Gas turbine could not be operated without a fuel supply

5. The valve was replaced.

6. Valve was replaced 12/22/89.

7. Negligible cost

1. South Texas Project Unit 1 : 1250 MW

2. Operating Temperature Range : 3°F to 105°F *
Freeze Protection : 3°F

* This represents the maximum ambient conditions under which an engineering evaluation has determined the unit can operate. This evaluation, performed after the cold weather of December 1989, determined that the freeze protection and HVAC systems can operate at ambient temperatures lower than the nominal design minimums of 11°F for freeze protection and 29°F for HVAC systems.

3. a. Feedwater and Feedwater Booster Pumps
b. Makeup Demineralizer System
c. Deaerator Level and Pressure Instrumentation
d. Emergency Cooling Water System Screen Wash Booster Pumps

4. a. <u>Failure Mode</u> - Seal water lines to feedwater and feedwater booster pumps froze, interrupting seal water supply to pumps.

<u>Cause of Failure</u> - Seal water lines are uninsulated, by design.

<u>Contribution to overall failure of unit</u> - Pumps were unable to operate without seal water. Unit could not be started without pumps.

b. <u>Failure Mode</u> - Various level instruments, pumps and water lines froze, causing the demineralizer to be inoperable.

<u>Cause of Failure</u> - Equipment was uninsulated by design, or was de-insulated for maintenance.

<u>Contribution to overall failure of unit</u> - The lack of demineralized makeup water prevented continuation of unit start-up.

c. <u>Failure Mode</u> - Level and pressure sensing lines froze.

<u>Cause of Failure</u> - Sensing lines root valve stems and handles were not insulated.

<u>Contribution to overall failure of unit</u> - Level and pressure indication are required during unit start-up and operation. Unit could not be started.

(STP Unit 1 cont'd)

d. <u>Failure Mode</u> - Screen wash booster pumps froze.

<u>Cause of Failure</u> - Plant operating procedures required cooling fans to run bringing outside air into pump enclosure which caused the pumps to freeze.

<u>Contribution to overall failure of unit</u> - Station declared Emergency Cooling Water System inoperable when Screen Wash Booster Pumps were found frozen. Plant Technical Specifications require the unit to be shut down when ECW is inoperable.

5. a. Engineering review is in progress to determine corrective action.
   b. Engineering review is in progress to determine corrective action.
   c. Instrument root valve stems and handles have been insulated.
   d. Plant operating procedures were revised to allow ECW cooling fans not to operate automatically in cold weather.

6. a. Corrective action will be completed 10/31/90.
   b. Corrective action will be completed 10/31/90.
   c. Corrective action was completed 2/16/90.
   d. Corrective action was completed 6/15/90.

7. a. Cost to be determined
   b. Cost to be determined
   c. $15,000 - Maintenance
   d. $5000 - Maintenance

ATTACHMENT B

ATTACHMENT B

PLANT	CORRECTIVE ACTION	COMPLETION DATE FOR ENGRG OF CORRECTIVE ACTION	COST OF CORRECTIVE ACTION
LEGS 1	Steam Drum End Enclosures	06-30-90	$10,000 - Maintenance
LEGS 1&2	Electromatic Relief Valve Pressure Controller Relocation	04-17-90	$8,000 Maintenance
LEGS 1&2	Sootblower Pressure Reducing Valve Relocation	04-16-90	$31,400 Maintenance
LEGS 1&2	Bottom Ash Hopper Sluice Gate Pistons	10-31-90	Not Available
WAP 1,2&3	Steam Drum End Enclosures	09-30-90	$30,000 - Maintenance
WAP 5,6,7&8	Steam Drum End Enclosures	08-31-90	$40,000 - Maintenance
WAP 5	Turbine Instrument Line Enclosure	09-31-90	$30,000 - Maintenance
WAP 1,2&3	Turbine Instrument Line Heat Tracing & Insulation Upgrade	08-31-90	$33,000 - Maintenance
WAP 5,6&7	Instrument Air Line Moisture Drains	08-31-90	$57,000 - Capital
PHR 1&2	Instrument Air Line Moisture Drains	06-30-90	$38,000 - Capital
PHR 2	Throttle Pressure Sensing Lines	10-01-90	$38,800 - Maintenance
PHR 3&4	Instrument Air Line Moisture Drains	06-30-90	$38,000 - Capital
PHR 4	Boiler Feed Tank Level Transmitter	09-01-90	$1,100 - Maintenance
PHR 3&4	Aux Boilers Steam Drum End Enclosures	10-31-90	Not Available
SRB 1,2,3&4	Steam Drum End Enclosures	09-30-90	$40,000 - Capital
SRB 1,2,3&4	Turbine Instrument Line Heat Tracing & Insulation Upgrade	03-30-90	$44,000 - Maintenance

PLANT	CORRECTIVE ACTION	COMPLETION DATE FOR ENGRG OF CORRECTIVE ACTION	COST OF CORRECTIVE ACTION
SRB 1,2,3&4	Instrument Air Line Moisture Drains	09-30-90	$76,000 - Capital
CBY 1&2 3	Instrument Air Line Moisture Drains Caustic Line Windbreak Wall	09-30-90	$38,000 - Capital Maintenance
GBY 5	Steam Drum End Enclosure	06-30-90	$10,000 - Maintenance
GBY 5	BWCP LINE HEAT TRACING & Insulation Upgrade	07-31-90	$4,100 - Maintenance
GBY 5	Burner Deck Enclosures	10-31-90	Not Available
THW 2	Steam Drum End Enclosure	06-08-90	$10,000 - Maintenance
THW 2	BWCP Line Heat Tracing & Insulation Upgrade	06-30-90	$5,500 - Maintenance
THW 2	Turbine Instrument Line Heat Tracing & Insulation Upgrade	04-18-90	$11,000 - Maintenance
STP 1&2	Additional freeze protection for auxiliary cooling surge tank	10-21-90	Not Available
STP 2	Feedwater Booster Pumps	10-31-90	Not Available
STP 2	Insulate Root Valves	02-16-90	$15,000 - Maintenance
STP 2	ECW Screen Wash Booster Pumps	06-15-90	$5,000 - Maintenance

ATTACHMENT C

Cogenerator Responses

OxyChem®

Irv Kowenski
Manager-Energy

June 12, 1990

Ms. Patricia E. Look
Sr. Contract Administrator
Cogeneration Department
Houston Lighting & Power
P. O. Box 1700
Houston, Texas 77001

Re: PUC Questionnaire

Dear Ms. Look:

Per your request, attached is information you requested concerning the severe cold weather period in December 1989. If you need any more information, please feel free to contact me.

Sincerely,

I. Kowenski

I. Kowenski
Manager-Energy

/ih

attachment

Occidental Chemical Corporation
Corporate Office
Occidental Tower, 5005 LBJ Freeway
P.O. Box 809050, Dallas, TX 75380-9050
214/404-3446

TO: Irv Kowenski - Dallas

FROM: Dwight Howell - Battleground

DATE: June 11, 1990

SUBJECT: PUC Questionnaire

1) Unit Name - OxyChem Cogeneration - Battleground Plant
Unit MW Capacity - 200

2) The unit site design conditions for capacity considerations are 30° F to 95° F.

The unit design temperature limitations are -25° F with no maximum limitation. Note: The instrumentation enclosures and heat trace tubing bundles in the plant are rated for a minus 25° F at 3 watts/FT electrical trace and 100 watts per enclosure.

3) The No. 2 Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG) was removed from service on December 23, 1989 due to instrumentation problems caused by the severe weather conditions. The power loss was approximately 100 megawatts with the unit being restarted after approximately twelve (12) hours.

4) On the No. 2 HRSG, the HP steam drum, pressure and level instruments, the deaerator pressure and level instruments and the high pressure steam flow and boiler feedwater instruments either froze or were erratic due to partial freezing. The GT experienced no failed instruments but is used to produce steam from the HRSG and therefore was shut down in conjunction with the HRSG.

Instruments started to freeze at about +25° F. For this to occur, there are problems with the installation, condition, operation and insulation of the instruments. Some of the problems were identified as tripped electrical circuits supplying heat trace and enclosures that were not completely tight and sealed.

5) and 6)

Corrective actions to ensure the reliability and operations of the instruments essential for the cogeneration plant will include the following:

1. The annual instrument freeze survey should be completed no later than the middle of November. Each installation must be inspected thoroughly.
2. Critical instruments to be upgraded or have new enclosures and heat trace installed as a top priority include:
   a. High pressure steam flows FT525/FT725 - completed 03/90.
   b. Boiler feedwater flows FT522/FT722 - completed 03/90.
   c. High pressure steam pressure PT538/PT738 - completed 04/90.
   d. High pressure steam drum level LT520/LT720 - expected completion 10/90.
   e. Low pressure steam drum level LT550/LT750 - expected completion 10/90.
   f. Deaerator level LT1121/LT1123 - expected completion 10/90.
   g. Deaerator pressure PT1120 - expected completion 10/90.
3. A method to determine that heat trace bundles are working will be developed, rather than relying on having power at the connections and feeling the temperature of the trace where it enters the bundle.
4. Instrument enclosures must be tight and sealed. This means replacing sealing gaskets and closing/repairing any cracks or holes in any part of the enclosure. This should be done on the survey each year.
5. Use of the fiberglass wrapping tape with the white sealer over it will be discontinued on instrument installations. The protection provided by this material is inadequate.
6. All installations must be inspected thoroughly for any openings or cracks, and must be repaired. The manufacturer's specifications are only valid if the installation is secure from heat loss.
7. Process block valves on the orifice plates, or on pressure outlets, should have the metal jacketed standard insulation installed. This end of the tubing bundle must be inspected carefully each year and all cracks and openings closed.
8. Thermometers should be installed on all critical instrument enclosures. This would eliminate the need for opening the enclosure during cold weather. The thermometer would indicate whether the heat system was operating sufficiently.

