Victoria University of Technology

Department of Electrical & Electronic Engineering

COGENERATION IN DISTRIBUTION SYSTEM: PLANNING, OPERATION AND TRANSIENTS

Mahavir Singh
B.Sc. Honours, B.Sc. (Engg.), M.S.

Thesis submitted for the degree of Master of Science at the Victoria University of Technology, Melbourne.

ACKNOWLEDGEMENTS

The work presented in this thesis was carried out under the supervision of Associate Professor Dr Akhtar Kalam, B.Sc., B.Sc. (Engg.), M.S., Ph.D. of the Department of Electrical and Electronincs Engineering, Victoria University of Technology, Footscray. His guidance, assistance and encouragement from the campus office as well as from overseas is highly appreciated. The project was started at the Royal Melbourne Institute of Technology under the supervision of Dr. Majid Al-Dabbagh to whom I thank very much. I had to make a few trips to Sydney in the initial phase of the project to consult Dr. Don Geddy, Planning and Development Engineer, at the Electricity Commission of New South Wales, to use the EMTP software. I thank him for offering his valuable experience in this field.

To make the project more meaningful to the electrical industry, I consulted Mr. Bob Coulter, Distribution Engineer at the State Electricity Commission of Victoria, very often. His advice and assistance have made this project valuable to electrical industry. I thank him for all the time spent for this project. I also thank Mrs Ann Pleasant, Senior Lecturer, who assisted me during the period of Dr. Kalam's absence.

The technical staff of the University have been helpful whenever problems with the functioning of the computer and software came up. Mr Neil Larchin, Mr Zoltan Varga and Mr Foster Hayward were always of assistance. When writing the thesis, colleagues Paul

Bridges and Mark Briffa were helpful in highlighting the features of Protel and Word Perfect softwares. I acknowledge their valuable assistance and thank them very much.

LIST OF CONTENTS

LIST OF FIGURES

List of Principal Symbols

$u(t)$	Instantaneous voltage at time t	33
$i(t)$	Instantaneous current at time t	33
Δt	Very small interval of time	33
i_1	Instantaneous current entering node 1	34
i_{1-2}	Instantaneous current flowing from node 1 to node 2	34
i_{1-3}	Instantaneous current flowing from node 1 to node 3	35
i_{1-4}	Instantaneous current flowing from node 1 to node 4	35
i_{1-5}	Instantaneous current flowing from node 1 to node 5	35
$i_1^{(t)}$	Current entering node 1 at time t	35
$i_{1-2}^{(t)}$	Current between nodes 1 and 2 at time t	35
$i_{1-3}^{(t)}$	Current between nodes 1 and 3 at time t	35
$i_{1-4}^{(t)}$	Current between nodes 1 and 4 at time t	35
$i_{1-5}^{(t)}$	Current between nodes 1 and 5 at time t	35
$u(x,t)$	Instantaneous voltage at distance x and time t	35
L'	Inductace per unit length	35
C'	Capacitance per unit length	35
x	Distance on the line from some arbitrary chosen point	35
v	Propagation velocity	36
τ	Time taken by a wave to travel from one end of line to the other	37
Z	Impedance of a line from one node to ground	38
Y	Nodal admittance matrix	41
$U^{(t)}$	Column vector of n node voltages at time t	41
$I^{(t)}$	Column vector of n injected node currents at time t	41
K	Constant column vector	41
T	Transformation matrix	49

Subscripts

a,b,c	Phases A, B and C	64
s,m	Self and mutual impedances	49
$0,\alpha,\beta$	Zero, alpha and beta components	49
zero	Zero value component of symmetrical components	49
pos	Positive value component of symmetrical components	49
neg	Negative value component of symmetrical components	49

List Of Abbreviations

Summary

Since the oil crisis of 1970's there has been an increasing awareness of the need for energy efficiency and sufficiency. Australia is also alert of the energy economy. The National Advisory Committee recommended in 1983 that the Commonwealth should urge the state governments to encourage the electricity supply authorities to "facilitate greater use in the grid of privately generated electricity" [68]. This law opened an opportunity for the use of private generators, which had been on standby duties for use only in emergency. They could become suppliers of electricity without having to install transmission lines and other components. Other dispersed sources which produce electric energy from hydrogenerators, wind turbines, biomass, waste and other non-conventional sources, could also be business partners of the utility. These DSGs (dispersed storage and generation) are allowed to use the transmission facilities built by the utility. The issue has gained so much momentum that Bates says, "In this respect we are totally at odds with the Industry Commission, which recommended the breaking-up of the State Electricity utilities by the wholesale selling-off of generating and distribution assets to the private sector" [67].

This thesis relates to a study of abnormal conditions on a three-phase distribution feeder of industry like State Electricity

Commission of Victoria (SECV) with several loads and a capacitor bank. An induction generator, which plays the role of a dispersed storage and generation unit, driven by a hydraulic turbine, which is a common form of renewable energy scheme, is connected to the distribution feeder through a Δ/Y transformer. Transients caused by switching of the induction generator, by single line-to-ground fault, double line-to-ground fault through contact resistances, broken conductor touching the ground through a small resistance, isolating the induction generator to form its own supply domain (islanding) etc are investigated and interesting conclusions of practical importance are derived.

The IBM PC version 4 of the Electro-Magnetic-Transient Program - Alternative Transient Program (ATP), was used to solve this problem. The program also gives output results for automatic plotting in time domain. Accordingly, transient voltages at several nodes and transient currents at interesting points were plotted from the output results.

Planning and operational aspects like voltage control, reliability, harmonics, earthing, and contractual matters between the private generator and the utility are also considered. Technical aspects of interconnections between the private generation and the utility has been considered.

Interesting conclusions, valuable for insulation co-ordination, interrupting duty on circuit breakers, effect on response of protective relays and automatic control systems are pointed out. It also considers security to personnel and protection of metering equipment. The thesis also offers guide for contractual matters between the utility and the private generation.

CHAPTER 1 INTRODUCTION

1.1 Literature Survey

If an induction motor is driven by an outside mechanical source at speeds above synchronism, the power current component in the stator reverses while the magnetising component remains in magnitude and phase position. The machine thus is converted to a generator, referred to as induction generator, and will deliver active power when its shaft input has overcome its internal losses. Induction generators are relatively smaller in sizes than synchronous alternators; for although they supply active power, they take reactive current from other synchronous machines. In other words, irrespective of load conditions, the induction generator must operate at leading power factor. The driving force for the generator can be supplied by a low speed water turbine or by high-speed steam and gas turbines. Induction generators in combination with switched capacitor banks can be used in relatively large-scale installations, provided they are tied to a transmission network, at least partly supplied by synchronous alternators to maintain frequency.

The West 59th Street power house of the Interborough Rapid Transit System of New York City has, since 1911, installed five

7500-kW exhaust turbine induction generator sets which operate from the steam discharged by five 7500-kW 25-cycle angle-compounded steam-engine alternators. This increased the thermal efficiency of the plant and doubled its output. A large number of induction motors were converted to induction generators during World War II because of the limitations of power usage and availability of induction motors as compared to synchronous alternators [69].

Dispersed storage and generation (DSG) is an expression coined by the Institute of Electrical & Electronic Engineers in an attempt to clear up the semantic confusion between interconnection and cogeneration [10]. DSG is also used by some authors for the abbreviation of Distribution System Generation [18]. The SECV uses the expression "Private generation" in place of DSG [64]. They all give the same idea of generating electricity from sources like wind power, water power, solar power and bio-gas (obtained from agricultural digester). DSGs may be defined as any source of electrical energy (including storage elements which act as sources at times) connected directly to a utility distribution system or sub-transmission system.

The class of devices which comprise the DSGs are listed below [5]:

* Hydroelectric
* Solar Thermal Electric
* Photovoltaic

* Wind
* Storage Battery
* Hydroelectric Pumped storage
* Cogeneration

Among these cogeneration has become very important and interesting too.

Since 1973 the oil embargo and the energy crisis generated by that embargo, there has been much concern expressed over ways to conserve and use energy more efficiently. One area of specific investigation is cogeneration. The Public Utility Regulatory Policy Act (PURPA) defines cogeneration as the production of electric energy and other useful energy (such as heat), which are used for industrial, commercial, heating, or cooling purposes [70].

Cogeneration is the combined production of two forms of energy, electrical or mechanical power plus thermal energy, in one technological process. The electrical power produced by a cogenerator can be used on site or distributed through the utility grid, or both. The thermal energy usually is used on site for industrial process heat or steam, space conditioning, and/or hot water. But, if the cogeneration system produces more useful thermal energy than is needed on site, distribution of the excess to nearby facilities can substantially improve the cogenerator's economics and energy efficiency.

The total amount of fuel needed to produce both electricity and thermal energy in a cogenerator is less than the total fuel needed to produce the same amount of electric and thermal energy in separate technologies. It is primarily this greater fuel use efficiency that has created a resurgence of interest in cogeneration systems. However, cogeneration also can be attractive as a means of adding electric generating capacity rapidly at sites where thermal energy already is produced.

Cogeneration systems recapture otherwise wasted thermal energy, usually from a heat engine producing electric power, and use it for applications such as space heating, industrial process needs, or water heating, or use it as an energy source for another system component. This "cascading" of energy use is what distinguishes cogeneration systems from conventional separate electric and thermal energy system. Thus, conventional energy systems supply either electricity or thermal energy while a cogeneration system produces both.

Cogeneration technologies are termed "topping cycles" if the electric or mechanical power is produced first, and the thermal energy exhausted from power production is then captured and used. "Bottoming cycle" cogeneration systems produce high-temperature thermal energy first and then recover the waste heat for use in generating electric or mechanical power plus additional, lower temperature thermal energy.

Another expression which is relevant in this context is "Total

Energy". In the late 1950's and early 1960's the "total energy" concept was promoted by many of the gas companies and some equipment suppliers [6-9].

Early in this century, at the time when electricity first became widely used, many large industrial or commercial enterprises maintained large steam boiler plants for space heating and/or process heating. It was relatively an easy matter to boost the boiler steam pressure somewhat beyond the process requirement, insert a turbine which was connected to an electric generator, and then use the steam for its original requirement after the added energy was extracted to generate electricity. It was a practical concept at that time [6]. The gas companies had tremendous quantities of natural gas and this concept created an almost constant demand for the natural gas to operate a combustion turbine or gas-fired engine which produced the electric energy required by the facility, and as a by-product, the exhaust could be used to produce process heating or cooling. The weak point in the total energy installation was that, for economic reasons, the electrical demand curve had to coincide with the heat energy [19-21].

The electric utilities did not want to lose their revenue. They argued against the weak aspect of the total energy installations and challenged the concept as uneconomical because of poor load balance. The maintenance required for high reliability was very costly and the supply of natural gas became very tight in 1971. These adverse situations effectively ended its wide-scale growth.

Herein, lies the difference between the total energy and cogeneration. The appeal of the total energy was based on complete independence from the electric utility and the utilities fought it. Cogeneration as presently conceived, however, is based on both parties participating in, and sharing the benefits of, cogeneration and has received utility endorsement [6].

Between the late 1880's and early 1900's oil-and-gas-fired cogeneration technologies were increasingly used throughout Europe and the United States. In 1900, over 59 percent of total U.S. electric generating capacity was located at industrial sites [22-27].

There has been a resurgence of interest in recent years in cogeneration for industrial sites, commercial buildings, and rural applications. In Australia, the National Energy Advisory Committee (NEAC) recommended in 1983 that the Commonwealth should advise the state governments to encourage the electricity supply authorities to permit the private generators to use their grid [68]. In the U.S.A. cogenerators faced three major obstacles when seeking interconnected operation with an electric utility. First, utilities were often reluctant to purchase cogenerated electricity at a rate that made interconnected cogeneration economically feasible. Second, some utilities charged very high rates for providing backup service to cogenerators. Third, a cogenerator that sold electricity risked being classified as an electric utility and was expected to be regulated under State and Federal laws. As a result of these and other disincentives, cogeneration was not able to compete with electricity generated in central station power plants.

A number of recent legislative initiatives are intended to clarify the role of cogeneration within national energy and environmental policy, and to encourage its use under those circumstances, where it would save fuel or allow increased efficiency in electric utilities' use of facilities and resources. Utilities are required to purchase electricity from, and provide backup service to cogenerators and at rates that are just and reasonable, that are in the public interest, and that do not discriminate against cogenerators. PURPA also allows Federal Energy Regulatory Commission (FERC) to exempt cogenerators from state regulation of utility rates and financial organisation, and from Federal regulations under the Federal and Public Utility Act [93-95].

"Qualifying cogeneration facility" (QF) is defined as one that produces electricity and steam or other forms of useful thermal energy for industrial, commercial, heating, or cooling purposes; that meets the operating requirements prescribed by the government. Electric utilities are also required to interconnect with QF and must offer to operate in parallel with them. Cogenerators must meet the operating requirements to qualify for interconnections and other benefits.

An electric utility can participate in the ownership of a qualifying cogenerator, either directly or through a subsidiary company. Efficiency and operating standards are also prescribed in the rules to distinguish bonafide cogenerators from essentially single purpose facilities. This standard specifies that at least 5% of a "topping cycle" cogenerator's total energy output (on an annual basis) must be useful thermal energy. This "topping cycle" efficiency standard is designed to ensure that an oil or natural-gas-fired cogenerator will use these fuels more efficiently than any combination of separately generated electric and thermal energy using efficient state-of-the-art technology. "Topping cycle" cogenerators that were installed prior to 1980, and those that use fuels other than oil and gas do not have to meet any efficiency standards in order to qualify under PURPA [71].

The 2-to-1 weighting in favour of electricity production in these "topping cycle" efficiency standards reflects the view that systems with high electricity to heat ratios have the highest energy efficiencies and their development and use should be encouraged [96]. This weighting will be more equitable to the various cogeneration technologies than a standard that simply summed electric and thermal output on an equal basis, because the latter would have made it relatively easy for steam turbines that produce little electricity to qualify, but would have penalised higher electricity-to-steam ratio systems through difficult heat recovery requirements.

In this context "Avoided Cost" has been defined as the incremental cost to an electric utility of electric energy or capacity or both, which but for the purchase from a cogenerator or small power producer, the utility would generate itself or purchase from another source. The rules impose electric utilities an obligation to purchase all electric energy and capacity made available from a QF with which the electric utility is directly or indirectly interconnected, except during system emergencies or during light load periods. PURPA specifies that purchase power rates must be just and reasonable to the electric utilities' consumers and in the public interest, and must not exceed the avoided cost to the utility of alternative electric energy.

"Capacity costs" are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of generating and other facilities [72]. The energy costs as aforementioned are the variable costs associated with the production of electricity, and include the cost of fuel and some operating and maintenance expenses. Thus, if by purchasing electricity, from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for the purchase from the QF must be based on those energy costs that the utility can thereby avoid. Similarly, if the QF offers energy of sufficient reliability and guarantees of deliverability to permit the purchasing utility to build a smaller, less expensive plant, avoid the need to construct a generating unit, or reduce firm power from the grid, then the purchase rates must be based on both the avoided capacity and energy costs [72]. In each case, it is the incremental costs, and not the average or embedded system costs.

There is a provision in the rules that a utility that receives energy or capacity from a QF may, with the consent of the QF, transmit that energy or capacity to a second utility. However, if the QF does not consent to transmission to another utility, the local utility retains the purchase obligation. Similarly, if the local utility does not agree to transmit the QF's energy or capacity, it retains the purchase obligation. Because the transmission can only occur with the consent of the utility to which the energy or capacity is first delivered, this rule does not force wheeling of power [72].

The rule on transmission of cogenerated power specifies that any electric utility to which such energy or capacity is delivered must purchase that energy or capacity under the same obligations and at the same rates as if the purchase were made directly from the QF. These rates should take into account any transmission losses or gains. If the electricity from the QF actually travels across the transmitting utility's system, the amount of energy delivered will be less than that transmitted, due to line losses, and the purchase rate should reflect these losses [73].

Section 210(a) of PURPA also requires that each electric utility offer to sell electric energy to a QF. This obligation to sell power is interpreted as requiring utilities to provide four classes of service to QF's [46, 58-60]:

(a) "Supplementary Power", which is energy or capacity used by a QF in addition to that which is generated itself

(b) "Interruptable Power", which is energy or capacity that is subject to interruption by the utility under specified conditions, and is normally provided at a lower rate than non-interruptable service if it enables the utility to reduce peak loads

(c) "Maintenance Power", which is energy or capacity supplied during scheduled outages of the QF, presumably during periods when the utility's other load is low

(d) "Backup Power", which is the energy or capacity supplied during unscheduled outages

A utility may avoid providing any of these four classes of service only if it convinces the Public Service Commission that compliance would impair its ability to render adequate service or would place an undue burden on the electric utility [74].

Interconnection costs must be assessed on a non-discriminatory basis with respect to non-cogenerating customers with similar load characteristics, and may not duplicate any costs including the avoided costs [75]. Standard or class charges for interconnection may be included in purchase power tariffs for QFs with a design capacity of 100 kW or less, and Public Service Commissions may also determine interconnection costs for larger facilities on either a class or individual basis.

Cogenerators' fuel choice may be influenced by the Fuel Use Act (FUA) prohibitions on oil and gas use and by the allocation and pricing rules of Natural Gas Policy Act of 1978 (NGPA), as well as by the environmental requirements and tax incentives.

A cogenerator may be subject to the FUA prohibitions if it has a fuel heat input rate 100 of million Btu per hour or greater and if it comes within the statutory definition of either a power plant or a major fuel-burning installation. Under FUA, a power plant includes "any stationary electric generating unit", consisting of a boiler, a gas turbine, or a combined-cycle unit that produces electric power for purposes of sale or exchange", but does not include cogeneration facilities if less than half of the annual electric output is sold or exchanged for resale. A major fuel-burning installation is defined as "a stationary unit consisting of a boiler, gas turbine unit, combined cycle unit or internal combustion engine". However, the prohibition against the use of oil and gas in new major fuel-burning installations applies only to boilers.

FUA allows a permanent exemption for cogenerators for if the "economic and other benefits of cogeneration are unobtainable unless petroleum or other gas, or both, are used in such facilities". The Department of Energy interprets the phrase "economic and other benefits" to mean that the oil or gas to be consumed by the cogenerator will be less than that which would otherwise be consumed by the conventional separate electric and thermal energy systems. Alternatively, if the cogenerator can show that the exemption would be in the public interest (e.g., a technically innovative facility, or one that would help to maintain employment in an urban area), the Department of Energy will not require a demonstration of oil/gas savings [73]. The regulation to implement the cogeneration exemption are subject to change; therefore, it is uncertain how difficult it could be to meet the exemption requirements, and thus how FUA will affect the market penetration [75].

Although the permanent exemption for cogeneration is likely to be the preferred route for potential cogenerators subject to the FUA prohibitions, several other exemptions may be applicable in certain circumstances. First, a permanent exemption is available to petitioners who propose to use a mixture of natural gas or petroleum and alternate fuel. Under this mixtures exemption, the amount of oil or gas to be used cannot exceed the minimum percentage of the total annual Btu heat input of the primary energy source needed to maintain operational reliability of the unit consistent with maintaining a reasonable level of fuel efficiency. Second, a temporary exemption is available to petitioners who plan to use a synthetic fuel (derived from coal or another fuel) by the end of the exemption period. Third, a temporary public interest exemption may be obtained when the petitioner is unable to comply with FUA immediately (but will be able to comply by the end of the exemption). One of the cases where this public interest exemption may be granted is for the use of oil or gas in an existing facility during the ongoing construction of an alternate fuel-fired unit [63-66, 76].

Natural Gas Policy Act (NGPA) of 1978 grants an exemption from its incremental pricing provisions to qualify cogeneration facilities under PURPA. Thus, the potential lower gas prices should not affect the relative competitiveness of gas-fired cogeneration significantly. Moreover, plants burning intrastate gas may not realise any savings because the fuel price is often at the same level as the incremental price. In addition, the deregulation could largely remove incremental pricing. These uncertainties mean NGPA probably will not be a major factor in cogeneration investment decisions [77].

Cogeneration can have significant impacts on air quality, especially in urban areas. Depending on cogenerator's size and location, it may be subject to one or more of the Clean Air Act (CAA) provisions, including New Source Performance Standards (NSPS) and programs for meeting and maintaining the National Ambient Air Quality Standards (NAAQS) in non-attainment and Prevention of Significant Deterioration (PSD) areas.

At present, NSPS exist for two types of sources that might be used for cogeneration, and have been proposed for a third. NSPS have been implemented for electric utility steam units of greater than 250-MMBtu/hr heat input. However, cogeneration facilities in this category are exempt from NSPS if they sell annually less than either 25 MW or one-third of their potential capacity. The other promulgated NSPS is for gas turbines of greater than 10 MMBtu/hr heat input at peak-loads. NSPS have been proposed for nitrogen oxide emissions from both gasoline and diesel stationary engines. As proposed, they would apply to all diesel engines with greater than 560 cubic inch displacement per cylinder. Finally, the Environmental Protection Agency (EPA) is considering NSPS for small fossil fuel boilers. The EPA is reportedly considering lower limits in the range of 50 to 100 MMBtu/hr heat input.

PSD would apply to fossil fuel boilers of greater than 250 MMBtu/hr heat input that emit more than 100 tons per year (tpy) of any pollutant, and also to any stationary source that emits more than 250 tpy of any pollutant (assuming that controls are in place). A PSD permit is only issued following a review of project impacts on air quality based on modelling data and up to one year of monitoring. These modelling and monitoring requirements can be expensive. For instance, one estimate suggests that the requisite modelling and other PSD requirements add from $35,000 to $80,000 to the installation costs of a 3 MW diesel cogenerator in New York City [78].

The application of the non-attainment area requirements to cogenerators also depends on system size; here the trigger is the capability of emitting 100 tpy of a pollutant. Sources with higher emissions must meet the Lowest Achievable Emission Rate (LAER), secure emission offsets, and demonstrate company wise compliance with the CAA. Smaller sources must use reasonably available control technology and are subject to the general requirement for "reasonable further progress" toward the NAAQS in non-attainment regions.

In addition to the potentially extensive permitting requirements for cogenerators under the CAA, facility with any cooling water discharges may also need National Pollution Discharge Elimination System (NPDES) permits. The NPDES permit generally specifies the applicable technological controls or effluent limitations required to achieve the water quality standards for the receiving waters. These permits are only likely to be required for large industrial cogenerators [27].

Because the only major federal permit or authorisation requirements for cogenerator are those under the Clean Air and Water Acts, they are not likely to be subject to the National Environment Policy Act (NEPA) process or to the other environmental requirements applicable to station power plants. However, operating cogeneration facilities can come under the purview of Occupation Service and Health Administration (OSHA) [27].

General consideration related to financing and ownership of cogeneration technologies include the ownership and purchase and sale terms of PURPA, the utility financing provisions of the National Energy Conservation Policy Act (NECPA) of 1978, tax incentives of the National Energy Act, the Windfall Profits Tax Act, and the Economic Recovery Tax Act, aspects of project financing and lease relationships, and capital recovery factors.

