NEWFOUNDLAND AND LABRADOR HYDRO

GULL ISLAND TO SOLDIERS POND HVDC INTERCONNECTION

DC SYSTEM STUDIES

VOLUME 1

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NEWFOUNDLAND AND LABRADOR HYDRO

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TABLE OF CONTENTS

Table of Contents (continued)

LIST OF TABLES

LIST OF FIGURES

Table of Contents (continued)

LIST OF APPENDICES

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NEWFOUNDLAND AND LABRADOR HYDRO

GULL ISLAND TO SOLDIERS POND HVDC INTERCONNECTION DC SYSTEM STUDIES

EXECUTIVE SUMMARY

This report summarizes the results of studies carried out jointly by Teshmont and Newfoundland and Labrador Hydro (NLH) for the Gull Island to Soldiers Pond HVDC Interconnection.

The purpose of the studies was to confirm the viability and operating performance of the proposed transmission system as described in Teshmont Report "Gull Island to Soldiers Pond HVDC Interconnection" dated June 1998.

The load flow, short circuit and stability studies showed that the HVDC transmission system is viable. Successful integration of the HVDC into the ac systems requires the following:

- Three synchronous condensers are needed at Soldiers Pond to avoid voltage collapse following faults under heavy Island load conditions. The studies in this report indicated that three synchronous condensers each rated at 150 Mvar would give satisfactory performance but further optimization of the rating may be possible.

  The June 1998 feasibility report had indicated that two 140 Mvar synchronous condensers would be adequate. However, those investigations were carried out on a simplified energy balance model of the ac system.

- Shunt capacitors are required to support the ac voltage in the Western Avalon area. Further ac system studies are needed to confirm this requirement.

- The HVDC system should have the capability of operating at 2.0 p.u. power for about 10 minutes on each pole of the dc transmission system as provided for in the June 1998 feasibility report.

- The back-up fault clearing time on the 230 kV protection systems near Soldiers Pond should be reduced to avoid voltage collapse for delayed clearing ac faults on the 230 kV system. In the studies it was demonstrated that reducing back-up clearing time from the existing 23 cycles to 15 cycles was sufficient to avoid voltage collapse. The NLH five year Capital Program includes plans to add a totally redundant primary protection on the 230 kV system. This should greatly reduce the probability of delayed fault clearing.

- The underfrequency load shedding on the Island should be reviewed to take advantage of the dc system overload capability and thus reduce the number of occurrences of underfrequency load shedding due to generator tripping.

The studies identified a number of areas where additional work should be undertaken to improve the system models and performance. These areas include load modelling, representation of Hardwoods and Stephenville excitation systems, damping of lightly damped electro-mechanical oscillations on the Island ac system, and investigation of the requirement for additional inertia on the Avalon peninsula.

NEWFOUNDLAND AND LABRADOR HYDRO

GULL ISLAND TO SOLDIERS POND HVDC INTERCONNECTION DC SYSTEM STUDIES

1.0 INTRODUCTION

This report describes studies carried out to confirm the viability and operating performance of the proposed Gull Island to Soldiers Pond HVDC transmission system. The scope of the studies described in this report is as defined in Newfoundland and Labrador Hydro's Terms of Reference dated 2nd July 1998 and Teshmont's response to those terms of reference dated 9th July 1998. The work was carried out by NLH engineers under the direction of Teshmont personnel. This report has been prepared by Teshmont.

The requirement for additional dc system studies was identified in Teshmont Report "Gull Island to Soldiers Pond HVDC Interconnection" dated June 1998. In that report the reactive power requirements and transient performance of the integrated system were established using simple equivalent models. The studies in this report were carried out using detailed load flow and stability models of the ac systems in Labrador and on the Island of Newfoundland.

The planned rating of the HVDC Interconnection at the rectifier is 800 MW nominal and 920 MW under low ambient temperature conditions. The corresponding rating of the inverter is 750 MW and 854 MW respectively for the nominal and low ambient conditions. The net dc infeed to the Island ac system is assumed to be 743 MW and 845 MW respectively taking into account the inverter station load and losses.

The HVDC interconnection will supply a high proportion of the Island load particularly during the initial years of operation when the thermal generation at Holyrood will be shut down. Under these conditions the transient and short time operational characteristics of the HVDC transmission system will have a significant impact on the performance of the ac systems.

Studies using the full system models were required to confirm the reactive requirement and overload characteristics of the dc system as well as to identify changes which might be required to existing features of the Island ac system including the underfrequency load shedding and back-up clearing times for ac faults.

The studies described in this report included the following:

- Investigations to confirm the required reactive power supply equipment at Gull Island and Soldiers Pond during steady state as well as transient and short-time overload conditions.
- Investigations of the performance of the ac systems following dc system disturbances.
- Investigations of the performance of the dc transmission system during and following ac system disturbances.

- Evaluation of existing underfrequency load shedding schemes on the Island and maximum permitted back-up clearing times of ac system faults.

- Investigations to confirm the required dc system overload ratings.

- Evaluation of ways in which the dc system could improve the black start performance of the Island ac system.

The PSS/E load flow and transient stability programs were the primary tools used in the study. Data for modelling of the ac systems for both load flow and stability studies was provided by NLH.

2.0 REACTIVE POWER SUPPLY AT SOLDIERS POND CONVERTER STATION

The reactive power supply requirements of a dc converter station is the sum of the requirements of the dc and ac systems. The requirements must be met for the steady state, transient and short-time conditions.

The transient time period is defined as the time during and immediately following a system disturbance. The short-time is defined as the period in minutes following a system disturbance. In this project a disturbance which causes the blocking of one pole results in the second pole delivering pre-fault power for about 10 minutes using the remaining pole (Figure 1) until generation on the Island can be re-dispatched to cover the deficit. During this period the total reactive power requirements of the dc converters is higher than for the bipolar case. The steady-state reactive power requirements are discussed in this section while the transient and short-time reactive power requirements are dealt with in Section 3.

Load flow studies were carried out on the Island system for normal and contingency conditions at various Island loading levels with the following objectives:

a) to establish the steady state reactive power requirements at Soldiers Pond
b) to establish the short circuit level at Soldiers Pond
c) to provide the initial conditions for system disturbance studies

2.1 Design Criteria

The reactive power required at Soldiers Pond by the ac system and the converter station will be supplied by synchronous condensers, ac filters and shunt capacitors at Soldiers Pond and generating unit Number 3 at the Holyrood thermal generating station operating as a synchronous condenser.

The Hardwoods gas turbine generator is assumed to be operating as a synchronous condenser whenever it is not dispatched as a generator.

The design criteria for steady-state reactive power at the Soldiers Pond converter station was selected as follows:

a) The bipole should be capable of operating at nominal rated power with a single reactive power source at Soldiers Pond or Holyrood out of service plus a 230 kV transmission line or the Hardwoods gas turbine out of service.

b) The bipole should be capable of operating at low ambient rated power with all reactive power sources at Soldiers Pond and Holyrood in service but with a 230 kV transmission line or the Hardwoods gas turbine out of service.

c) The system should be capable of operating for a short time (10 minutes) at the bipolar nominal power rating when one pole is out of service, with a single reactive power source at Soldiers Pond or Holyrood out of service.

d) The effective short circuit ratio at the Soldiers Pond 230 kV ac bus should be at least 2.5 with one synchronous condenser out of service.

e) The 230 kV bus voltages throughout the ac system should be maintained between 0.95 and 1.05 p.u. for all operating conditions.

2.2 DC System Reactive Power Requirements

The steady-state reactive power requirements of the Soldiers Pond Converter Station were determined in system studies carried out in the late 1970's. These studies assumed a dc reactive power demand as high as 65% of the transmitted power when operating at rated power. This value was consistent with the high values of commutating reactance (about 20%) used by most HVDC schemes in operation at that time. Advancements in thyristor short circuit current carrying capability have permitted dc system designs with much lower values of commutating reactance. Commutating reactances as low as 10 to 14% have been proposed and used on recent HVDC schemes. A conservative value of commutating reactance of 14% is used in this study resulting in a dc reactive power requirement of about 55% of the transmitted power when operating at rated power.

The converter data and the reactive power required by the converters, for the rectifier and inverter mode, are summarized in Table 1.

2.3 Load Flow Cases

Load flows were carried out using the PSS/E program. Input data for all load flow cases is included in Appendix 6.

Table 2 provides a summary of the operating conditions for nine base load flows cases with different levels of dc dispatch, Island generation and Island load.

In these load flows the Island ac system is represented in detail using the same ac model as used by NLH. The dc system is represented as a constant power generator and a constant Mvar load at the inverter bus and by a constant MW and Mvar load at the rectifier. Three dc power transfer levels are represented; nominal rated power , low ambient temperature rating and light load. The nominal and low ambient power levels are 743 MW and 845 MW respectively measured at Soldiers Pond while the light load condition of 80 MW is the minimum power transfer capability of the dc system.

The independent customer generation assumed in each case is summarized in Table 3.

The Island loading conditions in this study correspond to initial operation of the dc bipole at nominal and low ambient ratings with no thermal plants in service on the Island. The power factor of the Island loads is based on the results of a study by NLH as summarized in Appendix 1.

The transmission network representation includes the planned installation of new conductors on the 230 kV lines from Holyrood to Western Avalon to Sunnyside. Planned shunt capacitor banks of 2 x 25 Mvar are assumed to be in service at Hardwoods and Oxen Pond.

Cases 1 and 2 represent the Island system with a load level of 1333 MW which is close to the expected average maximum winter peak load. The dc system is at nominal power transfer of 743 MW in Case 1 and at low ambient power transfer of 845 MW in Case 2. Island generation is 631 MW in Case 1 and is reduced to 547 MW in Case 2 to allow for the higher level of dc infeed. Independent generation of 112 MW is included in the total Island generation in both cases.

Cases 3 and 4 are similar to Cases 1 and 2 except the Island load has been reduced to 996 MW which could be a typical off-peak winter load or an average peak autumn or spring load. To allow for the reduced loading level the corresponding Island generation is also reduced in both cases. In Case 3 the Island generation is 298 MW which includes independent generation of 112 MW. In Case 4 the Island generation is at a minimum level of 209 MW which includes independent generation of 98 MW.

In Cases 5 and 6 the total system generation on the Island is at a minimum level of approximately 202 MW which includes independent generation of 98 MW. The dc dispatch is at nominal power transfer of 743 MW and the Island load is reduced to 898 MW. The cases are identical except that in Case 6 the synchronous condenser at Holyrood is out of service while in Case 5 one of the synchronous condensers at Soldiers Pond is out of service.

In Case 7 the Island load is at a minimum level of 273 MW. The dc system is at minimum power transfer of 80 MW and Island generation is at a minimum level of 198 MW which includes independent generation of 98 MW. These conditions could be expected on holidays such as Labour day when virtually all industry is shut down.

Cases 8 and 9 represent the Island system at a maximum load of 1602 MW. The dc system is at nominal power transfer of 743 MW in Case 8 and at low ambient power transfer of 845 MW in Case 9. Island generation is 913 MW in Case 8 and reduced to 811 MW in Case 9 to allow for the higher level of dc infeed. Independent generation of 112 MW is included in the total Island generation in both cases.

A total of ten 230 kV transmission line or equipment outages were considered for each of Cases 1 through 9 as follows:

Transmission Line or Equipment Outages

Contingency	Description of Outage
0.1	Soldiers Pond-Holyrood
0.2	Soldiers Pond-Hardwoods
0.3	Soldiers Pond-Oxen Pond
0.4	Soldiers Pond-Western Avalon
0.5	Western Avalon-Come By Chance
0.6	Come By Chance-Sunnyside
0.7	Western Avalon-Sunnyside
0.8	Sunnyside-Bay d'Espoir
0.9	Hardwoods Gas Turbine
0.10	Permanent Block One Pole - Second Pole at 2 p.u. Power

Contingency 0.10 represents the short time operating period (approximately 10 minutes) following the permanent blocking or tripping of one dc pole prior to re-dispatching generation on the Island. In this case the dc pole remaining in service is operating at about 2.0 p.u. power transfer. The reactive power requirement of the dc system is 565 Mvar which is 163 Mvar higher than the reactive power required at equal power in bipolar operation. This contingency does not apply to cases where the pre-fault dc dispatch is at the low ambient value (Cases 2, 4 and 9).

2.4 Short Circuit Study Results

Three phase short circuit levels were calculated at the Soldiers Pond 230 kV bus for load flow Cases 1 to 9 and the contingency cases. The short circuit levels are summarised in Table 4a. The short circuit levels shown do not include contributions to the short circuit levels from the synchronous condensers, shunt capacitors and filter banks at the Soldiers Pond bus.

The short circuit values are utilised in Section 2.5 in sizing the synchronous condensers and shunt capacitor banks at the Soldiers Pond 230 kV bus.

For Cases 1 and 2 the maximum short circuit level is 1570 MVA without any outages and the minimum value is 1347 MVA with the outage of the Hardwoods gas turbine.

The lowest short circuit levels occur in Case 5 with the respective maximum and minimum values being 1014 MVA and 790 MVA.

2.5 AC Filters and Synchronous Condensers at Soldiers Pond

The ac filters required for the operation of the dc converter equipment will also supply a portion of the reactive power required by the converter equipment. Synchronous condensers are required at the Soldiers Pond bus to ensure that the equivalent short circuit level is met. Appendix 2 describes the basis for the selection of the synchronous condensers and the ac filter Mvar rating.

Two synchronous condensers each rated 150 Mvar and 245 Mvar of ac filters/shunt capacitor were selected to meet the steady-state reactive power requirements.

The following table summarizes the synchronous condenser data assumed for this study:

Synchronous Condenser Data

Synchronous Condenser rating	150 Mvar
Maximum underexcited Vars from bus	75 Mvar
Subtransient reactance on machine base	0.17 p.u.
Transformer leakage reactance on machine base	0.08 p.u.

Table 4b summarizes the short circuit ratio as calculated for Cases 1 through 9 for all outage conditions based on the fault levels in Table 4a, ac filters of 245 Mvar and the above synchronous condenser data. The effective short circuit ratio meets the minimum design criteria of 2.5 for all base cases.

For some of the contingency cases the effective short circuit ratio is less than 2.5. The minimum short circuit ratio is calculated to be 2.2 for Cases 4 and 6 with the gas turbine at Hardwoods out of service. For the contingency cases a lower short circuit ratio is considered acceptable as the cases represent a higher contingency case of an outage of a 230 kV transmission line or the Hardwoods gas turbine in addition to the outage of a synchronous condenser at Soldiers Pond or Holyrood.

2.6 Load Flow Study Results

Load flow case results for the nine base cases are shown in Figures 2.2 to 2.9. Results for the remaining cases are included in Appendix 8. The following summarizes the results of the load flow study.

2.6.1 Soldiers Pond Reactive Power

The results of the load flow studies indicate that the Soldiers Pond inverter station must supply vars to the ac system in order to maintain satisfactory voltages. Additional vars must also be supplied to the system under certain outage conditions. The system reactive power requirements are summarized in Tables 5A to 5K for all cases including line and equipment outages. These tables show the margin of available vars at Soldiers Pond including the Holyrood synchronous condenser over the dc converter and Island ac system reactive power requirements. The results of the load flow studies indicate that 245 Mvar of ac filters with two 150 MVA synchronous condensers at Soldiers Pond provides sufficient reactive power supply for all cases with a positive margin of reactive power except for Cases 8 and 9.

Case 7 shows that sufficient reactive power absorption capability is installed at the inverter bus to prevent excess var flow into the ac system.

2.6.2 Voltage Compensation in AC System

The load flow studies show that the Island ac system requires capacitive compensation for voltage support in the Western Avalon area. The subject of voltage compensation for the Island ac system is a topic for a separate study, however, the following highlights observations on voltage compensation noted from this study.

Nearly all base case load flows indicate that the 230 kV voltages around the Western Avalon/Come-By-Chance/Sunnyside area cannot be maintained at 1.0 p.u. The best 230 kV voltage for this area without any line out or other contingency is typically around 0.97 p.u. with the lower value occurring on the Western Avalon 230 kV bus. The following table lists the 230 kV voltage at Western Avalon for each of the base cases studied.

Best Voltage Attainable at Western Avalon 230 kV (p.u.)

Case	No Contingency	Western Avalon to Soldiers Pond (TL 217) Out
1	0.976	0.952
2	0.97	0.937
3	0.975	0.945
4	0.963	0.911
5	0.972	0.934
6	0.973	0.935
7	1.011	1.016
8.0*	0.985	0.977
9.0*	0.969	0.952

* In order to obtain these voltages, shunt capacitors were added to the 138 kV bus at Western Avalon.

The most severe contingency evaluated is an outage on TL 217 (Western Avalon to Soldiers Pond) which depresses the Western Avalon 230 kV voltage below 0.95 p.u. This is particularly noticeable in the peak load Cases 8 and 9 which require additional voltage compensation in the Western Avalon area for normal as well as contingency operation. The following table indicates the amount of shunt compensation required to maintain the voltage at an acceptable level in this area in Case 8 and Case 9.

No.	Case Contingency	Shunt Capacitors at Western Avalon 138 KV Case 8 (Mvar)	Case 9 (Mvar)
0	NONE	55	-
0.1	SOP-HRD	60	-
0.2	SOP-HWD	75	10
0.3	SOP-OPD	75	15
0.4	SOP-WAV	70	25
0.5	WAV-CBC	65	10
0.6	CBC-SSD	65	10
0.7	WAV-SSD	65	10
0.8	SSD-BDE	100	35
0.9	HWD G.T.	105	40

There are high overvoltages at several buses during extremely light load with minimum dc infeed (Case 7). This may be mitigated by switching out selected 230 kV circuits and utilizing the under-excited capability of generators and synchronous condensers to absorb excess reactive power from the ac system.

2.6.3 Thermal Overloading on the Soldiers Pond -Western Avalon Lines

Transmission line TL 217 (Western Avalon to Soldiers Pond) is assumed to be reconductored and upgraded to operate at a 75°C conductor temperature prior to the infeed as per current NLH capital projects. However, with this line out of service, the second circuit between Soldiers Pond and Western Avalon (TL 201) will become overloaded during certain operating conditions with reduced Island generation as indicated below.

CASE	Loading on Second Circuit Between Soldiers Pond and Western Avalon
4.4	121.8%
5.4	107.6%
6.4	107.2%

If the upgrading program for TL 201 currently proposed by NLH is approved and implemented, this overload problem will be eliminated.

Presently TL 217 has sections of 795 MCM ACSR and 559.5 MCM AASC conductors to operate at a 50°C conductor maximum temperature; while TL 201 has sections of 636 MCM and 795 MCM ACSR conductors also designed for 50°C. When reconductored the lines will be provided with an 804 MCM AACSR/TW, extra strength alloy, to operate at a 75°C conductor maximum temperature.

3.0 STABILITY STUDIES

3.1 Introduction

Load shedding occurs frequently on the Island. In 1996, there were nine incidents of load shedding of which seven were attributed to loss of generation. It is difficult to avoid load shedding because the available spinning reserve generation cannot pick up load fast enough to avoid a significant drop in frequency. The HVDC system can pick up load significantly faster than generators and thus may be used to help avoid load shedding due to generator tripping on the Island.

An earlier investigation [4] using a simplified energy balance model of the Island system showed that with dc capability per pole of 2.0 per unit power (about 2.5 p.u. current) for about 10 minutes followed by a "continuous" 1.5 per unit current overload capability (Figure 1), the risk of load shedding due to loss of generation or loss of a single pole of HVDC equipment could be reduced.

In this study, stability investigations were carried out for normal and contingency conditions on the Island with loading levels as described in each of the base cases . The studies had the following objectives:

a) to evaluate suitability of the existing underfrequency load shedding and identify changes required following the addition of the HVDC transmission system
b) to determine the maximum permitted fault clearing times on the Island and identify possible changes to existing ac protection systems
c) to confirm the dc system overload ratings established with the energy balance model
d) to determine the effect of a bipolar dc system block on the Island ac system
e) to establish the performance of the Island ac and Labrador ac systems following dc system disturbances especially with regard to the impact on ac system voltage and frequency
f) to determine the impact of ac system faults on the dc system
g) to review the system black start procedures and determine if they should be revised to include the dc system

3.2 Performance Criteria

The following criteria were assumed in the stability investigations:

a) There shall be no load shedding for either temporary or permanent outage of one dc pole when the dc system is operating in bipolar mode at any power transfer level up to the nominal rating of 800 MW.

b) There shall be no load shedding for ac system faults cleared in normal clearing times, including faults which result in a tripping of a single piece of equipment, while the dc system is operating in bipolar mode at any power transfer up to the nominal rating.

c) For all other disturbances there shall be no system collapse and the amount of load shed shall be minimized.

3.3 Base Case Load Dispatch

Table 2 lists the nine base case load dispatches which formed the basis of the load flow analysis.

Dispatch Cases 5.0 and 6.0 are nearly identical involving only the outage of the Holyrood synchronous condenser versus the Soldiers Pond synchronous condenser. The synchronous condensers at Soldiers Pond and Holyrood are each rated at 150 Mvar. Stability runs were carried out for Case 6.0 only, in which the outage of the synchronous condenser connected to the inverter commutating bus at Soldiers Pond was considered.

Case 7.0 is a light load case with low dc power transfer which would not be limiting in the stability studies and thus no stability analysis was performed for this dispatch.

The stability studies discussed below are based on dispatch Cases 1.0 to 4.0, 6.0, 8.0 and 9.0. These dispatch cases include 245 Mvar of ac filters and two 150 Mvar synchronous condensers installed, unless stated otherwise, at Soldiers Pond.

3.4 Disturbances

Table 6 lists five groups of disturbances and the associated duration of the fault or event as used in this study. The fault durations are based on data provided by NLH included in Appendix 4.

The first group of disturbances ("a" to "g") in Table 6 includes tripping of a transmission line or an equipment or blocking of the dc pole or bipole with no prior ac system fault. Disturbances "a" to "d" are mostly minor disturbances to the ac system and to the dc system. Disturbances "e" and "f" examine temporary and permanent blocking of one dc pole respectively with recovery to pre-fault bipolar power using the short-time overload of the healthy dc pole. Disturbance "g" examines the effect of a permanent block of the dc bipole on the Island and Gull ac systems.

The second group ("h" and "i") simulates three phase and single line to ground bus faults with no tripping of any transmission line or equipment following clearing of the fault.

The third group ("j" and "k") simulates three phase and single line to ground ac system faults with subsequent tripping of a transmission line, a synchronous condenser, a generator or permanent blocking of a dc pole. The disturbances in this group are the same as either "h" or "i" in combination with one of "a"-"d" or "f". For example case "j_a" is a three phase fault on a transmission line cleared by tripping the transmission line.

The fourth group ("l" to "o") simulates three phase and single line to ground faults on the 230 kV, 138 kV and 66 kV ac systems with unsuccessful single pole reclosing or clearing by back up protection.

The fifth group ("p" and "q") simulates three phase and single line to ground ac system faults at the rectifier ac bus.

3.5 Methodology and System Representation

Load flow cases and stability cases were carried out using the PSS/E program. Input data can be found in Appendix 6 for the load flow cases and in Appendix 7 for the stability cases.

a) DC System Representation

The dc transmission system was modelled using the CDC4 model of the PSS/E. The block diagram and model values are given in Appendix 5.

Modulation controls of the dc system were not modelled in detail. Instead the power order of the dc system was manually adjusted appropriately where a case required short time power support to avoid load shedding on the Island.

b) AC System Representation

Data used for representation of the generators, exciters, governors and turbines in the Island ac system are the same as are used by NLH in other studies. Parameters for the synchronous condensers at Soldiers Pond were based on typical values for 150 Mvar units.