9. A priority list for upgrade of less critical instruments will be developed.

All of the above items are expected to be completed by November 1, 1990.

7) Cost per installation and upgrade will be about $800.00 plus labor of $500.00. The total estimated cost is estimated to be approximately $15,000.00. These corrective action costs will be classified as a maintenance expense.

H. D. Howell

H. D. Howell

HDH:ja

cc: M. Gough
F. Carelli
D. Scholes

Clear Lake Cogeneration
Limited Partnership

9602 Bayport Road Pasadena, Texas 77507-1404 (713) 474-7611

June 8, 1990
CL-DWR-1367

Ms. Patricia Look
HOUSTON LIGHTING & POWER COMPANY
P.O. Box 1700
Houston, Texas 77001

Subject: Freeze Modifications, Clear Lake Cogeneration

Dear Ms. Look,

Clear Lake Cogeneration, which currently supplies nonfirm energy, to HL&P, has taken the following actions as a result of the December 1989 freeze.

1. GT104; 100 MW 501D5 Westinghouse Combustion Turbine

   GT104 tripped on a power supply failure to the Woodward Netcon 5000 governor. A computer grade uninterruptible power supply was installed with the existing UPS system becoming a backup power supply. This was completed in January 1990 at a cost of $15,000.

2. GT103; 100 MW 501D5 Westinghouse Combustion Turbine

   GT103 tripped and was removed from service when a lube oil supply pump failed. The pumps were a Buffalo Forge grease lubricated bearing design. All pumps have been modified to an oil lubricated bearing design. This was completed in March 1990 at a cost of $36,000.

3. ST101; 50 MW Westinghouse Steam Turbine
   ST102; 14 MW Westinghouse Steam Turbine

   Both units were forced out of service upon loss of boiler feedwater from steam host. They are currently making several modifications to prevent their water plant from freezing.

4. Instrumentation Systems

Several transmitters froze in the plant due to inadequate design and installation of the original freeze protection systems. Although no shutdowns occurred due to freezing instrumentation, a complete plant upgrade of the heat tracing and insulation is planned for completion in the fourth quarter of 1990 at an estimated expense of $300,000. Design criteria used for this upgrade was 5°F.

Should you require any further information feel free to contact me.

Sincerely,

CLEAR LAKE COGENERATION

DeWayne W. Roberts

DeWayne W. Roberts
Plant Manager

/dd

DESTEC
ENERGY

P. O. Box 19398
Houston, Texas 77224

DESTEC ENERGY, INC.
2500 CITYWEST BLVD. SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

June 11, 1990

Ms. Patricia E. Look
Senior Contract Administrator
Cogeneration Department
Houston Lighting & Power
P. O. Box 1700
Houston, Tx 77001

Dear Ms. Look:

The attached sheet is our response to the questions requested by the Public Utility Commission Staff. Please inform us if additional information is needed.

Sincerely,

Jerry C. Dearing

Jerry C. Dearing
Asset Management

JCD:wb

cc: D. K. Mott
W. P. Ruwe

PUBLIC UTILITY COMMISSION OF TEXAS

The following is CoGen Lyondell's response to the PUC questions concerning operating reliability during the December 1989 cold weather emergency.

1. The steam turbine generator 001 was the only unit lost during the period. The unit is rated at 135MW.

2. The unit does not have design ambient temperature limitations.

3. There were several instrumentation failures (i.e. level transmitters) but they did not adversely affect the generating capacity of the plant.

4. The steam turbine generator 001 tripped due to a failed vacuum pump. The cause of the vacuum pump failure was a frozen water seal line. The pump failed causing a loss of a condenser vacuum which tripped the steam turbine generator.

5. A thermal barrier was added near the vacuum pump and heaters will be used in the area.

6. This preventive measure has been completed at minimal cost.

DESTEC ENERGY

DESTEC ENERGY, INC.
2500 CITYWEST BLVD. SUITE 1700
P.O. BOX 4411
HOUSTON, TEXAS 77210-4411
(713) 974-8200

June 8, 1990

Patricia E. Look
Cogeneration Department
Houston Lighting & Power
Box 1700
Houston, Texas 77001

Dear Pat:

Please find attached our response to the questionnaire you forwarded to us in your letter of May 22, 1990, regarding the cold weather experience in December, 1989. Let me know if we can be any any further assistance.

Sincerely,

John J. Stauffacher

Attachment

RESPONSE TO HL&P COLD WEATHER QUESTIONS

1. UNIT NAME AND UNIT MW CAPACITY.

   ANSWER: Dow Chemical Freeport - Contract MWs - 325

2. UNIT GENERAL DESIGN TEMPERATURE LIMITATIONS (MAXIMUM AND MINIMUM), IN DEGREES F.

   ANSWER: All units are designed to operate between 0 and 120 degrees F provided freeze protection on controls and instrumentation is adequate.

3. LIST OF EQUIPMENT(S) (OR PLANT SYSTEMS) THAT WERE ADVERSELY AFFECTED BY THE COLD WEATHER.

   ANSWER: Boiler steam drum level controls
   Deaerator level controls
   Steam pressure controls
   Instrument air lines
   River water lines
   Potable water system
   Fire protection system
   Division condensate inventories

4. FOR EACH PIECE OF EQUIPMENT OR SYSTEM THAT FAILED, IDENTIFY THE FAILURE MODE, THE CAUSE OF THE FAILURE, AND HOW THE EQUIPMENT OR SYSTEM LOSS CONTRIBUTED TO THE OVERALL FAILURE OF THE UNIT.

   ANSWER: Drum level and steam pressure controls were adversely affected in most cases due to inability of the existing heat tracing systems to fully protect from the extreme temperatures and associated high winds experienced during the freeze. Inability to control drum levels caused brief run-back of one unit and a short-term trip of one boiler. Neither had significant effect on production capabilities.

   Problems with the various water systems were generally caused by freeze damaged valves and lines at various locations.

   Two units tripped when pre-filter pads plugged with snow at the inlet. Once down, associated condensate and cooling water lines froze and the unit could not be restarted until the freeze damage was repaired.

Some level and pressure controls experienced freezing problems when the heating capability of the existing heat tracing systems was exceeded due to the sub-freezing temperatures and high winds. These level and pressure control systems incorporate redundant transmitters and indications; therefore, when a primary control indication was lost a back-up was placed in service or the system was operated manually for a brief period while the primary was repaired. In one isolated case during the early stages of the freeze, the loss of a deaerator level control system caused one high pressure boiler feed pump to trip which resulted in a run-back of one unit. However, the level control was restored and the unit returned to full capacity within approximately 20 minutes.

5. FOR EACH PIECE OF EQUIPMENT OR SYSTEM, IDENTIFY THE NECESSARY CORRECTIVE ACTIONS(S) TO PREVENT RECURRENCE. PLEASE PROVIDE SUFFICIENT DETAIL TO DESCRIBE THE FULL RANGE OF ACTIVITIES NECESSARY TO REASONABLY PRECLUDE FUTURE FAILURE.

ANSWER: The following actions have been taken to prevent failure caused by a freeze of similar magnitude:

- Insulation and heat tracing systems were improved.

- Operating and freeze preparation procedures were modified.

- Temporary freeze protection equipment was purchased and inventoried and incorporated into procedures.

- Improvements were made in many of the existing transmitter locations.

6. FOR EACH PIECE OF EQUIPMENT OR SYSTEM IDENTIFIED ABOVE, REPORT THE ACTUAL OR ANTICIPATED DATE OF CORRECTIVE ACTION COMPLETION.

ANSWER: Implosion dampers on two units - these machines have no dampers to open to provide inlet air to the turbine in the event of plugged inlet filters. A project has been defined to install dampers on these two machines. Projected completion date is second quarter, 1991.

BAYOU COGENERATION PLANT

11777 Bay Area Blvd. / Pasadena, Texas 77507
(713) 474-8220 / Fax: (713) 474-8226

Richard H. Kidder
General Manager

June 1, 1990

Houston Lighting & Power Company
Patricia Look
Sr. Contract Administrator
Cogeneration Department
P. O. Box 1700
Houston, TX 77001

cc: WD Lindberg
BR Milam
RE McGinnis
CP Burckle

SUBJECT: PUC Request Dated May 10, 1990

Dear Ms. Look:

The Bayou Cogeneration Plant maintained 114.5% of our contract power during the 72 hour freeze from 12/22/89 through 12/24/89. We did however have problems with our plant when the temperature fell below 14 degrees Fahrenheit. I have attached the following documentation that will answer the questions asked by the PUC:

1. Net Plant Output vs Ambient Temperature
2. Bayou Cogeneration Plant Performance Characteristics
3. Sequence of Events on Problems
4. Generator Breaker Open and Closed Log
5. Corrective Action, Completion Dates and Estimated Costs

If you need additional information, please contact me.