The most important sections of the Energy Security Act for the purposes of this assessment are in title IV which establishes incentives for the use of renewable energy resources including wind, ocean, organic wastes, and hydropower; only those provisions related to the use of organic wastes as fuel are applicable to cogenerators. It also sets up a Solar Energy and Energy Conservation Bank in the Department of Housing and Urban Development to make payments to financial institutions in order to reduce either the principal or interest obligations of owners or tenants loans for energy conserving improvements to residential, multi-family, agricultural, and commercial buildings. For commercial buildings, the eligible improvements specifically include cogeneration equipment. Direct grants to owners and tenants of residential or multi-family buildings also were authorised but were limited to lower income people.

The Energy Security Act also amended NECPA to permit utilities to supply, install and finance conservation improvements or alternate energy systems (including cogenerators) as long as independent contractors and local financial institutions are used and no unfair competitive practices are undertaken by the utility. Utilities are eligible to qualify as lenders and receive subsidies to pass on to customers. Local governments and certain non-profit organisations are eligible borrowers.

In addition to the regular investment tax credit of 10 percent on most capital investments, several energy incentives have been passed. Also, a number of "energy properties" are defined and set aside for special treatment under the investment tax credit. Property is not eligible for these special incentives to the extent that it uses subsidised energy financing (including industrial development bonds), or is used by a tax-exempt organisation or governmental unit other than a cooperative. Public utility property (that for which the rate of return is fixed by regulation) is excluded from these energy incentives even if it utilises solar, wind, biomass, or other alternative sources of energy such as synthetic liquid or gaseous fuels derived from coal.

The methods of project finance are particularly appropriate to the financing of distributed electricity generation. Project financing looks to the cash flow associated with the project as a source of funds with which to repay the loan, and to assets of the project as collateral. For successful project financing, a project should be structured with as little resource as possible to the sponsor, yet with sufficient credit support (through guarantees or undertakings of the sponsor or third party) to satisfy lenders. In addition, a market for the energy output (electrical or thermal) must be assured (preferably through contractual agreements), the property financed must be valuable as collateral, the project must be insured, and all Government approvals must be available [79-80]. With the adoption of PURPA, a source of revenues (rates of power purchases) has become available for small-scale energy project finance.

The capital recovery factor, as used hereafter, is the cost per kilowatt hour which the owner of a cogenerator must receive to recover its capital in a given period of time. Table 1 compares capital recovery factors for four classes of ownership that reflect different income tax structures [81].

TABLE 1.1

(cents per year per kilowatthour, in 1980 cents)

Period	Non-Utility Investor	High tax rate utility	Low tax rate utility	Non-tax paying utility
5 years	3.6 cents	4.2 cents	3.0 cents	2.8 cents
10 years	1.6 cents	1.9 cents	1.5 cents	1.4 cents
5 years	1.1 cents	1.2 cents	0.99 cents	0.93 cents
20 years	0.77 cent	0.91 cents	0.74 cents	0.70 cents

One way for an investor to get around high capital recovery factors is to use long-term bond financing.

Continued federal and state government support of simultaneous purchase and sale at full avoided costs is viewed by some as the single most important factor in overcoming industry indecision to cogeneration [82].

Existing and potential industrial cogeneration participants include industrial parks, integrated pulp and paper mills, other process industries (e.g., chemicals, petroleum refining, steel, food processing, textiles etc.) and heavy oil recovery projects.

The incentive to commercial firms to invest in cogeneration will rest heavily on a comparison between the cost of cogenerated electricity (especially, the fuel cost), and the price the commercial cogenerator pays for its electricity and heat (on comparative basis). Because of their smaller size, commercial firms often do not have financial resources equivalent to those of industrial firms and will be less interested in large scale projects unless they can be cooperatively owned [83].

Because almost all electric Investors-Owned Utilities Ownership (IOUs) are in the business of generating electricity, they are logical potential owners of dispersed generation facilities. The small size, shorter lead times, and lower capital requirements of cogeneration systems may provide short-term advantages to utilities in planning for uncertain demand growth. However, the PURPA limitations on ownership discourages utility investment in cogeneration. Moreover, most large utilities do not see dispersed generating facilities, including cogeneration, as having the ability to replace future central generating stations, and the low-earned utility rates of return in recent years may not be high enough to encourage investment in technologies with uncertain electricity output.

Full utility ownership may be very advantageous if a utility faces revenue losses due to industrial or commercial cogeneration. Moreover, if potential industrial or commercial cogenerators are unable to burn coal (e.g., due to space or environmental limitations), or are unwilling to assume the risk of advanced technologies (e.g., gasification), utility ownership with electricity and steam distribution can centralise the burden of using alternate fuels. However, the full incremental Investment Tax Credits (ITC) is not available for utility owned cogenerators nor are PURPA benefits available if an Investor Owned Utility (IOU) owns more than 50 percent of the cogeneration facility.

Alternatively, a utility may decide to participate in joint venture for a cogeneration facility in order to structure the ownership in such a way that the investment tax credit and other tax benefits are diverted to the non-utility participants. In addition, financing can be structured so that any debt related to the facility will not appear on the utility's balance sheet. This structuring would be appropriate for utility-financed industrial cogeneration or biomass projects [27-29].

Industrial parks also are an excellent application in which municipalities can foster the development of cogeneration. Tax-exempt industrial development bonds can be issued without limit under a specific exemption for the acquisition of land for industrial parks and its upgrading including water, sewage, drainage, communication, and power facilities prior to use. Cogeneration facilities (including steam distribution lines) presumably would fall into this specific exemption. The requirements encourage joint ventures between the exempt entity and business, but the funds must be used by the non-exempt entity in a trade or business and payments secured by an interest in property used in a trade or business. Moreover, some state laws prohibit municipalities from entering into corporate relationships with the private sector, but independent public authorities usually can be established to get around such prohibitions [27].

Rural electric co-operatives are finding it more difficult to purchase additional electricity from their traditional sources (IOUs and federal power authorities) and consequently are being forced to build or participate in new generating capacity. Within this context, dispersed facilities (including cogeneration) may be advantageous due to the shorter construction times, greater planning flexibility, and lower capital costs. In addition, alternate energy projects are more readily financed at favourable terms. As with other electric utilities, co-operatives will prefer projects that provide most of their additional capacity during peak demand periods and whose electricity output is not intermittent (e.g., bio-mass, hydroelectric, and industrial cogeneration projects) [27].

Integration of DSG

For effective operation as part of the utility, a DSG must be integrated. Integration is defined as follows:

1) a DSG connection to a utility system in which provisions are made for protection of the DSG as well as the system
2) the operation of the DSG as a managed part of the total utility supply system

A single DSG unit of relatively small output, or a number of DSG units of whose aggregate output is small, may be connected to a system without being integrated [84] i.e, they may be connected but not integrated as a managed part of the supply mix. Integrated operations require interaction among the DSGs and the power system, including the electric utility's bulk supply systems.

Operational Problems

Cogeneration has impacted the utility generation due to their base load mode of operation. This base load usually compounds the utility's daily unit commitment problems associated with unit cycling, control reserves, and minimum load. The utility experiences a significant decrease in operating flexibility. Base load cogeneration affectively removes constant load of this utility. The worst case scenario is a cogenerator who sells to the utility only during the off peak, termed off peak dumping. To avoid this undesirable situation, four different types of contracts are advised [31-33]:

Firm capacity contracts

Non-firm energy sales only contract

Wheeling contracts

Combination of the above

The operational problems from cogenerator's point of view are that the basic philosophy behind design of QF generating facilities are much different than that typically used by utilities. Where the utility must design to meet the growing and periodically swinging electrical loads, the QF's concerns lie primarily with meeting thermal demands of manufacturing processes. Design of electrical capabilities then follows, but does not usually constitute the primary design constraint.

It is often difficult to comply with the expectations of and rules imposed by utilities. In some cases, this compliance is realised at significant economic expenses [2,4].

IEEE formed a Working Group on Current Operational Problems (COPS) with the goal of focusing attention of the industry on problems faced by those who are involved in actual power. Eight system operational areas are identified:

operations planning
normal systems operations
emergency system operations
system restoration
interconnections and pooling
dispatcher selection and training
system operations management
control centre design and maintenance

The group surveyed, conducted numerous technical sessions and published papers [39-45]. The mathematical modelling aspects of various types of cogeneration facilities along with the linear program optimisation procedures implemented to arrive at optimum operational schedules have been reported [53, 1, 38].

The aspects of energy management most impacted by DSG are associated with real time control. Automatic generation control (AGC) can be influenced by the addition of DSGs within the control area. The position of a schedulable DSG is dependent upon considerations of economic dispatch, and will also depend on the resource of the DSG. AGC is affected in two ways by unschedulable DSGs. First, the position in the loading order must be determined, but unlike the case of a schedulable DSG, the addition of a considerable penetration of uncontrollable power sources could influence existing generation [5].

If a DSG has independent voltage control capability, it can and must be operated cooperatively with any method of DSG voltage control on existing power system. Protection of radial feeders is generally by breakers or reclosures at the distribution substation, tripped by the action of an overcurrent relay. Protection of laterals and transformers is generally by use of fuses, including current limiting types [5, 15-17, 57]. Intertie protection schemes using undervoltage, overvoltage, underfrequency, overfrequency, voltage-controlled or voltage compensated, battery/DC undervoltage, reverse power are reported by the Power System Relaying Committee of IEEE. The committee has prepared a consumer-utility guide to establish a common understanding amongst those involved in the intertie design [51, 52-56, 61].

Some changes in the safety practices and protection hardware are required for low penetration of DSG devices. Additional feeder switches and lock-out disconnect switches at the DSG installations would reduce the size of feeder sections with DSG and prevent the re-energisation of a de-energised feeder section during maintenance. Because of DSG infeed to faults, fuse sizes may need to be increased and reclosure settings delayed to prevent damage to DSG devices operating out of-phase with the utility system following the occurrence of a system disturbance. The placement of capacitors to correct the power factor must take into consideration the possibility of DSG islanding and resonant overvoltage situations [28].

Automated systems and microprocessor-based protection packages may be a more practical and safer method for controlling the operation of DSG devices and protecting the distribution system.

DSG in significant concentrations can have beneficial effects at the distribution feeder level in terms of reduced voltage drop, losses, and breaker currents [28].

Before 1970 utilities used traditional planning that stabilised along a number of lines [29, 36]:

* Cost of fuel was constant or declining in real and often in current dollars;
* Economics of scale dictated even larger power plants;
* Financing needs were well understood, relatively stable, and mechanisms were adjustable to handle unusual situations;

* Heat rate improved regularly as power plant design was improved;
* The price of electricity declined;
* Load grew at 7% each year;
* Regulatory/industry interactions and dynamics evolved accordingly.
* Utilities were financially sound, and concern was for minimal consumer cost.

As uncertainty is the very essence of the problems facing utility management today, a new approach for planning evolved, known as the SMARTE (Simulation, Modelling and Regression, and Tradeoff Evaluation) strategic planning methodology. SMARTE was developed specifically to address decisions involving conflicting objectives, uncertainties, as such disparate issues as fuel, economics, environmental implications, reliability, etc [47-50,30,35].

Transient studies due to switching, fault conditions and islanding on a distribution feeder connected to DSG are negligible so far [11-15, 3].

1.2 Aims of the thesis

The thesis describes in detail the modelling of a three phase multi-section distribution feeder, using PI configuration and mutual couplings between phases, from the line constants. It also describes the modelling of a three phase Δ/Y transformer, a three phase induction generator, several inductive loads, a capacitor bank and circuit breakers connected to the distribution feeder.

The fourth version of the IBM-PC Electro-Magnetic Transients Program, known as Alternative Transient Program (ATP4) was used to study the fault and switching transient analysis of the distribution feeder. The main objectives are:

(1) To develop mathematical and digital techniques to simulate distribution feeder of industry like SECV connected to a DSG like induction generator.

(2) To display graphically the transient voltages and currents at interesting points on the feeders under several types of fault and switching conditions.

(3) To create situation for islanding of the induction generator and display graphically the current supplied by the generator to the loads.

(4) To study the effect of two induction generators, connected to the feeder at two points, on fault transients and the essential need to modify the capacitor bank.

(5) To investigate the changes needed in the protection components as a result of the connection of the DSG to the feeders.

(6) To report the operation and planning aspects of the power supplied to feeder connected to DSG.

The mathematical theory on which the models are based and the explanation of the Alternative Transient Program are described in Chapter 3.

The data used and the mathematical computations are shown in Chapter 4.

Chapter 5 contains the graphical plots of transient voltages and currents during switching and fault conditions. It also offers an explanation to the shape of the plots and draws valuable conclusions.

Chapter 6 deals with the operational, control and planning aspects of the distribution feeder connected to the DSG. It includes voltage control, reliability, harmonics, earthing, and contractual matters between the private generator and the utility. Technical aspects of interconnections are also considered.

Chapter 7 derives the conclusion of the research and also offers guides to future work in this field.

CHAPTER 2 MATHEMATICAL MODELLING

2.0 Introduction

Transient phenomena plays an important role in power system networks. This chapter describes a method which was developed for solving transient phenomena in multi-phase system on a digital computer [34]. The method is based on step-by-step integration procedure for lumped parameters and on Bergeron's idea [98] for lossless lines. Switches with changing positions are included in the study. The line parameters, which are part of the input data are for the transient study, are obtained by calculation. The formatting for computations in ATP4 is given in Appendix A.

2.1 The solution of transient phenomena

The problem of transient phenomena is to find the voltages $u(t)$ or current $i(t)$ as a function of time t for a given network. It is obvious that a discretisation of the problem is necessary when using digital computers. Instead of a continuous history in time t, only a sequence of snapshot pictures at discrete intervals Δt is obtained. The discretisation interval Δt is chosen small enough so that derivatives can be accurately approximated by simple differences.

2.2 **Single-phase network**

The method, which will first be described for single-phase networks, can solve any linear network consisting of branches:

1. resistance R
2. inductance L
3. capacitance C
4. lossless lines (distributed constants L′, C′, per unit length).

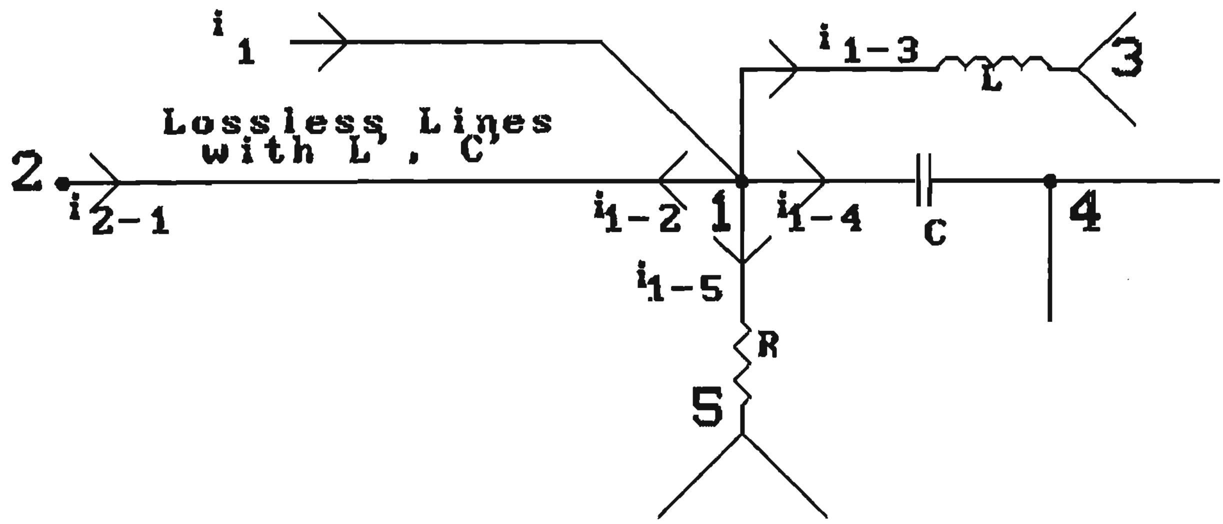


Fig. 2-1. Single-phase network

The configuration of Fig. 2-1 will be used for illustration. It contains all four types of branches and may be a part of a larger network. Suppose that the instantaneous voltages and currents have already been calculated at time intervals Δt up to time $t-\Delta t$ and must now be calculated for time t. The stepwidth Δt will be assumed constant. At any time t the sum of the currents leaving node 1 through the connected branches must be equal to the injected current i_1,

$$i_{1-2}^{(t)} + i_{1-3}^{(t)} + i_{1-4}^{(t)} + i_{1-5}^{(t)} = i_1^{(t)} \tag{1}$$

Nodal equations will be used. For node 1 it is found by expressing the individual branch currents in equation (1) as a function of node voltages.

2.3 **Branch equations**

(a) Lossless line.

For the lossless lines equation (2) exists

$$-\frac{\partial u}{\partial x} = L' \frac{\partial i}{\partial t} \qquad -\frac{\partial i}{\partial x} = C' \frac{\partial u}{\partial t} \tag{2}$$

with x = distance on the line from some arbitrary chosen point

u = u(x,t) = instantaneous voltage at distance x and time t

L' = inductance per unit length

C' = capacitance per unit length.

Eliminating one of the variables in equation (2) yields:

$$\frac{\partial^2 u}{\partial x^2} = L'C' \frac{\partial^2 u}{\partial t^2}$$

$$\frac{\partial^2 i}{\partial x^2} = L'C' \frac{\partial^2 i}{\partial t^2} \qquad (3)$$

The general solution, first given by D'Alembert, is:

$i = F(x - vt) + f(x + vt)$ (4a)

$u = ZF(x - vt) - Zf(x + vt)$ (4b)

with $F(x - vt)$ and $f(x + vt)$ being arbitrary functions of the variable $x - vt$ and $x + vt$. $F(x - vt)$ can be interpreted as a wave travelling at velocity v in the forward direction and $f(x + vt)$ as a wave travelling in the opposite direction. In equation (4) new parameters have been introduced, namely

surge impedance = $\sqrt{(L'/C')}$ (5a)

and velocity of wave propagation

$v = 1/\sqrt{(L'C')}$ (5b)

Equations (4a) and (4b) can be algebraically changed in the following forms:

$u + Zi = 2ZF(x - vt)$ (6)

$u - Zi = -2Zf(x + vt)$ (7)

$u + Zi$ is constant when $x - vt$ is constant and $u - Zi$ is constant when $x + vt$ is constant. $x - vt$ and $x + vt$ are called the characteristics of the differential equations.

Equation (6) may be interpreted in the following way: Let a fictitious observer travel along the line in positive direction with wave velocity v. Then x - vt and consequently u + Zi along the line will be constant for the observer. Let the travel time τ be defined as the time it takes a wave to travel from one end of the line to the other,

$$\tau = l/v = l/\sqrt{(L'C')} \tag{8}$$

where l is the length of the line. Then, on line section 2-1 in Fig. 2-1, the expression u + Zi encountered by the observer when leaving node 2 at time t $-\tau$ must be the same when arriving in node 1, that is,

$$u_2^{(t-\tau)} + Z.i_{2-1}^{(t-\tau)} = u_1^{(t)} + Z.(-i_{1-2}^{(t)}) \tag{9}$$

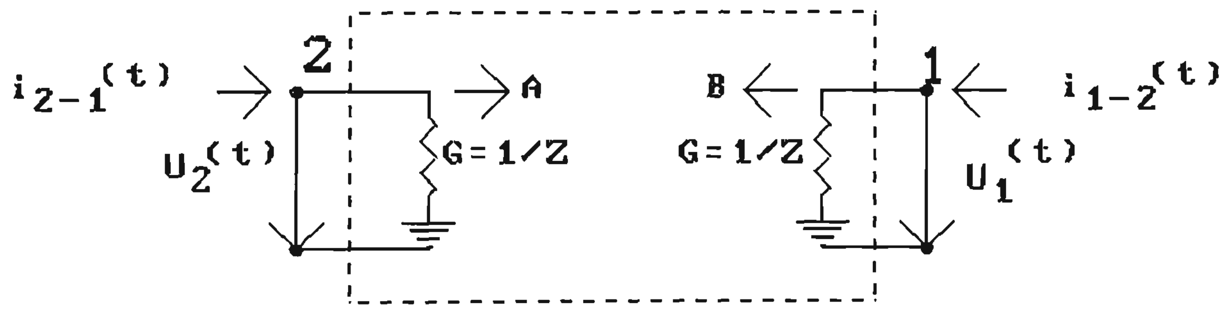
From equation (9) the branch equation for i_{1-2} is obtained,

$$i_{1-2}^{(t)} = (1/Z).\ u_1^{(t)} + const_{1-2}^{(t-\tau)} \tag{10a}$$

with a constant term, the value of which is known from the "past history" at time t - τ,

$$const_{1-2}^{(t-\tau)} = -[(1/Z).\ u_2^{(t-\tau)} + i_{2-1}^{(t-\tau)}] \tag{10b}$$

Equation (10) is an exact solution for the lossless line in terminal 1. This was the expression used by Bergeron for his graphical method [85].



A= $const_{2-1}^{(t-\tau)}$; B= $const_{1-2}^{(t-\tau)}$

Fig. 2-2. Equivalent circuit for lossless lines

Fig. 2-2 shows the equivalent circuit for the terminals, which consists of a conductance G = 1/Z from each node to ground. The nodes are linked only indirectly by means of fictitious current sources with known values, determined from the past history of the opposite terminal.