Detailed models of the generators, exciters, governors and turbines for Gull Island and Churchill Falls were provided by NLH.

The real component of each load in the Island ac system was represented as 100% constant current. The imaginary component of each load was represented as a constant impedance.

Additional shunt capacitor support of 120 Mvar was used in the Western Avalon region for Cases 8 and 9.

c) Fault Modelling

Three phase and single line to ground faults were applied at the 230 kV inverter bus at Soldiers Pond, at the 230 kV bus at Bay d'Espoir which is the largest connected generating station on the Island and at the 230 kV rectifier bus at Gull. Remote three phase and single line to ground faults were applied at the Holyrood 138 kV and 66 kV buses which are electrically closest to the Soldiers Pond inverter bus.

Fault clearing times used in this study are detailed in Appendix 4.

Zero impedance three phase faults are simulated by connecting a very small or zero impedance from the faulted node to ground. For faults at the Bay d'Espoir 230 kV bus, in cases 8.0 and 9.0, an impedance of about 10% of the positive sequence fault impedance is connected to avoid numerical instability in the simulation. The dc converters are blocked for the duration of the fault for faults at the inverter bus and for the first 100 msec for remote faults.

Single line to ground faults are simulated by connecting an impedance equal to the sum of the zero sequence and negative sequence impedance between the faulted node and ground. The dc converters are blocked for the duration of the fault for faults at the inverter bus and for the first 100 msec for remote faults.

NLH employs single phase reclosing on most of the 230 kV transmission lines. Because there are eight 230 kV lines at Soldiers Pond, outage of a single phase of one line will have little impact on the magnitude of the phase voltages. The dc system was assumed to transmit full power during this period.

Experience on other dc schemes indicates that for remote three phase or single line to ground faults, where the converter bus voltage is not reduced to zero, each inverter will suffer a commutation failure at the time of fault initiation. The protective response of the dc controls would act to reduce the dc current to zero and then allow the dc voltage and current to recover to the extent permitted by the voltages which are prevalent during the fault. Generally no power transfer can be counted on during the first 100 msec of the fault. For faults in excess of 100 msec the dc system is able to recover and transmit some level of power depending on the magnitude of the commutating bus phase voltages during the fault. The power which can be transferred during a remote three phase fault will generally be less than for a single line to ground fault at the same remote location.

The following maximum levels of power transfer were assumed during delayed cleared remote faults at the Holyrood 138 kV and 66 kV buses:

Bus	**Fault**	**Maximum Power Transfer by dc System**	
		0 - 100 msec	**> 100 msec**
138 kV	3 Phase	0	50%
66 kV	3 Phase	0	50%
138 kV	SLG	0	60%
66 kV	SLG	0	60%

During single line to ground faults at the rectifier commutating bus it is assumed that 25% power could be transmitted by the dc converters. For three phase faults at the rectifier commutating bus there is no power transfer.

d) Load Shedding

The load shedding scheme modelled in this study is based on Table VI-1 of Reference 3 and is presented in Appendix 3.

3.6 Study Results

Stability cases were run for a sufficient number of combinations of load dispatch conditions and disturbances to identify the limiting cases. Table 7 summarizes the stability cases carried out for this study. The cases in this table for which the design criteria is met without additional system support or other action are indicated with a check mark (√) while the cases which require additional action to meet the design criteria are marked with a comment.

A number of disturbance cases were simulated assuming two synchronous condensers installed at Soldiers Pond with one synchronous condenser operating for dispatch conditions 1, 3, 6 and 8 and two synchronous condensers operating for dispatch conditions 2, 4 and 9. However, during the course of the study it was found that an extra synchronous condenser was required to avoid voltage collapse on the Island ac system. Therefore, subsequent cases were simulated assuming the three synchronous condensers installed at Soldiers Pond. No attempt was made to re-run earlier cases which already indicated satisfactory performance. Table 7 notes cases which were run assuming three synchronous condensers installed at Soldiers Pond.

Representative sample plots of selected disturbances are included in the report as discussed below. Plots of each disturbance simulated are given in Appendix 8 along with a summary sheet which provides additional information on the case including the number of synchronous condensers at Soldiers Pond, the type, location and duration of the fault and the amount of shed load.

a) Equipment Tripping Without Faults (Disturbances "a" to "f")

The Island ac system is stable for all dispatch conditions.

No load was shed for the nominal dc dispatch conditions (Cases 1, 3, 6 and 8). For the low ambient dc dispatch condition (Case 2f), 55.2 MW load was shed due to underfrequency for the permanent loss of a dc pole.

These cases were simulated with two synchronous condensers installed at Soldiers Pond. For Cases 1, 8 and 9 extra short-term reactive support (10 minute duration) is required for the loss of a synchronous condenser at Soldiers Pond. Similarly, for Cases 1, 2, 8 and 9 extra short-term reactive support is required for the loss of one dc pole.

The additional reactive power could be provided by shunt capacitors or the addition of a third synchronous condenser at Soldiers Pond (see Section 3.6g for further discussion).

The tripping of one 230 kV circuit between Soldiers Pond and Western Avalon results in overloading the remaining healthy circuit in most dispatch conditions. The amount of overload depends upon the dispatch condition and circuit lost.

A typical system response following the permanent loss of a dc pole is shown in Figures 3.1 to 3.4 for Case 3f. These figures show the rectifier and inverter quantities, 230 kV system voltages and reactive power of the synchronous condensers around Soldiers Pond.

b) AC System Faults Without Tripping Equipment (Disturbances "h" and "i")

Three phase faults at the Soldiers Pond and three phase and SLG faults at the Bay d'Espoir 230 kV were simulated.

The Island system is stable for all simulated disturbances.

The faults at the Bay d'Espoir (Cases 1.0, 4.0 and 9.0) resulted in load shedding at the English Harbour and Hardwoods buses. Three phase faults at the Bay d'Espoir resulted in depressed voltage and frequency at the English Harbour bus, which has no local generation. This resulted in load shed at the English Harbour bus irrespective of the frequency at the Bay d'Espoir. To avoid this problem, in future studies, the load should be reconnected following fault removal.

The load shedding at the Hardwoods bus, in Cases 1 and 9, was found to be due to transient frequency variations in contrast to continuous underfrequency conditions which are typical in an ac system with loss of generation. A load shedding scheme based on the dc system overload capability would totally eliminate or limit the load shedding to a lower value.

c) AC System 3 Phase Faults with Tripping (Disturbances "j_a" to "j_f")

These cases have simulated tripping of a transmission line, a synchronous condenser, a generator or blocking of a dc pole following clearance of a three phase fault. All trippings except the generator tripping are associated with faults at the Soldiers Pond 230 kV bus. The generator tripping occurs for faults at the Bay d'Espoir 230 kV bus. The number of synchronous condensers installed at Soldiers Pond were either two or three as indicated in Table 7.

There was no load shed for all cases with fault at Soldiers Pond except for the case of dc pole block under low ambient dc operating condition, case 4.0 j-f. Under this case 55.2 MW load was shed with two synchronous condensers installed and it is expected that much smaller amount of load will be shed with a third synchronous condenser installed.

Load shed occurred in all cases for faults at the Bay d'Espoir bus. In most of the cases, it was the load at the radially fed English Harbour that was shed due to depressed voltages and frequency as explained in sections 3.6 (b). There was also load shed at the Hardwoods bus due to transient frequency variations. As explained in section 3.6 (b) it is expected that with a revised load shedding scheme the amount of load shed would be either completely eliminated or limited to a lower value.

The Island system is stable for all dispatch conditions except for one fault condition as discussed below.

The Island system is unstable for a three phase fault at the Bay d'Espoir 230 kV bus under maximum load dispatch conditions with the dc operating at its nominal rating (case 8j_d). Preliminary studies show that the system can be made to be stable for this case if the inertias for the synchronous condensers at Soldiers Pond are increased to twice their values. Other methods of increasing the inertia of the system should be investigated prior to finalizing the specification for the Soldiers Pond synchronous condensers.

Extra short-time reactive support is required, under certain conditions as shown in Table 7, if only two synchronous condensers are installed.

A typical system response for a three phase fault at Soldiers Pond 230 kV bus followed the outage of the Soldiers Pond to Western Avalon circuit 1 is shown in Figures 4.1 to 4.3 for case 9j_a. These figures show the rectifier and inverter quantities and the 230 kV system voltages.

d) System SLG Faults with Tripping (Disturbances "k_a" to "k_f")

Tripping of a transmission line, a synchronous condenser, a generator or blocking of a dc pole following clearance of a single line to ground fault were simulated. All trippings except the generator tripping are associated with fault at the Soldiers Pond 230 kV bus, where as for the generator tripping the fault is applied at the Bay d'Espoir 230 kV bus.

The Island system is stable for all dispatch conditions.

There was no load shed for all cases with fault at Soldiers Pond except for the case of dc pole block under low ambient dc operating condition, Case 4.0 k-f. Under this case 55.2 MW load was shed with two synchronous condensers installed and it is expected that much smaller amount of load will be shed with a third synchronous condenser.

Load shed occurred in all cases for faults at the Bay d'Espoir bus. In most of the cases, it was the load at the radially fed English Harbour that was shed due to depressed voltages and frequency as explained in sections 3.6 (b). There was also load shed at the Hardwoods bus due to transient frequency variations. As explained in section 3.6 (b) it is expected that with a revised load shedding scheme the amount of load shed would be either completely eliminated or limited to a lower value.

Extra short-time reactive support is required, under certain conditions as shown in Table 7, if only two synchronous condensers are installed.

Typical system response for Case 1k_f with a fault at Soldiers Pond 230 kV bus followed by permanent loss of one dc pole is shown in Figures 5.1 to 5.4. These figures show the rectifier and inverter quantities, 230 kV system voltages and reactive power of the synchronous condensers around Soldiers Pond.

e) System Faults with Delayed Clearance (Disturbances "l" to "o_s")

Three phase and single line to ground faults of delayed clearance were simulated on the 230 kV, 138 kV and 66 kV systems around the Soldiers Pond station.

A single line to ground fault with single pole unsuccessful reclosing was simulated on the Soldiers Pond to Western Avalon 230 kV transmission line. For this condition the Island system is stable for all dispatch conditions. The system required additional reactive power support for the nominal dc dispatch condition under heavy load conditions (Case 8) if only two synchronous condensers are installed.

For the dispatch condition Case 1, the 230 kV single line to ground fault with 23 cycle fault clearing time was found to result in voltage collapse even with two synchronous condensers in operation at Soldiers Pond. The voltage collapse was avoided by reducing the fault clearing time to 15 cycles. Subsequently all three phase and single line to ground fault faults, except for Case 4.0m, were investigated with 15 cycle fault clearing times.

The phenomena of voltage collapse for the 23 cycle fault is shown in Figure 6.1 and the voltage recovery for the 15 cycle fault is shown in Figure 6.2. These plots pertain to the case of two synchronous condensers at the Soldiers Pond for dispatch Case 1.

NLH has plans to add a totally redundant primary protection to the 230 kV protection system. This addition is expected to greatly reduce the probability of delayed fault clearing.

The system was stable for faults at 138 kV and 66 kV voltages. There was some load shed in certain cases but it is possible to reduce the amount of load shed by modulating the dc system. None of these cases required reduced fault clearance times to avoid voltage collapse as in the case of 230 kV faults discussed above.

f) System Faults at the Rectifier End (Disturbances "p" and "q")

Three phase 6 cycle and single line to ground 12 cycle faults were simulated at the rectifier 230 kV bus. These cases were simulated with three synchronous condensers installed at the Soldiers Pond. The Island ac system was found to be stable for all dispatch conditions.

For the three phase faults there was no load shed under nominal dc operating conditions (Cases 1, 3, 6 and 8). There was 11.4 MW load shed in Case 4, under low ambient temperature dc operating condition.

For single line to ground faults with delayed clearance load shedding occurred for Cases 3, 4, 6 and 8. The load sheddings that have occurred are due to transient frequency variations. As explained in Section 3.6 (b) it is expected that with a revised load shedding scheme the amount of load shed would be either completely eliminated or limited to a lower value.

Typical system response for Case 1p is shown in Figures 7.1 to 7.4. These figures show the rectifier and inverter quantities, 230 kV system voltages and reactive power of the synchronous machines around Soldiers Pond.

g) Short-time Reactive Power Requirements

Several of the stability cases require additional reactive support in order to meet the design criteria, if only two synchronous condensers are installed at Soldiers Pond.

Cases which use the short-time pole overload capability also require additional reactive power support. During the time while one pole is blocked and the remaining pole is at 2 p.u. power the reactive power requirements of the dc converters is increased by 163 Mvar over the bipolar requirements at nominal load. One of the following methods could be used to supply this short-time reactive power requirement:

i) a third synchronous condenser at Soldiers Pond
ii) switched capacitors at Soldiers Pond or elsewhere in the NLH ac system

The addition of a synchronous condenser provides support for the system voltage in the steady state, transient and short-time periods. A synchronous condenser would also provide additional inertia to the system which would help reduce frequency variation and would help maintain stability during system disturbances.

4.0 AC SYSTEM BLACK START

The dc system can be specified and designed to aid in restarting the Island ac system from a black start condition when no generating units are operating on the Island. DC systems which include provision for system black start include the Gotland HVDC Link (mainland Sweden to the island of Gotland) and the Cheju Island HVDC Link (mainland Korea to Cheju Island) [5].

Both schemes use a similar strategy on black start. The synchronous condenser is brought up to partial speed using a pony motor fed from a diesel generator. The synchronous condenser is then used to energize the converter transformers at reduced voltage. The valves at the inverter are deblocked followed by the rectifier valves. The rectifier raises the dc voltage to 1.0 p.u. and the inverter output accelerates the synchronous condenser to full speed (nominal system frequency). At this point the system operators take over and begin connecting the ac filters and dc system to the island load.

The restart strategy used on these other systems may not be very useful on the Island since sufficient quick starting generation (gas turbines and hydro units) would be available to be able to get the synchronous condensers on line without help from the dc converters. Once the condensers are started it would be possible to start one pole of the dc transmission system and switch it to frequency control. The second pole could be started as soon as the dc pole is transmitting more than 80 MW. The ability to operate the dc transmission system in frequency control is desirable since it would then allow the operators to restore load as quickly as possible without manually re-dispatching the dc system.

The strategy for black start utilizing the dc connection will need to be coordinated with the existing system black start procedure for the Island ac system. In addition to the condition where at least one pole of the dc transmission system is available, the procedures would need to address the situation where both poles of the dc transmission system are not available to help with system restoration because of a permanent fault to equipment which affects both poles. The revised strategy should strive to have as many generators as possible operating following a permanent block of the dc bipole in order to minimize the total recovery time.

5.0 FURTHER WORK

The studies described in this report identified a number of areas where additional work could be carried out either to improve system simulation models or system performance as follows:

- The rating of the third synchronous condenser was assumed to be 150 Mvar (the same as the first two synchronous condensers). The sizing of the three synchronous condenser combination should be carried out at the time of preparation of the converter equipment specification.

- The Island ac system requires additional capacitive compensation around Western Avalon for voltage support. Further ac system studies are needed to confirm this requirement and define the equipment needed. As a possible alternative to additional compensation the effect of operating the system at a higher set point voltage should be investigated.

- The representation of loads has an impact on the stability study results. In this work the real component of each load in the Island ac system was represented as varying in proportion to voltage (constant current load) while the imaginary component was represented as varying in proportion to the square of the voltage (constant impedance load). Further work should be carried out to establish the load modelling which most correctly represents the Island ac system loads to be used for future stability studies.

- The response of the excitation systems of the synchronous condensers at Hardwoods and Stevenville was found to be inconsistent with the rest of the exciters. The PSS/E data was modified to agree with the manufacturer's published data, however, further work including site measurements should be carried out to confirm the exciter representations.

- The stability studies have been carried out using the load shedding schedule as presently used by NLH. This load shedding schedule is predicated on the loss of generation which could lead to system collapse unless balanced with corresponding load shedding. The load shedding strategy should be reviewed considering the presence of the dc converters which have the potential to compensate for loss of generation and avoid load shedding.

- This study showed that the back-up clearing time of the 230 kV protection systems should be reduced from the existing value of 23 cycles. Further investigations should be made to establish the maximum acceptable value of 230 kV protection back-up clearing time.

- Lightly damped electromechanical oscillations were observed for several stability cases. The application of power system stabilizers on the generating units and modulation of the dc system to damp out these oscillations should be studied.

  Lightly damped oscillations of about 4 Hz were observed involving the Hardwoods, Holyrood and Soldiers Pond machines for three phase faults at the Soldiers Pond 230 kV bus. Further investigations should be carried out to identify methods to damp out these inter-machine oscillations.

- The power transfer on the dc system during delayed remote ac system faults should be evaluated.

- Some means of increasing the system inertia in the Avalon Peninsula, should be explored to ensure stable operation of the Island ac system for three phase faults at the Bay d'Espoir 230 kV bus under maximum load dispatch conditions.

The further work items identified above are considered to be refinements to the work completed and will not influence conclusions already made regarding the performance of the proposed system. It is not critical that this work be performed immediately and it could be carried out at the time of preparation of the dc equipment specification.

6.0 SUMMARY AND CONCLUSIONS

The load flow, short circuit and stability studies showed that the HVDC transmission system is viable. The performance of the integrated ac/dc system with the full system model compares favourably with the performance established earlier using simple equivalent models.

The studies performed with the full system model did however establish the need for additional reactive compensation at Soldiers Pond during transient conditions. The studies also indicated a need to install reactive compensation equipment away from the Soldiers Pond Converter Station to support the ac voltage in the Western Avalon region.

The studies also indicated a need to reduce the back-up fault clearing times of the 230 kV ac system protections from the existing time of 23 electrical cycles to about 15 cycles.

Specific conclusions and study results are summarized below:

a) The steady state reactive supply at Soldiers Pond Converter station can be met with the following equipment:

   - ac filters and shunt capacitors with a fundamental frequency reactive power output of 245 Mvar
   - two 150 Mvar synchronous condensers and one unit at Holyrood operating as a synchronous condenser

b) Additional reactive compensation equipment is required at Soldiers Pond to meet the short time and transient reactive power needs of the dc converters and the ac system. The technically preferred method to provide the reactive compensation is to add a third 150 Mvar synchronous condenser.

c) The Island ac system requires additional capacitive compensation for voltage support in the Western Avalon area.

d) The reactive requirements of the ac and dc systems at the Gull Island Converter Station can be met with the filter banks needed to meet harmonic performance plus additional var supply from the generators at Gull Island. The power factor of the generators at Gull Island was assumed to be 0.9.

e) It is not necessary to specify very low reactance converter transformers for Gull Island and Soldiers Pond. The studies showed that all steady state and transient performance criteria can be met with a converter transformer impedance of 14%.

f) The studies with the full system model confirmed that short-time monopole capability of 2.0 p.u. power is required on each pole of the HVDC transmission system to enable the Island ac system to operate without load shedding following a permanent pole fault.

g) The performance of the integrated ac/dc scheme with three synchronous condensers at Soldiers Pond is summarized below on the assumption that the currently implemented load shedding scheme is not changed:

- load shedding will not occur on the Island for a permanent or temporary pole fault when the dc system is operating in bipolar mode at any power transfer up to the nominal power transfer as the total pre-fault bipole power transfer can be completely picked up by the unfaulted pole

- load shedding will not occur on the Island for Island ac system faults with normal fault clearing times when the dc system is operating in either monopolar or bipolar mode at any power transfer up to the nominal power transfer

- load shedding would occur for some Island ac disturbances when the dc system is operating at the low ambient rating

- because the rating of each HVDC pole exceeds that of the largest generator on the Island and it has short-time capability of 2.0 p.u. of the nominal power rating, the dc system can increase power delivered to the Island and prevent load shedding for any single generator trip on the Island

- load shedding on the Island will not occur for three phase or single line to ground faults at the rectifier ac bus with normal fault clearing times

- load shedding would occur for single line to ground faults at the rectifier ac bus with back-up fault clearing times.

- the Island ac system is stable under all dispatch conditions for ac system faults at or near the Soldiers Pond bus. However, for a 3 phase fault at the Bay d'Espoir 230 kV bus under maximum load conditions, additional system inertia in the Avalon peninsula is required for the system to be stable.

h) The overload capability of the HVDC transmission will enhance the performance of the Island ac system by reducing the number of occurrences of underfrequency load shedding following disturbances and loss of generation. The load shedding strategy should be re-examined considering the presence of the HVDC system.

i) The back-up clearing time for 230 kV bus faults should be reduced from the present value of 23 cycles. The studies indicated that load shedding can be avoided if the back-up clearing time is reduced to 15 cycles. However, further work is required to establish the maximum permitted back-up clearing time. NLH has a plan to install fully redundant primary protections on the 230 kV system. This should greatly reduce the incidence of events requiring back-up clearing.

j) The existing black start procedure for the Island ac system should be re-evaluated considering the possible contribution of the dc converters. As the dc converters represent the largest generating units on the Island and can be loaded very rapidly compared with other generating units, they can contribute to speeding up the process of system restoration. The HVDC system should be capable of operation in frequency control mode so that re-dispatch of the dc system would not be required when bringing back the load.

k) The studies showed that some circuits can become overloaded following outages of certain parallel circuits. Further review is required

7.0 REFERENCES

1. Report on Transmission System Studies Phase 1: Study of Alternatives, Teshmont Report No. 446-90020-3 dated Nov. 27, 1979, revised March 20, 1980
2. Report on Transmission System Studies Phase 2:Recommended Systems, Teshmont Report No. 446-90020-3 dated March 14,1980, revised April 22, 1980
3. Underfrequency Load Shedding Schedule 4, Recommended Schedule, 1997 07 31 included in Newfoundland and Labrador Hydro report "Integrated Underfrequency Load Shedding Schedule, 1997 Review" dated 1997/09/30.
4. Gull Island to Soldiers Pond HVDC Interconnection, Load Shedding Considerations, Teshmont Technical Memorandum 182-10100-1, April 26, 1998.
5. System Design Characteristics for the 300 MW Submarine Link to Cheju, M. Baker et. al., CIGRE Meeting, Gold Coast, Queensland, Oct. 4, 1993.