Regards,

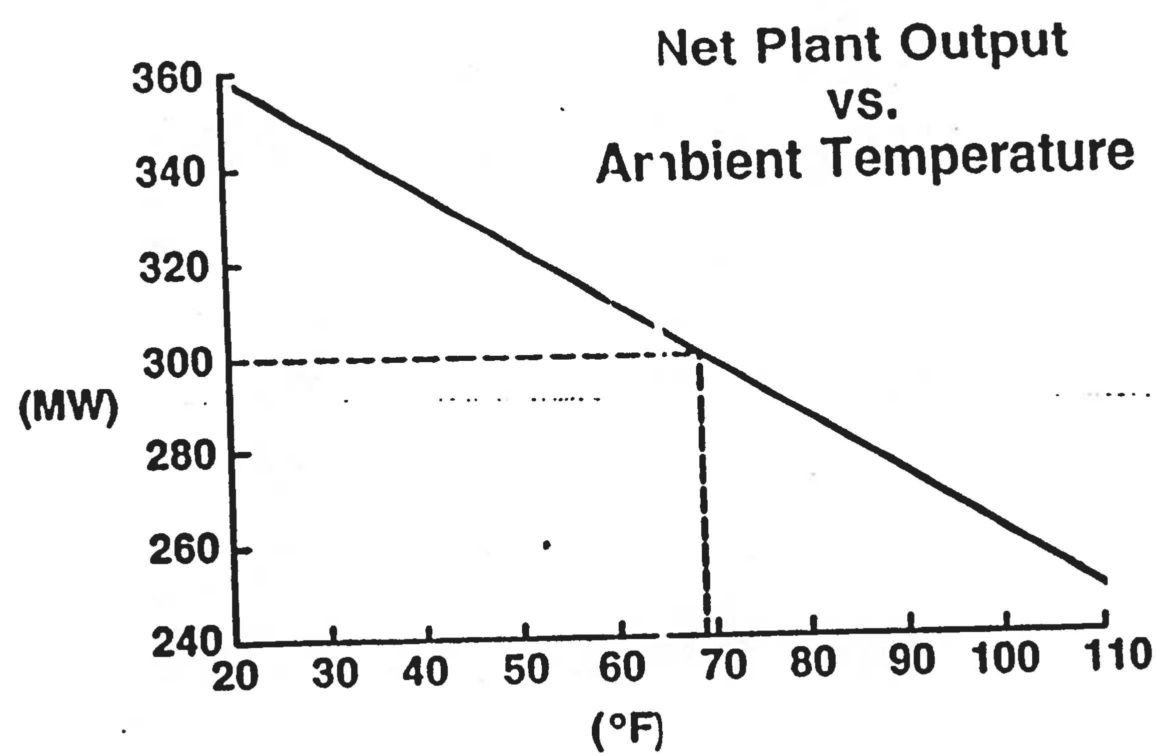
RH Kidder

Richard H. Kidder
General Manager

Attachment

kt/5~~06~~ 6

Attachment #1



Sensitivity to Inlet Temperature is Characteristic of Gas Turbine Cycles

Attachment #2

Bayou Cogeneration Plant Performance Characteristics

(4) MS7001 E Gas Turbine/Heat Recovery Steam Generator Trains

Net Power @ 69°F	300.[illegible] MW
Steam to Process	1,38[illegible],000 lb/hr
Heat Consumption (HHV)	3726 × 10^6 Btu/hr Natural Gas
Overall Energy Efficiency (HHV)	70%
Steam Injection for NO_x Control	< 4[illegible] ppmv NO_2 @ 15% 0_2 Dry Basis

PURPA Efficiency	54%
– Thermal Fraction	61%

Attachment #3

SUBJECT: Big Freeze of "89"

The following sequence of events summarizes the Bayou Cogeneration Plant's problems during the freeze from December 22, 1990 through December 24, 1990:

The temperatures at the plant were below freezing for approximately 48 hours with the lowest temperature being 8 degrees F early on the 23rd. Starting about 8:30 a.m. on December 22nd, we started losing all flow and pressure transmitters due to freezing sensing legs. This caused operators to control the plant manually with local; visually drum level readings radioed from the outside operators. All NOX steam transmitters and control valves froze and we were unable to restore NOX steam for the duration of the freeze. At 11:13 p.m. plant feedwater supplied by Big 3 was lost due to pressure instrumentation freezing. This caused trips on units #1, #2, and #3. Units were restarted and loaded as fast as possible after feedwater was restored. Units #1 and #2 each tripped later that night due to false level indication caused by freezing and were immediately restarted.

At 10:50 a.m. on December 34th, unit #1 was shutdown with a leaking cooling water skid. One side of the skid was isolated and the unit restarted after 1.75 hours.

The Bayou Cogeneration Plant normally has a 3 man operating crew. During the over 48 hours of the freeze we utilized our full complement of 20 people to run the plant.

Attachment #4

DATE	UNIT	REASON	BREAKER OPEN	BREAKER CLOSED	
12/22	2	BTI loss of feedwater	2213	0433	12/23
12/22	3	BTI loss of feedwater	2314	0137	12/23
12/22	1	BTI loss of feedwater	2316	2349	12/22
12/23	1	Instrument freeze on level indication	0655	0723	12/23
12/23	1	Instrument freeze on level indication	1016	1046	12/23
12/24	1	Cooling water skid	1050	1235	12/24

Attachment #5

SUBJECT: Corrective Action Taken to Remedy Freeze Problems

The cause of our freeze problems were isolated to our instrument lines from our boilers. These lines were heat traced but could not withstand temperatures below 15 degrees Fahrenheit. The corrective action is as follows:

1. Replace heat tracing and reinsulate 1500 feet of instrument lines to 20 degrees below zero.
2. Heat trace approximately 16 instrument cabinets throughout the plant.
3. This corrective action will be completed by September 1, 1990.
4. The cost of this project will be approximately 100,000 dollars and will be categorized as maintenance expense.

AES
Deepwater
Inc.

June 11, 1990

Houston Lighting & Power
P. O. Box 1700
Houston, TX 77001

Attn: Ms. Patricia Look
Sr. Contract Administrator
Co-Generation Department

Subject: Public Utility Commission Questionnaire - Freeze Protection

Dear Ms. Look:

In response to your request dated May 22, 1990, we would like to provide the following information:

(1) Unit Name and Unit MW Capacity

AES Deepwater, Inc.
160 MW - Gross

(2) Design Temperature Limitations

Maximum - 120°F
Minimum - 0°F

(3) List of Equipment affected by cold weather:

Flow and Level Transmitters - Plant Wide

The AES Deepwater Cogeneration facility was off line a total of 13.86 hours during the freeze period (Dec. 22 thru Dec. 27) with actual unit outages occurring Dec. 22 (9.05 Hrs) and Dec. 23 (4.81 hrs). The unit operated at 49.5% capacity (reduced load) from Dec. 24 thru Dec. 27 with no outages. The facility returned to full load on Dec. 28.

Specific equipment affected is as follows:

- Throttle Pressure Transmitter
- Mass Blow Down Valve
- Drum Level Transmitter
- Fan Bearing Housings - Water Cooled

(4) Equipment Failure

A. Equipment - Throttle Pressure Transmitter
Failure Mode - Erratic Readings
Cause - Freeze
Contribution to Plant - Unit Trip

COGENERATION

P.O. Box 6111
Pasadena, Texas 77506
(713) 472-8687
Telecopier:
(713) 472-0389

B. Equipment - Mass Blow Down Valve
Failure Mode - Stuck
Cause - Freeze
Contribution to Plant - Unit Trip

C. Equipment - Drum Level Transmitter
Failure Mode - Intermittent Operation
Cause - Freezing
Contribution to Plant - Reduced Load

D. Equipment - Water Cooled Fan Bearings
Failure Mode - Cracked
Cause - Freeze
Contribution to Plant - Reduced Load

5. Corrective Action

A. Throttle Pressure Transmitter -
Insulate and Heat Trace

B. Mass Blow Down Valve -
Insulate and Heat Trace
Possible Additional Dryer on Actuating Air

C. Drum Level Transmitter -
Re-insulate, Additional Heat Tracing,
Glycol in Dead Leg

D. Fan Bearings -
Install Water Flow and Temperature Monitors
Change Cold Weather Operating and Inspection Procedures

6. The anticipated completion date for all corrections is November 30, 1990.

7. Cost of Corrective Action (Estimated)

A.	Throttle Pressure Transmitter	$750.00
B.	Mass Blow Down Valve	$1,000.00
C.	Drum Level Transmitter	$750.00
D.	Fan Bearings	$3,000.00

We trust this information will comply with your request.

Sincerely,

J. R. Johnson

J. R. Johnson
Manager, Support Services

Lower Colorado River Authority
Post Office Box 220 Austin, Texas 78767 • (512) 473-3200

June 15, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

RE: Project No. 9542

Dear Mr. Oberg:

Enclosed please find LCRA's response to your request for information regarding LCRA unit outages during the December 1989, cold weather period.

If you need any further assistance, please contact Jim Briley at 385-7131.

Sincerely,

Walter J. Reid
Executive Director of
Electric Operations

WJR:JB:bcm

Attachment

LCRA RESPONSE - PROJECT 9542

There were two LCRA unit outages during the December 1989, cold weather period attributable to weather-related equipment problems. The requested information for these outages is listed below:

OUTAGE #1
December 22, 1989

1) Unit Name and Unit MW Capacity

   Sim Gideon Unit #2; Capacity 140 MW Gross

2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

   No temperature design limitations were available; the unit was placed in commercial service in April, 1967.

3) List of equipment(s) or (plant systems) that were adversely affected by the cold weather.

   Deaerator Level transmitters.

4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

   Water in sensing lines to the deaerator level transmitters froze causing a loss of level indication. The unit operator then tripped the unit according to established procedures.

5) For each piece of equipment of system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

   At the time of the trip, the sensing lines were wrapped with asbestos-based insulation material. Additional foil-backed blanket duct insulation was added. These lines will be stripped and re-wrapped with new materials at a future time when the asbestos can be dealt with safely.

6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

   This work was done on February 8, 1990.

7) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

This work incurred a maintenance expense of $300.