(b) **Inductance L**

For inductance L of branch 1-3 in Fig. 2-1, equation (11) is obtained:

$$u_1-u_3 = L.\frac{di_{1-3}}{dt} \tag{11a}$$

from which i_{1-3} at time t is obtained by integration:

$$i_{1-3}^{(t)} = i_{1-3}^{(t-\Delta t)}+\frac{1}{L}.\int_{t-\Delta t}^{t}(u_1-u_3)\,dt \tag{11b}$$

Since the voltage drop u_1 - u_3 is only defined at discrete points, an interpolation between t - Δt and t is necessary. With linear interpolation equation (11b) becomes

$$i_{1-3}^{(t)} = i_{1-3}^{(t-\Delta t)} + (\Delta t/2L)\{u_1^{(t-\Delta t)} - u_3^{(t-\Delta t)} + u_1^{(t)} - u_3^{(t)}\} \tag{12}$$

This is the well known trapezoidal rule for integration. The truncation error is the area between the curve and the chord in Fig. 2-3 and is of the order $(\Delta t)^3$ per step. If Δt is sufficiently small and cut in half, then the error can be expected to decrease by a factor of 1/8. The trapezoidal rule for integrating equation (11b) is identical with replacing the differential quotient in equation (11a) by a central difference quotient at midpoint between $t-\Delta t$ and t with linear interpolation for u. Equation (12) gives the branch equation for i_{1-3} :

$$i_{1-3}^{(t)} = (\Delta t/2L)\ [u_1^{(t)} - u_3^{(t)}] + const_{1-3}^{(t-\Delta t)} \tag{13a}$$

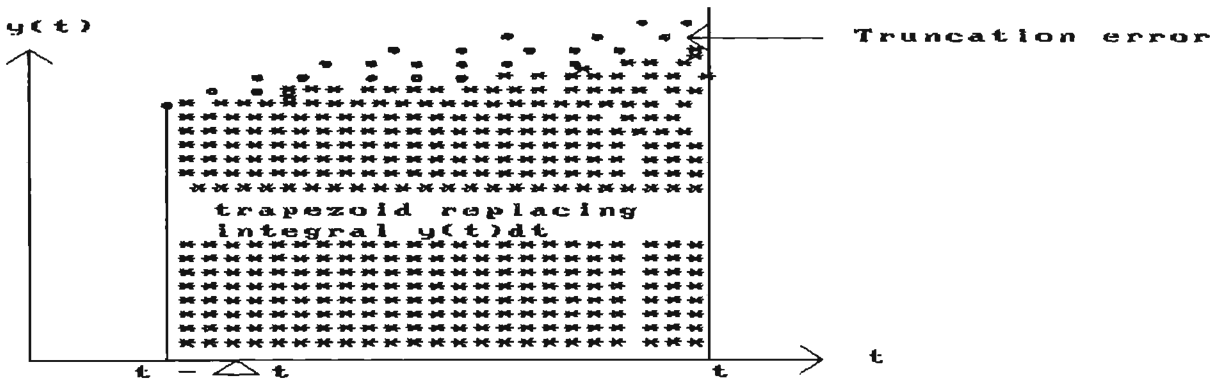


Fig. 2-3. Trapezoidal rule for integration

The constant term is again known from the past history:

$$const_{1-3}^{(t-\Delta t)} = i_{1-3}^{(t-\Delta t)} + (\Delta t/2L)\ [u_1^{(t-\Delta t)} - u_3^{(t-\Delta t)}] \tag{13b}$$

An equivalent circuit corresponding to equation (13) is shown in Fig. 2-4. It is a conductance $G = \Delta t/2L$ between nodes 1 and 3 with a parallel fictitious current source of known value.

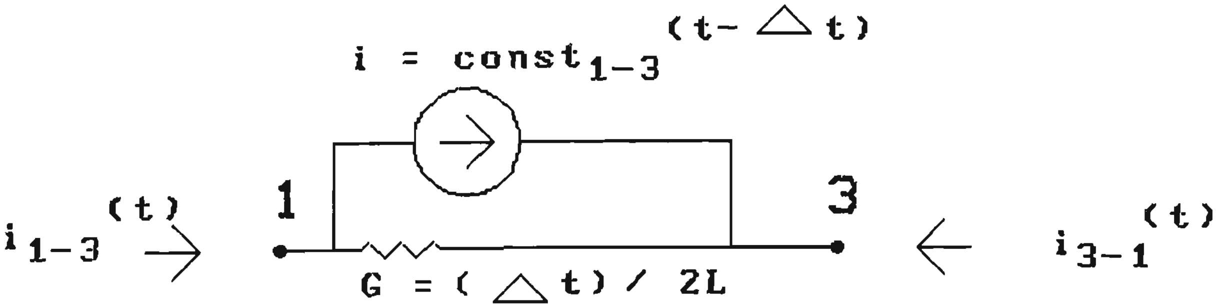


Fig. 2-4. Equivalent circuit for inductance

(c) **Capacitance C**

For the capacitance C of branch 1-4 in Fig. 2-1, the integral form is:

$$u_1^{(t)} - u_4^{(t)} = u_1^{(t-\Delta t)} - u_4^{(t-\Delta t)} + \left(\frac{1}{C}\right) \cdot \int_{t-\Delta t}^{t} i_{1-4} dt \tag{14}$$

$$u_1^{(t)} - u_4^{(t)} = u_1^{(t-\Delta t)} - u_4^{(t-\Delta t)} + (\Delta t/2C)\,[i_{1-4}^{(t)} + i_{1-4}^{(t-\Delta t)}] \tag{15}$$

This indicates linear interpolation for i. The truncation error is analogous to that of the inductance. From equation (15) the branch equation for i_{1-4} is obtained:

$$i_{1-4}^{(t)} = (2C/\Delta t)\,[u_1^{(t)} - u_4^{(t)}] + const_{1-4}^{(t-\Delta t)} \tag{16a}$$

with the constant term :

$$const_{1-4}^{(t-\Delta t)} = -(2C/\Delta t)\,[u_1^{(t-\Delta t)} - u_4^{(t-\Delta t)}] - i_{1-4}^{(t-\Delta t)} \tag{16b}$$

An equivalent circuit corresponding to equation (16) is shown in Fig. 2-5. Its form is identical with that for the conductance. A conductance $G = 2C/\Delta t$ between nodes 1 and 4 has a parallel fictitious current source of known value.

(d) **Resistance**

For the resistance R of branch 1-5 in Fig. 2-1 the current is given by :

$$i_{1-5}^{(t)} = (1/R)\,[u_1^{(t)} - u_5^{(t)}] \tag{17}$$

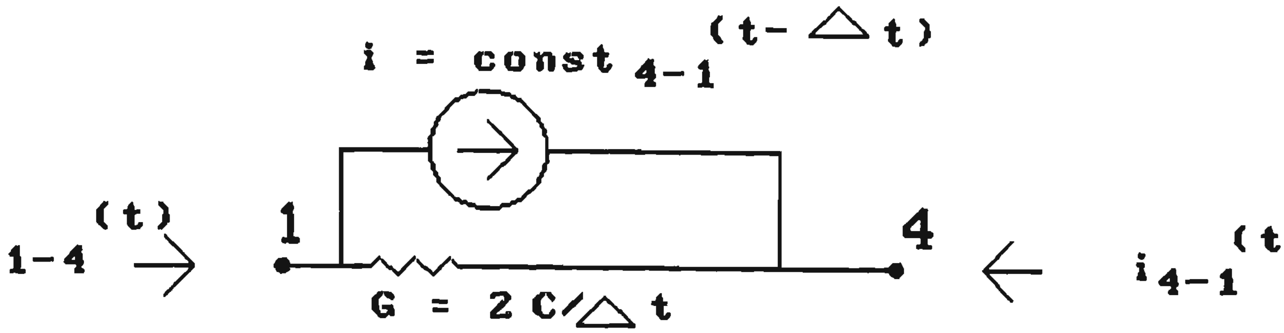


Fig. 2-5. Equivalent circuit for capacitance

2.4 Nodal equations

Inserting equations (10), (13), (16) and (17) into (1) gives the linear equation for node 1:

$$[1/Z + \Delta t/2L + 2C/\Delta t + 1/R].u_1^{(t)} - (\Delta t/2L).u_3^{(t)} - (2C/\Delta t).u_4^{(t)} - (1/R).u_5^{(t)} = i_1^{(t)} - [const_{1-2}^{(t-\tau)} + const_{1-3}^{(t-\Delta t)} + const_{1-4}^{(t-\Delta t)}] \quad (18)$$

For a general network with n nodes a system of such linear equations can be formed; in matrix notation

$$Y.U^{(t)} = I^{(t)} - K \quad (19)$$

where Y = nodal admittance matrix

$U^{(t)}$ = column vector of the n node voltages at time t

$I^{(t)}$ = column vector of the n injected node currents at time t

K = constant column vector, the value of which are made up of the "past-history terms" const.

The admittance matrix Y remains constant as long as Δt remains unchanged. It is real symmetric because the network is purely resistive with the equivalent circuits of Figs. 2-2, 2-4 and 2-5. Its formation follows the same rules known for the nodal admittance matrix in steady state analysis. The building algorithm can be shown more systematically with the use of incidence matrices, relating branch quantities to node quantities and vice versa.

In equation (19) part of the voltages will be given and the others will be unknown. Let the matrices and vectors be subdivided accordingly into a subset 'a' for nodes with unknown voltages and subset 'b' for nodes with known voltages. Then equation (19) becomes

$$\begin{bmatrix} Y_{aa} & Y_{ab} \\ Y_{ba} & Y_{bb} \end{bmatrix} * \begin{bmatrix} U_a^{(t)} \\ U_b^{(t)} \end{bmatrix} = \begin{bmatrix} I_a^{(t)} \\ I_b^{(t)} \end{bmatrix} - \begin{bmatrix} K_a \\ K_b \end{bmatrix} \qquad (20)$$

from which the unknown vector $U_a^{(t)}$ will be found by solving

$$U_a^{(t)} = [I_a^{(t)} - K_a - Y_{ab} . U_b^{(t)}] / Y_{aa} \qquad (21)$$

This is simply the solution of a system of linear equations for each time step with a constant coefficient admittance matrix Y_{aa}, provided Δt is not changed. The right sides must be calculated for each step with the injected currents in $I_a^{(t)}$, the voltage sources in $U_b^{(t)}$ and from the past history in K_a.

2.5 **Practical computation**

The problem of solving eqn. (21) is analogous to the steady state load flow solution with the impedance matrix or the triangularised admittance matrix. Instead of the iteration steps in the load flow solution time steps has been used. Equation (21) is best solved by initially triangularising Y_{aa} once and for all and extending the triangularisation process to the right sides in each step with back substitution to get $U_a^{(t)}$ [Fig. 2-6].

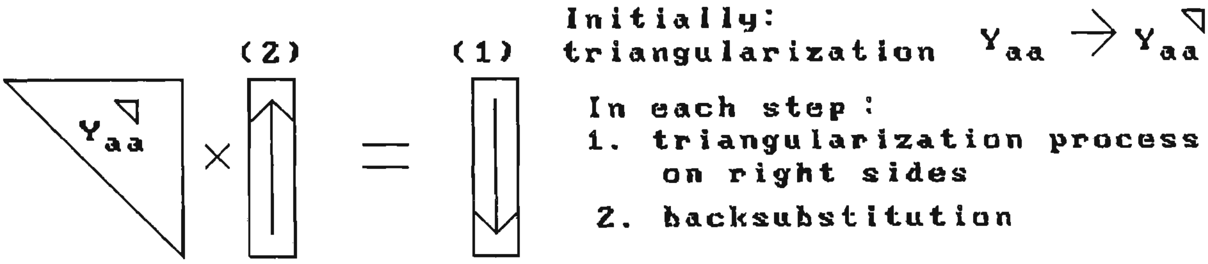


Fig. 2-6. Solving linear equations with changing right side

Only a few elements in Y_{aa} are non-zero. This sparsity should be exploited by storing only the non-zero elements of the triangularised matrix in compressed form. The savings in computer storage and computing time are impressive and can be optimised with an ordered elimination scheme.

Should the nodes be connected exclusively via lossless lines, with lumped parameters R, L, C only from nodes to ground, then Y_{aa} becomes a diagonal matrix. As a consequence the equations could be solved independently node by node. Using the sparsity technique automatically leads to this simplification, without having to restrict the generality of the network.

The construction of the column vector for the right sides in each is mainly an organisational problem. The given node currents are entered into $I_a^{(t)}$ and the given node voltages into $U_b^{(t)}$. The values may be read in point by point or calculated with standardised functions (sine curve, rectangular wave etc.). There are cases where the excitation may come from voltages only ($i_a = 0$) or from currents only (all nodes belong to subset 'a' then) or where there is no excitation at all (e.g. discharge of capacitors). Lighting strikes might best be represented as current sources. The past history is entered into K_a.

2.6 **Extension to multi-phase network**

The method can be used to include multi-phase circuits by formally replacing scalar quantities with matrix quantities. This generalisation is straight forward for lumped parameters. For lossless multi-phase lines the coupled phases quantities will be transformed into decoupled modal quantities. This linear transformation is similar to that of symmetrical components in steady state analysis.

2.6.1 **Lumped parameters with mutual couplings**

First consider a single branch consisting of series connection of a resistance R and inductance L between nodes 1 and 2. The conductance between the nodes, $G = 1/(2L/\Delta t + R)$ and the "past history term", $h = G.(2L/\Delta t - R)$. The current in the branch is given by

$$i_{1-2}^{(t)} = G.[u_1^{(t)} - u_2^{(t)}] + const_{1-2}^{(t-\Delta t)} \tag{22a}$$

with $const_{1-2}$ for the very first step from

$$const_{1-2}^{(t-\Delta t)} = G.[u_1^{(t-\Delta t)} - u_2^{(t-\Delta t)}] + h.i_{1-2}^{(t-\Delta t)} \tag{22b}$$

and then from the recursive formula:

$$const_{1-2}^{(t-\Delta t)} = G.(1+h)[u_1^{(t-\Delta t)} - u_2^{(t-\Delta t)}] + h.const_{1-2}^{(t-2\Delta t)} \tag{22c}$$

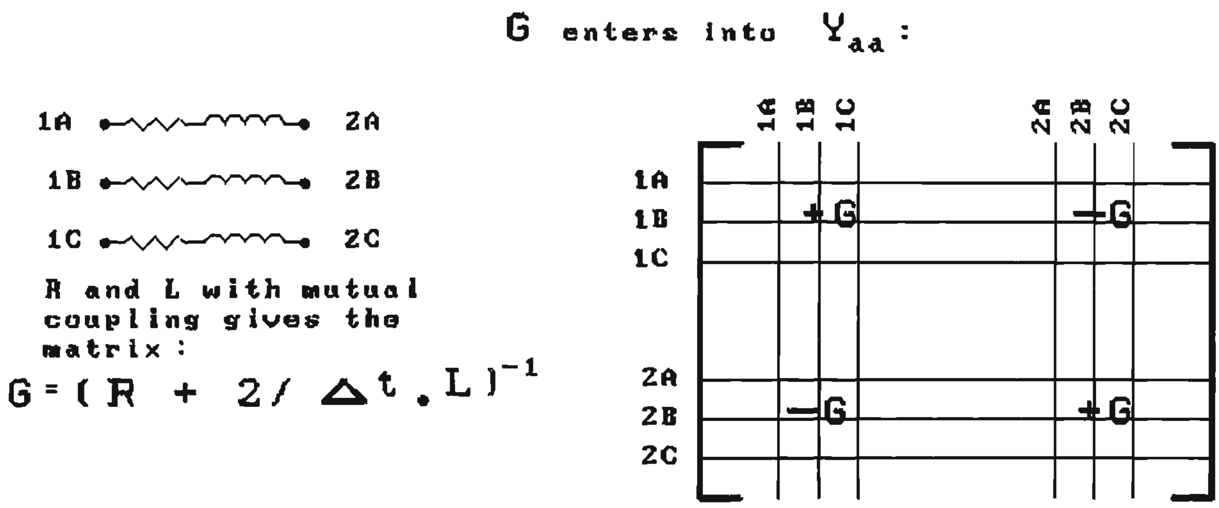


Fig. 2-7. Coupled R-L branches

Consider the circuit of Fig. 2-7 with matrix R for series resistance and matrix L for series inductances. Both will have off-diagonal elements for mutual coupling. Then the matrix equation corresponding to equation (22) will be :

$$I_{1-2}^{(t)} = G.[U_1^{(t)} - U_2^{(t)}] + const_{1-2}^{(t-\Delta t)} \qquad (23a)$$

with $const_{1-2}$ for the very first step from

$$const_{1-2}^{(t-\Delta t)} = G.[\{U_1^{(t-\Delta t)} - U_2^{(t-\Delta t)}\} - (R - 2L/\Delta t).I_{1-2}^{(t-\Delta t)}] \qquad (23b)$$

and then from the recursive formula

$$const_{1-2}^{(t-\Delta t)} = H[\{U_1^{(t-\Delta t)} - U_2^{(t-\Delta t)}\} + Z.const_{1-2}^{(t-2\Delta t)}] - const_{1-2}^{(t-2\Delta t)} \qquad (23c)$$

All matrices in equation (23) are symmetrical and real:

$$Z = R + 2L/\Delta t$$

$$G = Z^{-1}$$

$$H = 2(Z^{-1} - Z^{-1}RZ^{-1})$$

The only difference to a single-phase branch is, that in building the Y_{aa} matrix of equation (20) a matrix G instead of a scalar value is entered as schematically shown in Fig. 2-7. Also in each step a vector $const_{1-2}$ enters into K_a instead of a single value.

The set of nodes at each terminal of Fig. 2-7 will have capacitance between them and ground, if it is a multi-π circuit representing a line section. These capacitances are actually single-phase branches. No new formula is necessary therefore, even though it will be more economic to treat the capacitance as a matrix quantity C.

2.7 **Switches**

The network can contain switches with changing positions. They will be assumed ideal (R = 0 when closed, R = ∞ when open). Any branch may be connected in series or parallel to simulate certain physical properties. Switches represent either poles of circuit breakers or gaps, which can flash over. Closing of a breaker will be controlled by time criteria (closing when $t \geq t_{close}$) and opening by time and current criteria (opening when $t \geq t_{open}$ as soon as current over breaker $\leq$ current criteria). Closing of gaps are controlled by voltage criteria (closing when voltage across gap $\geq$ flash-over voltage) and opening by current criteria. With a gap-type switch the flash-over characteristic of an insulator may be simulated.

If there is only one switch in the network, say between nodes x and y, then it can be simulated with additional node currents $i_x = -i_y$. Y_{aa} in equation (21) is formed with the switch open.Let Z be the pre-calculated difference of the x-th and y-th columns of Y_{aa}^{-1}.

The vector is found by solving equation (21) for right sides being zero, except +1 for the x-th and -1 for the y-th component. Whenever the switch is open, the voltages U_k (open) are found by solving equation (21). Whenever the switch is closed, these results will be used to find

$$i_x = -\frac{u_{x(open)} - u_{y(open)}}{Z_x - Z_y} \qquad (24)$$

The solution is then obtained by superposition,

$$u_k(\text{closed}) = u_k(\text{open}) + Z_k . i_x \quad k = 1,2,... \qquad (25)$$

Equations (24) and (25) hold only if, both x and y are nodes with unknown voltages. Otherwise, modifications are necessary.

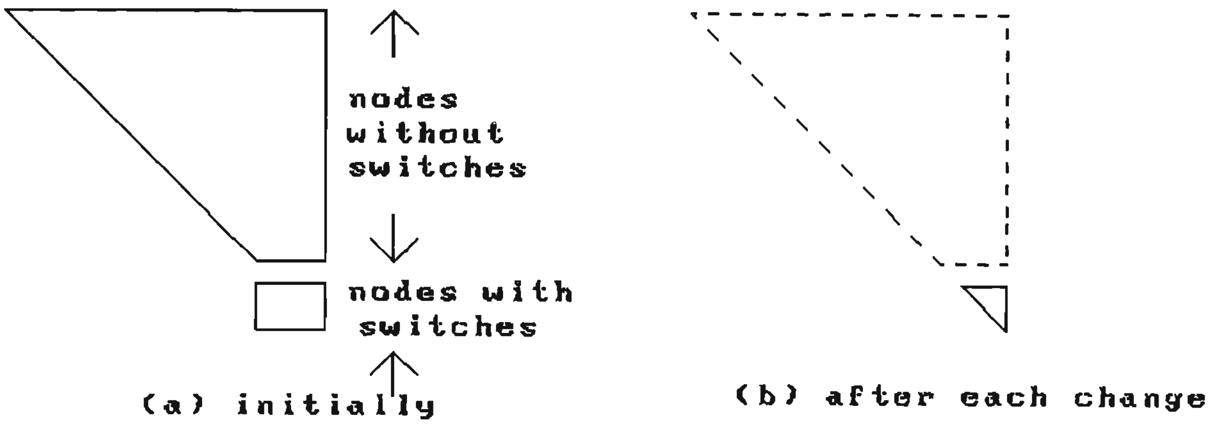


Fig. 2-8. Triangularisation in two steps

If there are more switches in the network, then Y_{aa} is best formed for the actual switch positions, whenever a change occurs. It is not necessary to repeat the triangularisation process entirely after each change. Let the nodes with switches be arranged at the bottom (Fig. 2-8), then the tringularisation process at the very beginning will be carried out for the nodes without switches. This yields a reduced, quadratic matrix for the switch nodes. Whenever a switch position changes, this reduced matrix will be modified for the actual switch positions and triangularised to complete the entire triangular matrix.

2.8 Positive and zero sequence parameters of single-circuit three-phase lines

The analysis of three-phase transmission lines becomes easier with α, ß, 0-components, because the three coupled equations in the phase domain, become three decoupled equations with α, ß, 0-components,

$$-\left[\frac{dv_{phase}}{dx}\right] = \begin{bmatrix} z_s & z_m & z_m \\ z_m & z_s & z_m \\ z_m & z_m & z_s \end{bmatrix} * \left[I_{phase}\right] \tag{26}$$

$$-dv_{zero}/dx = z_{zero}.I_{zero} \tag{27a}$$

$$-dv_{\alpha}/dx = z_{pos}.\ I_{\alpha} \tag{27b}$$

$$-dv_{ß}/dx = z_{pos}.\ I_{ß} \tag{27c}$$

where subscripts zero, pos correspond to zero and positive sequences of symmetrical components respectively; subscripts s, m correspond to self and mutual impedances; subscripts α, ß, 0 correspond to α, ß, 0-components.

Also phase voltages and phase currents can be transformed to α, ß, 0-components by the transformation matrix [T], such that

$$[v_{phase}] = [T].\ [v_{o\alpha ß}] \tag{28a}$$

$$[I_{phase}] = [T].\ [I_{0\alpha ß}] \tag{28b}$$

and

$$[V_{0\alpha\beta}] = [T]^{-1}. [V_{phase}] \tag{29a}$$

$$[I_{o\alpha\beta}] = [T]^{-1}. [I_{phase}] \tag{29b}$$

$$\left[V_{0\alpha\beta}\right] = \begin{bmatrix} V_0 \\ V_\alpha \\ V_\beta \end{bmatrix} \tag{30}$$

where with

$$[T] = \frac{1}{\sqrt{3}}.\begin{bmatrix} 1 & \sqrt{2} & 0 \\ 1 & -\frac{1}{\sqrt{2}} & \sqrt{(\frac{3}{2})} \\ 1 & -\frac{1}{\sqrt{2}} & -\sqrt{(\frac{3}{2})} \end{bmatrix} \tag{31}$$

$$[T]^{-1} = \frac{1}{\sqrt{3}}.\begin{bmatrix} 1 & 1 & 1 \\ \sqrt{2} & -\frac{1}{\sqrt{2}} & -\frac{1}{\sqrt{2}} \\ 0 & \sqrt{(\frac{3}{2})} & -\sqrt{(\frac{3}{2}} \end{bmatrix} \tag{32}$$

$$\text{and} \quad [T]^{-1} = [T]^{t} \tag{33}$$

Applying this transformation to Equation (26) produces

$$-\begin{bmatrix} dV_0 \\ dV_\alpha \\ dV_\beta \end{bmatrix} = \begin{bmatrix} z_s+2z_m & 0 & 0 \\ 0 & z_s-z_m & 0 \\ 0 & 0 & z_s-z_m \end{bmatrix}.\begin{bmatrix} I_0 \\ I_\alpha \\ I_\beta \end{bmatrix} \tag{34}$$

which is identical to equation (27), and where

$$z_{zero} = z_s + 2z_m \tag{35}$$

$$z_{pos} = z_s - z_m \tag{36}$$

The transformation from the three coupled equations in (26) to the three decoupled equations in (27) makes it convenient to solve the three phase line as if it consisted of three single-phase lines.