TABLE 1

CONVERTER DATA USED IN LOAD FLOW STUDIES

Transformer rating (rectifier)	468 MVA/pole
Valve side voltage (rectifier)	331 kV
Firing delay angle (alpha)	15 degrees
Transformer rating (inverter)	446 MVA/pole
Valve side voltage (inverter)	315 kV
Firing advance angle (gamma)	18 degrees
Commutating reactance at rectifier and inverter	14 %
DC Line resistance per pole, bipolar operation	24.5 Ohms
DC Line resistance, monopolar operation	28.5 Ohms

Mode	**Rectifier Parameters Per Pole**				**Inverter Parameters Per Pole**		
	Idc p.u.	**Pdc MW**	**Udc kV**	**Qdc MVAr**	**Pdc MW**	**Udc kV**	**Qdc MVAr**
Bipolar	1.00	400	400	198	375	375	201
Bipolar	1.15	460	400	210	427	371	212
Monopolar	1.50	600	400	236	563	363	236
Monopolar	2.23	892	400	621	750	336	565

TABLE 2

SUMMARY OF OPERATING CONDITIONS FOR LOAD FLOW CASES

	Case 1		Case 2		Case 3		Case 4	
Island Generation	Base		Base		Reduced		Reduced	
DC Dispatch	Nominal		Low Ambient		Nominal		Low Ambient	
Station	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**
Bay d'Espoir	5	331	5	347.4	3	177.6	2	110.9
	No 7 as S/C	0.0	No 7 as S/C	0.0	No 7 as S/C	0.0	No 7 as S/C	0.0
Cat Arm	2	100.0	2 as S/C	0.0	2 as S/C	0.0	2 as S/C	0.0
Gas Turbines	2 as S/C	0.0	2 as S/C	0.0	2 as S/C	0.0	2 as S/C	0.0
Hinds Lake	off	0.0	off	0.0	off	0.0	off	0.0
Upper Salmon	on	80.0	on	80.0	off	0.0	off	0.0
Paradise River	on	8.0	on	8.0	on	8.0	off	0.0
Independent Generation	Table 1a	112.0	Table 1a	112.0	Table 1a	112.0	Table 1a	98.0
Holyrood	No 3 as S/C	0.0	No 3 as S/C	0.0	No 3 as S/C	0.0	No 3 as S/C	0.0
Soldiers Pond S/C	1	0.0	2	0.0	1	0.0	2	0.0
Subtotal		**631.0**		**547.4**		**297.6**		**208.9**
Soldiers Pond DC		**743.0**		**845.0**		**743.0**		**845.0**
Total Generation		**1374.0**		**1392.4**		**1040.6**		**1053.9**
Total Island Load		**1333.3**		**1333.3**		**996.0**		**996.0**

TABLE 2 (continued)

SUMMARY OF OPERATING CONDITIONS FOR LOAD FLOW CASES

	Case 5		**Case 6**		**Case 7**	
Island Generation	Reduced		Reduced		Light	
DC Dispatch	Nominal		Nominal		Minimum	
Station	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**
Bay d'Espoir	2	104.4	2	104.8	2	100.5
	No 7 as S/C	0.0	No 7 as S/C	0.0	No 7 as S/C	0.0
Cat Arm	2 as S/C	0.0	2 as S/C	0.0	2 as S/C	0.0
Gas Turbines	2 as S/C	0.0	2 as S/C	0.0	2 as S/C	0.0
Hinds Lake	off	0.0	off	0.0	off	0.0
Upper Salmon	off	0.0	off	0.0	off	0.0
Paradise River	off	0.0	off	0.0	off	0.0
Independent Generation	Table 1a	98.0	Table 1a	98.0	Table 1a	98.0
Holyrood	off	0.0	No 3 as S/C	0.0	No 3 as S/C	0.0
Soldiers Pond S/C	2	0.0	1	0.0	1	0.0
Subtotal		**202.4**		**202.8**		**198.5**
Soldiers Pond DC		**743.0**		**743.0**		**80.0**
Total Generation		**945.4**		**945.8**		**278.5**
Total Island Load		**898.7**		**898.7**		**273.0**

TABLE 2 (continued)

SUMMARY OF OPERATING CONDITIONS FOR LOAD FLOW CASES

	Case 8		Case 9	
Island Generation	High		High	
DC Dispatch	Nominal		Low Ambient	
Station	**Units**	**Generation (MW)**	**Units**	**Generation (MW)**
Bay d'Espoir	6	383.8	5	281.7
	No 7	154.0	No 7	154.0
Cat Arm	2	100.0	2	100.0
Gas Turbines	2 as S/C	0.0	2 as S/C	0.0
Hinds Lake	on	75.0	on	75.0
Upper Salmon	on	80.0	on	80.0
Paradise River	on	8.0	on	8.0
Independent Generation	Table 1a	112.0	Table 1a	112.0
Holyrood	No 3 as S/C	0.0	No 3 as S/C	112.0
Soldiers Pond S/C	1	0.0	2	0.0
Subtotal		**912.8**		**810.7**
Soldiers Pond DC		**743.0**		**845.0**
Total Generation		**1655.8**		**1655.7**
Total Island Load		**1602.4**		**1602.4**

TABLE 3

INDEPENDENT CUSTOMER GENERATION

Plant	Generation Cases 1 to 3 Cases 8 and 9	Generation Cases 4 to 7
Deer Lake	62.0	48.0
Corner Brook Frequency Converter	18.0	18.0
Star Lake	15.0	15.0
Rattle Brook	4.0	4.0
North West River	8.0	8.0
South West River	5.0	5.0
Total	**112.0**	**98.0**

TABLE 4

FAULT LEVELS AND SHORT CIRCUIT RATIO AT SOLDIERS POND
Soldiers Pond S/C = 150 MVAr, AC Filters = 245 MVAr

Contingency	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**	**Case 7**	**Case 8**	**Case 9**
Gross DC Infeed	750	855	750	855	750	750	80	750	855
(a) Fault Level at Soldiers Pond 230 kV Bus Excluding Soldiers Pond Contributions (MVA)									
NONE	1570	1570	1521	1491	1014	1491	1486	1585	1572
SOP-HRD	1564	1564	1516	1486	1014	1486	1481	1579	1566
SOP-HWD	1566	1566	1517	1488	1010	1488	1483	1581	1568
SOP-OPD	1567	1567	1518	1488	1011	1488	1483	1582	1569
SOP-WAV	1459	1459	1423	1401	925	1401	1397	1469	1460
WAV-CBC	1480	1480	1442	1419	941	1419	1415	1491	1482
CBC-SSD	1480	1480	1442	1419	941	1419	1415	1491	1482
WAV-SSD	1450	1450	1416	1394	917	1394	1391	1460	1451
SSD-BDE	1412	1412	1386	1366	888	1366	1363	1420	1413
HWD GT	1347	1347	1298	1268	790	1268	1263	1361	1349
(b) Effective Short Circuit Ratio at Soldiers Pond 230 kV Bus									
No. S/C in Service	1	2	1	2	2	1	1	1	2
NONE	2.57	2.95	2.50	2.86	2.63	2.46	23.0	2.59	2.96
SOP-HRD	2.56	2.95	2.49	2.85	2.63	2.45	23.0	2.58	2.95
SOP-HWD	2.56	2.95	2.50	2.86	2.62	2.46	23.0	2.58	2.95
SOP-OPD	2.56	2.95	2.50	2.86	2.62	2.46	23.0	2.58	2.95
SOP-WAV	2.42	2.82	2.37	2.76	2.51	2.34	21.9	2.43	2.82
WAV-CBC	2.45	2.85	2.40	2.78	2.63	2.37	22.1	2.46	2.85
CBC-SSD	2.45	2.85	2.40	2.78	2.53	2.37	22.1	2.46	2.85
WAV-SSD	2.41	2.81	2.36	2.75	2.50	2.33	21.8	2.42	2.81
SSD-BDE	2.36	2.77	2.32	2.71	2.46	2.29	21.5	2.37	2.77
HWD GT	2.27	2.69	2.20	2.60	2.33	2.16	20.2	2.29	2.69

TABLE 5A

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND BASE CASES

Case	Description	DC Infeed MW	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
				DC Converter	Island System	Total	
1	Base Case	743	515	402	74.8	476.8	38.2
2	Base Case	845	653	484	107.9	591.9	61.1
3	Reduced Load	743	515	402	-7.6	394.4	120.6
4	Reduced Load	845	653	484	31.5	515.5	137.5
5	Reduced Load	743	515	402	-31.1	370.9	144.1
6	Reduced Load	743	515	402	-19.4	382.6	132.4
7	Light Load	80	515	26	30.9	56.9	458.1
8	High Load	743	515	402	123.0	525.0	-10.0
9	High Load	845	653	484	169.0	653.0	0.0

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

Equipment	MVAr Capacity at 230 kV Bus
Soldiers Pond Synchronous Condenser	138
Soldiers Pond AC Filters	245
Holyrood Synchronous Condenser	132

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5B

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 1

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
1.0	None	515	402.0	74.8	476.8	39.0
1.1	Soldiers Pond-Holyrood	515	402.0	76.8	478.8	36.2
1.2	Soldiers Pond-Hardwoods	515	402.0	89.1	491.1	23.9
1.3	Soldiers Pond-Oxen Pond	515	402.0	83.9	485.9	29.1
1.4	Soldiers Pond-West Avalon	515	402.0	88.1	490.1	24.9
1.5	West Avalon-Come By Chance	515	402.0	84.9	486.9	28.1
1.6	Come By Chance-Sunnyside	515	402.0	84.9	486.9	28.1
1.7	West Avalon-Sunnyside	515	402.0	86.9	488.9	26.1
1.8	Sunnyside-Bay d'Espoir	515	402.0	109.7	511.7	3.3
1.9	Hardwoods Gas Turbine	515	402.0	107.6	509.6	5.4
1.10	Permanent Block One Pole Second Pole at 2 p.u. Power	515	565.0	-41.6	523.4	-8.4

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5C

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 2

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
2	None	653	484.0	107.9	591.9	61.1
2.1	Soldiers Pond-Holyrood	653	484.0	110.5	594.5	58.5
2.2	Soldiers Pond-Hardwoods	653	484.0	115.2	599.2	53.8
2.3	Soldiers Pond-Oxen Pond	653	484.0	117.4	601.4	51.6
2.4	Soldiers Pond-West Avalon	653	484.0	112.8	596.8	56.2
2.5	West Avalon-Come By Chance	653	484.0	102.5	586.5	66.5
2.6	Come By Chance-Sunnyside	653	484.0	101.0	585.0	68.0
2.7	West Avalon-Sunnyside	653	484.0	106.1	590.1	62.9
2.8	Sunnyside-Bay d'Espoir	653	484.0	118.1	602.1	50.9
2.9	Hardwoods Gas Turbine	653	484.0	125.2	609.2	43.8

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 276 + 245 + 132 = 653 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5D

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 3

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
3.0	None	515	402.0	-7.6	394.4	120.6
3.1	Soldiers Pond-Holyrood	515	402.0	-4.0	398.0	117.0
3.2	Soldiers Pond-Hardwoods	515	402.0	-3.1	398.9	116.1
3.3	Soldiers Pond-Oxen Pond	515	402.0	-1.3	400.7	114.3
3.4	Soldiers Pond-West Avalon	515	402.0	23.4	425.4	89.6
3.5	West Avalon-Come By Chance	515	402.0	14.8	416.8	98.2
3.6	Come By Chance-Sunnyside	515	402.0	11.0	413.0	102.0
3.7	West Avalon-Sunnyside	515	402.0	20.7	422.7	92.3
3.8	Sunnyside-Bay d'Espoir	515	402.0	26.8	428.8	86.2
3.9	Hardwoods Gas Turbine	515	402.0	26.9	428.9	86.1

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5E

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 4

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
4	None	653	484.0	31.5	515.5	137.5
4.1	Soldiers Pond-Holyrood	653	484.0	33.6	517.6	135.4
4.2	Soldiers Pond-Hardwoods	653	484.0	36.2	520.2	132.8
4.3	Soldiers Pond-Oxen Pond	653	484.0	38.1	522.1	130.9
4.4	Soldiers Pond-West Avalon	653	484.0	85.9	569.9	83.1
4.5	West Avalon-Come By Chance	653	484.0	64.0	548.0	105.0
4.6	Come By Chance-Sunnyside	653	484.0	55.2	539.2	113.8
4.7	West Avalon-Sunnyside	653	484.0	72.1	556.1	96.9
4.8	Sunnyside-Bay d'Espoir	653	484.0	78.4	562.4	90.6
4.9	Hardwoods Gas Turbine	653	484.0	66.3	550.3	120.6

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 276 + 245 + 132 = 653 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5F

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 5

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
5	None	515	402.0	-31.1	370.9	144.1
5.1	Soldiers Pond-Holyrood	515	402.0	-28.8	373.2	141.8
5.2	Soldiers Pond-Hardwoods	515	402.0	-26.7	375.3	139.7
5.3	Soldiers Pond-Oxen Pond	515	402.0	-25.0	377.0	138.0
5.4	Soldiers Pond-West Avalon	515	402.0	6.0	408.0	107.0
5.5	West Avalon-Come By Chance	515	402.0	-9.2	392.8	122.2
5.6	Come By Chance-Sunnyside	515	402.0	-15.0	387.0	128.0
5.7	West Avalon-Sunnyside	515	402.0	-1.2	400.8	114.2
5.8	Sunnyside-Bay d'Espoir	515	402.0	5.2	407.2	107.8
5.9	Hardwoods Gas Turbine	515	402.0	-2.9	399.1	115.9

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5G

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 6

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
6	None	515	402.0	-19.4	382.6	132.4
6.1	Soldiers Pond-Holyrood	515	402.0	-17.2	384.8	130.2
6.2	Soldiers Pond-Hardwoods	515	402.0	-15.0	387.0	128.0
6.3	Soldiers Pond-Oxen Pond	515	402.0	-13.3	388.7	126.3
6.4	Soldiers Pond-West Avalon	515	402.0	22.9	424.9	90.1
6.5	West Avalon-Come By Chance	515	402.0	5.8	407.8	107.2
6.6	Come By Chance-Sunnyside	515	402.0	0.1	402.1	112.9
6.7	West Avalon-Sunnyside	515	402.0	13.8	415.8	99.2
6.8	Sunnyside-Bay d'Espoir	515	402.0	20.1	422.1	92.9
6.9	Hardwoods Gas Turbine	515	402.0	12.7	414.7	100.3

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5H

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 7

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
7	None	515	26.0	30.9	56.9	458.1
7.1	Soldiers Pond-Holyrood	515	26.0	33.1	59.1	455.9
7.2	Soldiers Pond-Hardwoods	515	26.0	35.5	61.5	453.5
7.3	Soldiers Pond-Oxen Pond	515	26.0	37.3	63.3	451.7
7.4	Soldiers Pond-West Avalon	515	26.0	48.9	74.9	440.1
7.5	West Avalon-Come By Chance	515	26.0	42.3	68.3	446.7
7.6	Come By Chance-Sunnyside	515	26.0	36.8	62.8	452.2
7.7	West Avalon-Sunnyside	515	26.0	43.4	69.4	445.6
7.8	Sunnyside-Bay d'Espoir	515	26.0	42.4	68.4	446.6
7.9	Hardwoods Gas Turbine	515	26.0	31.9	57.9	457.1

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5I

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 8

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
8	None	515	402.0	123.0	525.0	-10.0
8.1	Soldiers Pond-Holyrood	515	402.0	123.0	525.0	-10.0
8.2	Soldiers Pond-Hardwoods	515	402.0	119.0	521.0	-6.0
8.3	Soldiers Pond-Oxen Pond	515	402.0	121.0	523.0	-8.0
8.4	Soldiers Pond-West Avalon	515	402.0	121.0	523.0	-8.0
8.5	West Avalon-Come By Chance	515	402.0	121.0	523.0	-8.0
8.6	Come By Chance-Sunnyside	515	402.0	122.0	524.0	-9.0
8.7	West Avalon-Sunnyside	515	402.0	121.0	523.0	2.0
8.8	Sunnyside-Bay d'Espoir	515	402.0	122.0	524.0	-9.0
8.9	Hardwoods Gas Turbine	515	402.0	122.0	524.0	-9.0
8.10	Permanent Block One Pole Second Pole at 2 p.u. Power	515	565.0	-30.4	534.6	-19.6

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 138 + 245 + 132 = 515 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5J

SYSTEM MVAR REQUIREMENTS AT SOLDIERS POND - OUTAGE CONDITIONS CASE 9

Case	Description of Outages	Total MVAr Capacity (1)	MVAr Requirements			MVAr Margin (2)
			DC Converter	Island System	Total	
9	None	653	484.0	169.0	653.0	0.0
9.1	Soldiers Pond-Holyrood	653	484.0	171.0	655.0	-2.0
9.2	Soldiers Pond-Hardwoods	653	484.0	171.0	655.0	-2.0
9.3	Soldiers Pond-Oxen Pond	653	484.0	167.0	651.0	2.0
9.4	Soldiers Pond-West Avalon	653	484.0	157.0	641.0	12.0
9.5	West Avalon-Come By Chance	653	484.0	167.0	651.0	2.0
9.6	Come By Chance-Sunnyside	653	484.0	167.0	651.0	2.0
9.7	West Avalon-Sunnyside	653	484.0	169.0	653.0	0.0
9.8	Sunnyside-Bay d'Espoir	653	484.0	169.0	653.0	0.0
9.9	Hardwoods Gas Turbine	653	484.0	169.0	653.0	0.0

1. Total MVAr Capacity = Soldiers Pond S/C + Soldiers Pond AC Filters + Holyrood #3 S/C

   Total MVAr Capacity = 276 + 245 + 132 = 653 MVAr

2. MVAr Margin = Total MVAr Capacity - Total MVAr Requirements

TABLE 5K

SUMMARY OF MVAR MARGIN

Contingency	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
					Bipole Operation				
Gross DC Infeed	750	855	750	855	750	750	80	750	855
					MVAr Surplus at Soldiers Pond and Holyrood				
NONE	39.0	61.1	120.6	120.6	144.1	132.4	458.1	-10.0	0.0
SOP-HRD	36.2	58.5	117.0	117.0	141.8	130.2	455.9	-10.0	-2.0
SOP-HWD	23.9	53.8	116.1	116.1	139.7	128.0	453.5	-6.0	-2.0
SOP-OPD	29.1	51.6	114.3	114.3	138.0	126.3	451.7	-8.0	2.0
SOP-WAV	24.9	56.2	89.6	89.6	107.0	90.1	440.1	-8.0	12.0
WAV-CBC	28.1	66.5	98.2	98.2	122.2	107.2	446.7	-8.0	2.0
CBC-SSD	28.1	68.0	102.0	102.0	128.0	112.9	452.2	-9.0	2.0
WAV-SSD	26.1	62.9	92.3	92.3	114.2	99.2	445.6	2.0	0.0
SSD-BDE	3.3	50.9	86.2	86.2	107.8	92.9	446.6	-9.0	0.0
HWD GT	5.4	43.8	86.1	86.1	115.9	100.3	457.1	-9.0	0.0
Pole at 2 p.u. Power	-8.4	-	-	-	-	-	-	-19.6	-

TABLE 6

LIST OF DISTURBANCES WITH FAULT DURATION

Case	Loss of / Disturbance	Duration
Equipment Tripping without Faults		
a	Line	Permanent
b	Shunt Capacitor / Filter	Permanent
c	Synchronous Condenser	Permanent
d	Generator	Permanent
e	DC Pole	300 ms
f	DC Pole	Permanent
g	DC Bipole	Permanent
AC System Bus Faults without Equipment or Transmission Line Tripping Support		
h	230 kV Three Phase Bus Fault	6 cycles
i	230 kV SLG bus Fault	6 cycles
AC System Faults with Tripping		
j	230 kV Three Phase Fault with Disconnection of: • Line • Shunt Capacitor / Filter • Synchronous Condenser • Generator • DC Pole	6 cycles
k	230 kV SLG Fault with Disconnection of: • Line • Shunt Capacitor / Filter • Synchronous Condenser • Generator • DC Pole	6 cycles
AC System Faults with Delayed Clearance		
l	230 kV SLG Fault with Unsuccessful Single Pole Reclosing	6 – 45 – 4 cycles
m	230 kV 3 Phase Fault with Back up Clearing	23 cycles
m_s	230 kV SLG Fault with Back up Clearing	23 cycles
n	138 kV 3 Phase Fault with Back up Clearing	30 cycles
n_s	138 kV SLG Fault	40 cycles
o	66 kV 3 Phase Bus Fault	30 cycles
o_s	66 kV SLG Fault	40 cycles
AC System Faults at Rectifier		
p	230 kV 3 Phase Fault at Gull	6 cycles
q	230 kV SLG Fault at Gull	12 cycles

TABLE 7

LIST OF SIMULATED STABILITY CASES

Case	Disturbance	Dispatch Conditions						
		1	2	3	4	6	8	9
Equipment Tripping without Faults								
a	Line	✓	✓	✓		4	✓	
c	Synchronous Condenser	1	✓			4	1	
d	Generator					4		✓
f	DC Pole, Permanent	1	1	✓	✓	✓	1	
AC System Faults without Tripping								
h	230 kV Three Phase Bus Fault	4	✓	✓	4	4	✓	
i	230 kV SLG Bus Fault	4			4	4		1
AC System Faults with Tripping								
	230 kV 3 Phase Fault, Disconnect							
j_a	Line	✓	✓	✓	✓	✓	✓	✓
j_c	Synchronous Condenser	1	✓	✓	✓	✓	4	1
j_d	Generator	4	4	4	4	4		4
j_f	DC Pole	1	1	✓	✓	✓	1	1
	230 kV SLG Fault, Disconnect							
k_a	Line							
k_c	Synchronous Condenser	1	✓	✓	✓	4	4	1
k_d	Generator	4	4	4	4	4	4	4
k_f	DC Pole	1	1	✓	✓	4	4	1
AC System Faults with Delayed Clearance								
l	230 kV SLG Fault , Unsuccessful Reclosing	4	4	4	4	4	4	✓
m	230 kV 3 Phase Fault, Back up Clearing	✓	4	4	✓	4	2	4
m_s	230 kV SLG Fault, Back up Clearing	3, 4	4	3, 4	3, 4	4	3	4
n	138 kV 3 Phase Fault, Back up Clearing	4	4	✓	4	4	4	4
n_s	138 kV SLG Fault	4	4	✓	4	4	4	4
o	66 kV 3 Phase Fault	4	4	✓	4	4	4	4
o_s	66 kV SLG Fault	4	4	✓	4	4	4	4
AC System Faults at Rectifier End								
p	230 kV 3 Phase Fault at Gull	4	4	4	4	4	4	4
q	230 kV SLG Fault at Gull	4	4	4	4	4	4	4

✓ Satisfies design criteria
(1) Requires additional short term (10 minutes duration) var support
(2) Requires additional transient var or inertia support
(3) Fault duration reduced
(4) Case run assuming three synchronous condensers installed at Soldiers Pond

Note: Only cases marked with a ✓ or a number have been run

TABLE 8

MINIMUM FREQUENCY AND LOAD SHED FOR NOMINAL DISPATCH CASES

Case	Disturbance	Dispatch Conditions							
		1		3		6		8	
		Hz	MW	Hz	MW	Hz	MW	Hz	MW
AC System Faults without Tripping									
h	230 kV Three Phase Bus Fault	58.8	34.1 *			58.96	0.0 *		
i	230 kV SLG Bus Fault	58.8	0 *			58.85	0.0 *		
AC System Faults with Delayed Clearance									
l	230 kV SLG Fault , Unsuccessful Reclosing	58.8	17.50 *		19.3 *	58.86	0.0 *	59.1	0 *
m	230 kV 3 Phase Fault, Back up Clearing	59.3	0	59.4	0 **	58.92	0.0 *	59.6	0 *
m_s	230 kV SLG Fault, Back up Clearing	58.2	17.5 **	58.6	19.3 **	59.15	0.0 *		
n	138 kV 3 Phase Fault, Back up Clearing	58.9	0 *	58.4	58.1	59.09	0.0 *	58.6	79.2 *
n_s	138 kV SLG Fault	58.7	17.5 *	58.4	43.4	58.85	0.0 *	58.9	0.0 *
o	66 kV 3 Phase Fault	58.8	0 *	58.4	31.6	58.97	0.0 *	58.78	22.0 *
o_s	66 kV SLG Fault	58.7	44 *	58.2	82.3	58.87	0.0 *	58.78	0.0 *
AC System Faults at Rectifier End									
p	230 kV 3 Phase Fault at Gull	59	0 *	58.8	0 *	58.80	0.0 *	58.78	0.0 *
q	230 kV SLG Fault at Gull	59.1	0 *	58.7	11.4 *	58.67	9.6 *	58.48	45.2 *

* 3 synchronous condensers installed at Soldiers Pond (2 in service).