OUTAGE #2
December 23, 1989

1) Unit Name and Unit MW Capacity

Sam K. Seymour Unit #3; Capacity 440 MW Gross

2) Unit general design temperature limitations (Maximum and minimum), in degrees F.

General design temperature limitations (taken from Unit Design Specification CP 300(2.3.3), Section E. Temperatures are dry bulb, degrees Fahrenheit.

	Temperature
Extreme Maximum	110
Temp. exceeded 1% of the time	101
Mean Daily Maximum	80
Mean	69
Mean Daily Minimum	58
Temp. exceeded 99% of the time	25
Extreme Minimum	1

3) List of equipment(s) (or plant systems) that were adversely affected by the cold weather.

A & B Drum Level transmitters

4) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

Water in the A & B Drum Level transmitter sensing lines froze, causing the unit to trip automatically due to loss of level indication.

5) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

The sensing lines were re-insulated, leveled and installed in hangers to prevent excess water accumulation.

6) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.

This work was completed on May 30, 1990.

7) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense.

This work incurred a maintenance expense of $420.

TMPA

Serving the cities of Bryan, Denton, Garland & Greenville

PUBLIC UTILITY COMMISSION OF TEXAS
RECEIVED
JUN 12 1990
BY ______
ELECTRIC

June 8, 1990

Letter No. SP-90-0074
File Code: 513.75

Chester R. Oberg
Public Utility Commission of Texas
7800 Shoel Creek Blvd., Suite 400N
Austin, Texas 78757-0100

Subject: Winterizing Corrective Actions

Dear Mr. Oberg:

Enclosed is the information you requested concerning winterizing corrective actions.

If additional information or data is required, please advise.

Sincerely,

Gailord M. White
Manager of System
Planning & Operations

GMW/it

cc: Document Control

Texas Municipal Power Agency P.O. Box 7000 Bryan, Texas 77805 (409) 873-2013

TEXAS MUNICIPAL POWER AGENCY

1. Gibbons Creek Steam Electric Station Unit #1 - 440 MW

2. Unit Design Temperature Limitation - 15^{o}F minimum

   107^{o}F maximum

3. Actual Equipment Failures:
   A) Boiler Drum Level Transmitter (see attached sheet for details)
   B) (BWCP) Boiler Water Circulation Pump Differential Pressure Transmitter (see attached sheet for details)

4. Potential Equipment Failures:
   A) (D.A.) Deareator Storage Tank Level Transmitter (see attached sheet for details)
   B) Reheat Spray Trip Valve And Control Valves (see attached sheet for details)

Actual Equipment Failure: Boiler Drum Level Transmitter

The boiler drum level transmitters are located in a weather enclosed building adjacent to the steam drum. Normally this enclosure has adequate heating supplied by the steam drum. At near $0^{o}F$ this protection became insufficient. The freezing of these transmitters tripped the boiler on erroneous low drum level indication.

We are in the process of redesigning the steam drum enclosure to provide greater access to the transmitters. We will reinsulate the transmitters, their associated taps and instrument lines.

We will be installing a floor that will reduce/eliminate cold air in leakage.

The operating procedures and the Winter preparedness checklist have been changed to include provisions for an additional heat source to be used whenever the outside ambient air temperature reaches $32^{o}F$.

Estimated completion date for redesigning and construction of the drum enclosure is October 1, 1990.

Total Improvement Costs $20,000.00

Actual Equipment Failure: Boiler Water Circulation Pump Differential Pressure Transmitter

The boiler waterwall circulation pump differential pressure transmitters are housed in an all weather building with an electric heater inside for freeze protection. Due to the freezing weather conditions near 0°F, the protection was insufficient. The transmitters froze creating a false indication of a low waterwall circulation which in turn tripped the boiler.

The heater was returned to service and an additional kerosene heater was placed inside the enclosure.

Operation procedures have since been modified to increase the awareness of all Operations personnel on the possible failure of electrical equipment associated with freeze protection. The Winter preparedness checklist has been changed to include the inspection of all heaters and breakers to insure their reliability.

Total cost $0.00

Potential Equipment Failure: Deareator Storage Tank Level Transmitter

The Deareator Storage Tank Level transmitter did not contribute (NC) to any unit trips or unit failure but the potential was there if corrective measures had not been taken.

The Deareator Storage Tank Level transmitter is presently enclosed in a insulated housing and is heat traced. The Deareator Storage Tank Level and its transmitter are located on the north side of the boiler structure about 150 feet above the ground. Additional heat tracing and insulation were added several years ago and generally can handle a typical winter cold spell, but the winter of 1989 was not typical. A portable heater was placed near the housing to provide additional protection.

Our long term plan is to enclose the whole Deareator Storage Tank Level area but this is a costly venture. Our short term improvements will be to install a permanent windbreak along the north wall and lay down a solid plate floor (replacing the grating) to protect the area from the bitter windchills.

Total Cost $2,500 (short term corrective action)

Potential Equipment Failure: Reheat Spray Trip Valve And Control Valves

The superheat and reheat spray trip valves and control valves did not contribute to any unit failures, however, the potential was there for at least a major load reduction due to the failure of the valves. After the unit had tripped on Boiler Water Circulation Pump differential pressure, the valves closed as they are supposed to do. Before the unit was able to return to 20% load, the trip valves froze in the closed position. This limited our capability to spray for high steam temperatures. We erected a temporary wind break and placed a kerosene heater alongside the valve to thaw it out. Plans call for a permanent wind break to be installed before October 1, 1990.

Total Cost $3,000.00

TU ELECTRIC

Dwight Royall
Director
Regulatory Services

June 18, 1990

Mr. Chester R. Oberg
Nuclear Projects
Public Utility Commission of Texas
7800 Shoal Creek Boulevard
Suite 400N
Austin, Texas 78757

RECEIVED
JUN 18 1990
PUBLIC UTILITY COMMISSION
GENERAL COUNSEL BY

Dear Mr. Oberg:

Pursuant to your letter dated May 10, 1990, attached is TU Electric's response to your questionnaire concerning the performance of our generating units during the cold weather emergency in December 1989.

Nine (9) TU Electric generating units were identified that had weather related failures and were unable to respond to the emergency conditions. These units were able to return to service soon after the units tripped. Please refer to the January 10, 1990 cold weather filing for the generating unit sequence of events. For clarity, three additional generating unit failures are described although the failures were not weather related. In addition to the above, reports from cogeneration facilities that experienced weather related difficulties are attached.

The effects of the December 1989 freeze were minimized due to the efforts of TU Electric's Freeze Protection Task Force commissioned in 1982 as a result of severe weather during the winter of 1981. The task force identified several areas of concern and developed recommendations to alleviate the causes for unit trips related to cold weather. During the period of time from Fall 1982 through Spring 1984, approximately five million dollars were expended to enhance the reliability of TU Electric generating units during freezing conditions.

Each Fall, a special effort is made to inspect the freeze protection on each TU Electric generating unit for adequacy in the event of freezing weather. Plant personnel evaluate the heat tracing circuits, wind breaks, fuel oil related equipment and the weather sensitive instrumentation. Operations personnel conduct testing and training on fuel oil burning prior to the winter peak period. As the extreme cold weather approaches, additional units are brought on-line for reserve as needed and when natural gas curtailments are imminent, units are transferred to oil burning.

If you have any questions, please let me know.

Yours very truly,

Dwight Regall

ld
Attachment

1.) Unit Name and Unit MW Capacity:

River Crest Unit 1; 110 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Condenser plugging due to shad runs.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The condenser became plugged.

Cause of the Failure - The condenser became plugged due to an exhorbitant number of shad which entered the intake area, plugged the intake screens and carried over into the waterboxes of the condenser.

Contribution to Unit Failure - Excessive back pressure on the low pressure turbine caused a turbine trip.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The shad were removed from the waterboxes of the condenser. A portable net was installed in front of the intake screens. An improved net will be available for installation during cold weather periods.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completion - August, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $900.

1.) Unit Name and Unit MW Capacity:

Valley Unit 2; 550 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing pressure to Valve No. 263.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - Transmitter sensed low feedwater flow.

Cause of the Failure - The freeze protection circuit failed.

Contribution to Unit Failure - The transmitter, sensing low feedwater flow, closed Valve No. 263. The unit tripped on low feedwater flow.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The freeze protection circuit has been repaired by plant personnel.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $300.

1.) Unit Name and Unit MW Capacity:

Morgan Creek Combustion Turbine No 4; 65 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: 115 degrees F.
Minimum limit: - 5 degrees F.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Natural Gas Fuel Supply.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - Minimal natural gas supply pressure.

<u>Cause of the Failure</u> - Minimum natural gas supply pressure necessitated a fuel supply transfer to fuel oil which created a temperature mismatch in the combustion zone.

<u>Contribution to Unit Failure</u> - This temperature mismatch caused a runback to off-line for the combustion turbine.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

By design, the combustion turbines must operate within temperature mismatch limits in the combustion zone. If a loss of natural gas pressure can be anticipated, a manual fuel transfer at lower loads is preferable to an automatic fuel transfer at full load.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completion - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Mountain Creek Unit 7; 125 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - An increase in fuel/air flow resulting in high furnace pressure.

<u>Cause of the Failure</u> - While operating at high load, the unit responded to a frequency deviation.

<u>Contribution to Unit Failure</u> - The increase in fuel/air flow led to a high furnace pressure trip. A subsequent trip occurred upon restarting the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

A runback has been incorporated into the control system that will drop fuel/air flow a few percent upon a high furnace pressure condition.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Mountain Creek Unit 2; 33 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Circulating water screens.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A heavy shad run clogged the revolving and stationary intake screens.

Cause of the Failure - The clogged intake screens caused the circulating water pumps to loose suction.