The positive sequence inductance of overhead lines is practically constant, while the positive sequence resistance remains more or less constant until skin effect in the conductors becomes noticeable. Zero sequence inductance and resistance are very much frequency-dependent, due to skin effects in the earth return.

The shunt capacitance matrix of a balanced three-phase line becomes diagonal in α, ß, 0-components as well, with

$$C_{zero} = C_s + 2\ C_m \tag{37}$$

$$C_{pos} = C_s - C_m \tag{38}$$

The self and mutual capacitances are often specified as positive and zero sequence parameters C_{pos}, C_{zero} which can be converted to self and mutual capacitances

$$C_s = 1/3\ .(2C_{pos} + C_{zero}) \tag{39}$$

$$C_m = 1/3\ .(C_{zero} - C_{pos}) \tag{40}$$

CHAPTER 3 CIRCUIT PARAMETERS

3.0 Introduction

The circuit studied under transient conditions is on a part of the distribution feeder of the State Electricity Commission of Victoria, as shown in Fig. 3-1. This feeder is connected to an induction generator through a transformer. Several inductive loads are connected between the induction generator and the utility supply, whose demands vary during the summer and the winter seasons; the maximum and the minimum demands are shown in Table 3-1. A capacitor is connected in shunt to compensate for the lagging MVAR required by the induction generator. The parameters for these components are as follows:

A. Supply system: 3-phase, 22kV, 50 Hz.

B. Induction generator: Squirrel-cage, 6.3 MVA, 3-phase, 11 kV, 50 Hz.

Resistances and reactances of the induction generator:

Stator resistance	0.087 Ω
Magnetising reactance	56.4 Ω
Transformation ratio	4.593

Parameters at slip s = 0

Stator reactance	2.226 Ω
Rotor resistance referred to stator	0.067 Ω
Rotor reactance referred to stator	1.662 Ω

DISTRIBUTION CIRCUIT OF SECU

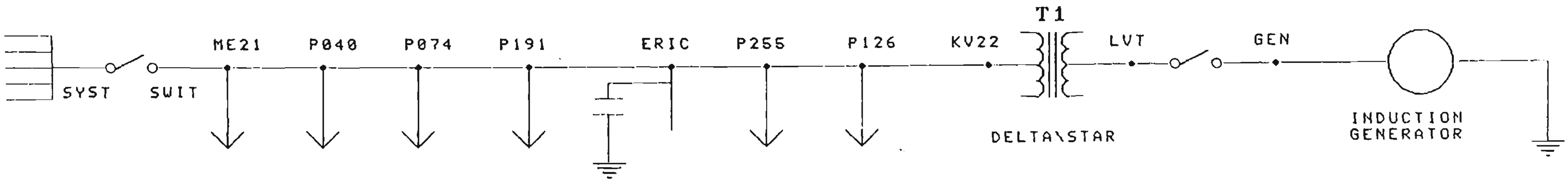


FIGURE 3-1.

LOADS IN MVA

NAMES OF NODES	ME21	P040	P074	P191	ERIC	P255	P126
SUMMER MAX. LOAD		1.5 + j1.0	1.0 + j0.6	0.1 + j0.05	j4.0	1.4 + j0.9	0.2 + j0.01
WINTER MIN. LOAD		0.4 + j0.15	0.2 + j0.1	0.06 + j0.02	j4.0	0.5 + j0.1	0.2 + j0.1

TABLE 3-1.

Impedance 3.890 Ω

Parameters at slip s = 1

	Stator reactance, saturated	1.930 Ω
	Stator reactance, unsaturated	2.226 Ω
	Impedance, saturated	2.976 Ω
	Rotor reactance referred to stator	
(a)	Saturated	1.029 Ω
(b)	Unsaturated	1.187 Ω
	Rotor resistance referred to stator	0.238 Ω

C. Capacitor bank: 5 x 0.8 MVAR, 22kV

D. Transformer: 3-phase, 10 MVA, 50 Hz, Δ/Y, 22kV/11kV

3.1 Line impedance and formation of Pi-models

Line and transformer data (% on 100 MVA base)

TABLE 3-2

FROM BUS	TO BUS	R (Ω)	X (Ω)	MVA
SYST	ME21	4.0	45.0	0.000
ME21	P40	27.79	40.83	0.000
P40	P74	18.57	26.76	0.006
P74	P191	106.15	140.74	0.028
P191	ERIC	19.51	24.14	0.005
ERIC	P255	27.09	33.75	0.006
P255	P126	99.89	124.87	0.024
P126	22kV	11.24	13.90	0.003
22kV	GEN	6.40	108.97	0.000

3.2 Computation procedure

To construct the Pi-model for each section of the feeder, the length of each section was calculated from the percentage resistances given in Table 2, and the resistances corresponding to all aluminium conductors 7/4.75 mm and 1800 x 300 mm Δ-configuration spacings. Positive and zero sequence impedances were calculated corresponding to different lengths of the section, using overhead line constants from standard tables. The self and mutual impedances, in terms of positive and zero-sequence impedances, are given by the following equations:

$$z_m = (z_{zero} - z_{pos})/3 \qquad (1)$$

$$z_s = (2z_{pos} + z_{zero})/3 \qquad (2)$$

These values could be easily derived from equations (35) and (36) of Chapter 2. Similarly, from positive and zero-sequence susceptances corresponding to different lengths, self and mutual capacitances were calculated, using equations (39) and (40) from Chapter 2. They are repeated here for easy reference.

$$C_s = 1/3 \; . \; (2C_{pos} + C_{zero}) \qquad (3)$$

$$C_m = 1/3 \; . \; (C_{zero} - C_{pos}) \qquad (4)$$

3.2.1 Computations of line parameters

Line voltage = 22 kV   Base MVA = 100

Base impedance: $(22)^2/100 = 4.84\ \Omega$

Actual impedance = (Impedance per unit) x (Base impedance)

Positive sequence resistance : 0.245 Ω/km

Positive sequence reactance : 0.34 Ω/km

Zero sequence resistance : 0.40 Ω/km

Zero sequence reactance : 1.6 Ω/km

Pos. sequence susceptance : 1.71 μS/phase/km

Zero sequence susceptance : 0.67 μS/phase/km

A switch is connected between nodes SYST and ME21.

Line impedances between nodes SWIT and ME21

Actual resistance = 0.04 x 4.84 = 0.1936 Ω

Actual reactance = 0.45 x 4.84 = 2.178 Ω

Length of line = 0.1936 / 0.245 = 0.8 km

Zero sequence resistance = 0.40 x 0.8 = 0.32 Ω

Zero sequence reactance = 1.6 x 0.8 = 1.28 Ω

$z_{pos} = 0.1936 + j\ 2.178\ \Omega$

$z_{zero} = 0.32 + j\ 1.28\ \Omega$

From equations (1) and (2)

$z_s = 0.23573 + j\ 0.57187\ \Omega$

$z_m = 0.0421 + j\ 0.3541\ \Omega$

Line capacitance between nodes SWIT and ME21

From the tables of overhead line constants

Positive sequence susceptance = 1.71 x 0.8 = 1.368 μS

Zero sequence susceptance = 0.67 x 0.8 = 0.536 μS

On the basis of the discussion given in Chapter 2,

$$\omega(C_s - 2C_m) = 0.536$$

and $$\omega(C_s + C_m) = 1.368$$

From equatons (3) and (4)

$$C_s = 0.0034718\ \mu F$$

and $$C_m = 0.00088\ \mu F$$

Line impedance between nodes ME21 and P040

Actual resistance = 0.2779 x 4.84 = 1.345 Ω

Actual reactance = 0.4083 x 4.84 = 1.976 Ω

Length of line = 1.345 / 0.245 = 5.49 km

Zero sequence resistance = 0.40 x 5.49 = 2.196 Ω

Zero sequence reactance = 1.6 x 5.49 = 8.784 Ω

$z_{pos} = 1.345 + j\ 1.976\ \Omega$

$z_{zero} = 2.196 + j\ 8.784\ \Omega$

From equations (1) and (2)

$z_s = 1.6287 + j\ 4.2453\ \Omega$

$z_m = 0.2837 + j\ 2.2693\ \Omega$

Line capacitance between nodes ME21 and P040

Positive sequence susceptance = 1.71 x 5.49 = 9.388 μs

Zero sequence susceptance = 0.67 x 5.49 = 3.678 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 3.678$$

$$\omega(C_s + C_m) = 9.388$$

From equations (3) and (4)

$$C_s = 0.023717\ \mu F$$

and $$C_m = 0.006166\ \mu F$$

Line impedance between nodes P040 and P074

Actual resistance = 0.1857 x 4.84 = 0.8987 Ω

Actual reactance = 0.2676 x 4.84 = 1.295 Ω

Length of line = 0.8987 / 0.245 = 3.67 km

Zero sequence resistance = 0.40 x 3.67 = 1.468 Ω

Zero sequence reactance = 1.6 x 3.67 = 5.872 Ω

z_{pos} = 0.8987 + j 1.295 Ω

z_{zero} = 1.468 + j 5.872 Ω

From equations (1) and (2)

z_s = 1.088 + j 2.8207 Ω

z_m = 0.1898 + j 1.5257 Ω

Line capacitance between nodes P040 and P074

Positive sequence susceptance = 1.71 x 3.67 = 6.276 μS

Zero sequence susceptance = 0.67 x 3.67 = 2.459 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 2.459$$

$$\omega(C_s + C_m) = 6.276$$

From equations (3) and (4)

$$C_s = 0.05927\ \mu F$$

and

$$C_m = 0.0.004098\ \mu F$$

Line impedance between nodes P074 and P191

Actual resistance = 1.0615 x 4.84 = 5.1377 Ω

Actual reactance = 1.4074 x 4.84 = 6.812 Ω

Length of line = 5.1377 / 0.245 = 20.97 km

Zero sequence resistance = 0.40 x 20.97 = 8.388 Ω

Zero sequence reactance = 1.6 x 20.97 = 33.552 Ω

z_{pos} = 5.1377 + 6.812 Ω

z_{zero} = 8.388 + j 33.552 Ω

From equatios (1) and (2)

z_s = 6.2211 + j 15.7253 Ω

z_m = 1.0834 + j 8.9133 Ω

Line capacitance between nodes P074 and P191

Positive sequence susceptance = 1.71 x 20.97 = 35.859 μS

Zero sequence susceptance = 0.67 x 20.97 = 14.05 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 14.05$$

$$\omega(C_s + C_m) = 35.859$$

From equations (3) and (4)

$$C_s = 0.091002\ \mu F$$

and

$$C_m = 0.002341\ \mu F$$

Line impedance between nodes P191 and ERIC

Actual resistance = 0.1952 x 4.84 = 0.9442 Ω

Actual reactance = 0.2414 x 4.84 = 1.168 Ω

Length of line = 0.9442 / 0.245 = 3.85 km

Zero sequence resistance = 0.40 x 3.85 = 1.54 Ω

Zero sequence reactance = 1.6 x 3.85 = 6.16 Ω

z_{pos} = 0.9442 + j 1.168 Ω

z_{zero} = 1.54 + j 6.16 Ω

From equation (1) and (2)

$z_s = 1.1428 + j\ 2.832\ \Omega$

$z_m = 0.1986 + j\ 1.664\ \Omega$

Line capacitance between nodes P191 and ERIC

Positive sequence susceptance = 1.71 x 3.85 = 6.584 μS

Zero sequence susceptance = 0.67 x 3.85 = 2.58 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 2.58$$

and $$\omega(C_s + C_m) = 6.584$$

From equations (3) and (4)

$$C_s = 0.016708\ \mu F$$

and $$C_m = 0.004249\ \mu F$$

Line impedance between nodes ERIC and P255

Actual resistance = 0.2709 x 4.84 = 1.3112 Ω

Actual reactance = 0.3375 x 4.84 = 1.6335 Ω

Length of line = 1.3112 / 0.245 = 5.35 km

Zero sequence resistance = 0.40 x 5.35 = 2.14 Ω

Zero sequence reactance = 1.6 x 5.35 = 8.56 Ω

$z_{pos} = 1.3112 + j\ 16335$

$z_{zero} = 2.14 + j\ 8.56$

From equations (1) and (2)

$z_s = 1.5875 + j\ 3.9423\ \Omega$

$z_m = 0.2763 + j\ 2.3088\ \Omega$

Line capacitance between nodes ERIC and P255

Positive sequence susceptance = 1.71 x 5.35 = 9.149 μS

Zero sequence susceptance = 0.67 x 5.35 = 3.585 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 3.585$$

and $$\omega(C_s + C_m) = 9.149$$

From equations (3) and (4)

$$C_s = 0.023217\ \mu F$$

and $$C_m = 0.005905\ \mu F$$

Line impedance between nodes P255 and P126

Actual resistance = 0.9989 x 4.84 = 4.8346 Ω

Actual reactance = 1.2487 x 4.84 = 6.044 Ω

Length of line = 4.8346 / 0.245 = 19.73 km

Zero sequence resistance = 0.40 x 19.73 = 7.892 Ω

Zero sequence reactance = 1.6 x 19.73 = 31.568 Ω

$z_{pos} = 4.8346 + j\ 6.044\ \Omega$

$z_{zero} = 7.892 + j\ 31.568\ \Omega$

From equations (1) and (2)

$z_s = 5.8537 + j\ 14.552\ \Omega$

$z_m = 1.0191 + j\ 8.508\ \Omega$

Line capacitance between nodes P255 and P126

Positive sequence susceptance = 1.71 x 19.73 = 33.738 μS

Zero sequence susceptance = 0.67 x 19.73 = 13.22 μS

As calculated in the previous case

$$\omega(C_s - 2C_m) = 13.22$$

and $\omega(C_s + C_m) = 33.738$

From equations (3) and (4)

$$C_s = 0.085621\ \mu F$$

and $C_m = 0.021770\ \mu F$

Line impedance between nodes P126 and KV22

Actual resistance = 0.1124 x 4.84 = 0.544 Ω

Actual reactance = 0.1390 x 4.84 = 0.673 Ω

Length of line = 0.544 / 0.245 = 2.22 km

Zero sequence resistance = 0.40 x 2.22 = 0.888 Ω

Zero sequence reactance = 1.6 x 2.22 = 3.552 Ω

$z_{pos} = 0.544 + j\ 0.673\ \Omega$

$z_{zero} = 0.888 + j\ 3.552\ \Omega$

From equations (1) and (2)

$z_s = 0.659 + j\ 1.633\ \Omega$

$z_m = 0.1147 + j\ 0.9597\ \Omega$

Line capacitance between nodes P126 and KV22

Positive sequence susceptance = 1.71 x 2.22 = 3.796 μS

Zero sequence capacitance = 0.67 x 2.22 = 1.487 μS

As calculated in the previous case

$$\omega(C_s - 2C_s) = 1.487$$

and $\omega(C_s + C_m) = 3.796$

From equations (3) and (4)

$$C_s = 0.009633\ \mu F$$

and $C_m = 0.002450\ \mu F$

3.3 **Format for entering the line parameters**

The self and mutual values of resistances, inductances and capacitances which are calculated in section 3.1 for each section of the line are entered in the program according to certain rules, as shown in Appendix A. The node names are suffixed with A, B, and C to represent the three phases of the distribution feeders. As the method of entering these parameters is identical for each section of the feeder, only one section is shown here, specifically section SWIT to ME21. The values calculated are:

z_s = 0.23573 + j 0.57187 Ω

z_m = 0.0421 + j 0.3541 Ω

C_s = 0.0034718 μF; C_m = 0.00088 μF

Card 1:

SWITA in cols. 3-8 ME21A in cols. 9-14

R_{11} = 0.23573 Ω in cols. 27-32

L_{11} = 0.57187 Ω in cols. 33-38

C_{11} = 0.0034718 μF in cols. 39-44

Card 2:

SWITB in cols. 3-8 ME21B in cols. 9-14

R_{21} = 0.0421 Ω in cols. 27-32

L_{21} = 0.3541 Ω in cols. 33-38

C_{21} = 0.00088 μF in cols. 39-44

R_{22} = 0.23573 Ω in 45-50

L_{22} = 0.57187 Ω in cols. 51-57

C_{22} = 0.00347 μF in cols. 57-62

Card 3:

SWITC in cols. 3-8 ME21C in cols. 9-14

R_{31} = 0.0421 Ω in cols. 27-32

L_{31} = 0.3541 Ω in cols. 33-38

C_{31} = 0.00088 μF in cols. 39-44

R_{32} = 0.0421 Ω in cols. 45-50

L_{32} = 0.3541 Ω in cols. 51-56

C_{32} = 0.00088 μF in cols. 57-62

R_{33} = 0.23573 Ω in cols. 63-68

L_{33} = 0.57187 Ω in cols. 69-74

C_{33} = 0.00347 μF in cols. 75-80

CHAPTER 4 ABNORMAL CONDITIONS: GRAPHICAL OUTPUTS

4.0 Introduction

This chapter contains the graphical outputs of transient voltages and currents under fault conditions. Transients caused by switching of the induction generator, single line-to-ground fault, double line-to-ground fault, a broken conductor touching the ground through a small resistance, etc. are plotted at various points of interest on the distribution feeder. The case of islanding the induction generator with certain portion of the feeder has also been studied. In all cases the period of study under fault condition is 20 milliseconds, but in case of islanding an additional period of 2 seconds has been added. Each case of fault, switching or islanding is illustrated by a diagram drawn below the complete circuit diagram. This is followed by description of the fault and other interesting graphical plots and comments. Most of the plots contain changes in voltages or currents in all three phases; however, in order to identify the individual curves, the sequence in which the peak of the curves is reached is always considered as A, B, C.

4.1 Abnormalities at various points when ground fault occurs at SYSTA

This section describes zero resistance phase to ground fault on phase A at 5 ms near the system. The switch connecting the system to line remains closed with the induction generator spinning at - 2.5697 % slip, as shown in Fig. 4-1.

Plot 1 shows currents in all phase at node P255. Phases B and C maintain their sinusoidal forms, but current wave in phase A, being the faulty phase, is distorted. As node P255 is far from the fault point, the distortion is not so prominent.

Plot 1A shows the currents in the three phases supplied from the system to the feeders. As SYSTA touches the ground at 5 ms, there is a markable change in the current waves, and a sudden change in the waveform exists, which is more conspicuous in phase A than in the other phases.

Plot 2 shows the fault current through phase A. It appears that the current through this phase is zero from time t = 0 to 5 ms. However, as the current scale of Plot 2 is much larger than that of Plot 1A, the normal current appears is quite small with the fault current, and therefore it appears zero during the said time interval. Thus current through phase A is several times more than the normal current, which is due to the ground fault at SYSTA.

Plot 3 shows the current fed into the ground fault. Comparing the shape and magnitude of this plot with those of Plot 2, it is seen that they are symmetrical about the zero-axis; that is, the shapes are identical but opposite in sign.