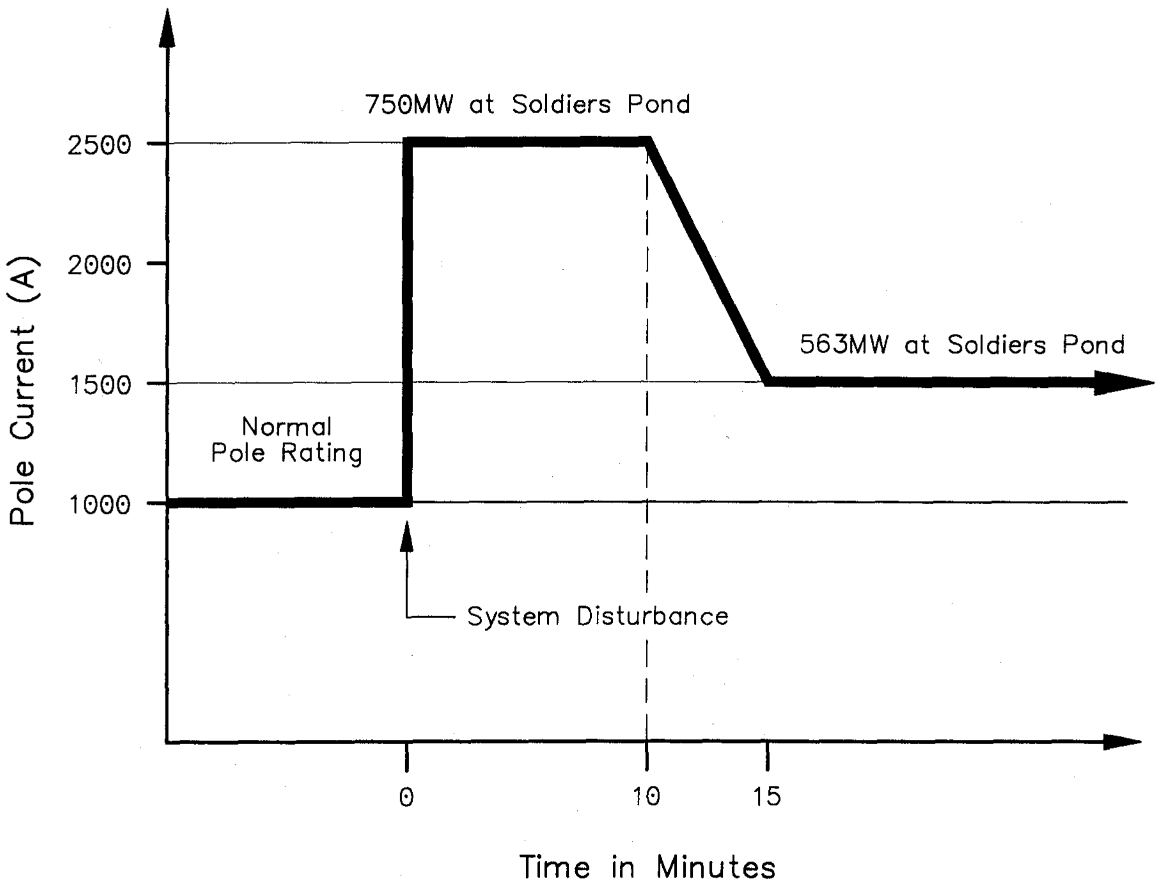
** 3 synchronous condensers installed at Soldiers Pond (2 in service) plus reduced fault clearing time.

TABLE 9

MINIMUM FREQUENCY AND LOAD SHED FOR LOW AMBIENT DISPATCH CASES

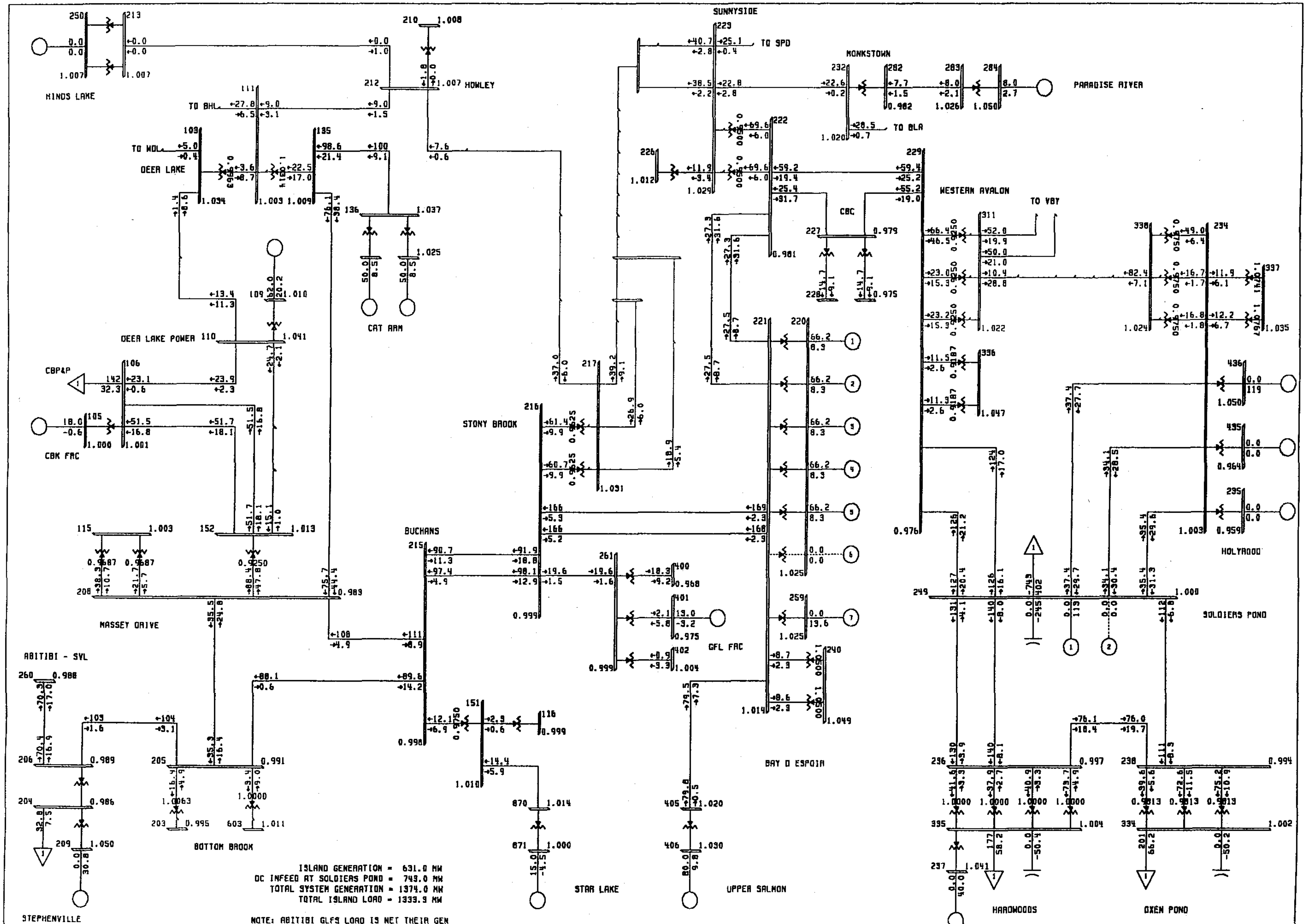
Case	Disturbance	Dispatch Conditions					
		2		4		9	
		Hz	MW	Hz	MW	Hz	MW
Equipment Tripping without Faults							
a	Line Tripping	60.00	0.00				
c	Synchronous Condenser Tripping	60.00	0.00				
d	Generator Tripping					59.30	0.00
f	DC Pole, Permanent	60.00	0.00	58.70	55.20		
AC System Faults without Tripping							
h	230 kV Three Phase Bus Fault	60.00	0.00	58.90	10.70 *		
i	230 kV SLG Bus Fault			58.83	0.00	58.70	21.80 *
AC System Faults with Tripping							
	230 kV 3 Phase Fault, Disconnect						
j_a	Line	60.00	0.00	59.70	0.00	59.90	0.00
j_c	Synchronous Condenser	60.00	0.00	59.60	0.00	59.90	0.00
j_d	Generator	58.72	17.50 *	58.95	10.70 *	58.70	21.80 *
j_f	DC Pole	59.10	0.00	58.80	55.20	59.30	0.00
	230 kV SLG Fault, Disconnect						
k_a	Line						
k_c	Synchronous Condenser	60.00	0.00	59.20	0.00	59.30	0.00
k_d	Generator	58.85	0.00 *	58.77	19.30 *	58.70	21.80 *
k_f	DC Pole	60.00	0.00	58.70	55.20	59.00	0.00
AC System Faults with Delayed Clearance							
l	230 kV SLG Fault, Unsuccessful Reclosing	58.84	0.00 *	58.40	31.40 *	58.90	0.00
m	230 kV 3 Phase Fault, Back up Clearing	59.00	0.00 *	59.00	7.90	59.50	0.00 *
m_s	230 kV SLG Fault, Back up Clearing	58.70	17.50 *	58.56	61.00 *	59.20	0.00 *
n	138 kV 3 Phase Fault, Back up Clearing	58.70	17.50 *	58.65	55.20 *	59.20	0.00 *
n_s	138 kV SLG Fault	58.70	17.50 *	58.40	96.70 *	58.97	0.00 *
o	66 kV 3 Phase Fault	58.45	59.00 *	58.76	58.40 *	59.03	0.00 *
o_s	66 kV SLG Fault	58.66	52.60 *	58.30	114.20 *	58.94	0.00 *
AC System Faults at Rectifier End							
p	230 kV 3 Phase Fault at Gull	58.83	0.00 *	58.66	11.40 *	58.90	0.00 *
q	230 kV SLG Fault at Gull	58.75	17.50 *	58.34	31.40 *	59.00	0.00 *

* 3 synchronous condensers in service at Soldiers Pond



Inverter Pole Rating following an Outage of Other Pole
Figure 1

200\000001\Fig.1

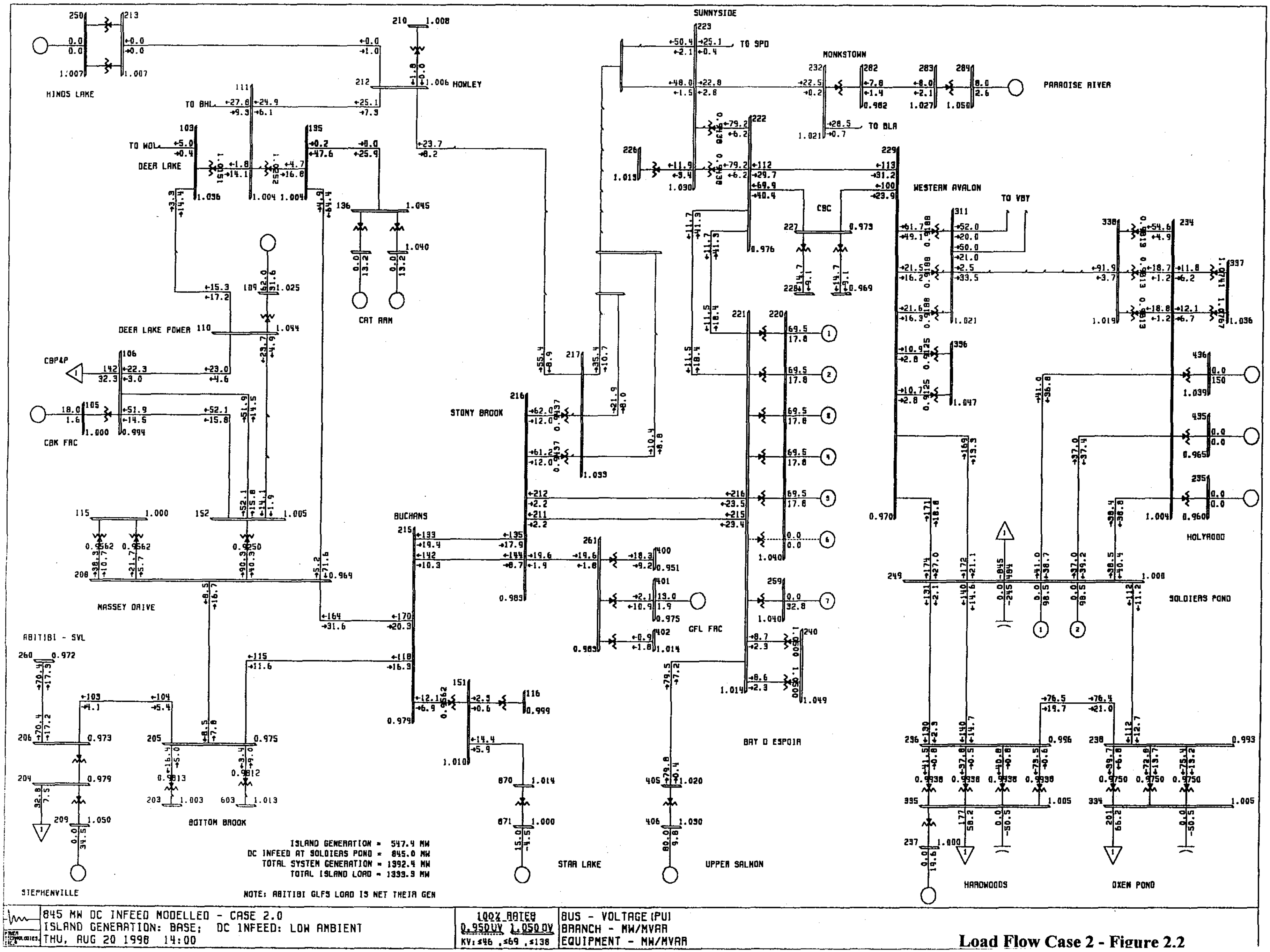


743 MW DC INFEED MODELLED-CASE_1.0:
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
FRI, AUG 21 1998 8:09

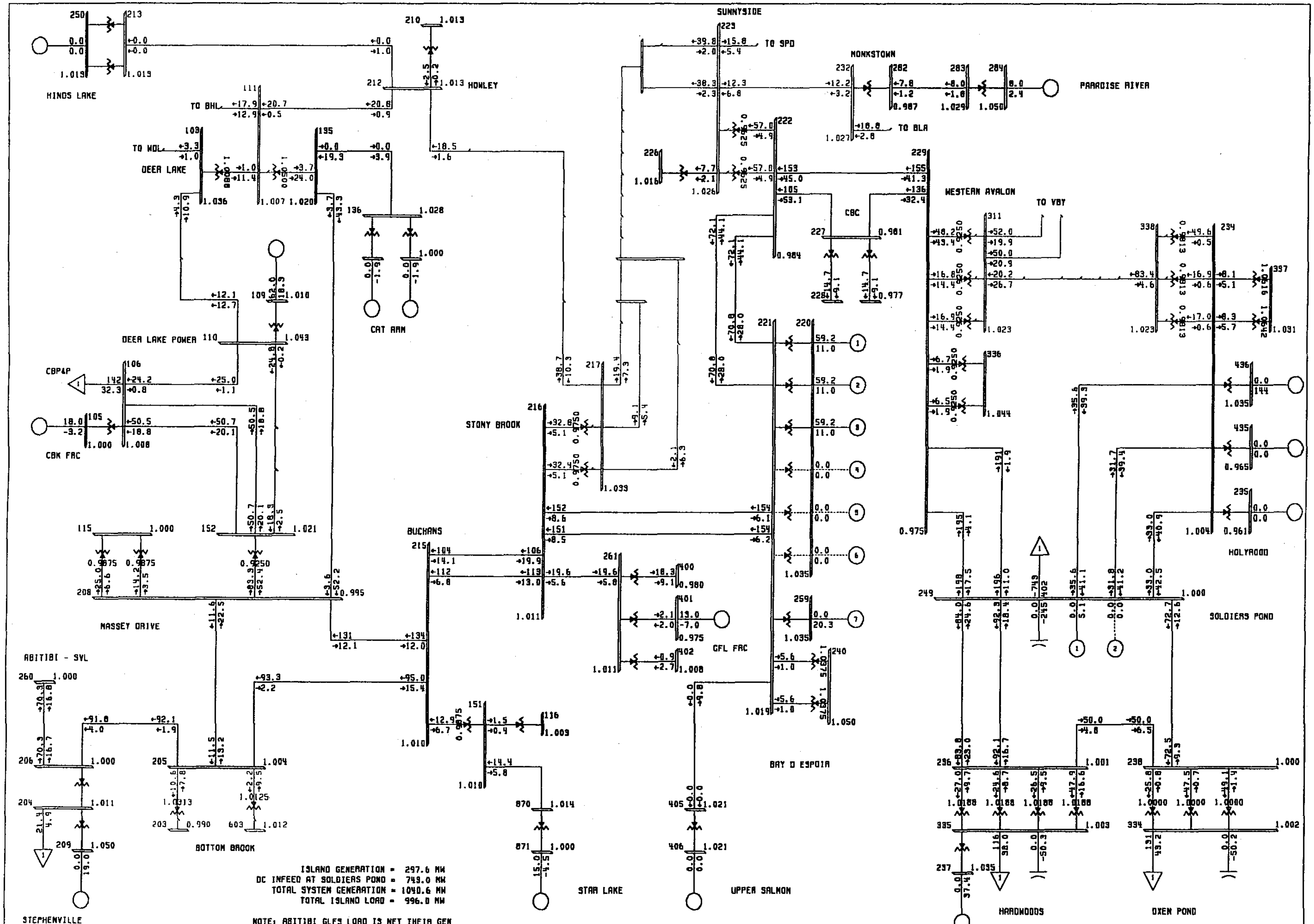
100% RATEB
0.950UV 1.050OV
KV: ≤46 , ≤69 , ≤138

BUS - VOLTAGE (PU)
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

Load Flow Case 1 - Figure 2.1



Load Flow Case 2 - Figure 2.2

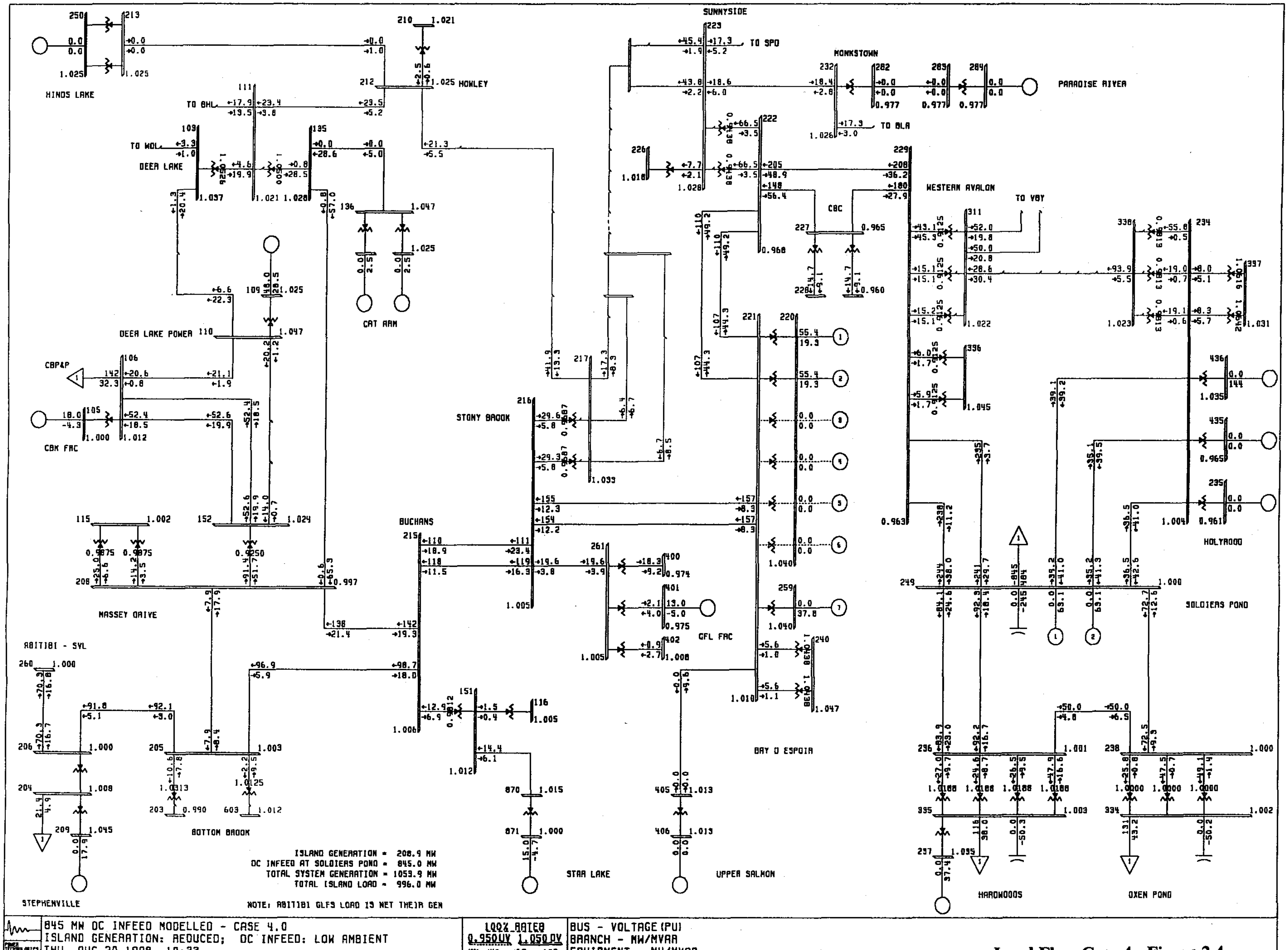


743 MW DC INFEED MODELLED - CASE 3.0
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL
THU, AUG 20 1998 11:57

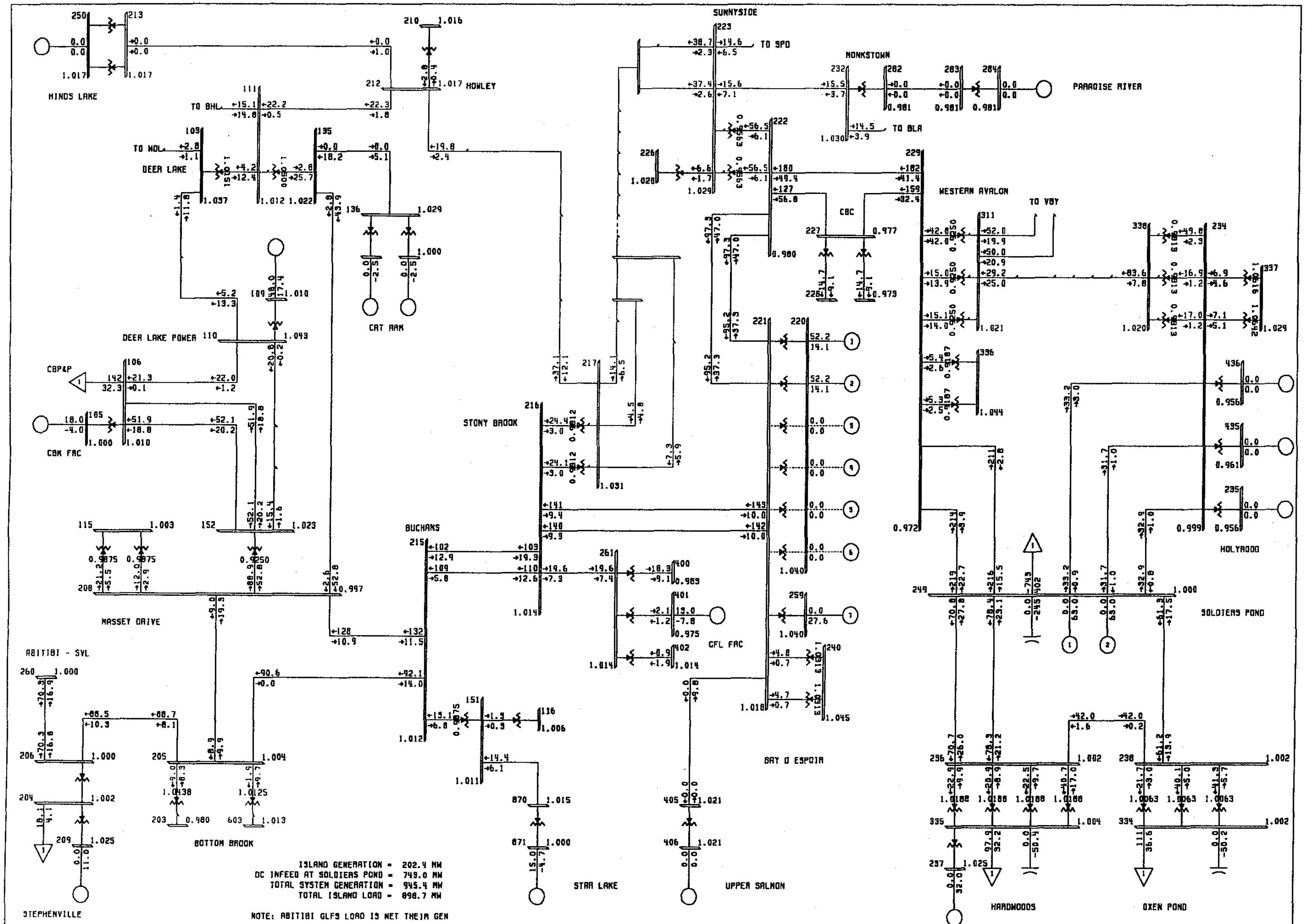
100% RATEB
0.950UV 1.050OV
KV: ≤46 , ≤69 , ≤138