Contribution to Unit Failure - The unit tripped on low vacuum.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The screens were immediately cleaned and the unit restarted. A new screen wash pump was installed to better wash the revolving screens when in use.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $13,000.

1.) Unit Name and Unit MW Capacity:

Monticello Unit 2; 575 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing waterwall pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The sensing line to the waterwall pressure transmitter froze.

Cause of the Failure - A pipe hangar, located near the sensing line, propagated low temperatures to the line.

Contribution to Unit Failure - The transmitter sent a high waterwall pressure signal to the control system, which tripped the unit to protect it.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The plant personnel have installed insulating material at these hanger locations to prevent the hangers from propagating low temperatures to the sensing line.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - December, 1989.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,000.

1.) Unit Name and Unit MW Capacity:

Tradinghouse Unit 1; 565 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing boiler convection pass outlet header pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The sensing line at the pressure tap root valve froze.

Cause of the Failure - The transmitter enclosure heater was operating, but the heat tracing was found grounded.

Contribution to Unit Failure - The transmitter sent the control system a signal that the boiler convection pass outlet header pressure was high, which tripped the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The freeze protection circuit has been repaired and the root valve reinsulated.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $500.

1.) Unit Name and Unit MW Capacity:

Stryker Creek Unit 1; 175 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - The combustion controls swung which caused low burner gas header pressure.

Cause of the Failure - While the unit was firing a combination of natural gas and fuel oil, a control upset caused the combustion controls to swing.

Contribution to Unit Failure - The low burner gas header pressure caused a low pressure trip.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The low gas block setting has been increased.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Monticello Unit 3; 750 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing primary superheater outlet pressure.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - A sensing line to the primary superheater outlet transmitter froze.

<u>Cause of the Failure</u> - Freeze protection, heat tracing wiring on the sensing line failed.

<u>Contribution to Unit Failure</u> - The transmitter sent a false indication to the control system that the unit was operating below supercritical pressure, which trip the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The plant personnel replaced the failed freeze protection, heat tracing wiring on the sensing line.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,700.

1.) Unit Name and Unit MW Capacity:

Martin Lake Unit 2; 750 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Transmitter sensing low differential pressure on the boiler water circulation pump.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

Failure Mode - A sensing line to the low boiler water circulation pump differential pressure transmitter froze.

Cause of the Failure - Additional freeze protection was needed.

Contribution to Unit Failure - The transmitter sent a false indication to the control system for boiler circulation pump differential pressure, which tripped the unit.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

Additional freeze protection has been added to this circuit. Plant personnel have added valves and drip legs in the sensing lines. During a freeze alert, the Instrument and Control technicians will drip these lines to allow water to flow to help prevent freezing. This will be monitored hourly during the freezing conditions.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

Maintenance Expense - $2,000.

1.) Unit Name and Unit MW Capacity:

Eagle Mountain Unit 3; 375 MW.

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Condenser plugging caused by shad and fish.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - A heavy shad and fish run plugged one condenser while the other was being cleaned.

<u>Cause of the Failure</u> - The reduced circulating water flow through the condenser caused excessive back pressure.

<u>Contribution to Unit Failure</u> - Excessive back pressure on the low pressure turbine caused a low vacuum trip.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

Operations will closely monitor waterbox pressure and vacuum to minimize excessive plugging during shad and fish run. The use of a portable net during extreme cold weather conditions will be considered to avoid condenser plugging due to shed runs.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

1.) Unit Name and Unit MW Capacity:

Handley Unit 5; 425 MW

2.) Unit general design temperature limitations (maximum and minimum), in degrees F:

Maximum limit: Designed to meet highest regional temperatures with only minor derations.
Minimum limit: -10 degrees F and 35 MPH wind velocity.

3.) List of equipment(s) (or plant systems) that were adversely affected by the cold weather:

Not cold weather related.

4.) For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

<u>Failure Mode</u> - An air flow transmitter feedback signal error was being investigated by plant personnel.

<u>Cause of the Failure</u> - The transmitter along with the air flow trip switch were inadvertently valved out.

<u>Contribution to Unit Failure</u> - When the trip switch was valved out the unit tripped.

5.) For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure:

The transmitter has been clearly marked to differentiate the trip switch from the flow transmitters.

6.) For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

Completed - January, 1990.

7.) For each piece of equipment or system identified above, report the cost of the corrective action, and whether the costs will be capitalized as a necessary plant modification or if the corrective action costs will be categorized as a maintenance expense:

No significant expense.

Texasgulf Cogeneration Facility
Newgulf (Wharton County) Texas
June 4, 1990
77 MW Capacity - 100F
96 MW Capacity - 20F
Design temperature range - 20F to 100F

Numerous control devices and systems were adversely affected by the extreme cold weather but only one failed and contributed to reduction in output. It is believed that the facility would have remained at maximum capacity and all other systems would have remained operative if the raw water supply had not been interrupted.

Raw Water Supply - Raw water which provides feedwater to Heat Recovery Unit, make-up to Cooling Tower, and process water to mining operation is gravity fed from a 265 acre reservoir through two 30" underground lines. Intake screens on each line prevent fish and debris from entering plant. At time of December freeze, reservoir level was about 5 feet lower than normal (dry weather), and the intake screens were dirty. Freezing temperatures caused slush and ice to be swept into screens interrupting flow of incoming water. It was necessary to take steam turbine off line and cease mine water production in order to conserve the small amount of water available and keep feedwater to the HRU.

Corrective action

1. Clean screens. - Completed
2. Maintain water level in reservoir higher. - Pump installed behind reservoir to capture water which leaks out of reservoir. - Completed
3. Provide tempering water at intakes to thaw slush. - Pipe run from abandoned water well (74F water). - Completed

Intake water flow was reestablished after about three hours, but steam turbine could not be returned to service until ambient temperatures rose above freezing.

Additional systems or equipment adversely affected but not contributing in the December 1989 freeze are listed below:

Raw Water

* In-line strainers became plugged with ice, fish, silt, etc. after intake screens were lifted. 12" valves and lines froze while cleaning the three strainers. - Wind barrier and homemade space heater to be installed - 12/01/90.
* Gas turbine lube oil cooling water heat exchanger, E1-A or B, which is out of service will be cracked into service to prevent freezing. - Operating procedure
* Insulation and heat tracing on all flow and pressure transmitters to be inspected and repaired. Critical transmitters are PI-25002, LIT-25101. - 12/01/90
* Wind barrier to be erected near Pumps, P2, where cold air tunnels through opening. - 12/01/90

June 4, 1990

Treated Feedwater

* No significant problems on main line, but bleeders to be tagged on backwash line, brine dilution line, and drain. - Operating procedure - 12/01/90
* Low Pressure HRU drum level has three control devices, LIT-40302 & LI-40305 on the south side and LIT-40303 on north side. All are critical transmitters, but operator selects which transmitter is in control. Problems occurred with LIT-40303 on north side; control tubing insulation and heat tracing to be inspected. Additional blanket & heat tracing installed in O'Brien enclosure to prevent freezing, but will cause boiling if activated when ambient temperature is above 25F and/or wind is idle. Completed
* Medium Pressure HRU drum level has three control devices, LIT-41302 & LI-41305 on the south side and LIT-41303 on north side. Ditto low pressure drum. Completed
* 3-Sided enclosure to be erected around boiler chemical feed tank and pumps, D-11, P-114 A&B. - Completed

Steam System

* Critical transmitters to have tubing lines insulation and heat tracing inspected - 12/01/90
  - PIT-40304 LP Drum pressure
  - PIT-403 LP Drum pressure
  - PIT-40405 135 psig header
  - PIT-30303 Boiler 4 Master pressure
  - PIT-30304 Boiler 4 Master pressure
* 3-Sided enclosure to be erected around neutralizing amine tank and pumps, T-111, P-111 A&B. - 12/01/90

Condensate

* Deaerator level control, LIT-27123, insulation and heat tracing to be inspected - 12/01/90
* Feedwater transfer pump, P-271 A or B, which is out of service to have valves cracked permitting flow of water - Operating procedure

Cooling Tower

* Make-up water level transmitter, LIC-57002, to have insulation and heat trace inspected, plus enclosure to keep spray and resultant ice off. 12/01/90
* By-pass around flow control valve, LCV-57002, to be cracked. - Operating Procedure
* Chlorinator injection water to be placed on manual with continuous flow. - Operating procedure
* Blowdown to be placed on manual with by-pass cracked. - Operating procedure
* 3-Sided enclosure to be erected around Inhibitor feed tank & pumps, T-114, P-114 A&B. 12/01/90

Items marked with 12/01/90 completion dates will be completed as part of normal winterization. When temperatures are expected to fall below 20F, special operating procedures will be enacted.

Dow Chemical

6/8/90

RESPONSE TO TUEC COLD WEATHER QUESTIONS

1. UNIT NAME AND UNIT MW CAPACITY.

   ANSWER: Dow Chemical Freeport - Contract MWs - 300

2. UNIT GENERAL DESIGN TEMPERATURE LIMITATIONS (MAXIMUM AND MINIMUM), IN DEGREES F.

   ANSWER: All units are designed to operate between 0 and 120 degrees F provided freeze protection on controls and instrumentation is adequate.

3. LIST OF EQUIPMENT(S) (OR PLANT SYSTEMS) THAT WERE ADVERSELY AFFECTED BY THE COLD WEATHER.

   ANSWER: Boiler steam drum level controls
   Deaerator level controls
   Steam pressure controls
   Instrument air lines
   River water lines
   Potable water system
   Fire protection system
   Division condensate inventories

4. FOR EACH PIECE OF EQUIPMENT OR SYSTEM THAT FAILED, IDENTIFY THE FAILURE MODE, THE CAUSE OF THE FAILURE, AND HOW THE EQUIPMENT OR SYSTEM LOSS CONTRIBUTED TO THE OVERALL FAILURE OF THE UNIT.