DISTRIBUTION CIRCUIT OF SECV

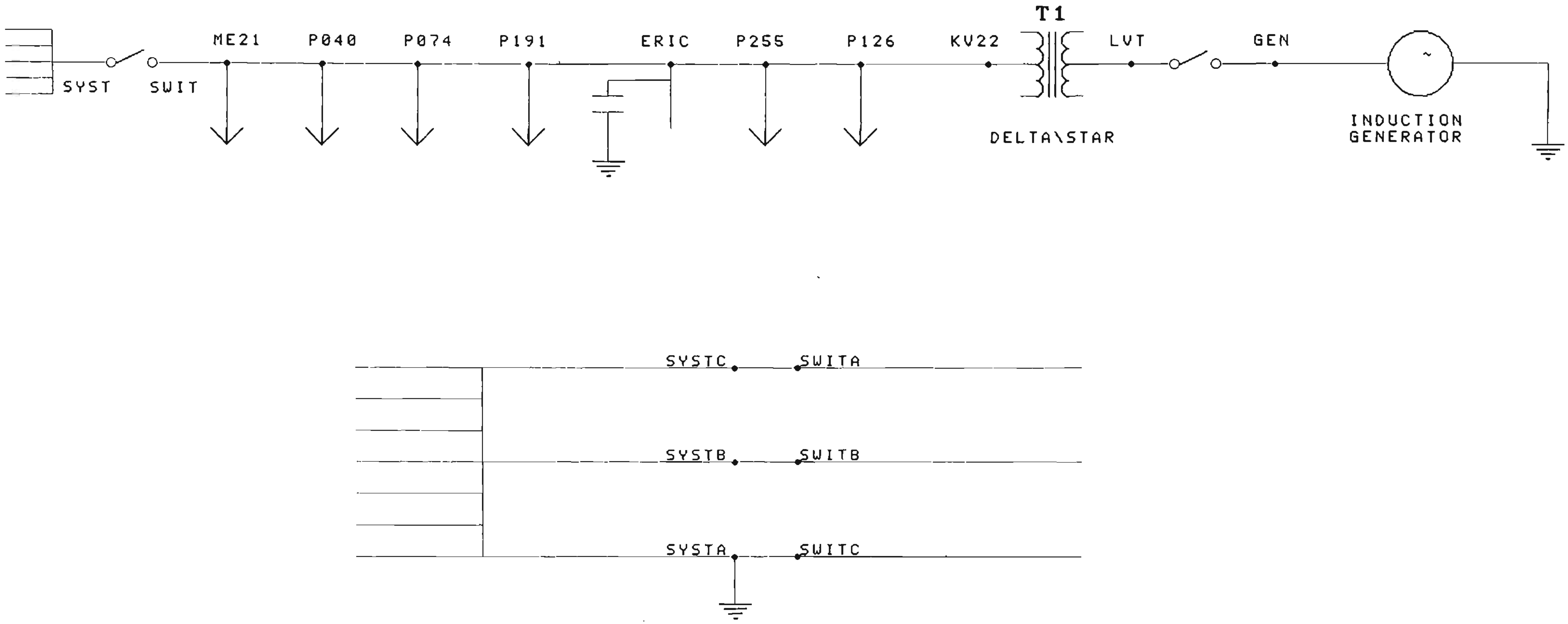
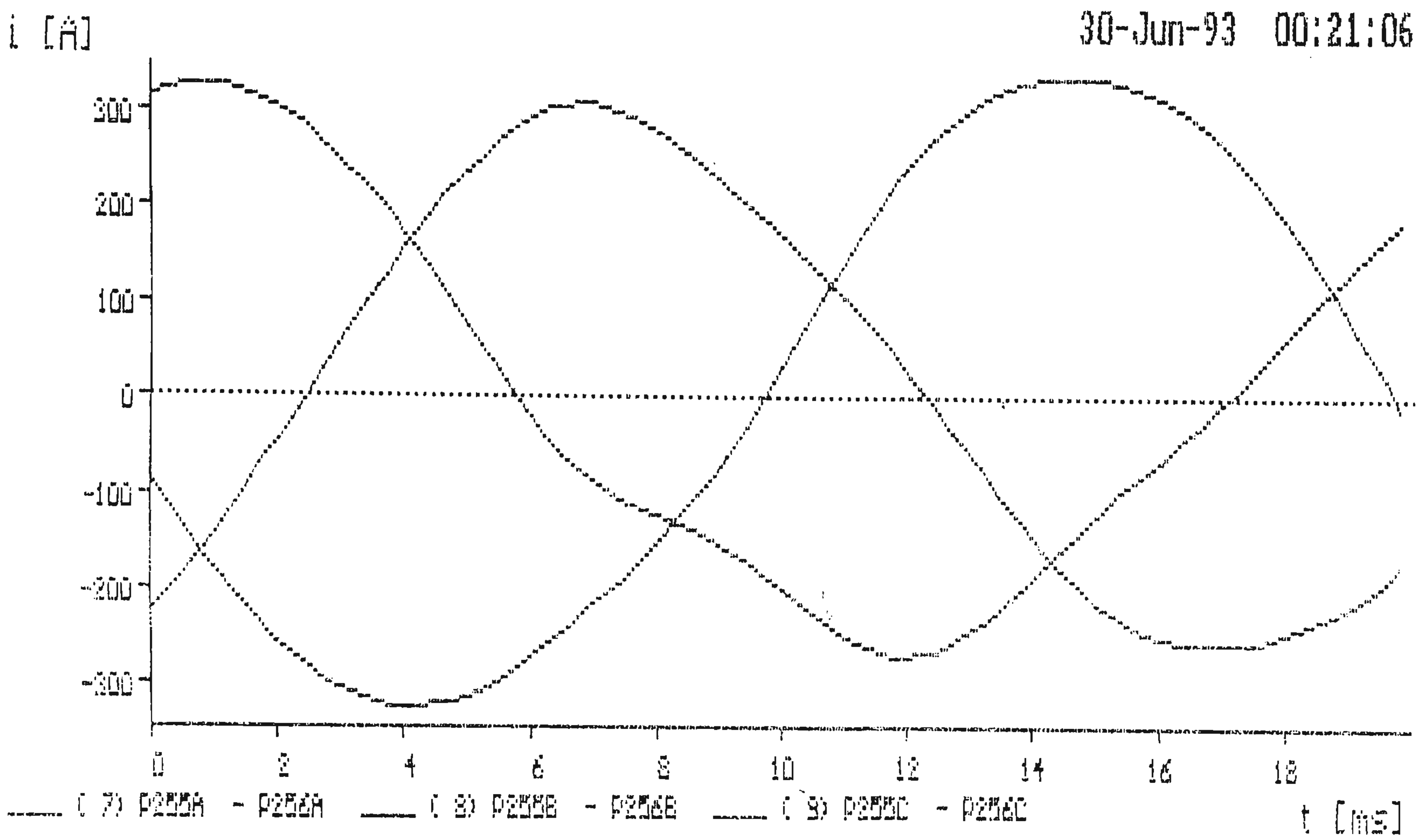
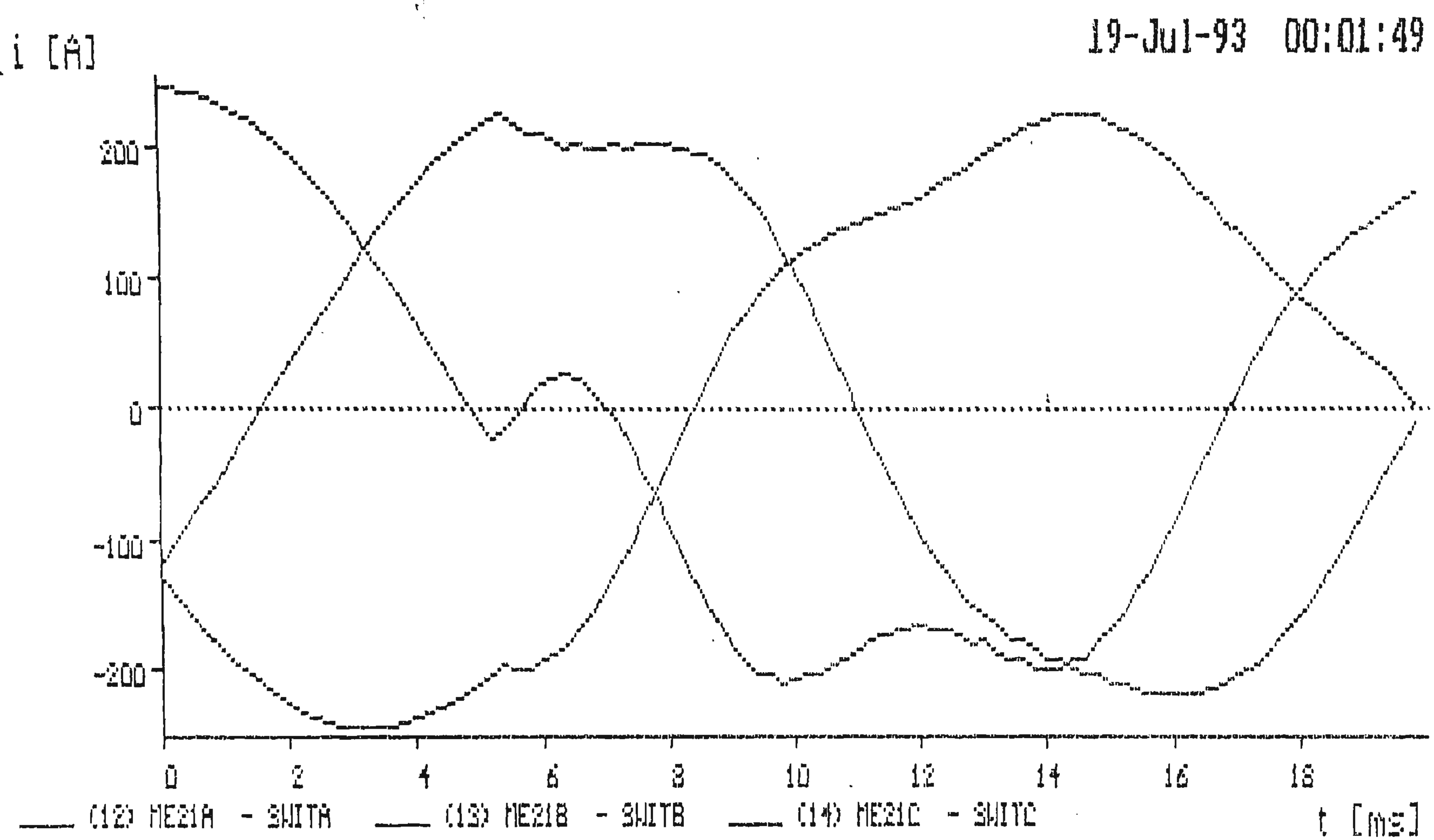


FIG. 4-1 GROUND FAULT AT SYSTA



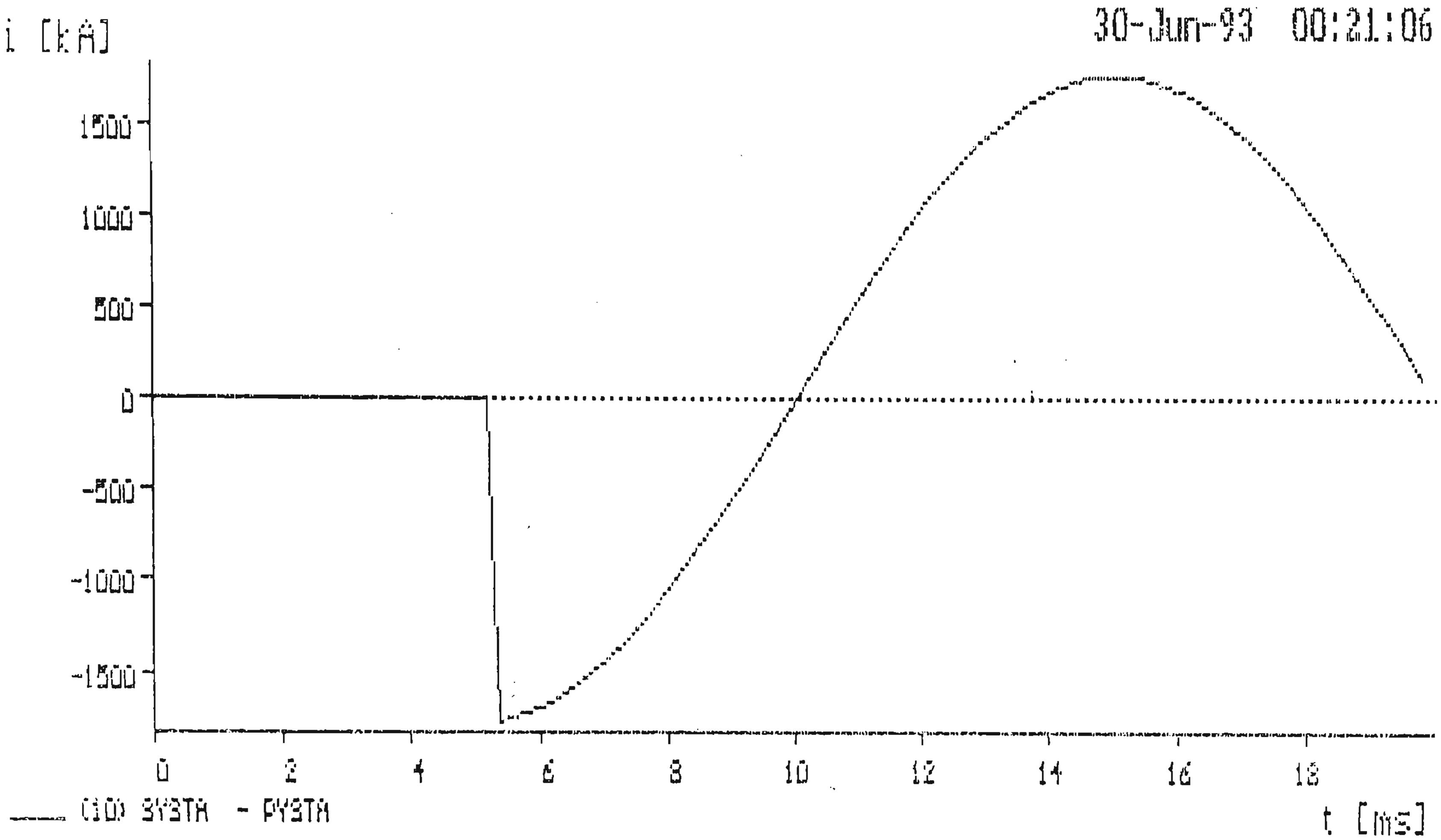
PLOT 1. TRANSIENT CURRENTS NEAR NODE P255.

print date: 30. June 1993



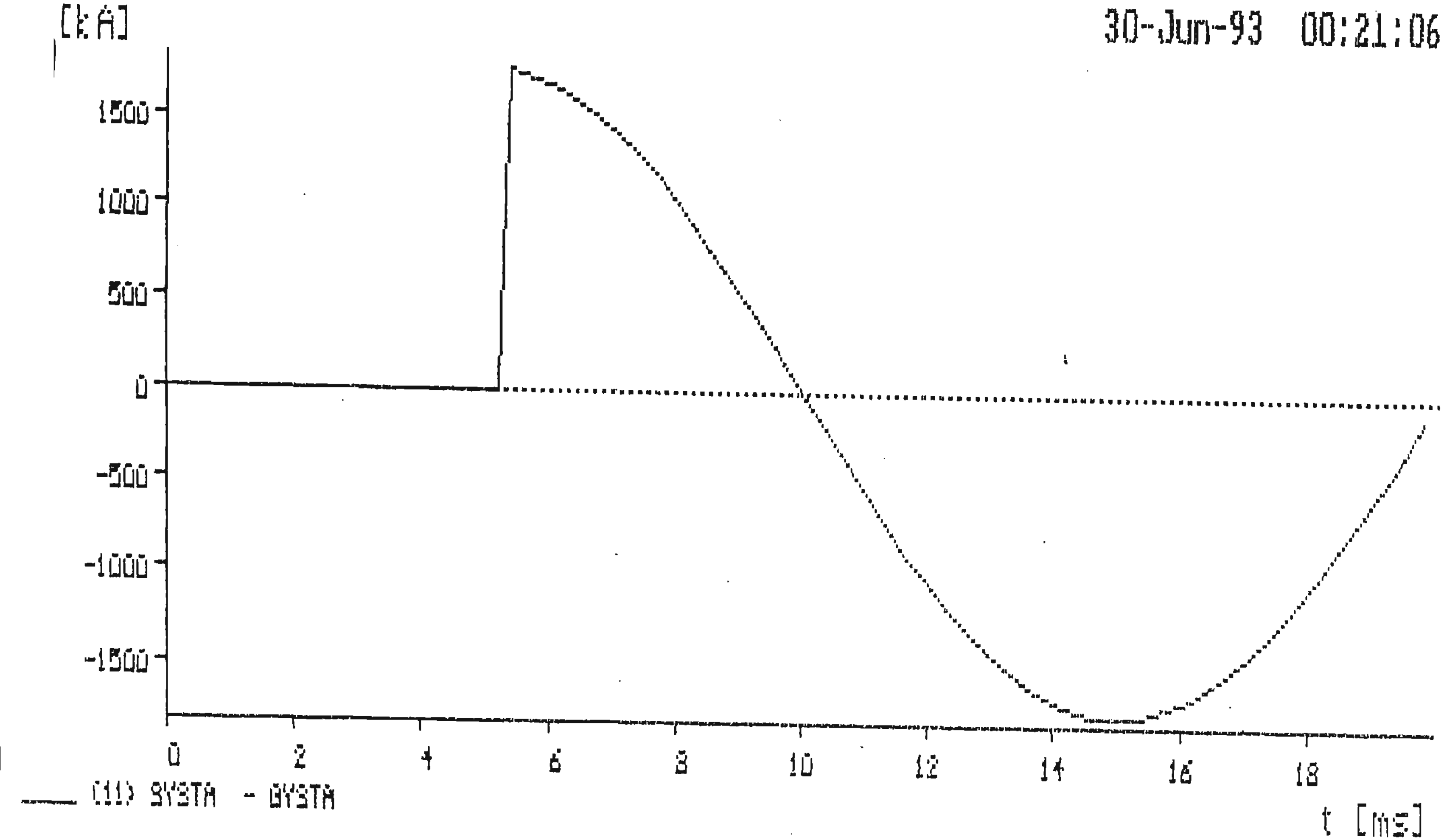
PLOT 1A. TRANSIENT CURRENTS THROUGH THE THREE SWITCHES NEAR SYST.

print date: 19. July 1993



PLOT 2. TRANSIENT CURRENTS NEAR SYST.

print date: 30. June 1993



PLOT 3. CURRENT FED INTO THE FAULT.

print date: 9. July 1993

The magnitude of current in Plot 2 is more than the one shown in Plot 3, the difference being the load current shown in Plot 1A.

Plots 4 and 5 show the transient voltages at nodes P040 and P074 respectively. There is no load between P074 and P040; hence, virtually the transient characteristics remain the same at both the nodes. An abrupt dip in voltage of phase A is noticed in each case at 5 ms, when the ground fault occurs. The magnitude of the voltage in this phase is reduced to nearly half as seen at 15 ms. The effect of transient is more pronounced in phase A than in B and C. Transient effects in voltages of phases B and C are caused by the mutual couplings of the inductances in all phases.

Fig. 4-1a shows the current flow in different parts of the feeder in this case.

The oscillating nature of the waveforms of Plots 4 and 5, and other future plots is discussed here. In order to illustrate the phenomena of oscillations, a section of the feeder between P191 and ERIC has been considered. The inductive reactance between these nodes is 0.9442 Ω, which corresponds to an inductance of 3.005 mH at 50 Hz. The capacitance from ERIC to ground is 26.3 μF, which forms a parallel circuit with 3.005 mH. These elements produce parallel resonance, whose frequency, on calculation is 566 Hz. From the above outputs, the time period for one cycle is found to be 1.69696 ms. Hence, the

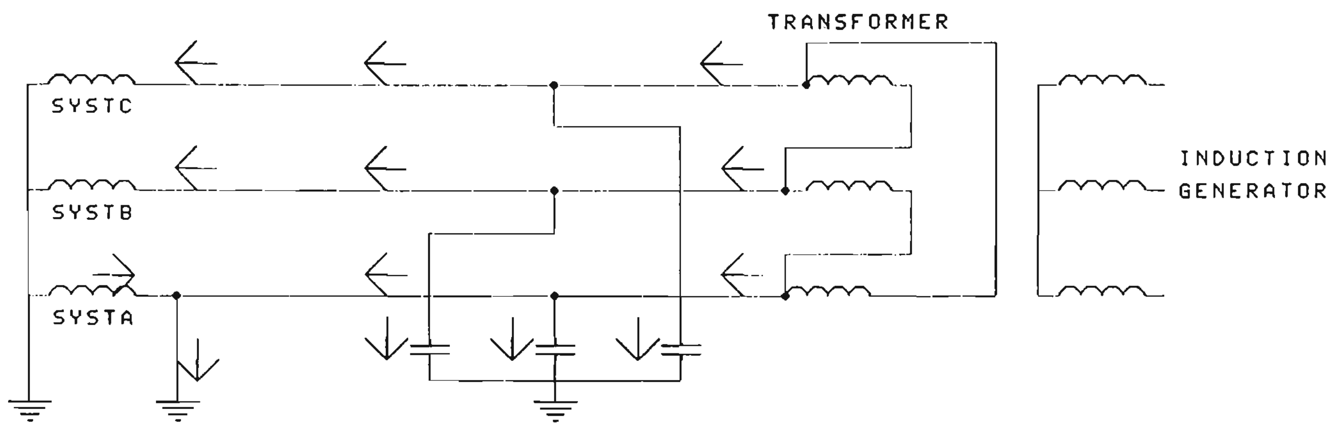
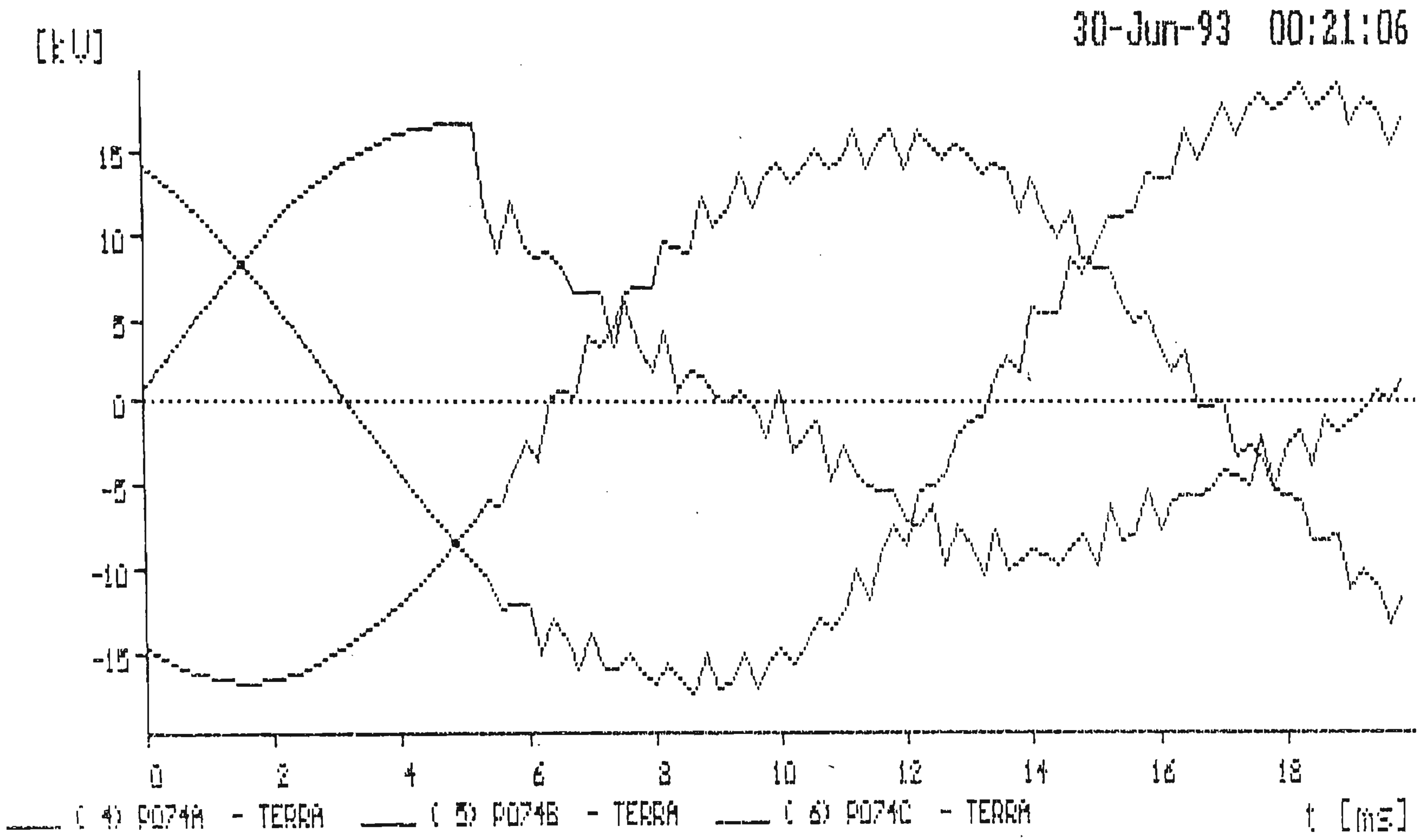


FIG. 4-1A. ARROWS SHOW CURRENT FLOW DURING FAULT AT SYSTA.

PLOT 4. TRANSIENT VOLTAGES AT NODE PO40.

print date: 2. July 1993



PLOT 5. TRANSIENT VOLTAGES AT NODE PO74.

print date: 2. July 1993

frequency of oscillations is 1/1.69696 or 589 Hz. Thus the frequency of oscillations is the frequency of resonance. It can thus be concluded that parallel resonance at high frequency causes the oscillations.

4.2 Abnormalities at various points when 2-phase to ground fault occurs at P191

This section describes 2-phase to ground fault which occurs at node P191 through zero fault resistance. The fault is energised by both system and the induction generator; the generator runs at -1.0 % slip.

Fig. 4-2 shows phases A and B contact ground through zero fault resistance at node P191.

Plot 6 shows transient voltages at node P074. Voltages in phases A and B collapse to almost half at the instant of fault. There is an increase in phase C to ground voltage. The large fault currents in phases A and B create abnormally high armature reaction, which is vectorially added to the exciting field. This increased field causes the voltage in phase C to rise. Also, as the magnetic field intensity increases, saturation of the magnetic core occurs, which causes the voltage wave of phase C to depart from sinusoidal form.