BUS - VOLTAGE (PU)
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

Load Flow Case 3 - Figure 2.3



Load Flow Case 4 - Figure 2.4

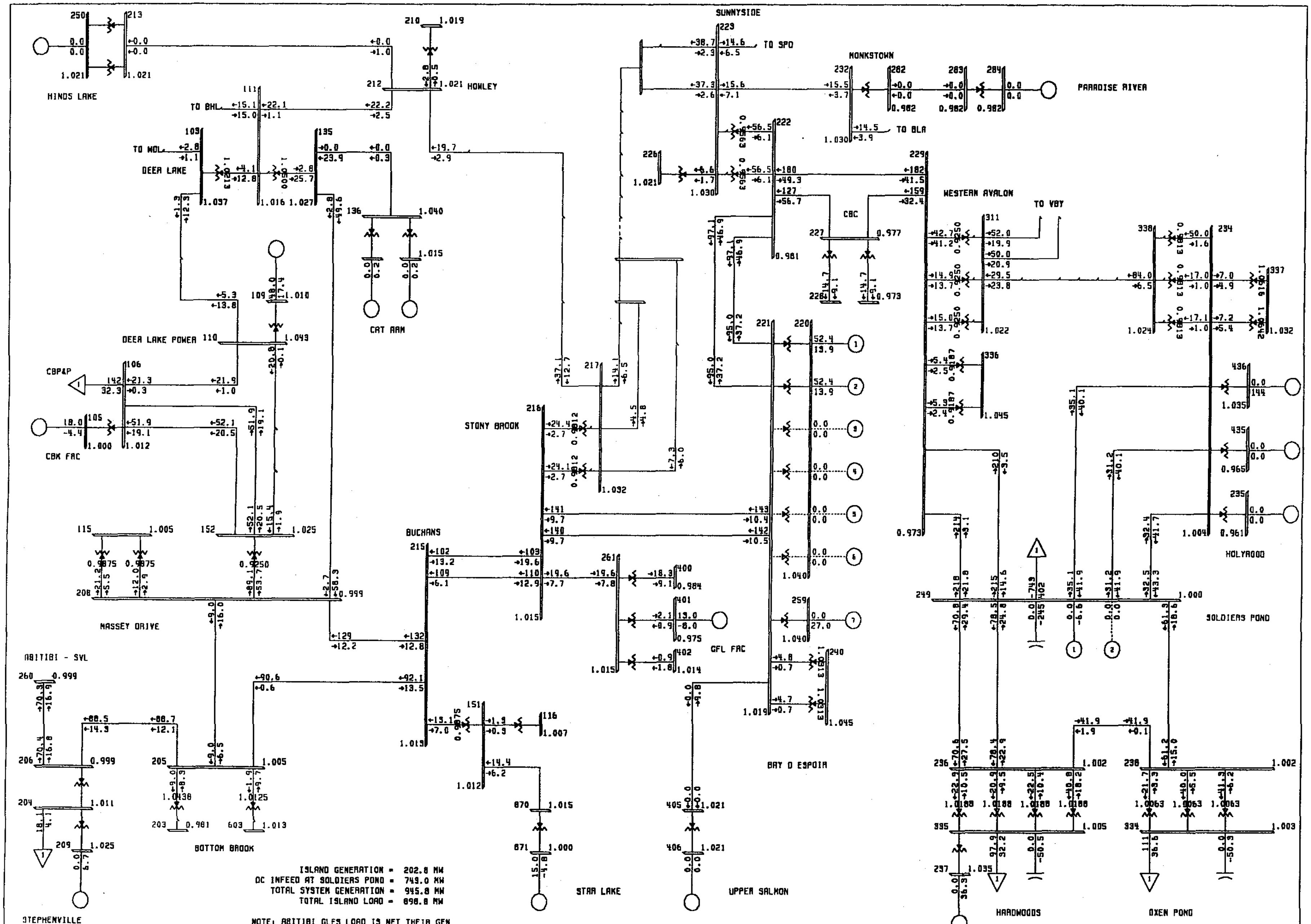


743 MW DC INFEED MODELLED - CASE 5.0
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL
THU, AUG 20 1998 10:43

100% RATEB
0.950UV 1.050OV
KV: ≤46, ≤69, ≤138

BUS - VOLTAGE (PU)
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

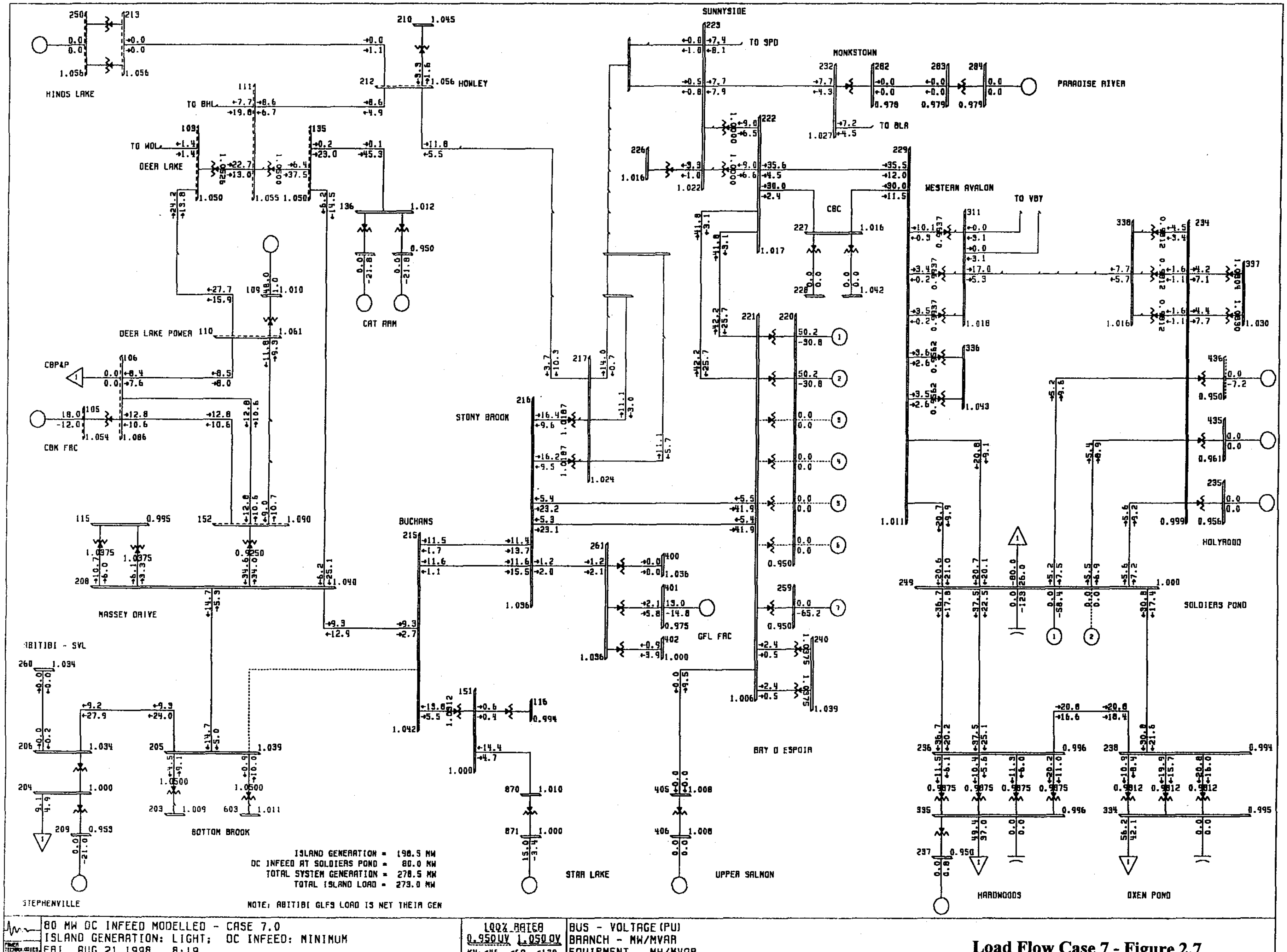
Load Flow Case 5 - Figure 2.5



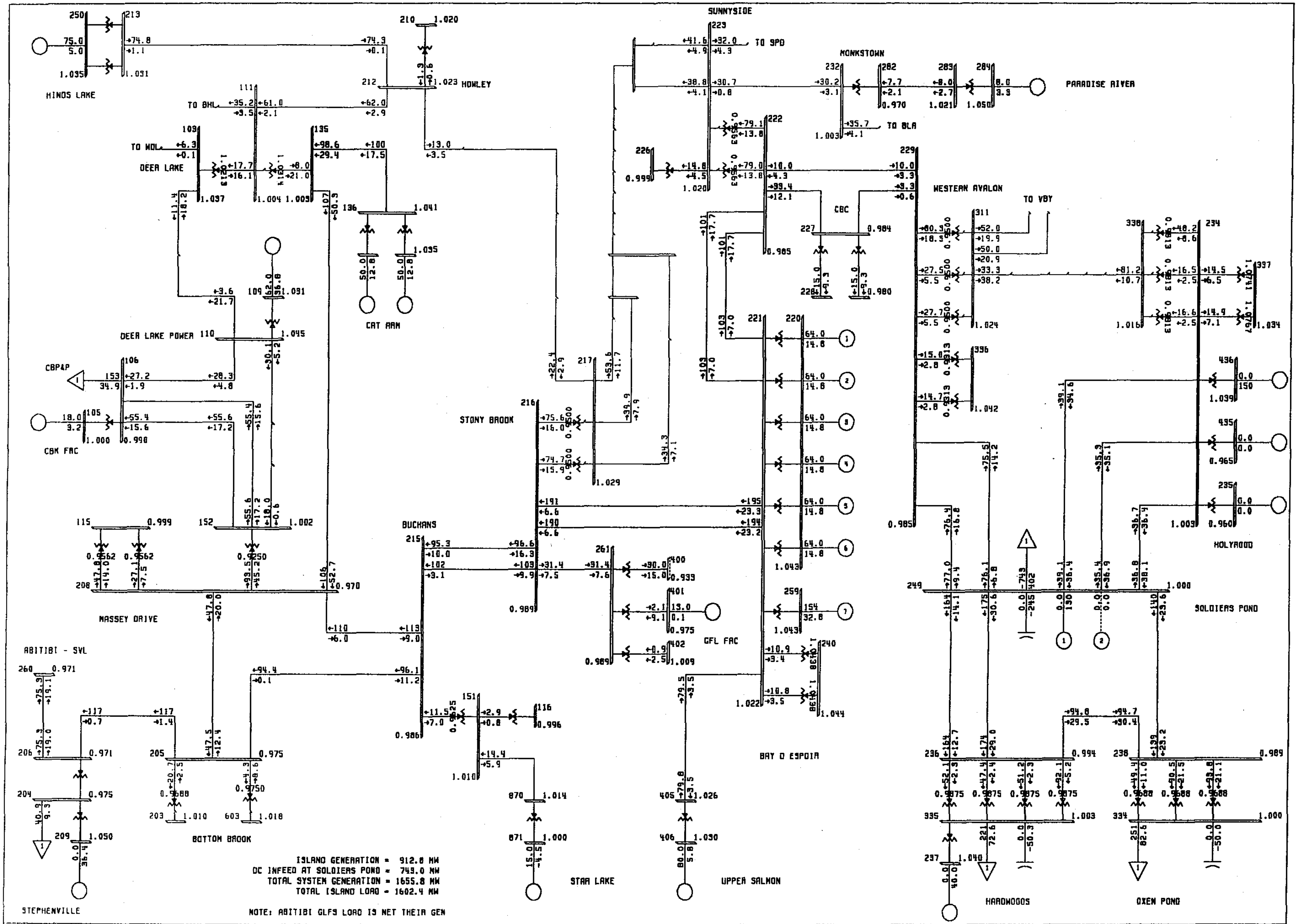
743 MW DC INFEED MODELLED - CASE 6.0
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL
THU, AUG 20 1998 14:32

100% RATEB	BUS - VOLTAGE (PU)
0.950UV 1.050OV	BRANCH - MW/MVAR
KV: ≤46 , ≤69 , ≤138	EQUIPMENT - MW/MVAR

Load Flow Case 6 - Figure 2.6



Load Flow Case 7 - Figure 2.7

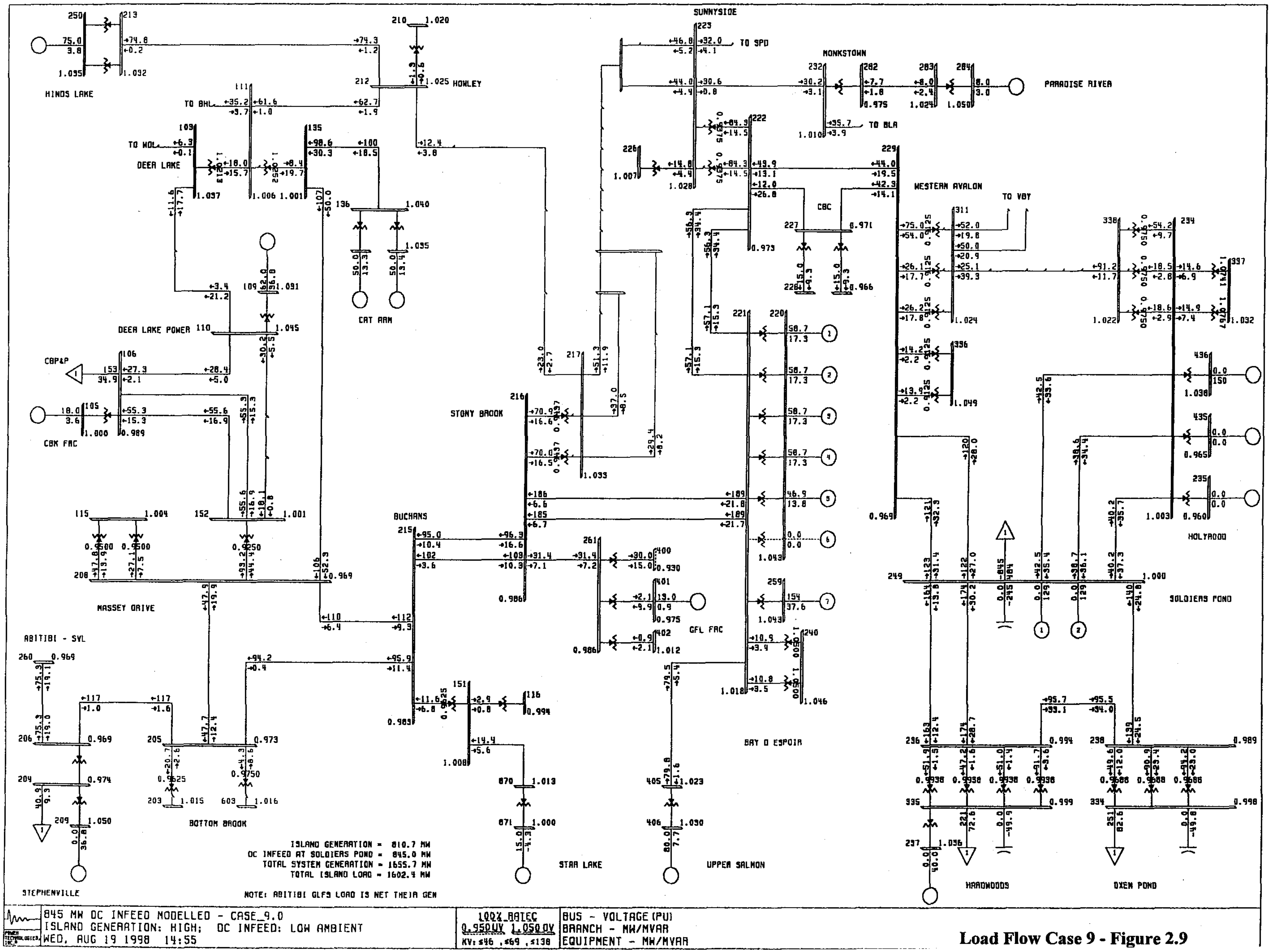


743 MW DC INFEED MODELLED - CASE_8.0
ISLAND GENERATION: HIGH; DC INFEED: NOMINAL
THU, AUG 20 1998 13:18

100% RATEC
0.950UV 1.050OV
KV: ≤46, ≤69, ≤138

BUS - VOLTAGE (PU)
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

Load Flow Case 8 - Figure 2.8



Load Flow Case 9 - Figure 2.9

POWER TECHNOLOGIES, INC.

751 MW DC INFEED MODELLED - CASE 3.0 - 1 SC AT SOLD.POND
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL - AMIN = 15
BLOCKED 1 POLE PERMANENTLY

FILE: c:\psse25w\HVDC\CASE3\case3.0f_a15_imode_1sc_a.out

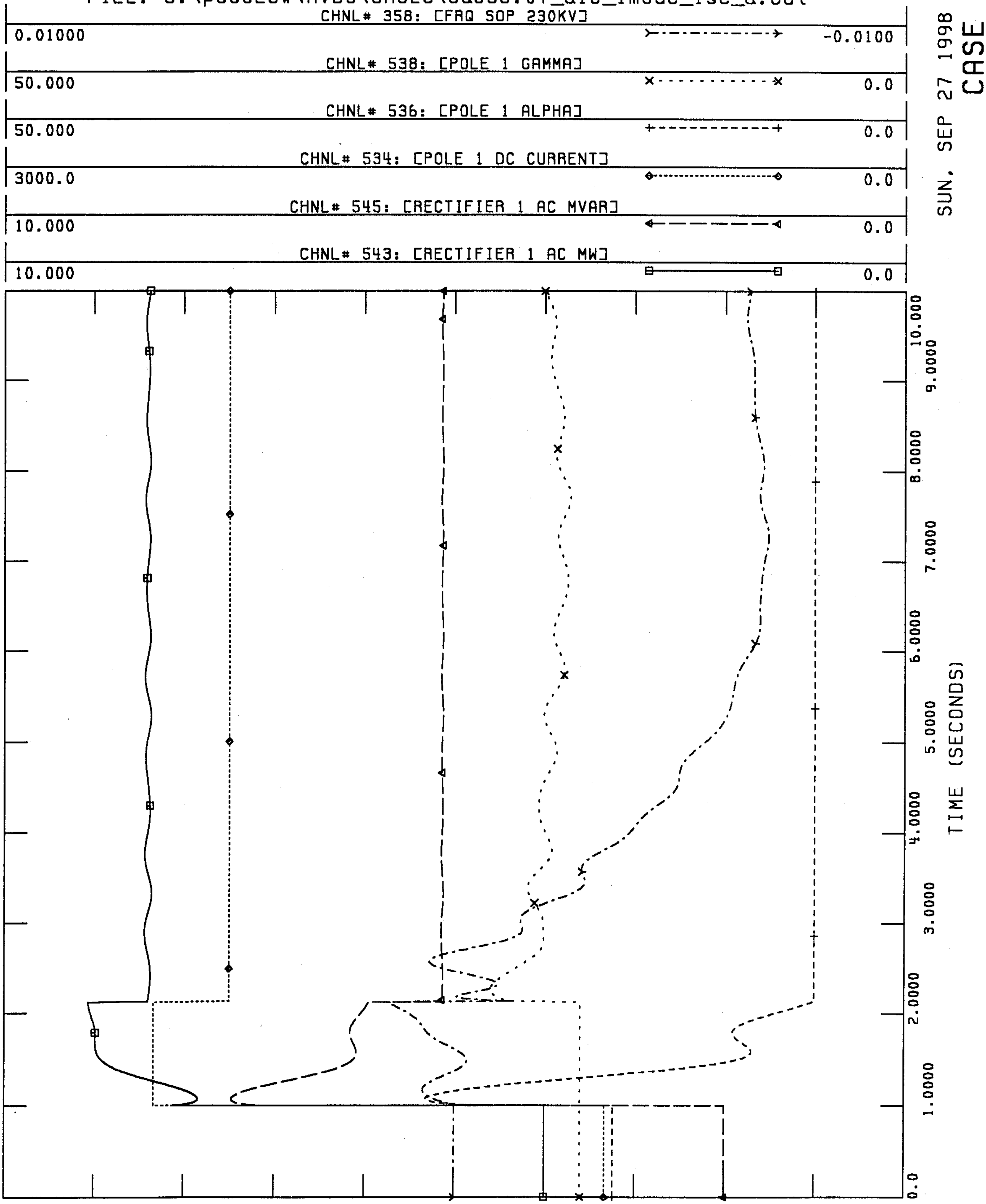


Figure 3.1

751 MW DC INFEED MODELLED - CASE 3.0 - 1 SC AT SOLD.POND
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL - AMIN = 15
BLOCKED 1 POLE PERMANENTLY