   ANSWER: Drum level and steam pressure controls were adversely affected in most cases due to inability of the existing heat tracing systems to fully protect from the extreme temperatures and associated high winds experienced during the freeze. Inability to control drum levels caused brief run-back of one unit and a short-term trip of one boiler. Neither had significant effect on production capabilities.

   Problems with the various water systems were generally caused by freeze damaged valves and lines at various locations.

   Two units tripped when pre-filter pads plugged with snow at the inlet. Once down, associated condensate and cooling water lines froze and the unit could not be restarted until the freeze damage was repaired.

Some level and pressure controls experienced freezing problems when the heating capability of the existing heat tracing systems was exceeded due to the sub-freezing temperatures and high winds. These level and pressure control systems incorporate redundant transmitters and indications; therefore, when a primary control indication was lost a back-up was placed in service or the system was operated manually for a brief period while the primary was repaired. In one isolated case during the early stages of the freeze, the loss of a deaerator level control system caused one high pressure boiler feed pump to trip which resulted in a run-back of one unit. However, the level control was restored and the unit returned to full capacity within approximately 20 minutes.

5. FOR EACH PIECE OF EQUIPMENT OR SYSTEM, IDENTIFY THE NECESSARY CORRECTIVE ACTIONS(S) TO PREVENT RECURRENCE. PLEASE PROVIDE SUFFICIENT DETAIL TO DESCRIBE THE FULL RANGE OF ACTIVITIES NECESSARY TO REASONABLY PRECLUDE FUTURE FAILURE.

ANSWER: The following actions have been taken to prevent failure caused by a freeze of similar magnitude:

- Insulation and heat tracing systems were improved.

- Operating and freeze preparation procedures were modified.

- Temporary freeze protection equipment was purchased and inventoried and incorporated into procedures.

- Improvements were made in many of the existing transmitter locations.

6. FOR EACH PIECE OF EQUIPMENT OR SYSTEM IDENTIFIED ABOVE, REPORT THE ACTUAL OR ANTICIPATED DATE OF CORRECTIVE ACTION COMPLETION.

ANSWER: Implosion dampers on two units - these machines have no dampers to open to provide inlet air to the turbine in the event of plugged inlet filters. A project has been defined to install dampers on these two machines. Projected completion date is second quarter, 1991.

ATTACHMENT #1

COGEN LYONDELL

Unit Name	Unit Capacity (mw)	Temperature Limitations (F)	Failure mode	Equipment Affected	Cause of failure	Affect on overall system	Preventive measures
GTG101	75	N/A	N/A	N/A	N/A	N/A	N/A
GTG201	75	N/A	N/A	N/A	N/A	N/A	N/A
GTG301	75	N/A	N/A	N/A	N/A	N/A	N/A
GTG401	75	N/A	N/A	N/A	N/A	N/A	N/A
GTG501	75	N/A	N/A	N/A	N/A	N/A	N/A
STG001	135.	N/A	TRIP	VACUUM PUMP	WATER SEAL FROZE	LOSS OF CONDENSOR VACUUM (TRIP CONDITION)	ADDITION OF THERMAL BARRIER IN THE FORM OF HEATERS (COMPLETE)
HRSG	101	N/A	N/A	N/A	N/A	N/A	N/A
HRSG	201	N/A	N/A	N/A	N/A	N/A	N/A
HRSG	301	N/A	N/A	N/A	N/A	N/A	N/A
HRSG	401	N/A	N/A	N/A	N/A	N/A	N/A
HRSG	501	N/A	N/A	N/A	N/A	N/A	N/A

· Design Temperatures = 0°F min.
= 100°F max.

WICHITA FALLS ENERGY CO., LTD.
(A Limited Partnership)

Wichita Falls Energy Investments, Inc.
(Managing General Partner)

614 Ridglea Bank Building
Fort Worth, Texas 76116

817-731-7271 (Ft. Worth)
817-696-3270 (Wichita Falls)

P.O. Box 9349
Fort Worth, Texas 76147

Telecopy 817-732-8984 (Ft. Worth)
Telecopy 817-692-9018 (Wichita Falls)

June 5, 1990

TU Electric
Skyway Tower
400 N. Olive Street, L.B. 81
Dallas, Texas 75201

Attn: Mr. Kevin Delcarson
Cogeneration Department

Gentlemen:

In response to inquiry dated May 22, 1990 with respect to our plant's performance during the cold weather experienced in December, 1989, the following information is submitted in the same numbered order as set forth in the May 22 request.

1. Unit name and unit MW capacity:

   Wichita Falls Energy Co., Ltd. cogeneration facility; 74 megawatts.

2. Unit general design temperature limitations (maximum and minimum), in degrees F.:

   General design parameters were 0° Farenheit minimum and 120° Farenheit maximum. Added heat tracing has been implemented over and above design specs.

3. List of equipment (or plant systems) that were adversely affected by the cold weather [Dates specified]:

   12/21/89 - (1) HRSG B level transmitter froze at 0520 hours.
   (2) House service water tank level transmitter froze at 1938 hours.
   (3) HRSG B superheater outlet pressure transmitter froze at 1955 hours.

   12/22/89 - (1) HRSG superheater outlet pressure transmitter froze at 0522 hours.

RECEIVED
JUN 0. 1990
COGENERATION

(2) Unit requested to curtail gas consumption by transportation company (Lone Star Gas) at 1004 hours; honoring this request resulted in reduced output.

12/23/89 - (1) Unit had to operate at reduced load from 1030 hours to 1247 hours due to high system frequency (60.00 to 60.14 Hz).

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit:

12/21/89 - (1) HRSG B level transmitter froze. No shutdown or reduction in output occurred. Operator took manual control of HRSG until transmitter was thawed out and additional insulation added.

(2) House service water tank level transmitter froze. No shutdown or reduction in output occurred. Operator manually controlled tank level until transmitter was thawed out and additional insulation added.

(3) HRSG B superheater outlet pressure transmitter froze. Failure of the pressure transmitter caused the HRSG damper to close resulting in a 2 megawatt drop in hourly averages. Efforts to thaw the transmitter failed and unit was subsequently disconnected so HRSG could be placed back in service before further freeze-ups occurred.

12/22/89 - (1) HRSG C superheater outlet pressure transmitter froze. Failure of the pressure transmitter caused the HRSG damper to close resulting in a 4 megawatt drop in hourly averages. Efforts to thaw the transmitter failed and unit was subsequently disconnected so HRSG could be placed back in service before further freeze-ups occurred.

(2) Unit requested to curtail gas consumption by transportation company (Lone Star Gas); honoring this request resulted in reduced output. At 1020 hours, the standby LPG system was activated, but the blending air compressors tripped on high discharge air temperature. Upon testing, it was

determined that the lubricant used in the blending air compressors was not adequate for existing ambient conditions (-5°F to -7°F). Compressors were reset and restarted without using the lube oil cooler fans until the lubricant warmed up and the units stabilized. LPG was then introduced and utilized until curtailment was lifted at 1430 hours, whereupon the unit went back on natural gas (100%).

12/23/89 - (1) Unit operated at reduced load from 1030 hours to 1247 hours due to high system frequency (60.00 to 60.14 Hz). Unit is designed to reduce output when the frequency rises above the 60.00 Hz range.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence:

12/21/89 - (1) Although the HRSG B level transmitter was adequately heat traced, the insulation was not sufficient to withstand the conditions (-35°F windchill factor) at the time it froze. Additional insulation, as well as the installation of weatherproof/windproof enclosures, required.

(2) Although the house service water tank level transmitter was heat traced and insulated, it was not adequate enough to withstand the conditions at the time. Additional heat trace and insulation required.

(3) Although the HRSG B superheater outlet pressure transmitter was adequately heat traced, the insulation around the transmitter was not sufficient to withstand the conditions at the time it froze. Insulation needed to be upgraded along with installation of weatherproof/windproof enclosures.

12/22/89 - (1) Although the HRSG C superheater outlet pressure transmitter was adequately heat traced, the insulation around the transmitter was not sufficient to withstand the conditions at the time it froze.

Insulation needed to be upgraded along with installation of weatherproof/windproof enclosures.

(2) The unit's gas supplier (Coastal) has a firm delivery transportation agreement with the transporter (Lone Star Gas). Prior to the cold weather period in December, the supplier was delivering quantities of natural gas to the transporter less than the unit's contract requirements in order to balance a previous oversupply scenario. Overlooking or mistaking this balancing agreement, the transporter's dispatcher contacted the unit's operator on duty requesting a consumption cut-back to the level or quantities the supplier was then furnishing the transporter. The unit's operator felt that he had no choice but to comply with this request, mistaken as it was. When this curtailment request was brought to the immediate attention of the supplier, supplier contacted transporter and the matter was resolved. With respect to LPG blending air compressor lubricant, the existing lubricant needed to be replaced with a lubricant which would allow operation of the compressors at ambient temperatures below -10°F.

12/23/89 - (1) No action required with respect to the design parameters of the unit wherein outputs reduce when frequency increases over 60.00 Hz.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion:

12/21/89 - (1) Additional insulation and weatherproof/windproof enclosures completed in April, 1990.
(2) Additional heat trace and insulation was completed in April, 1990.
(3) Insulation upgraded and weatherproof/windproof enclosures completed in April, 1990.

12/22/89 - (1) Insulation upgraded and weatherproof/windproof enclosures completed in April, 1990.