Plot 7 shows the transient voltages at node P191, where the fault has occurred. Voltages at phases A and B are zero at 5

DISTRIBUTION CIRCUIT OF SECU

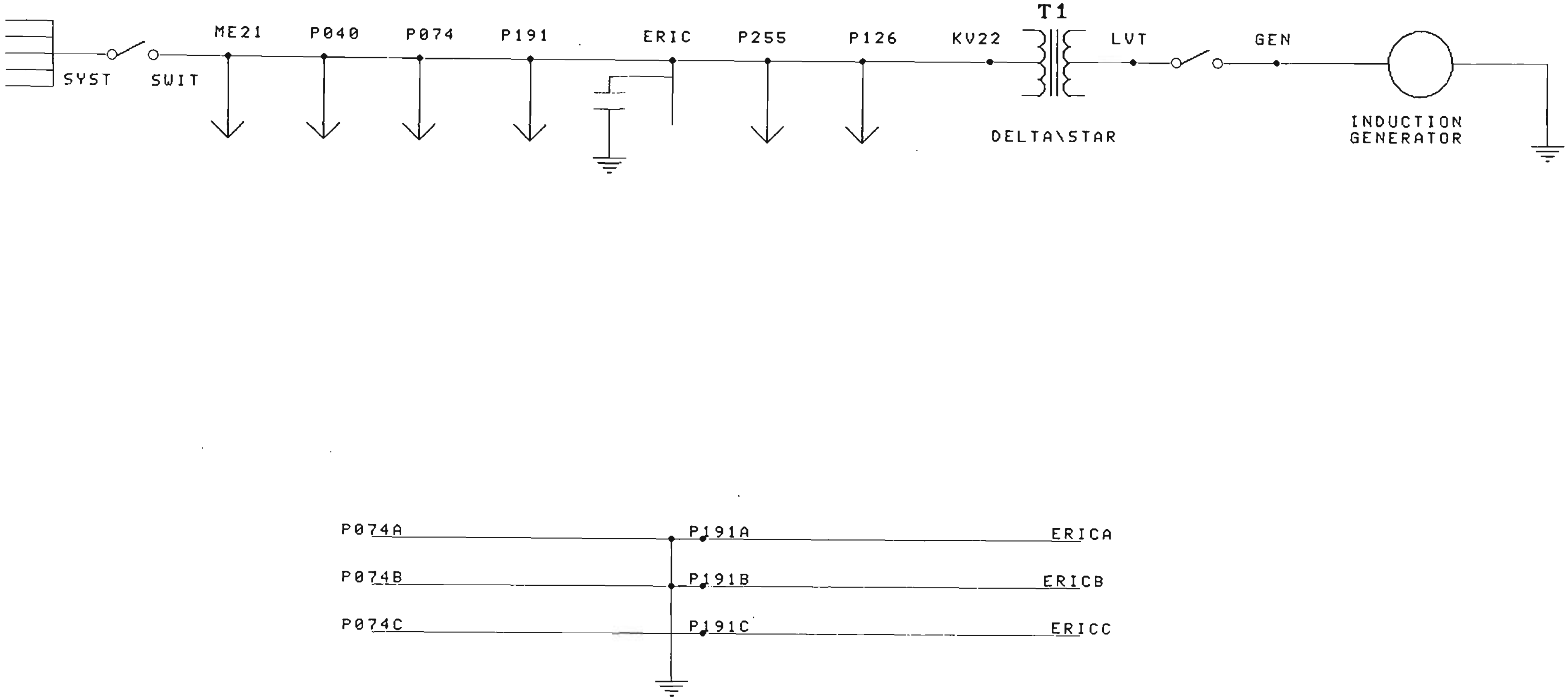
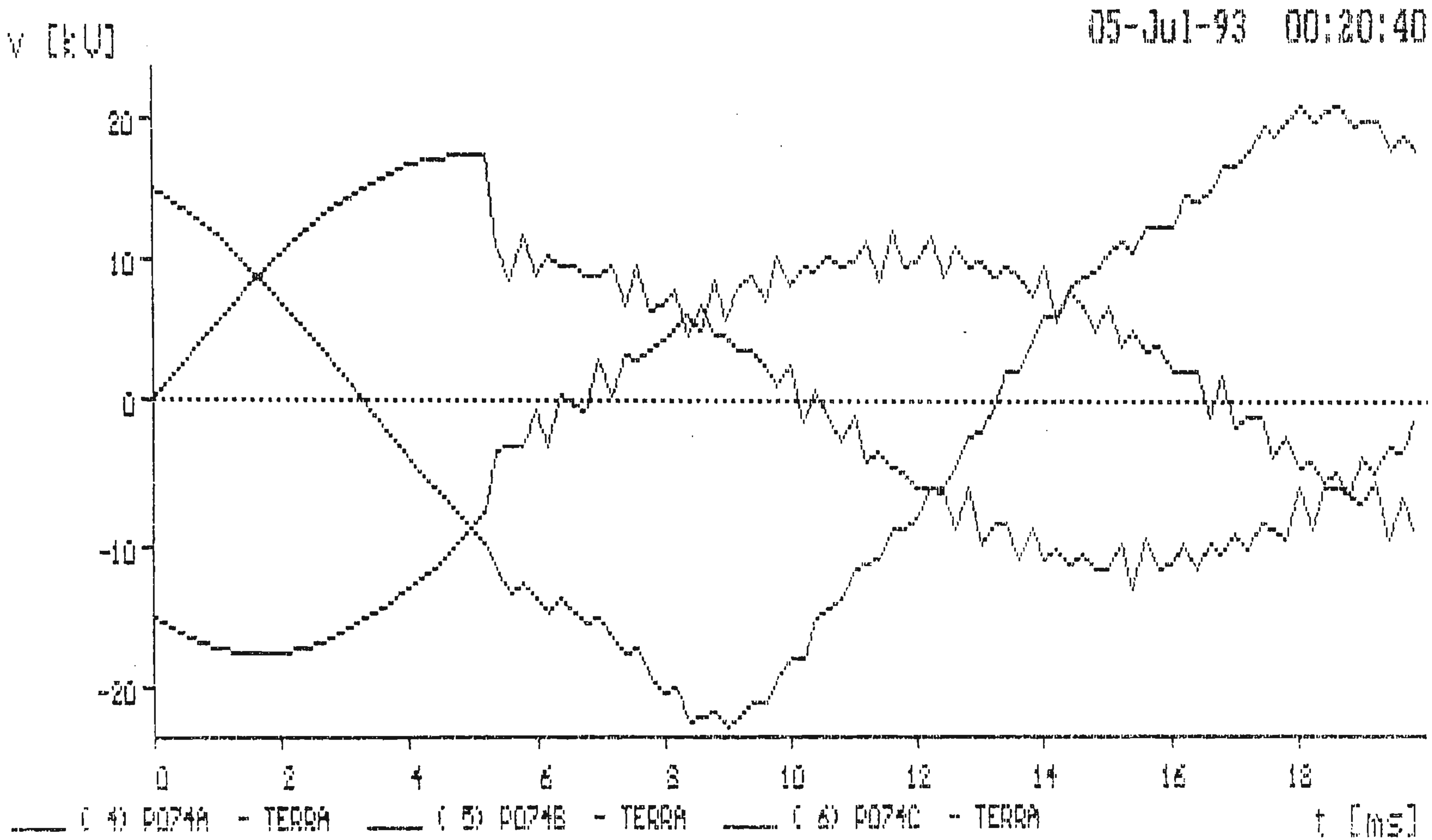
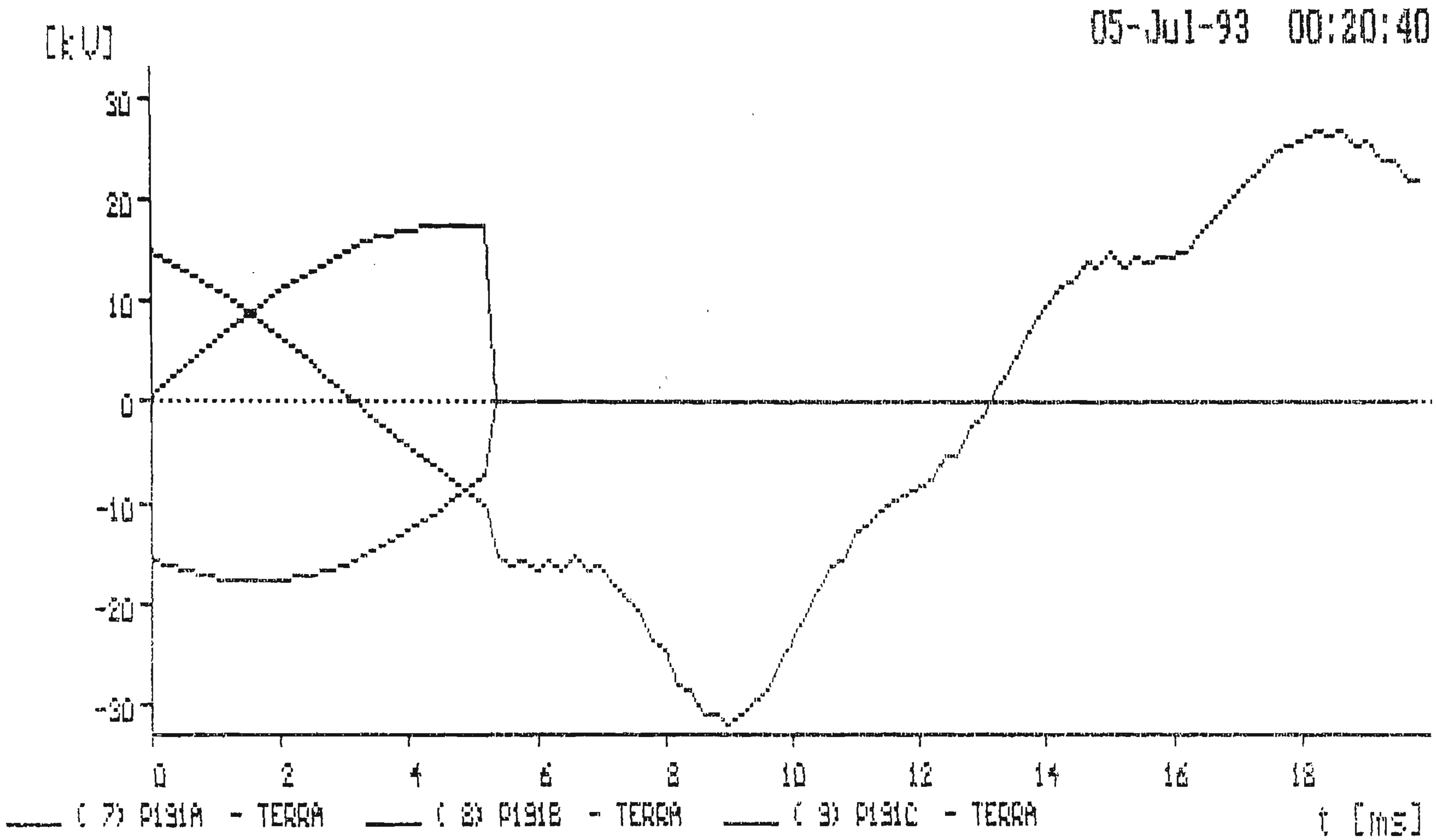


FIG. 4-2 DOUBLE LINE-TO-GROUND FAULT.



PLOT 6. TRANSIENT VOLTAGES AT NODE P074.

print date: 5. July 1993



PLOT 7. TRANSIENT VOLTAGES AT NODE P191.

print date: 5. July 1993

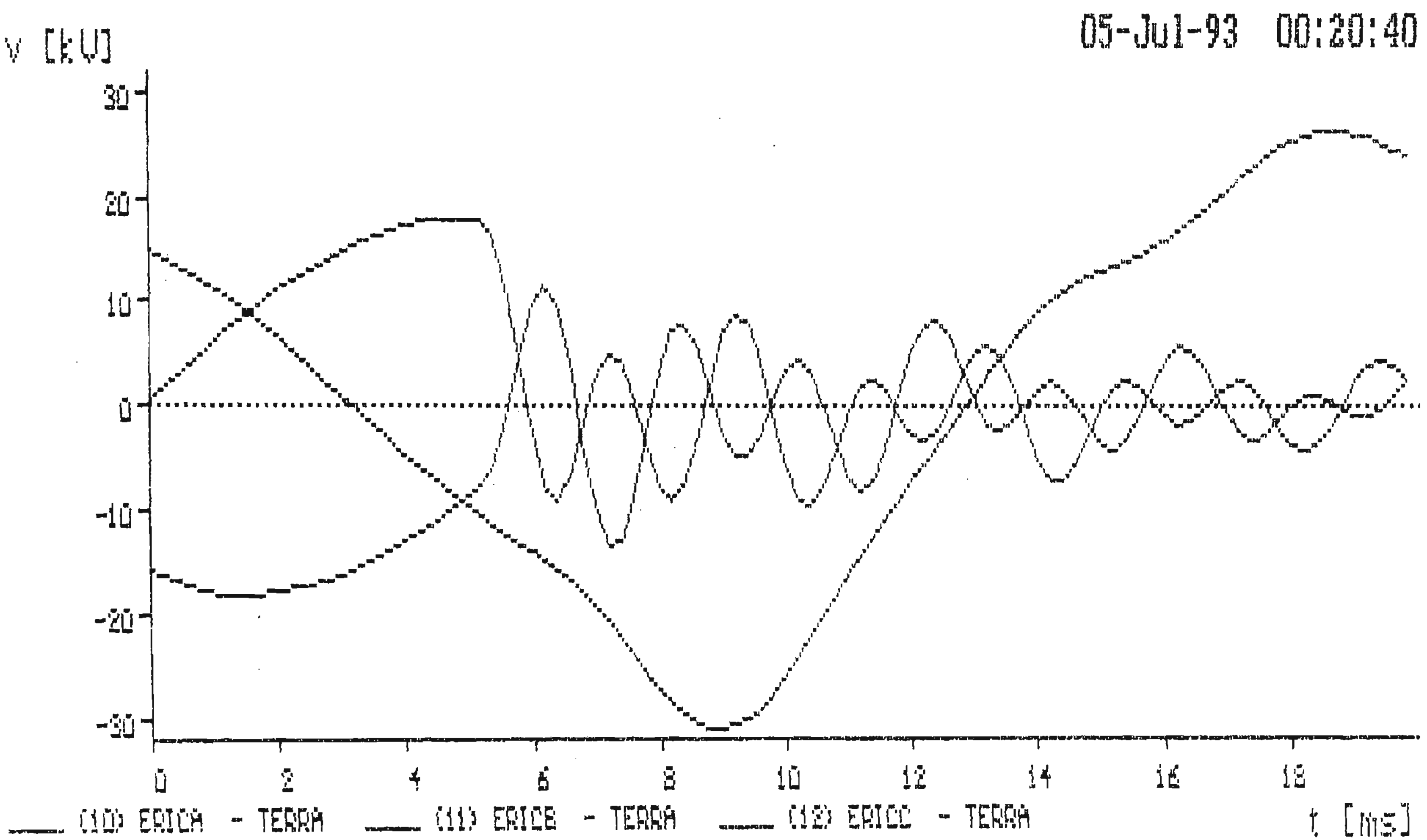
ms, which is obvious, and abnormal shape of voltage wave in phase C is explained in case of Plot 6.

Plots 8 and 9 show the transient voltages at nodes ERIC and P255. In contrast to Plot 7, voltages in phases A and B are non-zero. However, they decay fast with time. The presence of high frequency components is seen in these phases, which was explained in case of Plots 4 and 5. The shape of waveform of phase C voltage is explained in case of Plot 6.

Plot 9A shows the fault current near node P191. The fault currents in phases A and B are several times more than the normal current in the unfaulted phase C. However, it is seen to decay due to line impedance.

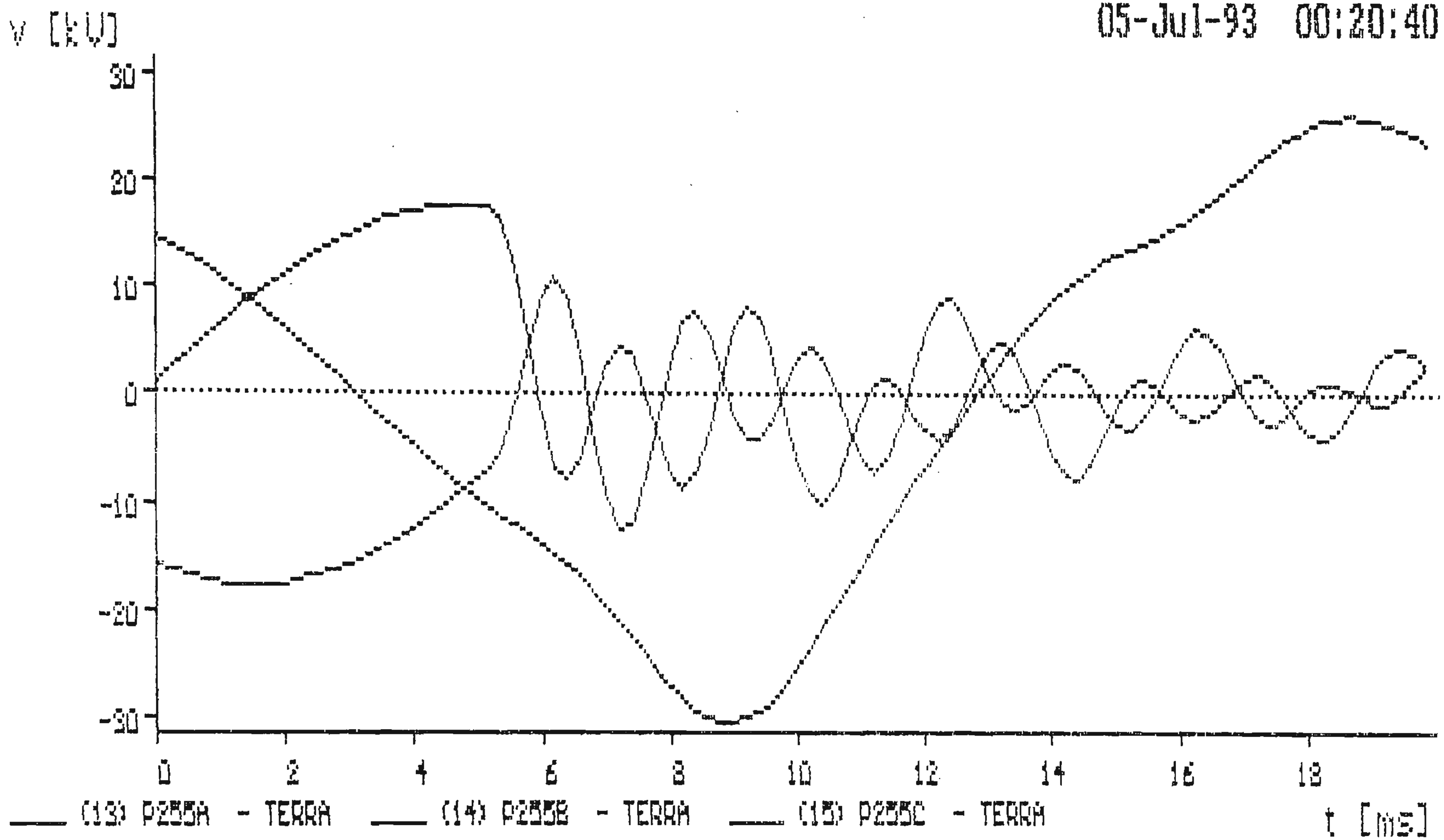
Plot 10 shows the transient currents between nodes P126 and P255. This consists of fault current, capacitor bank current and load current components. No zero sequence current can flow through transformer T1. Earth return currents can circulate between fault, capacitors bank and line capacitance. As the distance from the fault increases, the spikes of the wave-forms become smooth as seen from this case. However, the abrupt change in the characteristics of waveforms of phases A and B are noticeable at 5 ms.