FILE: c:\psse25w\HVDC\CASE3\case3.0f_a15_imode_1sc_a.out

SUN, SEP 27 1998 11:01
CASE 3.0F

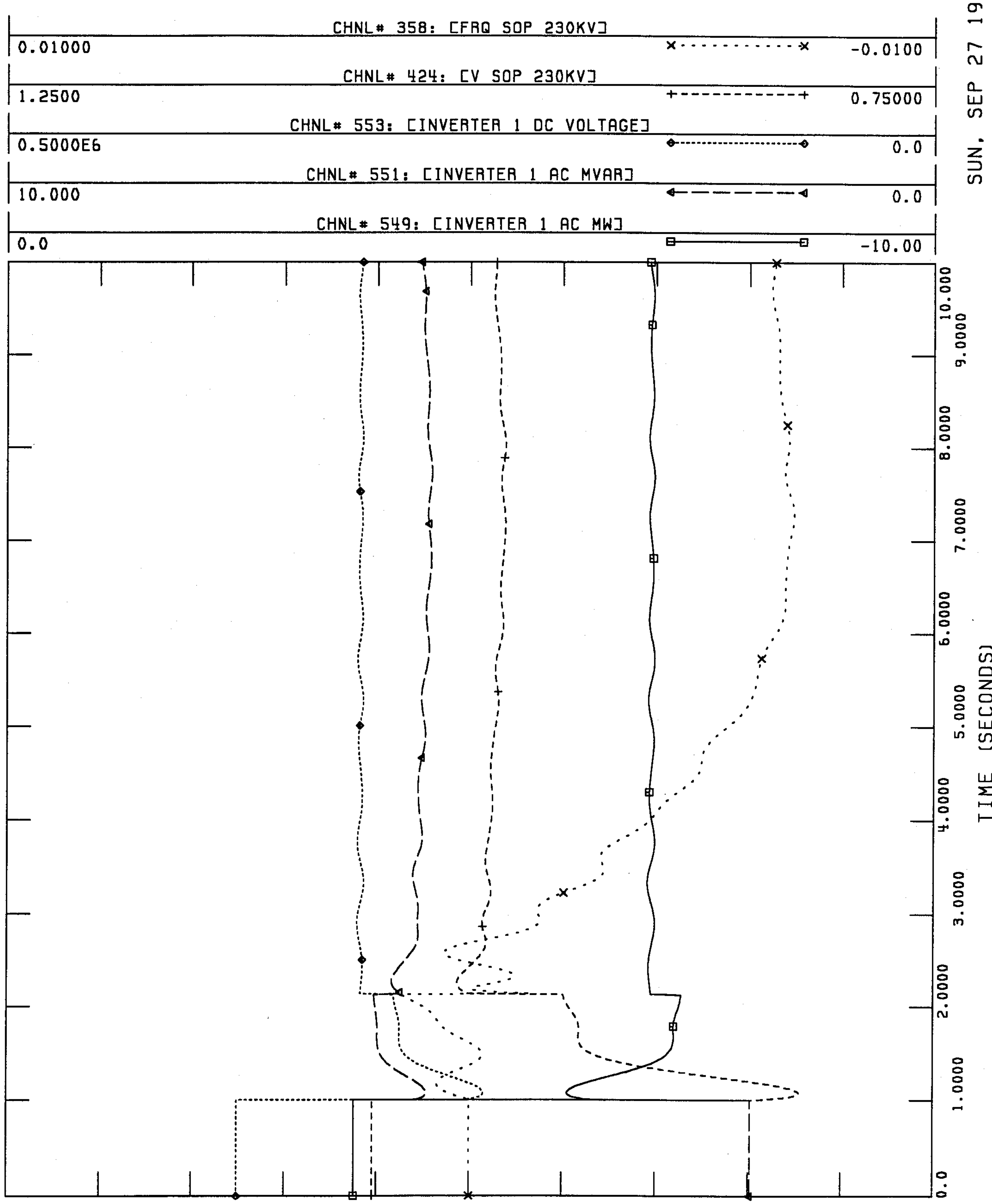


Figure 3.2

751 MW DC INFEED MODELLED - CASE 3.0 - 1 SC AT SOLD.POND
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL - AMIN = 15
BLOCKED 1 POLE PERMANENTLY

FILE: c:\psse25w\HVDC\CASE3\case3.0f_a15_imode_1sc_a.out

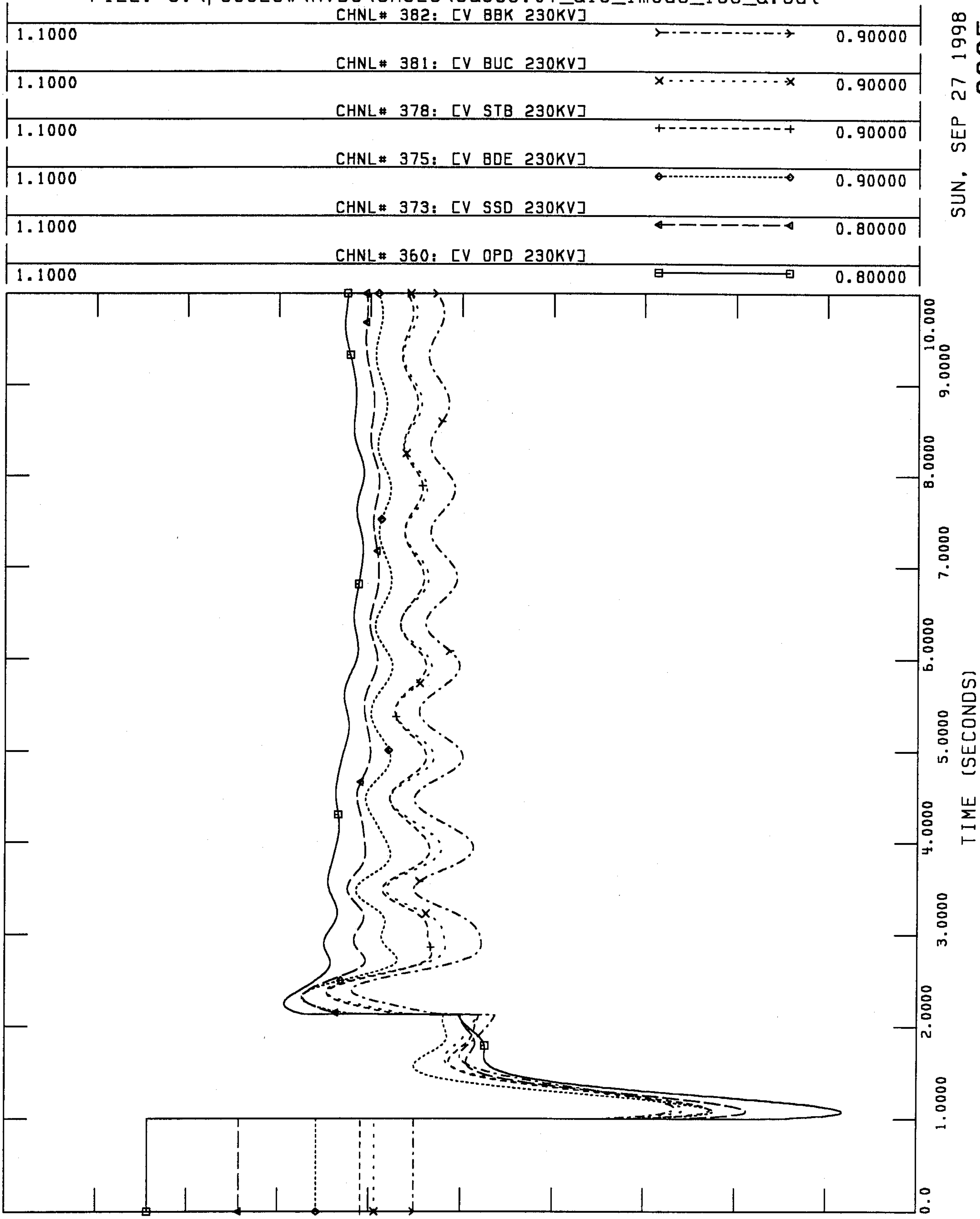


Figure 3.3

POWER TECHNOLOGIES, INC.®

751 MW DC INFEED MODELLED - CASE 3.0 - 1 SC AT SOLD.POND
ISLAND GENERATION: REDUCED; DC INFEED: NOMINAL - AMIN = 15
BLOCKED 1 POLE PERMANENTLY

FILE: c:\psse25w\HVDC\CASE3\case3.0f_a15_imode_1sc_a.out

SUN, SEP 27 1998 11:11
CASE 3.0F

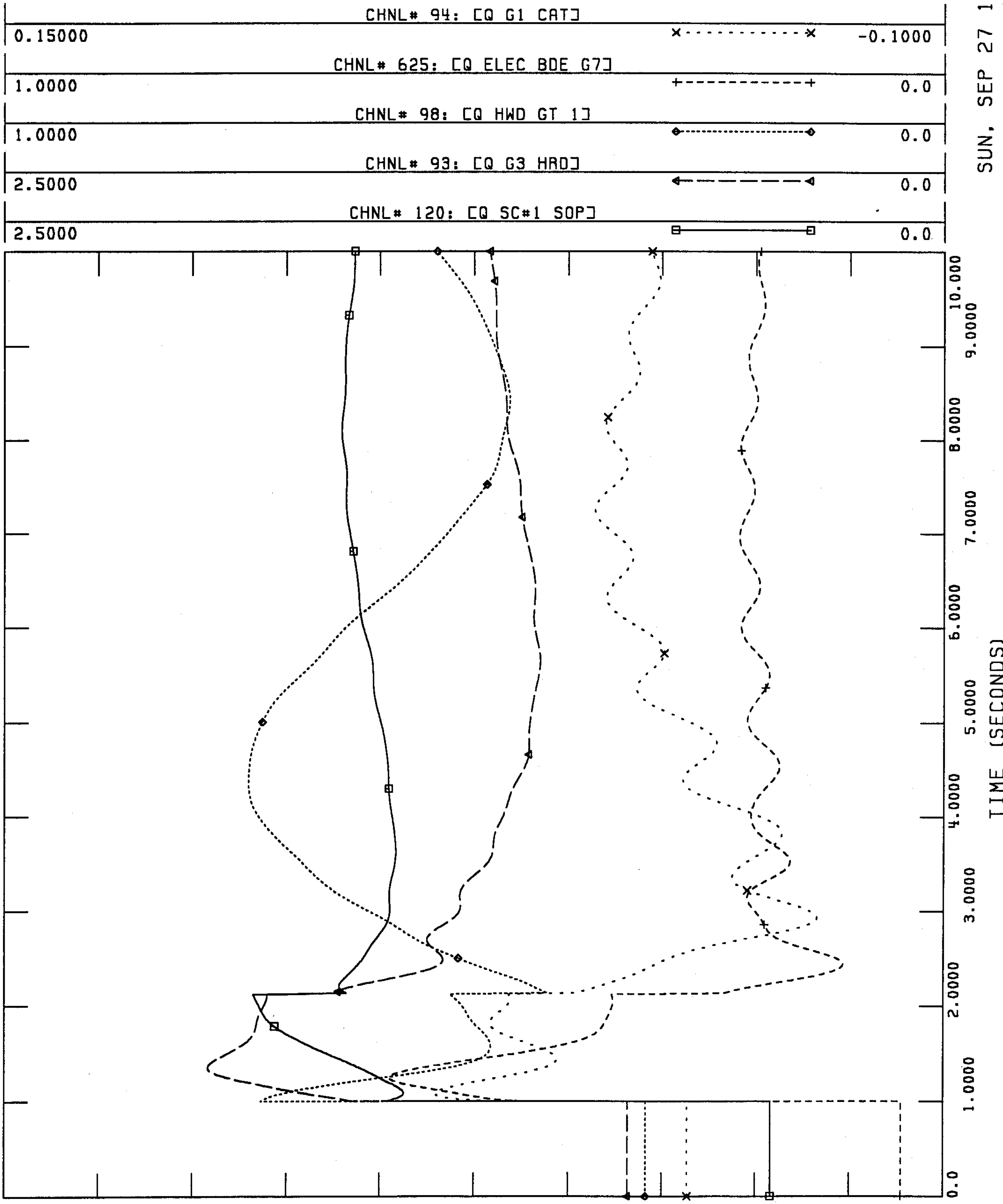


Figure 3.4

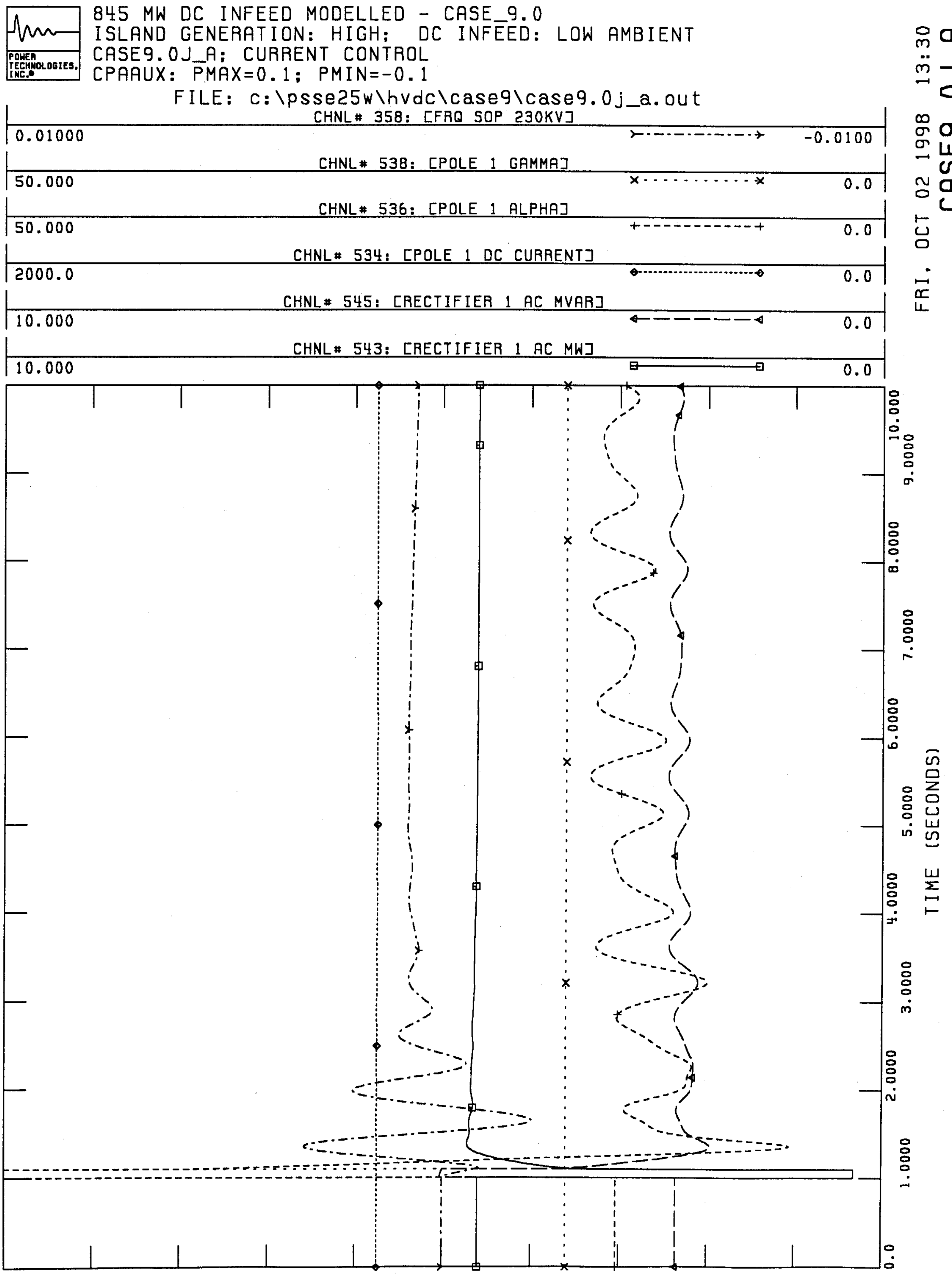

POWER TECHNOLOGIES, INC.
845 MW DC INFEED MODELLED - CASE_9.0
ISLAND GENERATION: HIGH; DC INFEED: LOW AMBIENT
CASE9.0J_A; CURRENT CONTROL
CPAAUX: PMAX=0.1; PMIN=-0.1
FILE: c:\psse25w\hvdc\case9\case9.0j_a.out
CHNL# 358: [FRQ SOP 230KV]
0.01000
-0.0100
CHNL# 538: [POLE 1 GAMMA]
50.000
0.0
CHNL# 536: [POLE 1 ALPHA]
50.000
0.0
CHNL# 534: [POLE 1 DC CURRENT]
2000.0
0.0
CHNL# 545: [RECTIFIER 1 AC MVAR]
10.000
0.0
CHNL# 543: [RECTIFIER 1 AC MW]
10.000
0.0
FRI, OCT 02 1998 13:30
CASE9.0J_A
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)

Figure 4.1

POWER TECHNOLOGIES, INC.®

845 MW DC INFEED MODELLED - CASE_9.0
ISLAND GENERATION: HIGH; DC INFEED: LOW AMBIENT
CASE9.0J_A; CURRENT CONTROL
CPAAUX: PMAX=0.1; PMIN=-0.1
FILE: c:\psse25w\hvdc\case9\case9.0j_a.out

FRI, OCT 02 1998 13:28
CASE9.0J_A

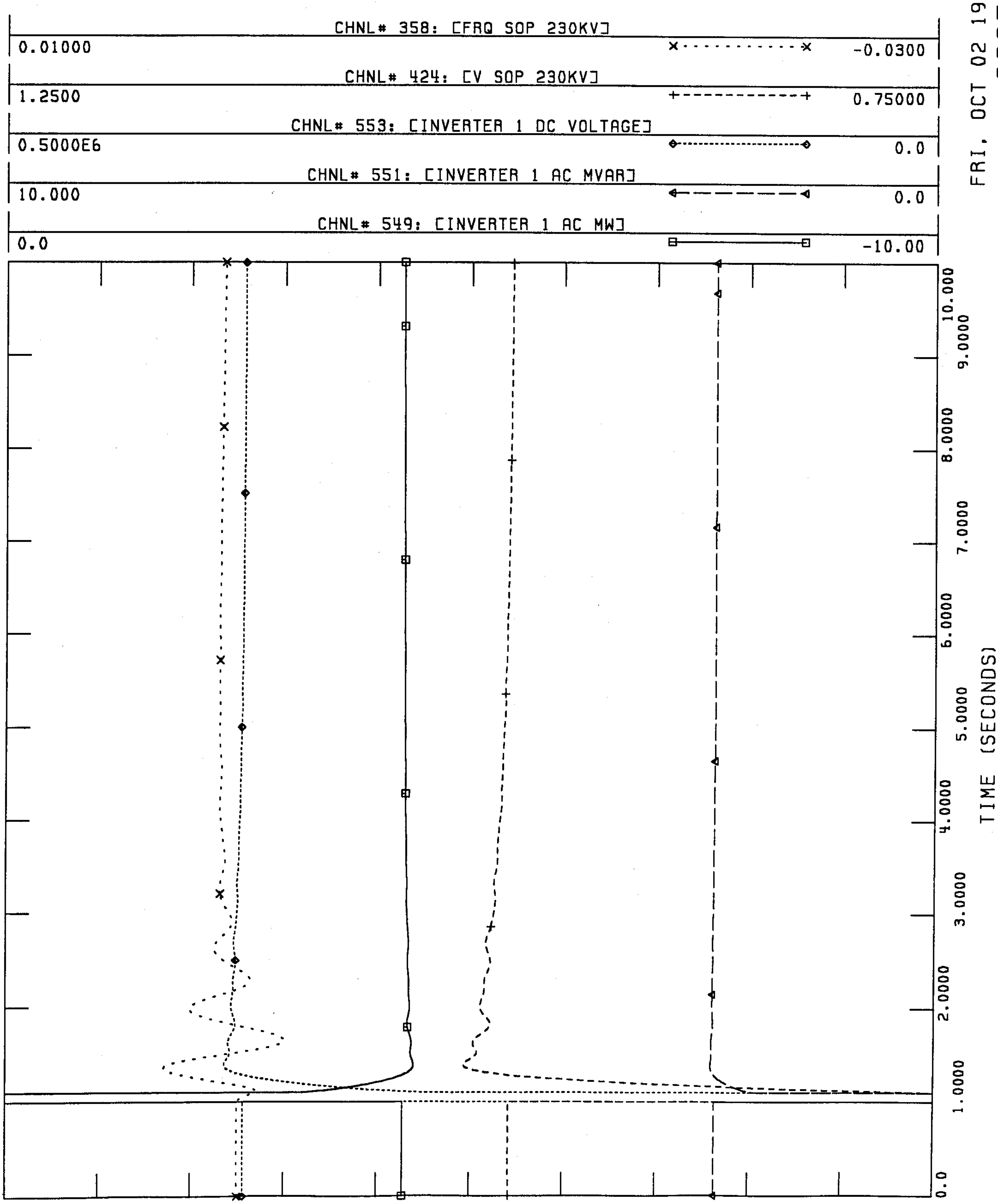


Figure 4.2

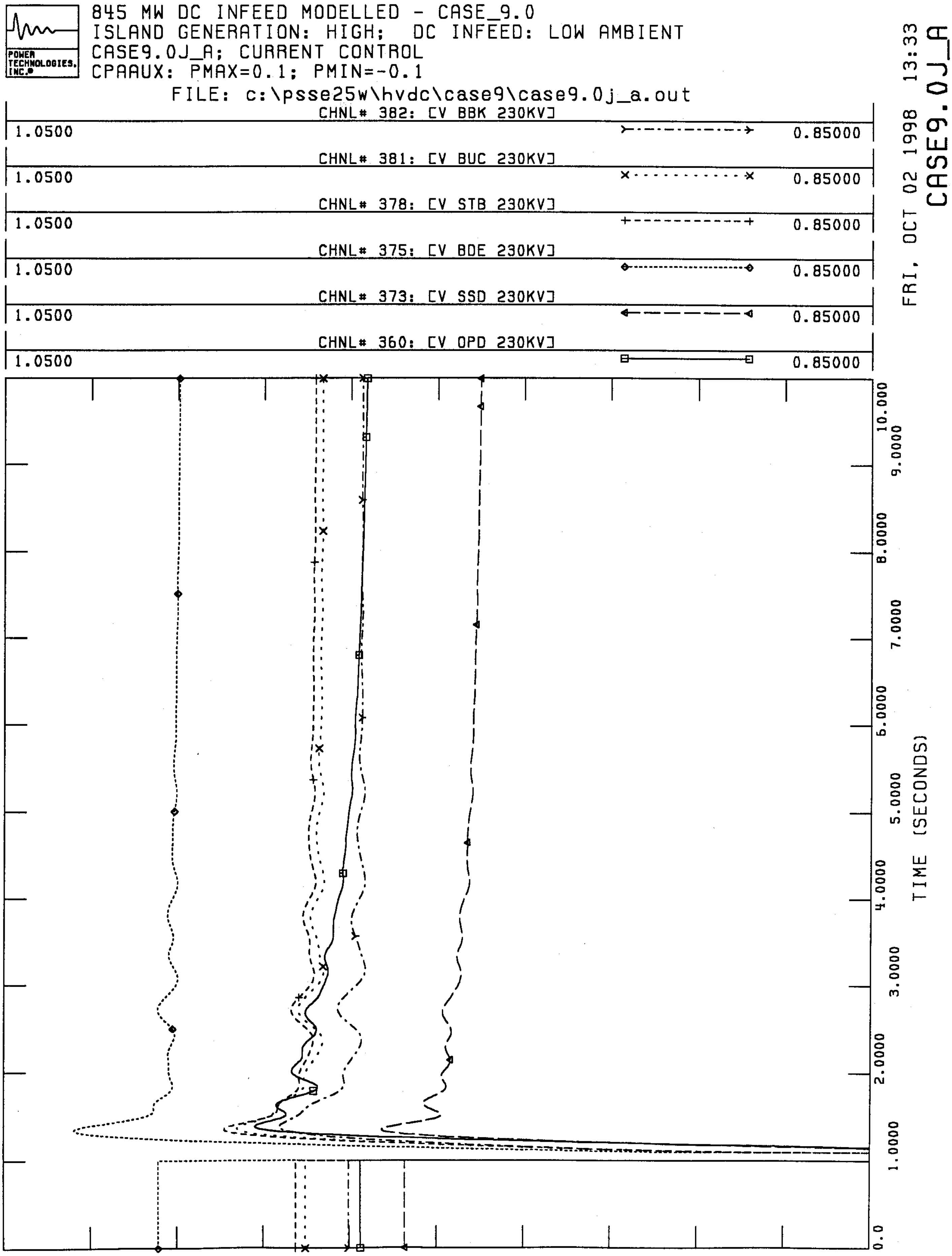

POWER TECHNOLOGIES, INC.
845 MW DC INFEED MODELLED - CASE_9.0
ISLAND GENERATION: HIGH; DC INFEED: LOW AMBIENT
CASE9.0J_A; CURRENT CONTROL
CPAAUX: PMAX=0.1; PMIN=-0.1
FILE: c:\psse25w\hvdc\case9\case9.0j_a.out
CHNL# 382: [V BBK 230KV]
1.0500
0.85000
CHNL# 381: [V BUC 230KV]
1.0500
0.85000
CHNL# 378: [V STB 230KV]
1.0500
0.85000
CHNL# 375: [V BDE 230KV]
1.0500
0.85000
CHNL# 373: [V SSD 230KV]
1.0500
0.85000
CHNL# 360: [V OPD 230KV]
1.0500
0.85000
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
FRI, OCT 02 1998 13:33
CASE9.0J_A

Figure 4.3

POWER TECHNOLOGIES, INC.