(2) Operators were instructed in January, 1990 not to comply with a curtailment request from the transporter except in cases of pipeline emergency on the transporter's system, but to refer any future weather-related curtailment request, if one should occur, directly to the supplier for appropriate action. Furthermore, cogeneration facility's personnel will routinely contact the supplier in the late fall of each year (beginning in 1990) to remind supplier that natural gas supply requirements must be met to contract limits throughout cold weather months to avoid a repeat of the December '89 mixup. With respect to the LPG blending air compressor lubricant, the lubricant was changed to a Mobil brand synthetic in January, 1990 rated to cope with the ambient conditions experienced in December, 1989.

12/23/89 - (1) No action was required.

Very truly yours,

WICHITA FALLS ENERGY INVESTMENTS, INC.

Gerald N. Craig
President

GNC:sz

PRI POWER RESOURCES, INC.

June 4, 1990

Mr. Kevin Delcarson
T.U. Electric
400 N. Olive
Suite 3118
Dallas, TX 75201

Dear Kevin:

The following comments are in reply to your correspondence of May 22nd, 1990, "Severe Cold Weather Operation":

1. Unit name and unit MW capacity.
   1. "Power Resources, Inc. " 200 MW

2. Unit general design temperature limitations (maximum & minimum), in degrees F.
   2. Summer Design Dry Bulb Temperature = 100°F.
      Winter Design Dry Bulb Temperature = 16°F.

3. List of equipment(s) (or plant systems) that were adversely affected by the cold weather.
   3. * Gas Turbine liquid fuel system (not directly due to cold weather)
      * Boiler instrumentation

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.
   4. Gas Turbine liquid fuel system - Purge air check valves mechanically failed allowing liquid fuel to bypass the burner. This caused starving of some of the burners which resulted in a high exhaust temperature spread. The unit was able to operate at a reduced output. The failure mode of the check valve, in our opinion, is caused by continuous vibration due to being hard piped to the gas turbine. This causes the "poppett" and seat to wear prematurely.

P. O. Box 2700, Big Spring, Texas 79721 / Tel: (915)263-8468 / Fax: (915)267-9772

Boiler Instrumentation - One level transmitter on each high pressure boiler drum was out of service due to the freezing. We are however, equipped with redundant level indicators and this caused no production problems. A few other instruments were out of service due to freezing but these did not affect production or plant safety and are therefore considered unimportant. Instrumentation freezups are caused by inadequate heat tracing and insulation of the process side instrument tubing and inadequate protection of the transmitter section of the instrument loop.

5. For each piece of equipment or system, identify the necessary corrective action(s) to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.
   5. Gas Turbine liquid fuel system -
      a. Isolation of each of 10 purge air check valves from the vibration caused by the gas turbine. We have accomplished this by installing "flexhose" between the check valve and turbine.
      b. Frequent wintertime testing of the liquid fuel system to be as confident as possible that all systems function properly.

   Boiler Instrumentation
      a. Provide heated instrument boxes for all critical instrument transmitters. We have budgeted to install 18 of these on the critical instruments before winter operation this year.
      b. Confirm proper operation of heat trace circuits before predicted cold weather.
      c. After maintenance activities, which involved tearing away of insulation and/or heat tracing, repair such immediately.
      d. Provide protection from the elements by using tarps or temporary buildings. This year we will enclose the ends of our boiler drums with buildings designed to be put up in the winter and removed during the summer. This will protect the ends of the drums where most of the critical boiler instrumentation is located.

6. For each piece of equipment or system identified above, report the actual or anticipated date of corrective action completion.
   6. * Liquid fuel system modifications completed 5/15/90.
      * Instrumentation protection-completion of all projects by 11/15/90.

KHamby

Ken Hamby

KH:sc

Lone Star Energy
Company

P.O. Box 548
Sweetwater, Texas 79556
915-235-4921

JAMES E. PACK
MANAGER

June 4, 1990

REF. DOC. NO.: 380

Kevin Delcarson
TU Electric
Skyway Tower
400 N. Olive St., L. B. 81
Dallas, TX 75201

RE: Severe Cold Weather Operation

Dear Mr. Delcarson:

This letter is in response to your letter dated May 22, 1990, which requested information on plant operations during severe cold weather experienced in December, 1989. Following are the specific requests, each accompanied by our response.

1. Unit name and unit MW capacity.

   Unit Name: Encogen One
   Unit Capacity: Nominal 255 MW
   Unit Location: Sweetwater, Texas

2. Unit general design temperature limitations (maximum and minimum), in degrees F.

   Maximum Design Temperature: Plant will operate at all summer ambient temperatures. Successful operation is expected at ambient temperatures somewhat above 115 degrees F.

   Minimum Design Temperature: Plant will operate at winter ambient temperatures of -10 degrees F and lower.

3. List of equipment or systems that were adversely affected by the cold weather.

   a. Steam turbine-generator / 87 MW
   b. Air cooled steam condenser

4. For each piece of equipment or system that failed, identify the failure mode, the cause of the failure, and how the equipment or system loss contributed to the overall failure of the unit.

   a. Steam turbine-generator tripped due to freezing of turbine exhaust backpressure transmitters.

   b. Air cooled steam condenser experienced freeze problems due to extremely low steam loads. The steam turbine was not available due to previous freezing of exhaust pressure transmitters, and bypass steam loading did not provide sufficient load to keep the condenser free from ice.

5. For each piece of equipment or system, identify the necessary corrective actions to prevent recurrence. Please provide sufficient detail to describe the full range of activities necessary to reasonably preclude future failure.

   a. Steam turbine-generator:

      1. Heat tracing of backpressure transmitters and piping.

      2. Installation of additional variable speed controls to allow variable speed control of 12 fans instead of 6.

      3. Installation of additional steam jet ejector capacity to keep the condenser coils free from non-condensables.

6. For each piece of equipment or system identified above, report the actual or anticipated date corrective action completion.

   a. Steam turbine-generator:

      1. Heat tracing of backpressure transmitters and piping is complete.

b. Air cooled steam condenser/steam turbine-generator:

1. Heat tracing of condensate hotwell and drain piping for each condenser tube bundle is complete.

2. Installation of additional variable speed controls to allow variable speed control of 12 fans instead of 6 will be completed prior to winter operation, 1990.

3. Installation of additional steam jet ejector capacity to keep the condenser coils free from non-condensables will be completed prior to winter operation, 1990.

Should you have any further questions, please do not hesitate to contact me.

Sincerely,

James Pack

James Pack
Plant Manager

JP/kdp

cc: D. Martin
N. Perry

Cogenron Inc.

3221 5th Avenue South Texas City, Texas 77590 (409) 945-7324

June 12, 1990
JJK-065-90

Mr. Kevin Delcarson
TU Electric
400 North Olive Street
Dallas, TX 75201

RE: Response to PUC requested freeze information.

Dear Kevin:

Question 1:

Enron Cogeneration One Company
3221 5th Avenue South
Texas City, TX 77590

MW Capacity: 400 MW

Question 2:

-Minimum Design Temperature: 8°F
-Maximum Design Temperature: 101°F

Question 3,4,5,6:

Deaerator instrumentation:

Deaerator instrumentation froze on all units until more insulation was added at which time the electric heat trace thawed the lines and they stayed in service. The 'B' unit deaerator level was lost for a short period of time and during this the safety valve lifted and would not reseat. This necessitated a unit shutdown to replace with the spare safety valve. Plant output was reduced by one hundred twenty megawatts.

To prevent this from happening again the wattage for the deaerator electric heat tracing was doubled and the insulation was increased. In addition, an internal electronic level indicator was added for additional reliability for level control. All projects are 95% complete and will be complete by the end of September.

Demineralization Plant:

The demineralization plant had frozen lines since it is not enclosed in a building. This reduced the amount of water that could be produced and the quality of the water suffered since regenerations were difficult. The result of this was that plant output had to be reduced because steam injection to the gas turbines was reduced.

It was not until a week after the freeze had occurred that we experienced tube problems with our boiler that were a result of the water quality produced during the freeze. Sections of high pressure boiler tubing needed replacing on the two boilers that ran thru the freeze.

By the end of July, bids for adding a heated enclosure around the demineralization plant will be received and by the end of August a decision will be made on the enclosure. This should eliminate the majority of problems associated with the freeze that this facility incurred.

Regards,

James J. Keegan
Plant Manager

JJK/cw

TENASKA III TEXAS PARTNERS

General Office:
407 North 117 Street
Omaha, NE 68154
Telephone: (402) 691-9500
Telecopy: (402) 691-9526

Plant Office:
301 Lake Crook Road
Paris, TX 75460
Telephone: (214) 785-2992
Telecopy: (214) 785-1360

June 08, 1990

Mr. Kevin Delcarson
Cogeneration Department
TU ELECTRIC
Skyway Tower
400 N. Olive St., L.B. 81
Dallas, TX 75201

RE: Severe Cold Weather Operation (Letter Dated 05/22/90)

Question: Unit name and MW capacity.

Answer: TENASKA III (Nominal Capacity)
2 ea Gas Turbines @ 80 MW ea - 160 MW
1 ea Steam Turbine @ 90 MW ea - 90 MW
Plant Rating - 223,200 KW Total

Question: Unit general design temperature limitations

Answer: Minimum - 0°F
Maximum - 98°F dry bulb

Question: List of equipment or plant systems that were adversely affected by the cold weather.

Answer:
a. Heat Recovery Steam Generator #1
b. Heat Recovery Steam Generator #2
c. Plant Instrumentation
d. Assorted Water Lines

Question: For each piece of equipment or system that failed, identify failure mode, the cause of failure, and how the equipment or system loss contributed to the overall failure of the unit.