Plot 11 shows the voltages at the induction generator's terminals. The voltages here are affected by phase shifts through the Δ/Y transformer. High frequency components make the



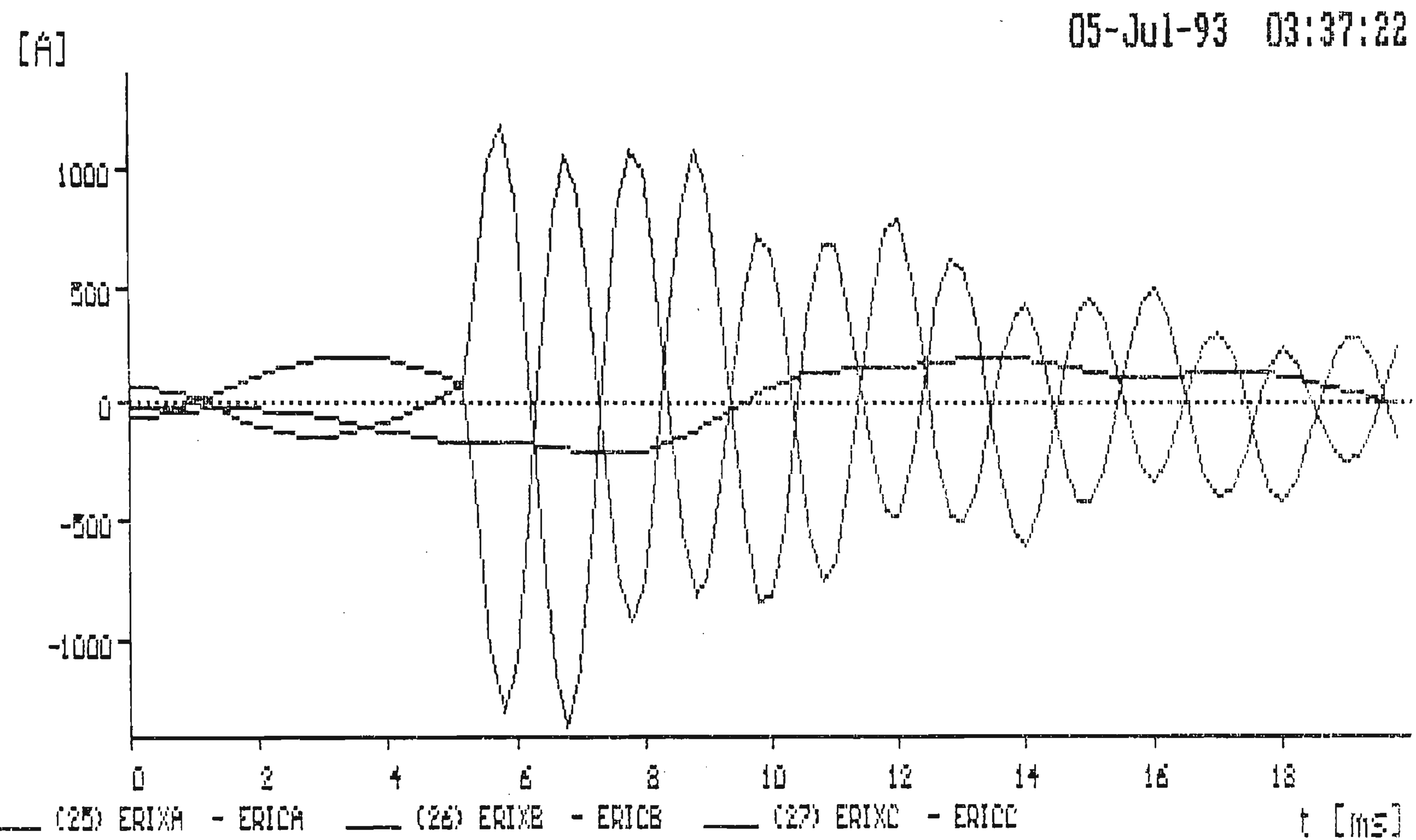
PLOT 8. TRANSIENT VOLTAGES AT NODE ERIC.

print date: 5. July 1993



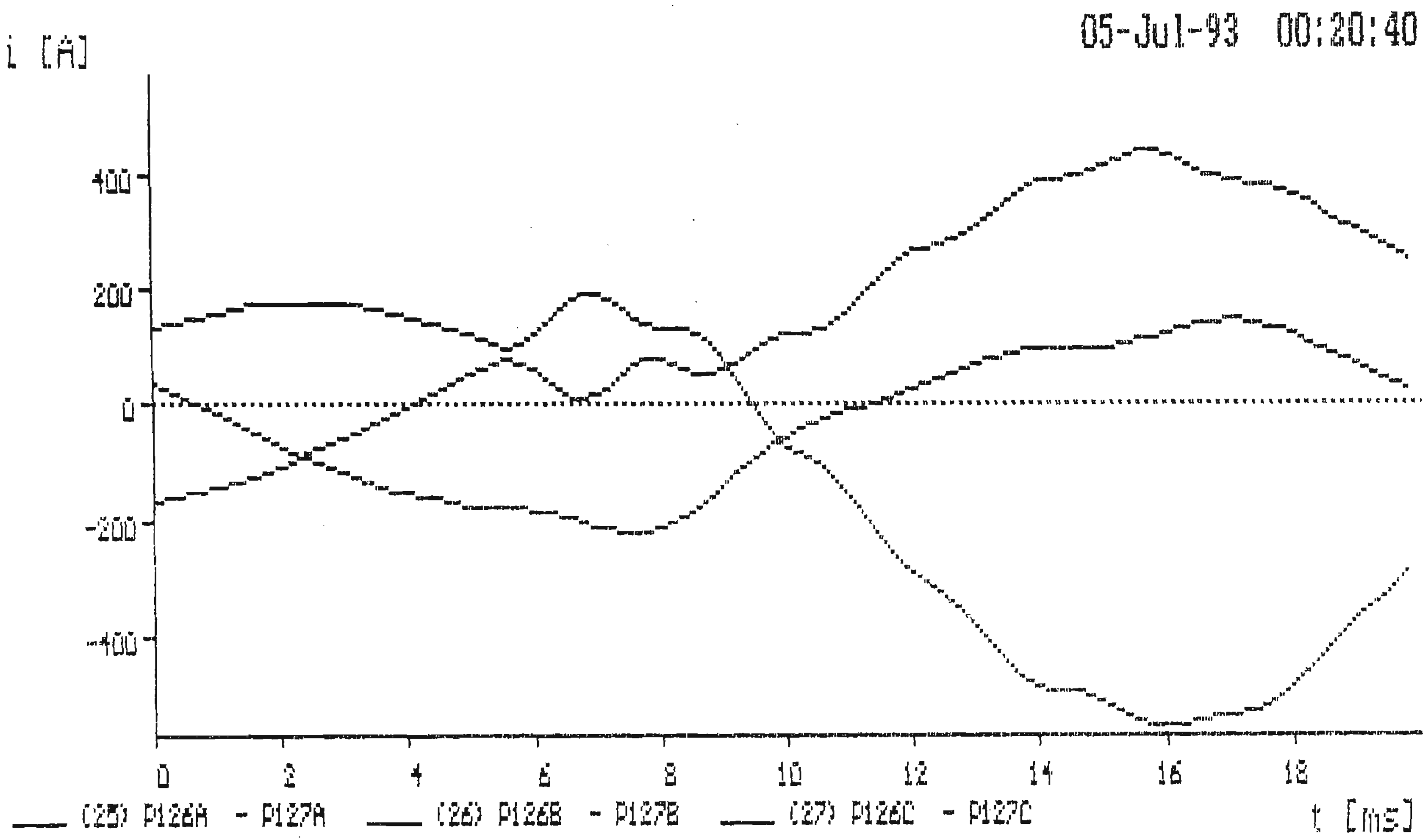
PLOT 9. TRANSIENT VOLTAGES AT NODE P255.

print date: 5. July 1993



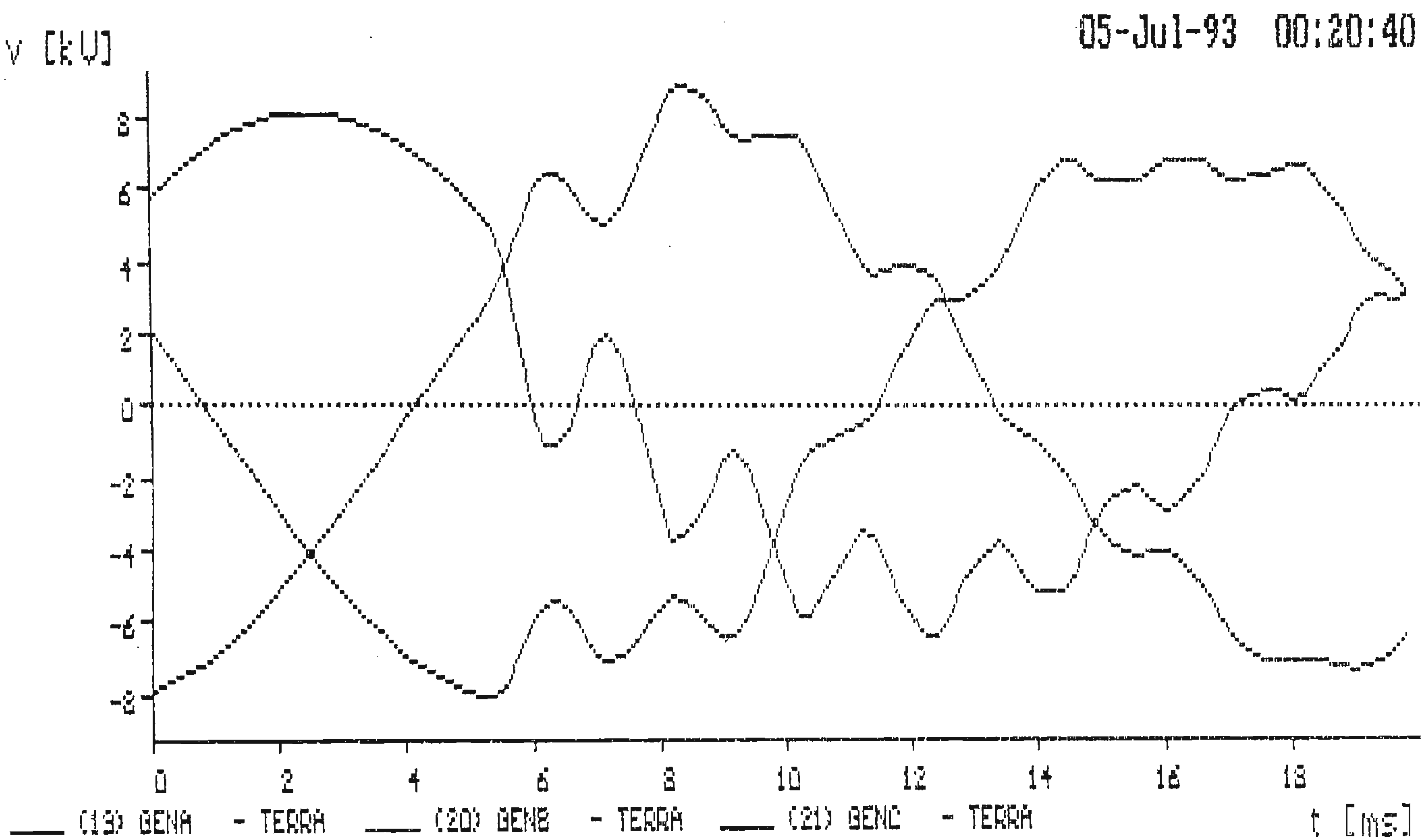
PLOT 9A. TRANSIENT CURRENTS BETWEEN NODES P191 & ERIC.

rint date: 5. July 1993



PLOT 10. TRANSIENT CURRENTS BETWEEN NODES P126 & P255.

print date: 5. July 1993



PLOT 11. TRANSIENT VOLTAGES AT THE INDUCTION GENERATOR'S TERMINALS.

print date: 5. July 1993

voltage waveforms spiky; the reasons for the presence of high frequency voltages is explained as in case of Plots 4 and 5.

4.3 Abnormalities at various points when two phases form short circuit on the generator's terminals and simultaneously open circuit on the load side

This section describes the fault caused by opening two terminal switches which form a short circuit at the induction generator's side and simultaneously form an open circuit on the load side.

Fig. 4-3 shows that the two terminals of the induction generator, GENA and GENB form a short circuit at 2 ms. Simultaneously, switches LVTA-GENA and LVTB-GENB open while the induction generator runs at -2.5697% slip.

Plot 12 shows that even after short circuit of phases A and B, there is non-zero voltage, which is of oscillating nature. This is due to the high frequency components of voltages, as explained in case of Plots 4 and 5. From 9 ms onwards, these voltages increase several times, because the transient currents take this much time to build up. This case is explained in Plot 13.

Plot 13 shows the transient currents in the stator windings of the induction generator. Currents in phases A and B are very high due to these phases forming a short circuit. However, this

DISTRIBUTION CIRCUIT OF SECU

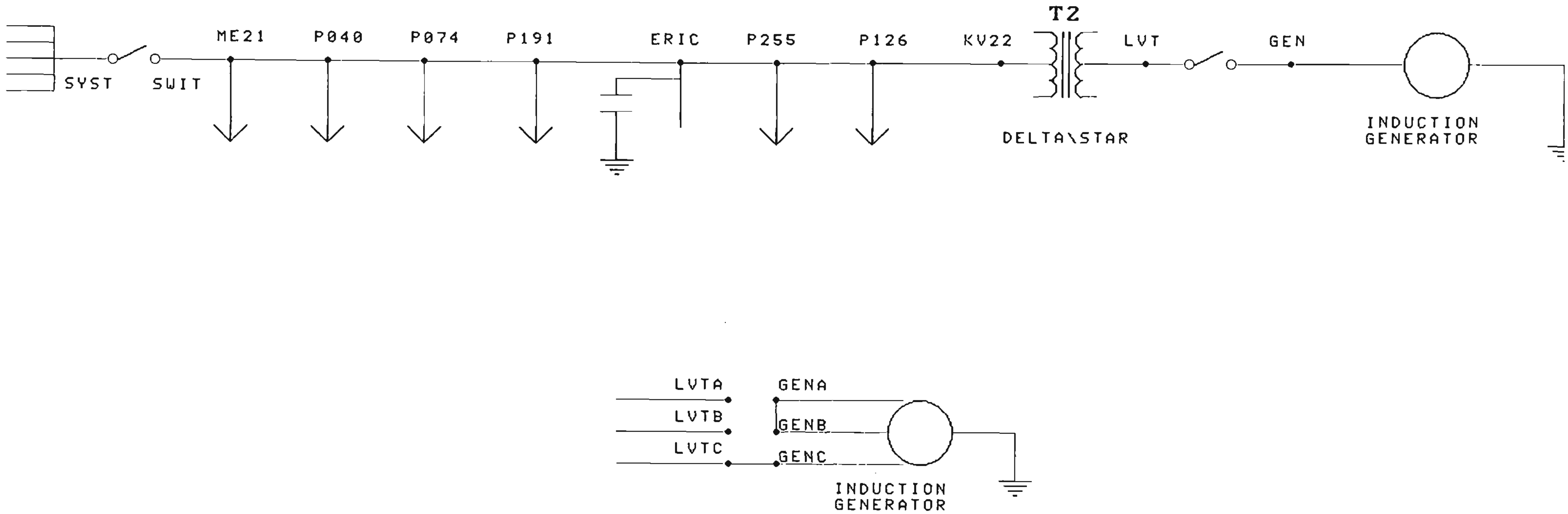
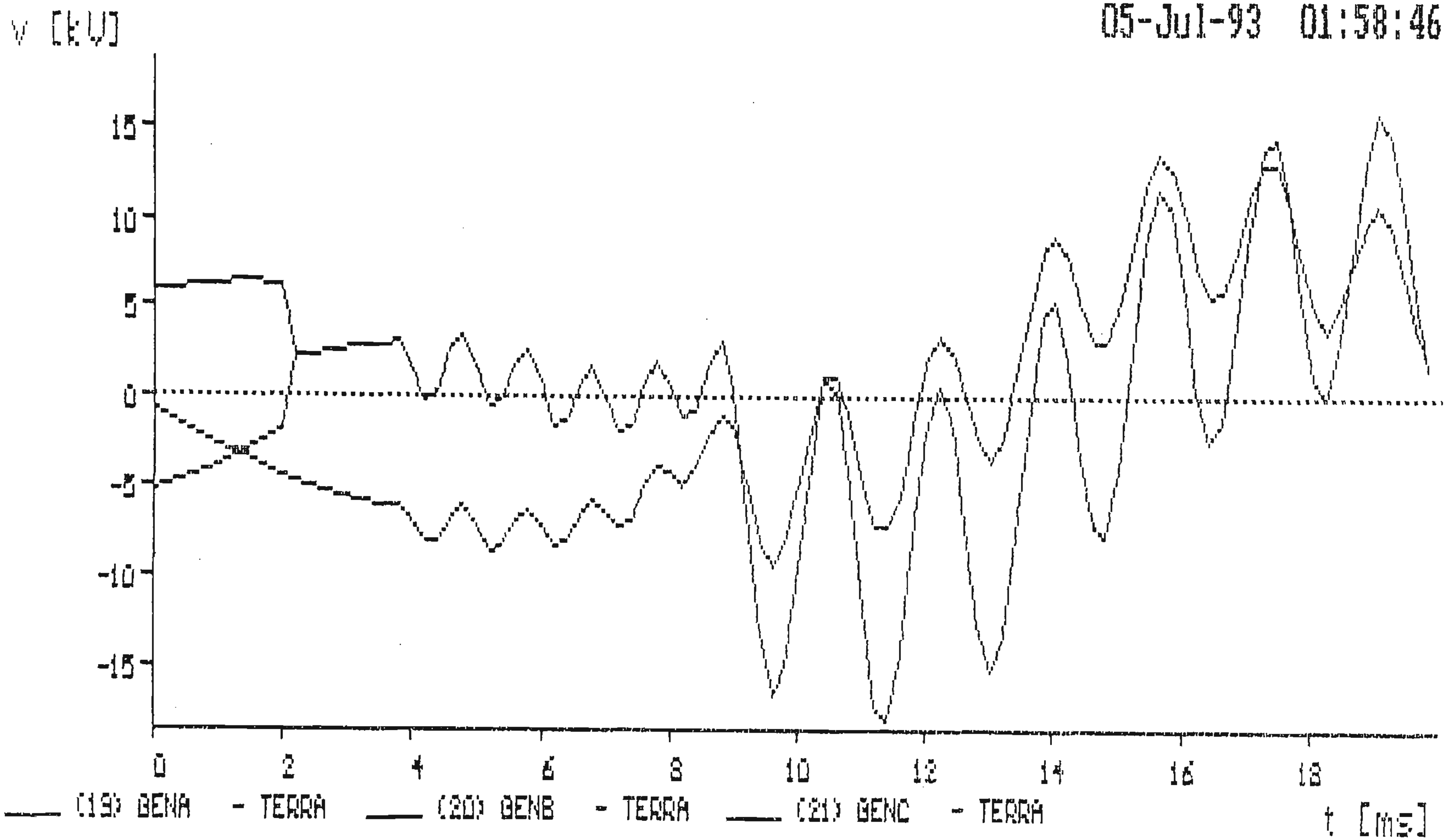
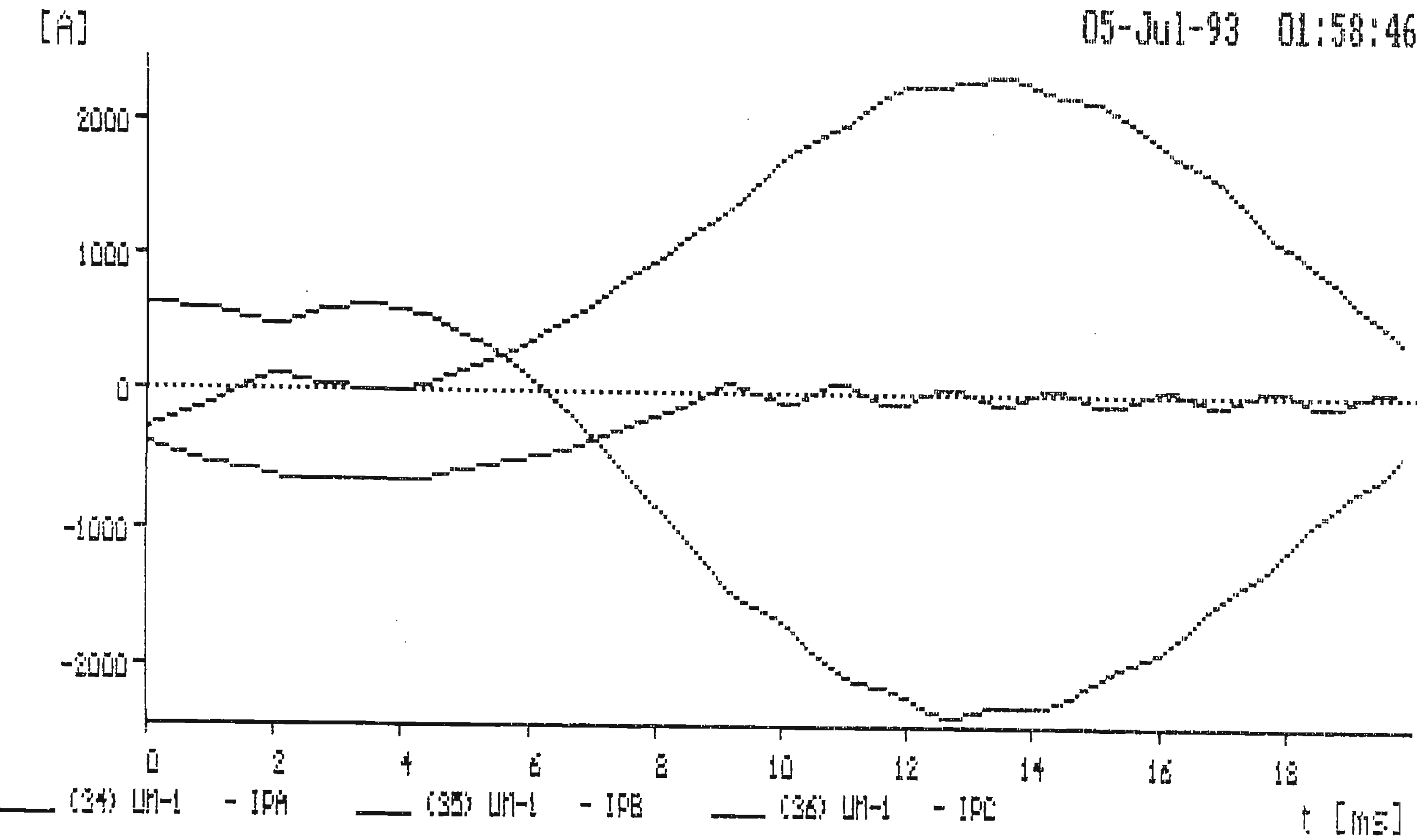


FIG. 4-3. PHASE TO PHASE SHORT CIRCUIT .



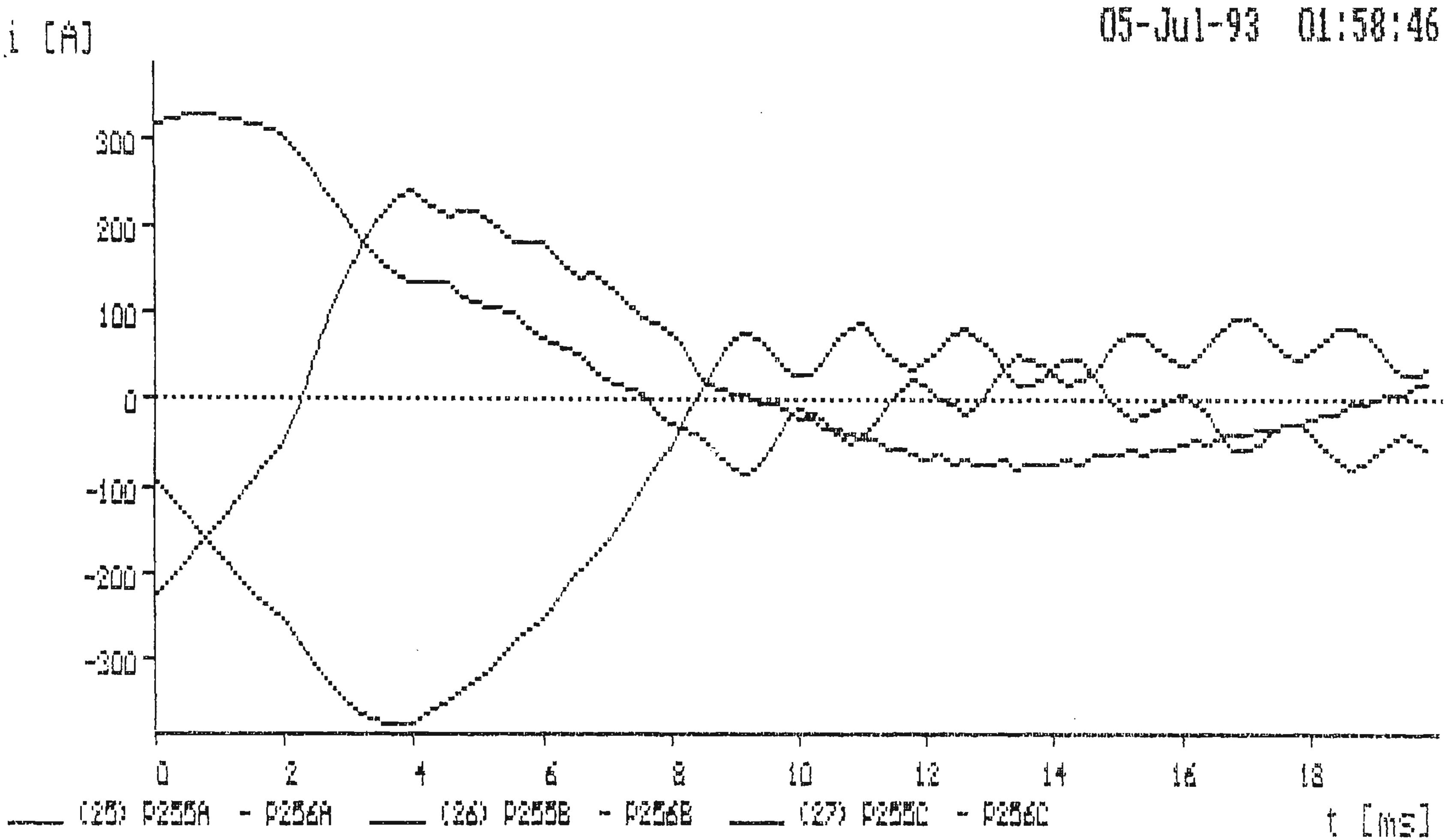
PLOT 12. TRANSIENT VOLTAGES AT INDUCTION GENERATOR'S TERMINALS.

print date: 5. July 1993



PLOT 13. TRANSIENT CURRENTS AT INDUCTION GENERATOR'S TERMINALS.

print date: 5. July 1993



PLOT 14. TRANSIENT CURRENTS BETWEEN NODES P255 & ERIC.

print date: 5. July 1993

build up of the current has occurred after 9 ms, which corresponds to the voltage build up in Plot 12.