743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
6 CYCLE L-G FAULT ON SOP BUS FOLLOWED BY
PERMANENT LOSS OF A DC POLE

FILE: c:\psse25w\HVDC\Case1\Case1.0k_f_2sc.out

CHNL# 358: [FRQ SOP 230KV]	0.02000	-0.0200
CHNL# 538: [POLE 1 GAMMA]	50.000	0.0
CHNL# 536: [POLE 1 ALPHA]	50.000	0.0
CHNL# 534: [POLE 1 DC CURRENT]	3000.0	0.0
CHNL# 545: [RECTIFIER 1 AC MVAR]	10.000	0.0
CHNL# 543: [RECTIFIER 1 AC MW]	10.000	0.0

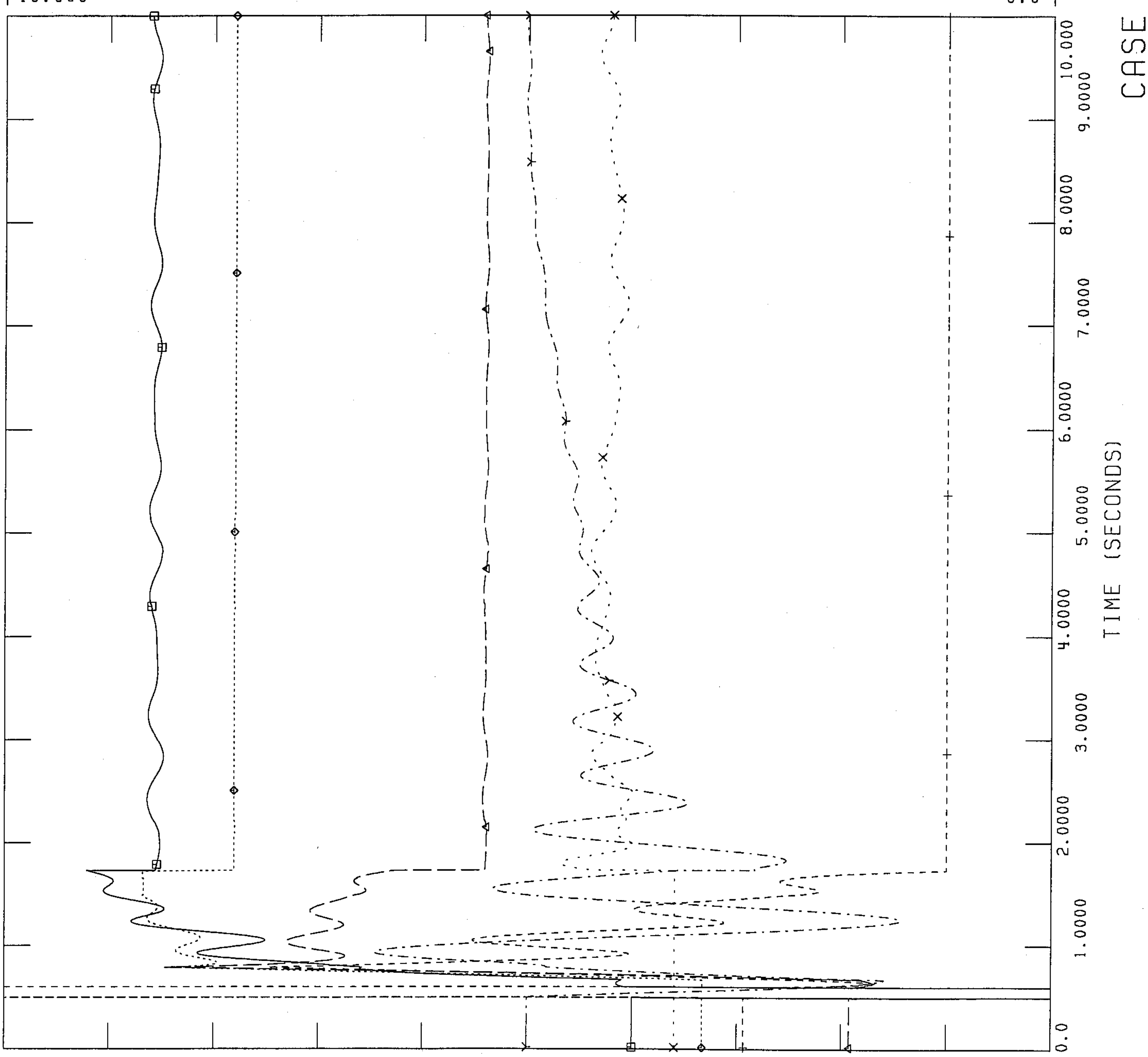
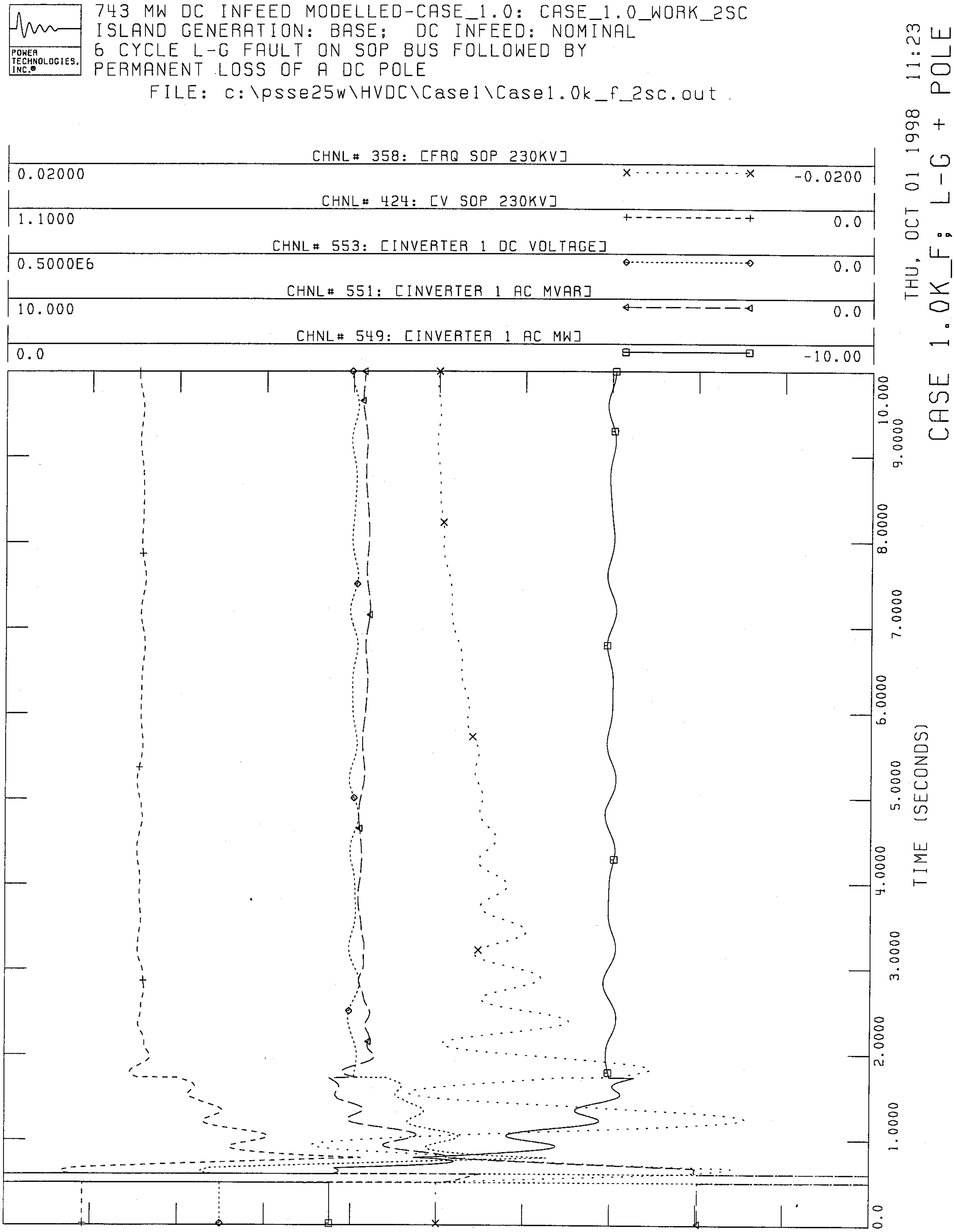


Figure 5.1


POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
6 CYCLE L-G FAULT ON SOP BUS FOLLOWED BY
PERMANENT LOSS OF A DC POLE
FILE: c:\psse25w\HVDC\Case1\Case1.0k_f_2sc.out
CHNL# 358: [FRQ SOP 230KV]
0.02000
-0.0200
CHNL# 424: [V SOP 230KV]
1.1000
0.0
CHNL# 553: [INVERTER 1 DC VOLTAGE]
0.5000E6
0.0
CHNL# 551: [INVERTER 1 AC MVAR]
10.000
0.0
CHNL# 549: [INVERTER 1 AC MW]
0.0
-10.00
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 01 1998 11:23
CASE 1.0K_F; L-G + POLE

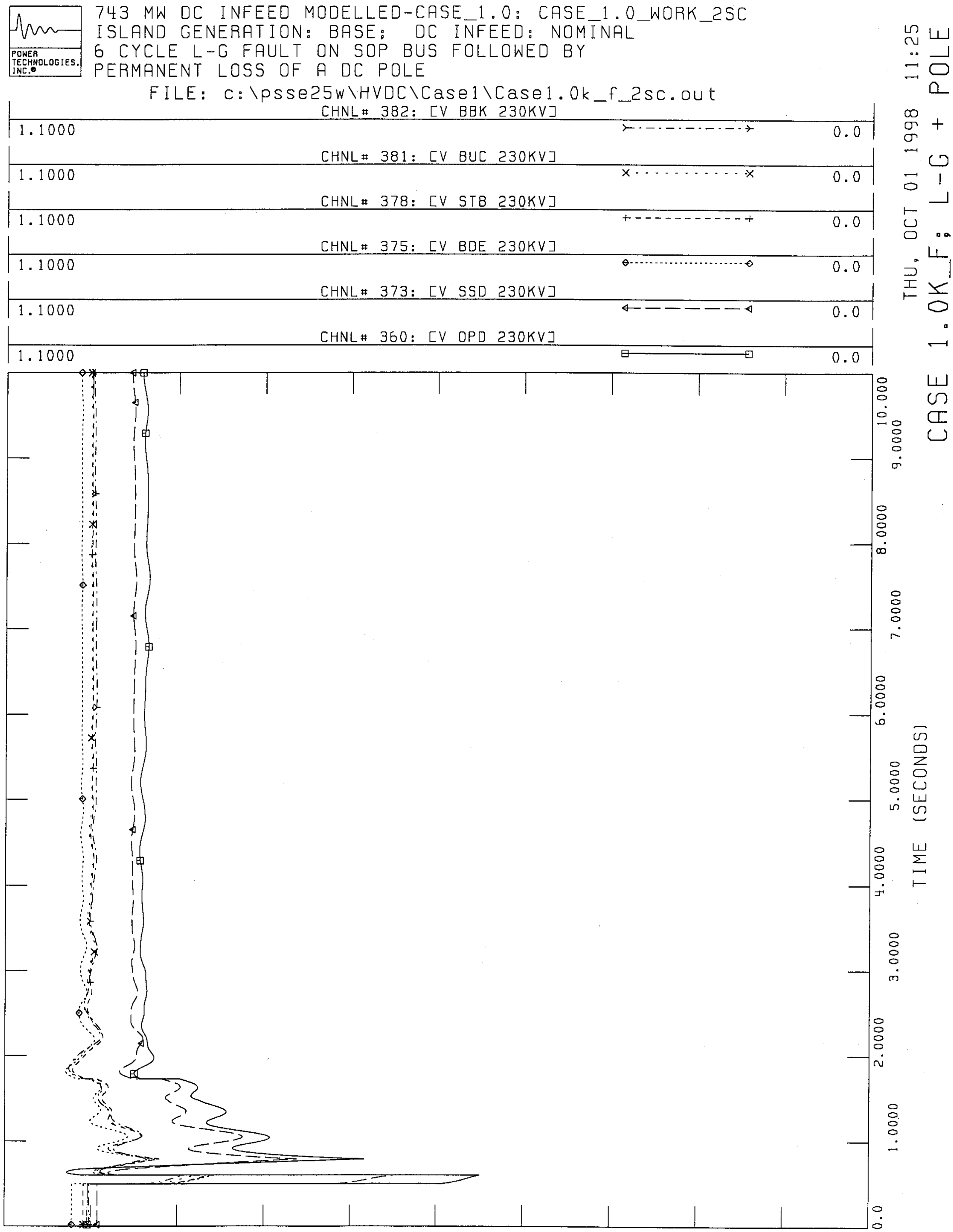

POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
6 CYCLE L-G FAULT ON SOP BUS FOLLOWED BY
PERMANENT LOSS OF A DC POLE
FILE: c:\psse25w\HVDC\Case1\Case1.0k_f_2sc.out
CHNL# 382: [V BBK 230KV]
1.1000
0.0
CHNL# 381: [V BUC 230KV]
1.1000
0.0
CHNL# 378: [V STB 230KV]
1.1000
0.0
CHNL# 375: [V BDE 230KV]
1.1000
0.0
CHNL# 373: [V SSD 230KV]
1.1000
0.0
CHNL# 360: [V OPD 230KV]
1.1000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 01 1998 11:25
CASE 1.0K_F; L-G + POLE

Figure 5.3

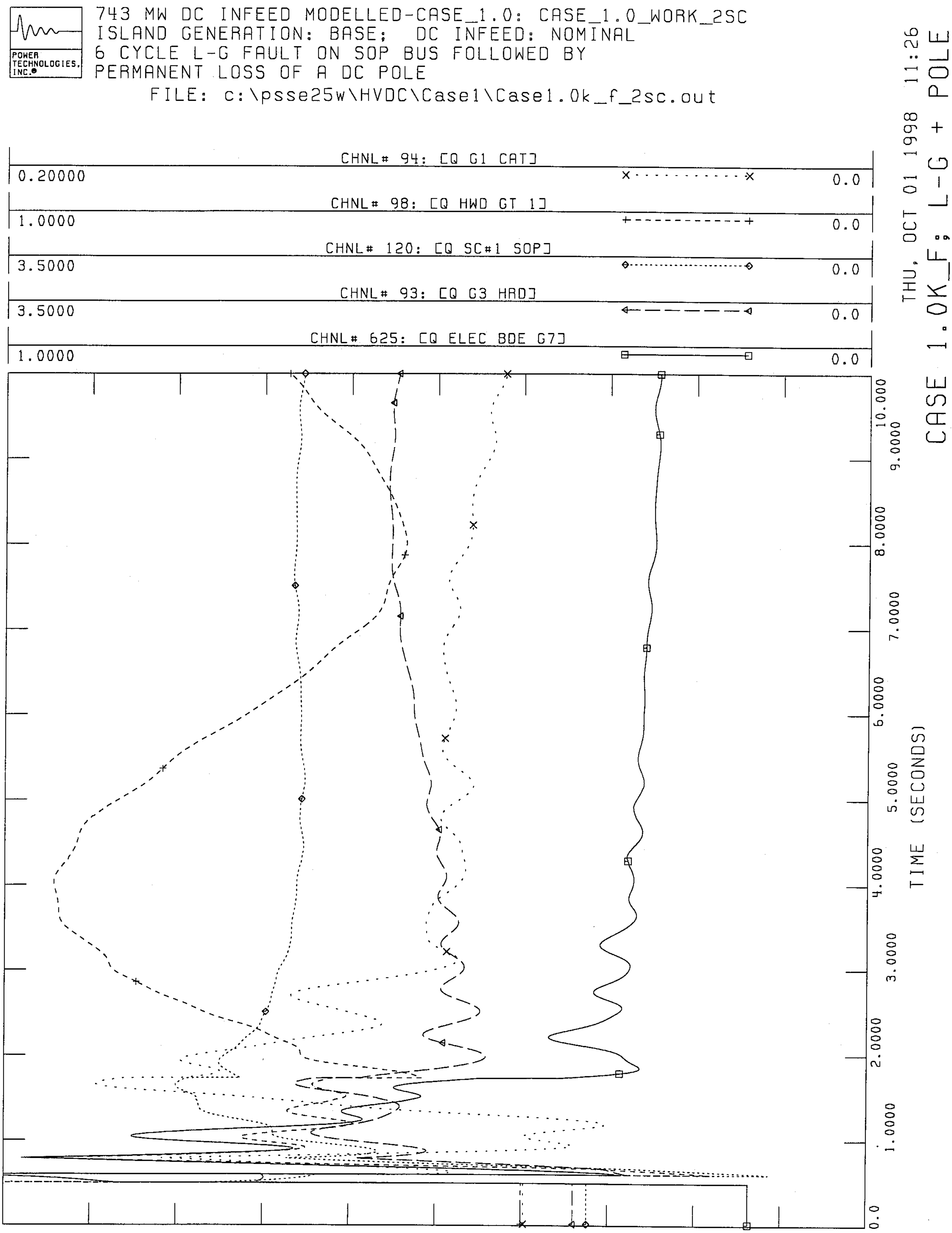
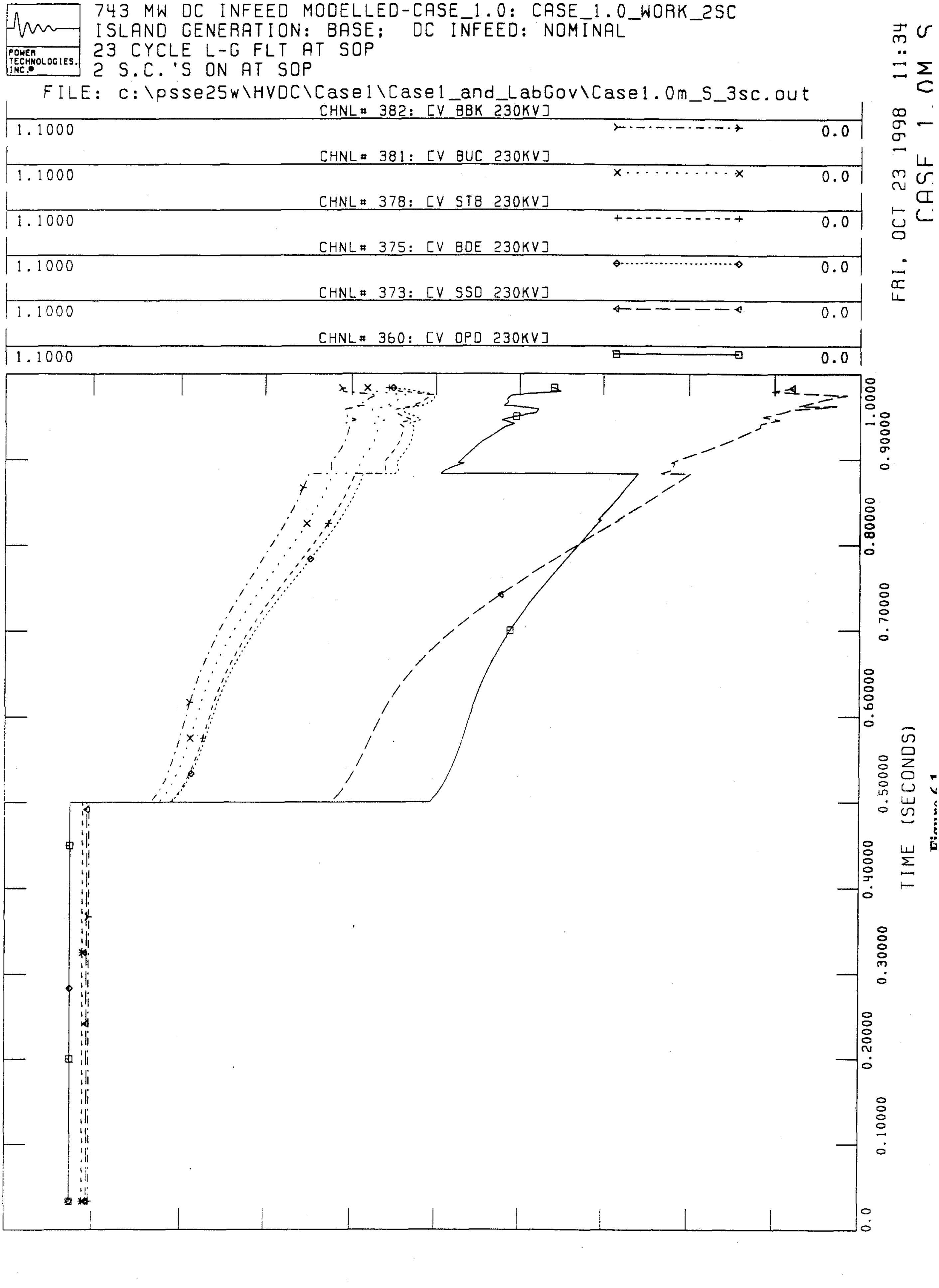

POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
6 CYCLE L-G FAULT ON SOP BUS FOLLOWED BY
PERMANENT LOSS OF A DC POLE
FILE: c:\psse25w\HVDC\Case1\Case1.0k_f_2sc.out
CHNL# 94: [Q G1 CAT]
0.20000
0.0
CHNL# 98: [Q HWD GT 1]
1.0000
0.0
CHNL# 120: [Q SC#1 SOP]
3.5000
0.0
CHNL# 93: [Q G3 HRD]
3.5000
0.0
CHNL# 625: [Q ELEC BDE G7]
1.0000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
THU, OCT 01 1998 11:26
CASE 1.0K_F; L-G + POLE