Answer: During the severe cold weather time frame December 21, 22, 23, 24 the TENASKA III Site was in the process of converting from a simple cycle (gas turbines only) operation to a combined cycle operation (gas turbines and steam turbine). In preparation for combined cycle commissioning, certain construction measures were taken that prevented running simple cycle and combined cycle equipment was still being debugged. Therefore, the entire plant was not available for service.

During the shutdown, it was discovered that an economized header on HRSG #1 was not drained due to a plugged drain valve. Several other boiler drain valves were also discovered plugged.

Heat tracing for a lot of the plant instruments was also incomplete.

Since the severe cold weather, the plant has been commissioned for combined cycle operation. All plant heat tracing has been completed and insulated houses were built around each plant transmitter.

Question: For each piece of equipment or system, identify the necessary corrective action(s) to prevent the recurrence.

Answer: If Plant is operating, follow the Freeze Protection Checklist.

If Plant is not operating then make sure that the Heat Recovery Steam Generator is drained and also follow the Freeze Protection Sheet if applicable.

Question: For each piece of equipment or system identified above, report actual or anticipated date of corrective action completion.

Answer: The Plant was restarted on Dec. 28, 1989 as a combined cycle plant. The plant heat tracing and new transmitter boxes were completed by March 1990.

All freeze damage on the Heat Recovery Steam Generators was completed by December 28, 1989.

If I may be of further assistance, please do not hesitate to call.

Sincerely,

Mike

Mike Hart, P.E.
Plant Manager

MH/se

cc: Tony Fontana
Duke Cockfield
Leo Finnegan
File

ATTACHMENT NO. 4

COGENERATOR RESPONSES

ATTACHMENT NO. 4

COGENERATOR RESPONSES

The following is a listing of cogeneration units that experienced problems during the December 1989 freeze. The cogenerator reports were submitted through HL&P and TU Electric.

Occidental Chemical Corporation,

Battleground Plant, 200 MW Capacity
No. 2 Gas Turbine/Heat Recovery Steam Generator(HRSG)

Corrective actions to frozen instruments included instrument upgrading, installing heat tracing and enclosures, and instituting an annual instrument freeze survey.

Maintenance Costs: $ 15,000

Clear Lake Cogeneration

GT 104; 100 MW Westinghouse Combustion Turbine

Power supply failed. Installed upgraded power supply with backup capability.

Maintenance Costs: $ 15,000

GT 103 100 MW Westinghouse Combustion Turbine

Lub oil supply pump failed. Replaced bearings with oil lubricated design.

Maintenance Costs: $ 36,000

ST 101; 50 MW Westinghouse Steam Turbine
ST 102; 14 MW Westinghouse Steam Turbine

Both units force out of service upon loss of boiler feedwater.

Maintenance Costs: (not provided)

Several instrument transmitters froze in the plant due to inadequate design and installation of the original freeze protection systems. An upgrading is planned for fourth quarter, 1990.

Maintenance Costs: $ 300,000

Attachment No. 4 Cogenerator Responses

Destec Energy, Inc.

CoGen Lyondell
Steam Turbine Generator 001, 135 MW

Unit tripped due to loss of condenser vacuum pump, frozen seal water line. Thermal barrier added near vacuum pump.

Maintenance Costs: (minimal)

Dow Chemical

Dow Chemical Freeport, 325 MW

Unit tripped when pre-filter pads plugged with snow at inlet. Once down associated water lines froze and could not be restarted until freeze damage was repaired. Existing heat tracing systems were unable to fully protect instruments. Corrective actions include installation of implosion dampers to bypass plugged inlet filters (second quarter 1991), and improved insulation and heat tracing systems.

Maintenance Costs: (not provided)

Bayou Cogeneration Plant

Four MS7001 E Gas Turbine/Heat Recovery
Steam Generator Trains 300.5 MW

Heat tracing systems were inadequate to prevent instrumentation lines from freezing. Corrective measures include replacement of heat tracing and insulation (1500 feet of lines and 16 instrument cabinets).

Maintenance Costs: $ 100,000

AES Deepwater Cogeneration

AES Deepwater Cogeneration Facility; 160 MW

Freezing weather caused the failure of the Throttle Pressure Transmitter, Mass Blow Down Valve, Drum Level Transmitter, and Water Cooled Fan Bearing Housings. Corrective actions include insulation and heat tracing and water temperature and flow monitors, and changes to operating procedures.

Maintenance Costs: $ 5,500

Attachment No. 4 Cogenerator Responses

Texasgulf Cogeneration Facility

Newgulf (Warton County) Texas
Gas Turbine and Steam Turbine with Heat Recovery Unit, 77 MW

Clogged and frozen intake screens interrupted the supply of raw water (feedwater) to heat recovery unit. Corrective actions include replacement or repair of heat tracing systems and insulation on raw water system and instrumentation. (No costs reported)

Wichita Falls Energy Investments, Inc.

Wichita Falls Energy Co., Ltd. Cogeneration Facility
74 MW Capacity

Primary problems with instrumentation freezing due to lack or inadequate heat tracing and insulation protection. Had limited gas curtailment problems. (No corrective action costs provided)

Power Resources, Inc.

Power Resources, Inc. (PRI)
Gas Turbine, 200 MW

Problems encountered with the GT liquid fuel system and boiler instrumentation. Instrumentation problems caused by inadequate heat tracing and insulation. (No corrective action costs provided.)

Lone Star Energy Company

Encogen One, 255 MW
Steam Turbine generator 87 MW

Weather caused freezing of instrumentation and controls for the steam turbine and air cooled steam condenser. Corrective actions included heat tracing, additional insulation, and additional steam jet ejector capacity. (No corrective action costs provided.)

Attachment No. 4 Cogenerator Responses

Cogenron, Inc.

Enron Cogeneration One Company
400 MW Capacity

Freezing problems occurred in the deaerator instrumentation and demineralizer plant water lines. Corrective actions included adding a heated enclosure around the demineralizing plant and additional heat tracing and insulation on instrumentation lines. (No corrective action costs were provided.)

Tenaska III Texas Partners

Tenaska III
Two gas turbines, 160 MW; One steam turbine 90 MW; Total Capacity of plant: 250 MW (Combined Cycle Plant)

Freezing problems were encountered with steam generator heat recovery systems, plant instrumentation and water lines. The plant was in the process of being "debugged" and heat tracing system was not complete. The plant has been completed and the heat tracing and insulation has been completed. (No corrective action costs were provided.)

ATTACHMENT NO. 3

INDIVIDUAL UTILITY RESPONSES

Utility Responses:

- Brazos Electric Power Cooperative, Inc.
- Central Power and Light Company
- Houston Lighting and Power Company
- Lower Colorado River Authority
- Texas Municipal Power Agency
- Texas Utilities Electric Company

ATTACHMENT NO. 5

PLANT DESIGN TEMPERATURES

ATTACHMENT NO. 5

PLANT DESIGN TEMPERATURES

Central Power and Light Company

Unit Name	Design Temperature Ranges (Degrees F)
Barney Davis 1 Barney Davis 2	All units designed to operate at 10 degrees F, with wind velocity of 30 MPH.
Caleto Creek 1 E. S. Joslin 1	
J. L. Bates 1 J. L. Bates 2	
La Palma 6	
Laredo 1 Laredo 2 Laredo 3	
Lon C Hill 3 Lon C Hill 4	
Nueces Bay 6 Nueces Bay 7	
Victoria 6	

Attachment No. 5 Plant Design Temperatures

Houston Light & Power Company

Unit Name	Design Temperature Range (Degrees F.)
Cedar Bayou 1	10 - 105
Cedar Bayou 2	
Cedar Bayou 3	
Greens Bayou 5	10 - 105
Limestone 1	10 - 110
Limestone 2	(Freeze Protection to 5)
P H Robinson 1	10 - 105
P H Robinson 2	
P H Robinson 3	
P H Robinson 4	
S R Bertron 1	10 - 105
S R Bertron 2	
S R Bertron 3	
S R Bertron 4	
South Texas 1	3 - 105*
South Texas 2	
T H Wharton 2	10 - 105
T H Wharton 3	
T H Wharton 4	
T H Wharton GT21	10 - 105
T H Wharton GT54	
W A Parish 1	10 - 105
W A Parish 2	
W A Parish 3	
W A Parish 5	
W A Parish 6	
W A Parish 7	
W A Parish 8	
W A Parish GT21	
Webster GT	10 - 105

* This represents the maximum ambient conditions under which and engineering evaluation has determined the unit can operate. This evaluation, performed after the cold weather of 1989, determined that the freeze protection and HVAC systems can operate at ambient temperatures lower than the nominal design minimums of 11 degrees F for freeze protection and 29 degrees F for HVAC systems.

Attachment No. 5 Plant Design Temperatures

Texas Utilities Electric Company (TU Electric)

Unit Name	Design Temperature Range (Degrees F)
Eagle Mountain 3	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Handley 5	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Martin Lake 2	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Monticello 2 Monticello 3	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Morgan Creek CT4	-5 to 115
Mountain Creek 2 Mountain Creek 7	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
River Crest 1	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Stryker Creek 1	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Tradinghouse 1	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures
Valley 2	-10 - and 35 MPH wind velocity to (Highest Regional Temperatures

Attachment No. 5 Plant Design Temperatures

Lower Colorado River Authority (LCRA)

Unit Name	Design Temperature Range (Degrees F)
Sim Gideon 2	No design temperature limitations available.
Sam K Seymour 3	1 to 110

Texas Municipal Power Agency (TMPA)

Unit Name	Design Temperature Range (Degrees F)
Gibbons Creek 1	15 - 107