Figure 5.4


POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
23 CYCLE L-G FLT AT SOP
2 S.C.'S ON AT SOP
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0m_S_3sc.out
CHNL# 382: [V BBK 230KV]
1.1000
0.0
CHNL# 381: [V BUC 230KV]
1.1000
0.0
CHNL# 378: [V STB 230KV]
1.1000
0.0
CHNL# 375: [V BDE 230KV]
1.1000
0.0
CHNL# 373: [V SSD 230KV]
1.1000
0.0
CHNL# 360: [V OPD 230KV]
1.1000
0.0
FRI, OCT 23 1998 11:34
CASE 1.0M S
TIME (SECONDS)
0.0
0.10000
0.20000
0.30000
0.40000
0.50000
0.60000
0.70000
0.80000
0.90000
1.0000

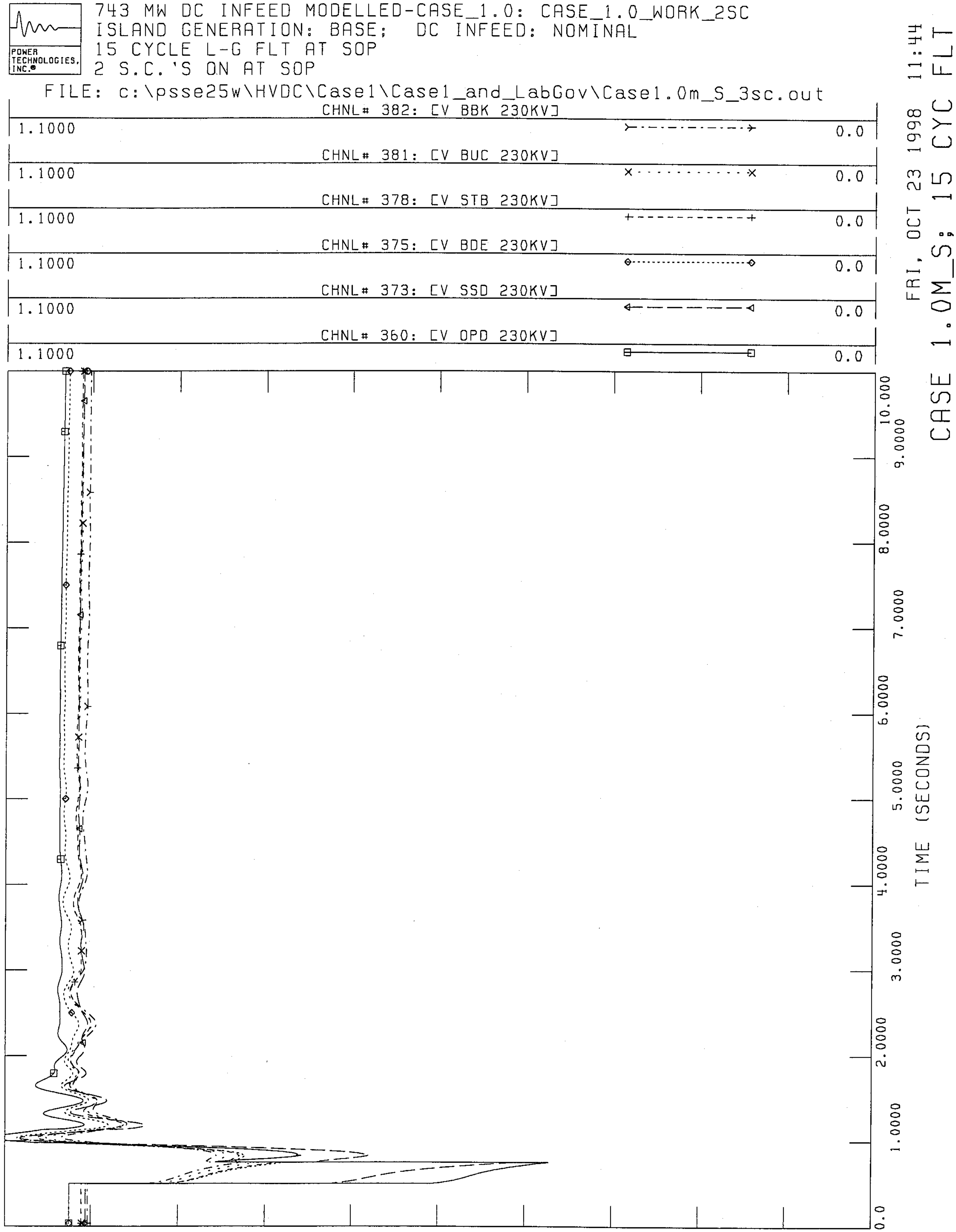

POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
15 CYCLE L-G FLT AT SOP
2 S.C.'S ON AT SOP
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0m_S_3sc.out
CHNL# 382: [V BBK 230KV]
1.1000
0.0
CHNL# 381: [V BUC 230KV]
1.1000
0.0
CHNL# 378: [V STB 230KV]
1.1000
0.0
CHNL# 375: [V BDE 230KV]
1.1000
0.0
CHNL# 373: [V SSD 230KV]
1.1000
0.0
CHNL# 360: [V OPD 230KV]
1.1000
0.0
FRI, OCT 23 1998 11:44
CASE 1.0M_S; 15 CYC FLT
TIME (SECONDS)
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000

Figure 6.2

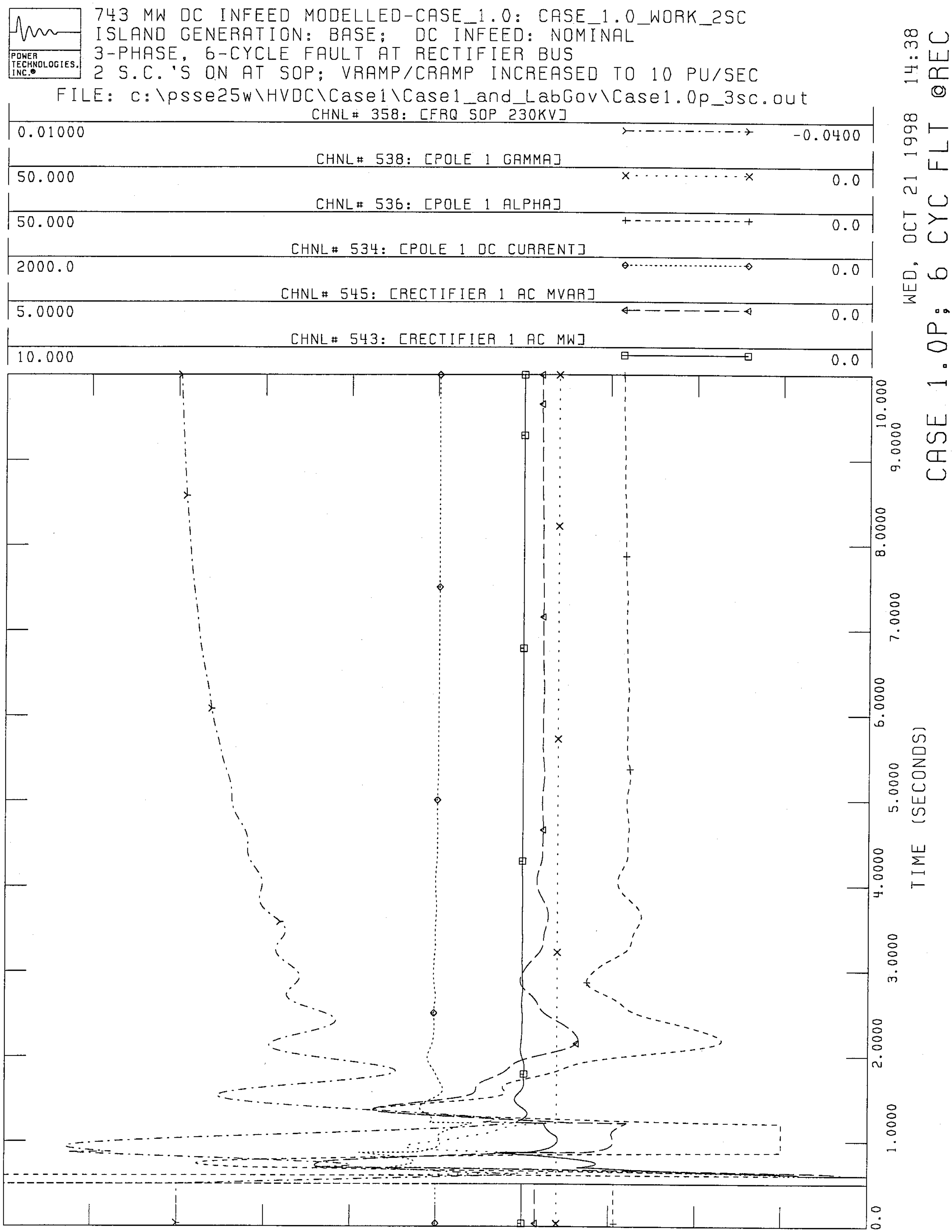

POWER TECHNOLOGIES, INC.
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
3-PHASE, 6-CYCLE FAULT AT RECTIFIER BUS
2 S.C.'S ON AT SOP; VRAMP/CRAMP INCREASED TO 10 PU/SEC
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0p_3sc.out
CHNL# 358: [FRQ SOP 230KV]
0.01000
-0.0400
CHNL# 538: [POLE 1 GAMMA]
50.000
0.0
CHNL# 536: [POLE 1 ALPHA]
50.000
0.0
CHNL# 534: [POLE 1 DC CURRENT]
2000.0
0.0
CHNL# 545: [RECTIFIER 1 AC MVAR]
5.0000
0.0
CHNL# 543: [RECTIFIER 1 AC MW]
10.000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, OCT 21 1998 14:38
CASE 1.0P; 6 CYC FLT @REC

Figure 7.1

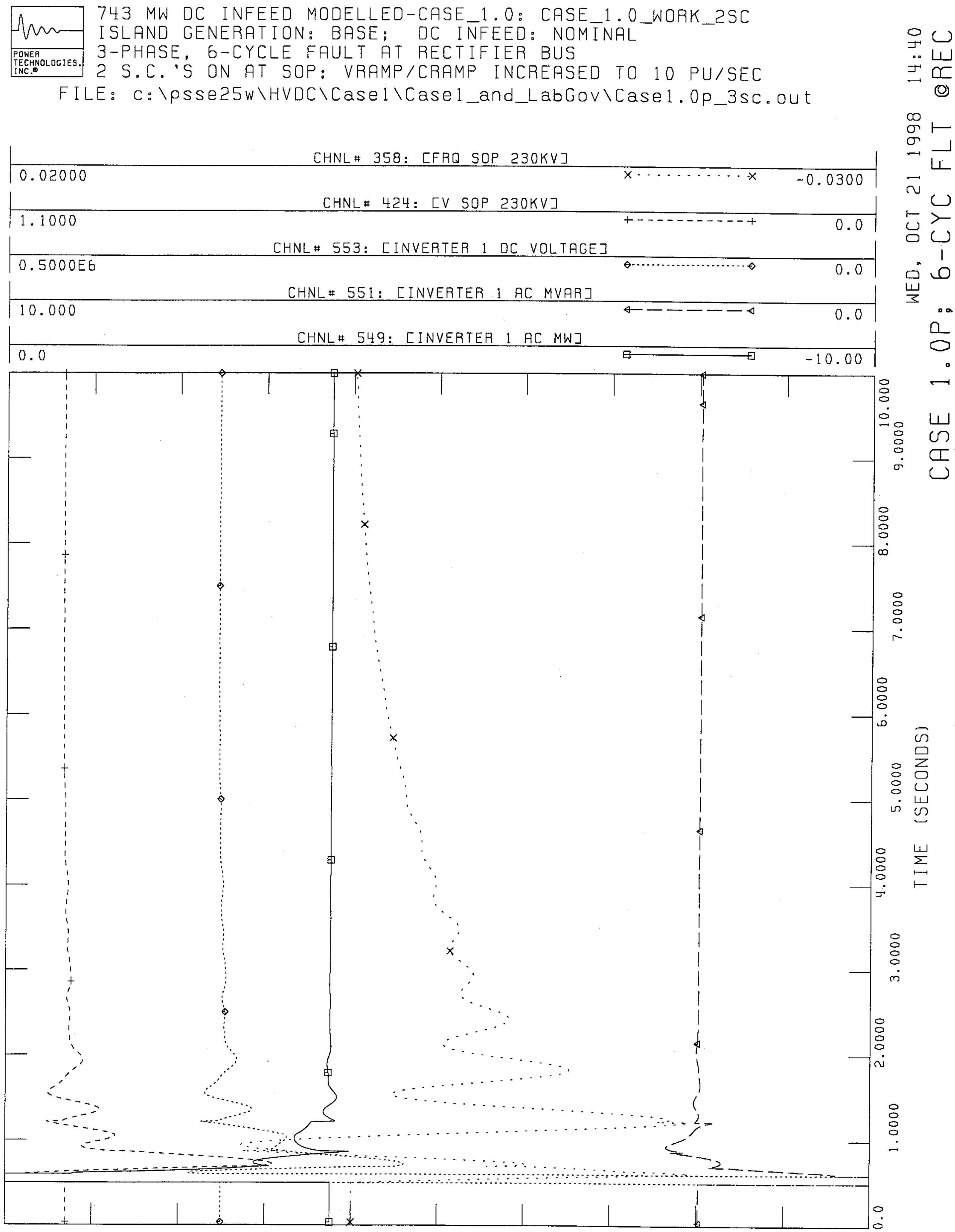

743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
3-PHASE, 6-CYCLE FAULT AT RECTIFIER BUS
2 S.C.'S ON AT SOP; VRAMP/CRAMP INCREASED TO 10 PU/SEC
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0p_3sc.out
POWER TECHNOLOGIES, INC.
CHNL# 358: [FRQ SOP 230KV]
0.02000
-0.0300
CHNL# 424: [V SOP 230KV]
1.1000
0.0
CHNL# 553: [INVERTER 1 DC VOLTAGE]
0.5000E6
0.0
CHNL# 551: [INVERTER 1 AC MVAR]
10.000
0.0
CHNL# 549: [INVERTER 1 AC MW]
0.0
-10.00
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, OCT 21 1998 14:40
CASE 1.0P; 6-CYC FLT @REC

Figure 7.2

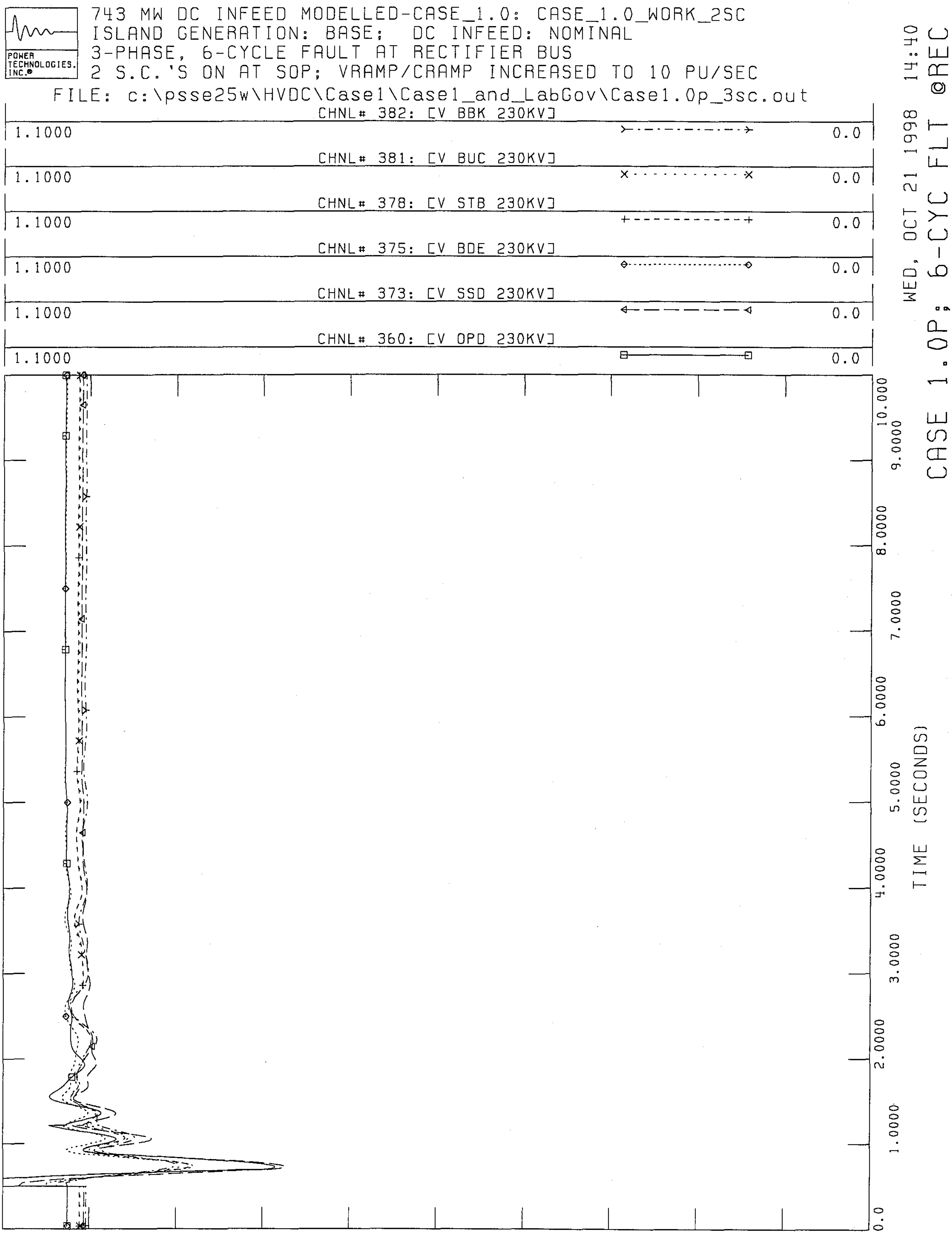

POWER TECHNOLOGIES, INC.®
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
3-PHASE, 6-CYCLE FAULT AT RECTIFIER BUS
2 S.C.'S ON AT SOP; VRAMP/CRAMP INCREASED TO 10 PU/SEC
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0p_3sc.out
CHNL# 382: [V BBK 230KV]
1.1000
0.0
CHNL# 381: [V BUC 230KV]
1.1000
0.0
CHNL# 378: [V STB 230KV]
1.1000
0.0
CHNL# 375: [V BDE 230KV]
1.1000
0.0
CHNL# 373: [V SSD 230KV]
1.1000
0.0
CHNL# 360: [V OPD 230KV]
1.1000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, OCT 21 1998 14:40
CASE 1.0P; 6-CYC FLT @REC

Figure 7.3

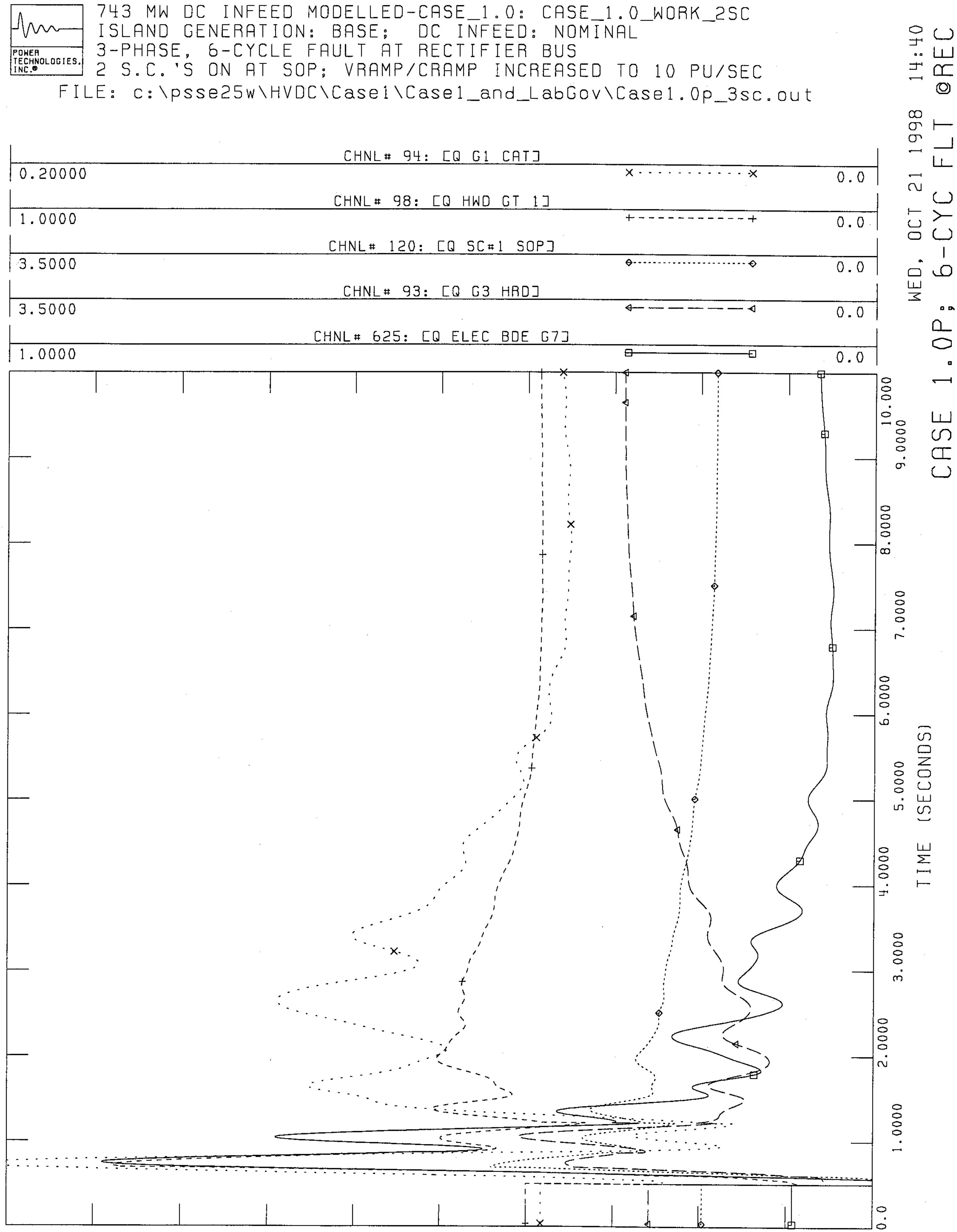

POWER TECHNOLOGIES, INC.®
743 MW DC INFEED MODELLED-CASE_1.0: CASE_1.0_WORK_2SC
ISLAND GENERATION: BASE; DC INFEED: NOMINAL
3-PHASE, 6-CYCLE FAULT AT RECTIFIER BUS
2 S.C.'S ON AT SOP; VRAMP/CRAMP INCREASED TO 10 PU/SEC
FILE: c:\psse25w\HVDC\Case1\Case1_and_LabGov\Case1.0p_3sc.out
CHNL# 94: [Q G1 CAT]
0.20000
0.0
CHNL# 98: [Q HWD GT 1]
1.0000
0.0
CHNL# 120: [Q SC#1 SOP]
3.5000
0.0
CHNL# 93: [Q G3 HRD]
3.5000
0.0
CHNL# 625: [Q ELEC BDE G7]
1.0000
0.0
0.0
1.0000
2.0000
3.0000
4.0000
5.0000
6.0000
7.0000
8.0000
9.0000
10.000
TIME (SECONDS)
WED, OCT 21 1998 14:40
CASE 1.0P; 6-CYC FLT @REC

Figure 7.4