Plot 14 shows the transient currents between nodes P255 and ERIC. Even though phases A and B are open, the current in these phases do not drop to zero. Their magnitudes gradually decrease because of line impedance and keep on oscillating for a long time because of mutual coupling with phase C. As the distance on the feeder increases transient effect is less noticeable.

4.4 Abnormalities at various points when a broken conductor fault occurs at P191: induction generator side of break contacting ground

This section describes the fault caused by breaking apart one phase-conductor of the feeder; the broken end on the induction generator side touches the ground through a contact resistance.

Fig. 4-4 shows a broken conductor of phase A at node P191; the induction generator side of the break is grounded through a contact resistance of 10 Ω at 5 ms. The induction generator runs at -2.5697 % slip.

Plot 15 shows transient voltages at node P074A, which is the node next to the faulted node. The smooth form of the voltage waveforms, which are seen before the fault turned into spiky, is due to the presence of the high frequency components, which is as described in case of Plots 4 and 5.

DISTRIBUTION CIRCUIT OF SECU

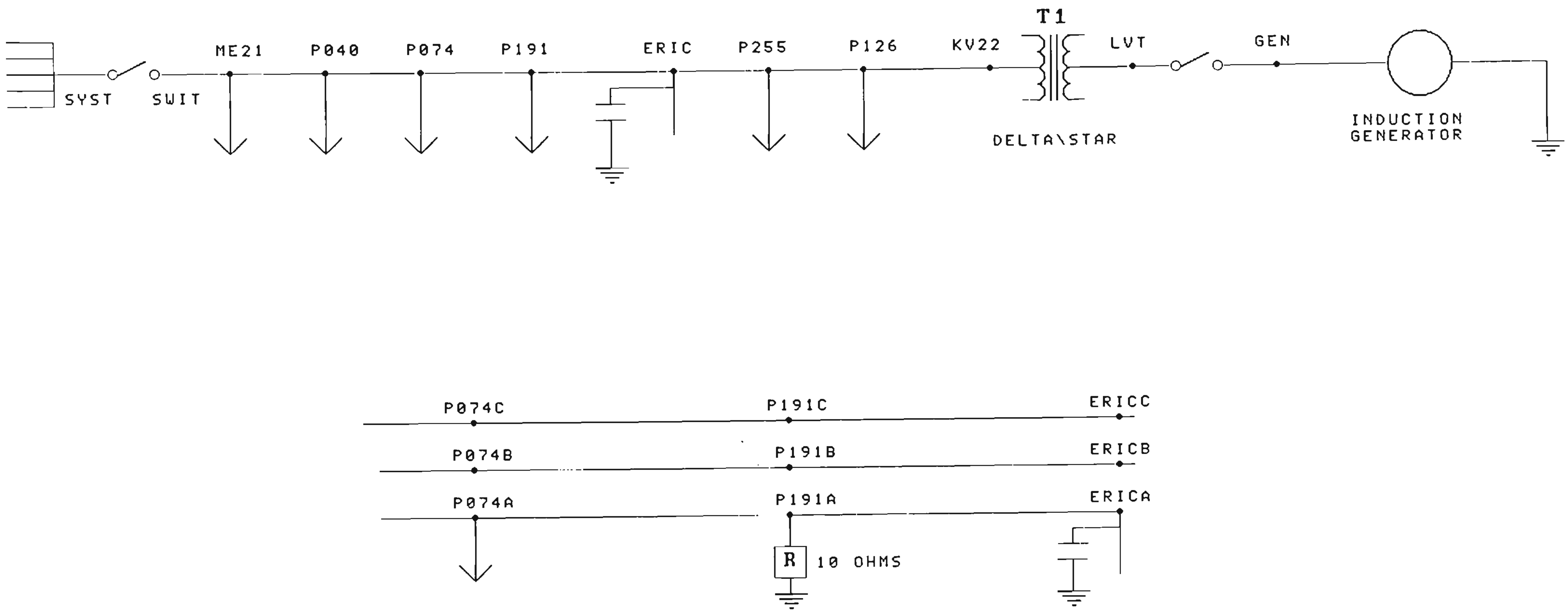
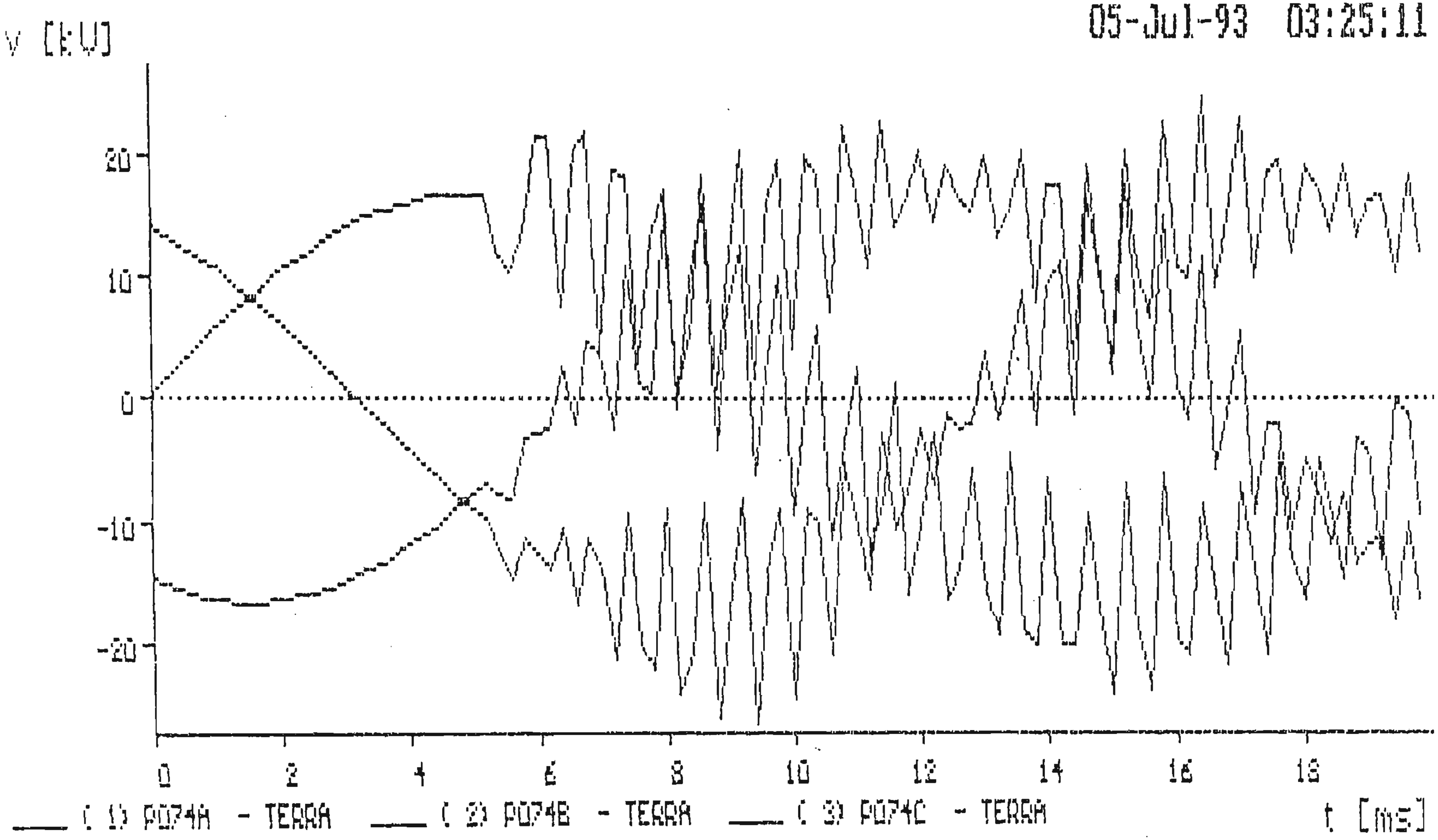


FIG. 4-4. BROKEN CONDUCTOR AT P191 ; INDUCTION GENERATOR SIDE OF BREAK GROUNDED.

05-Jul-93 03:25:11



PLOT 15. TRANSIENT VOLTAGES AT NODE P074.

print date: 5. July 1993

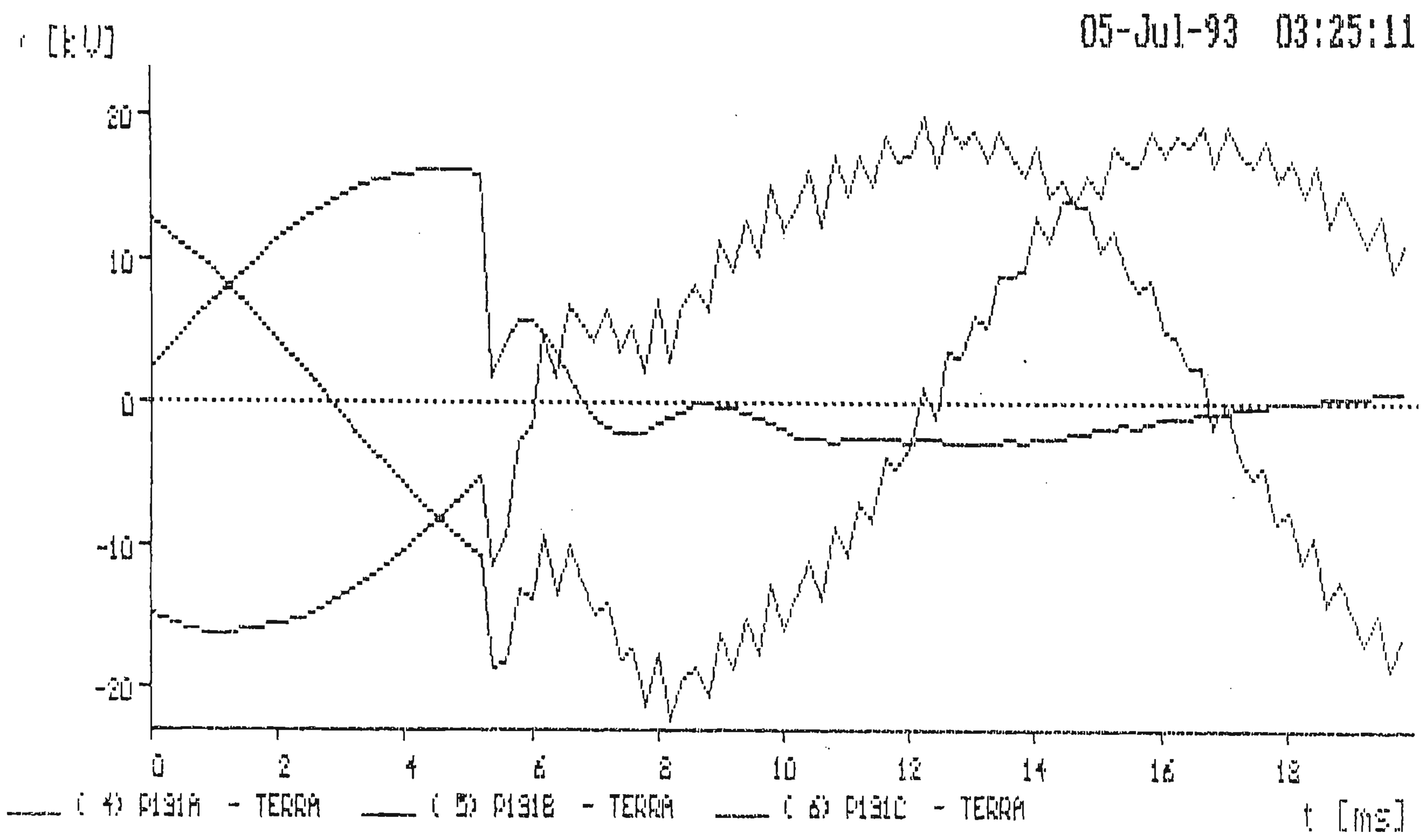
Plot 16 shows the voltages at node P191, where the fault occurred. The voltage of phase A is seen to collapse to almost zero value at 5 ms and then grazes the zero-voltage axis. The other phases, B and C, show presence of high frequency components and their peak values increase for the reason as explained in case of Plot 6.

Plot 17 shows the transient currents between nodes P191 and ERIC. After the fault the current in phase A is very high compared to the normal value. Also, between 9 and 18 ms its waveshape is no longer sinusoidal. The high fault current causes very large flux to flood the magnetic circuit, which is saturated and causes the waveshape to be non-sinusoidal.

Plot 17A shows the current between nodes P040 and P074. At 5 ms, when the conductor of phase A breaks, there is a sudden change of current in this phase. The current supplied to the remaining loads beyond the break stops, causing a sudden decrease in the phase current. The only current supplied to the load by this section of the feeder is the load at P074A. Transients due to high frequency components are prominent in this phase and are also reflected in phases B and C after 5 ms.

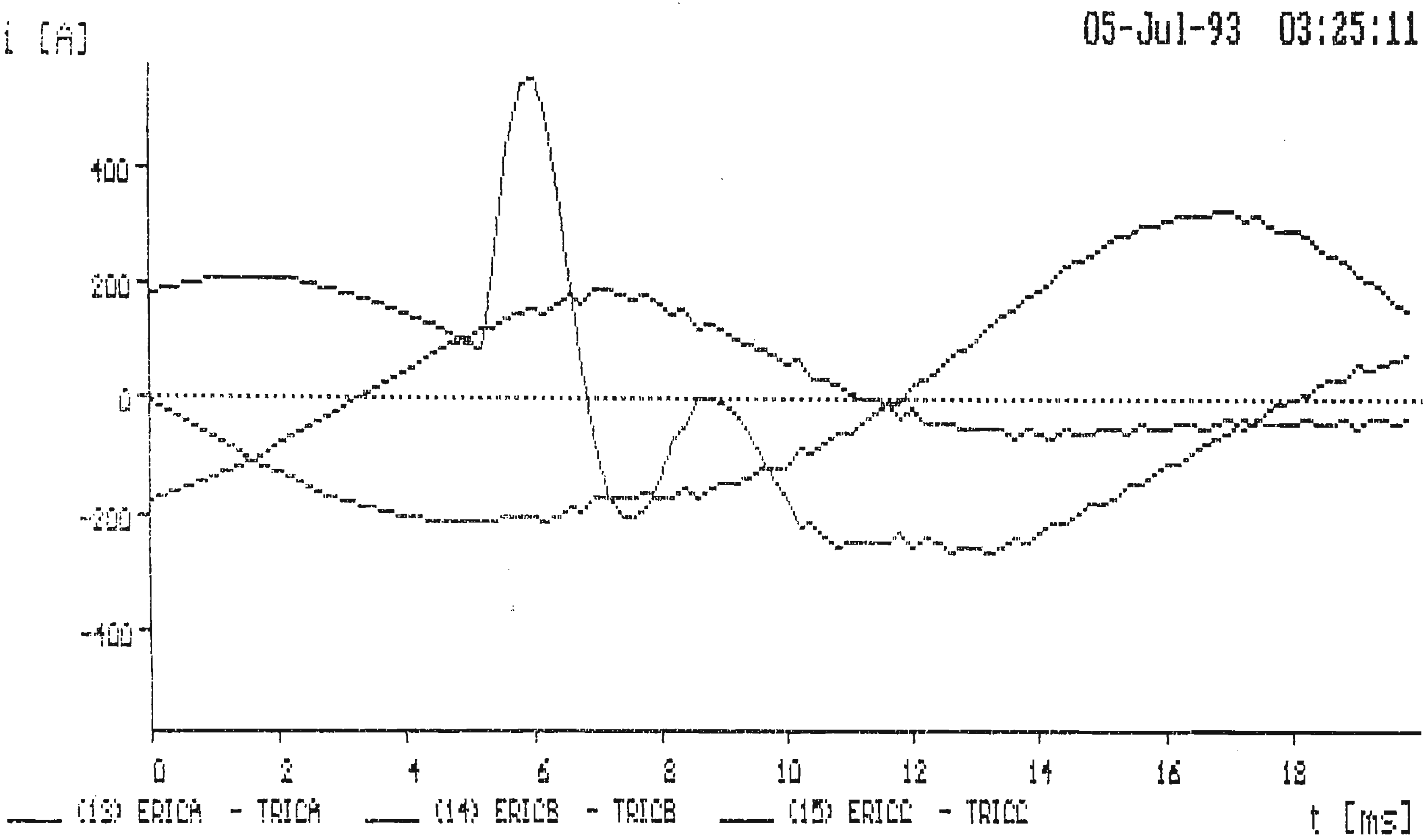
4.5 Abnormalities at various points when a broken conductor fault occurs at point P191A: system side of break contacting ground

This section describes the fault caused by breaking apart one



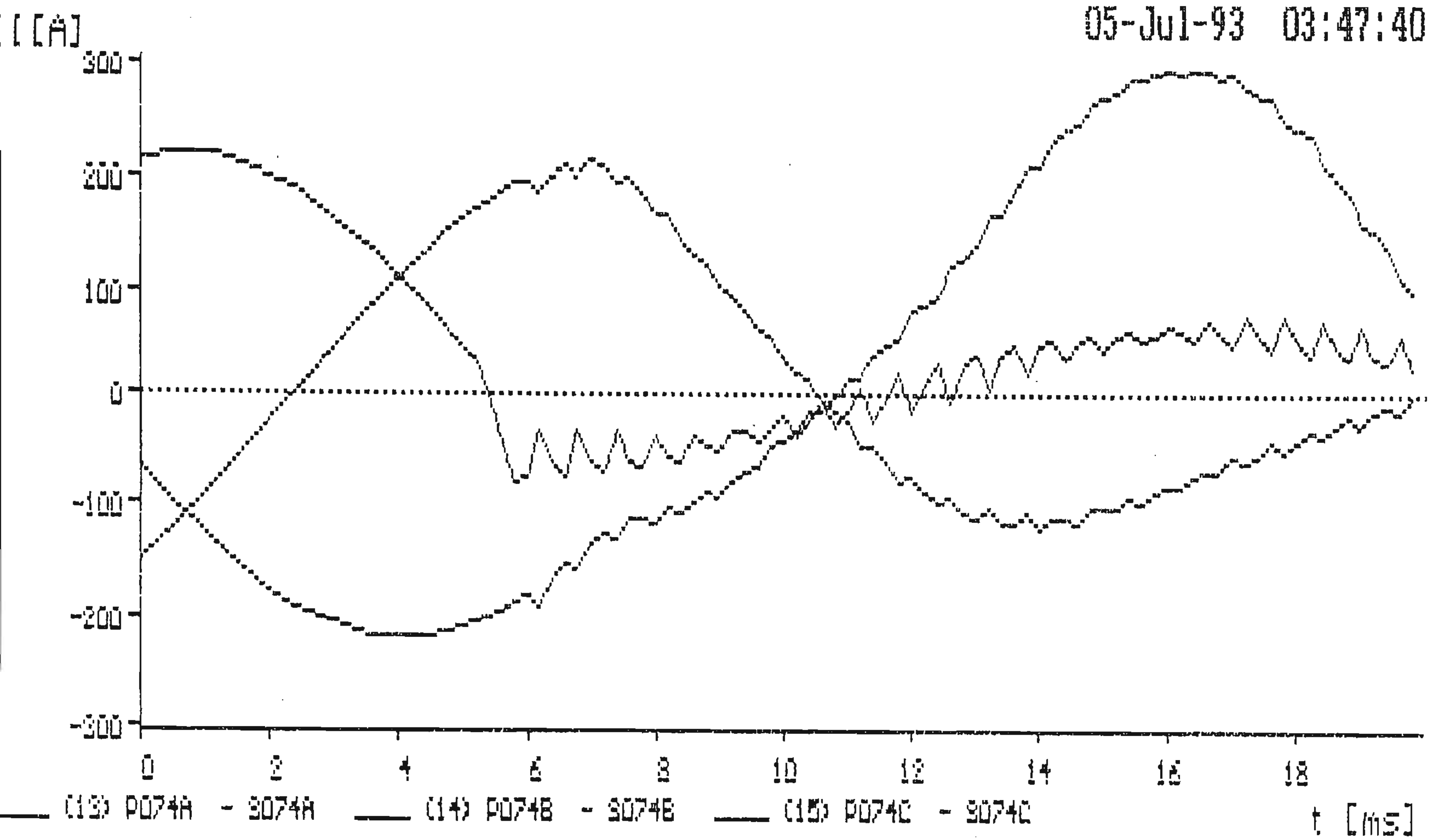
PLOT 16. TRANSIENT VOLTAGES AT NODE P191.

print date: 5. July 1993



PLOT 17. TRANSIENT CURRENTS BETWEEN NODES P191 & ERIC.

print date: 5. July 1993



PLOT 17A. TRANSIENT CURRENTS BETWEN NODES P040 AND P074.

print date: 5. July 1993

phase-conductor; the system side of the break touches the ground.

Fig. 4-5 shows a broken conductor of phase A; the system side of the break contacts the ground through a 10 Ω resistor at 2 ms and the induction generator runs at -2.5697% slip.

Plot 18 shows the transient voltages at node P074. Compared to the previous case, where fault occurred in 5 ms, fault in this case occurred at 2 ms. The effect of the fault in phase A is seen in the voltage reduction of phase A compared to those of phases B and C. High frequency components of voltage are more noticeable in phase A than in phases B and C. This node is next to the faulted node P191, where the effect of fault is more vivid, as shown in Plot 19.

Plot 19 is the plot at the faulted node P191 and phase A. The dip in phase A voltage is sharp and more in magnitude than in phases B and C, which is expected. Again, high frequency components of voltages are seen in all phases after the occurrence of fault. As mentioned in the previous case the magnitude of voltage in phase A is less than the normal phase voltage.

Plot 20 shows the transient currents between nodes ERIC & P255. The effect of breaking phase A conductor is seen as a minor dip in phase A current at 2 ms. The magnitude of phase A current has decreased to almost 50%, but the phases B and C are

DISTRIBUTION CIRCUIT OF SECU

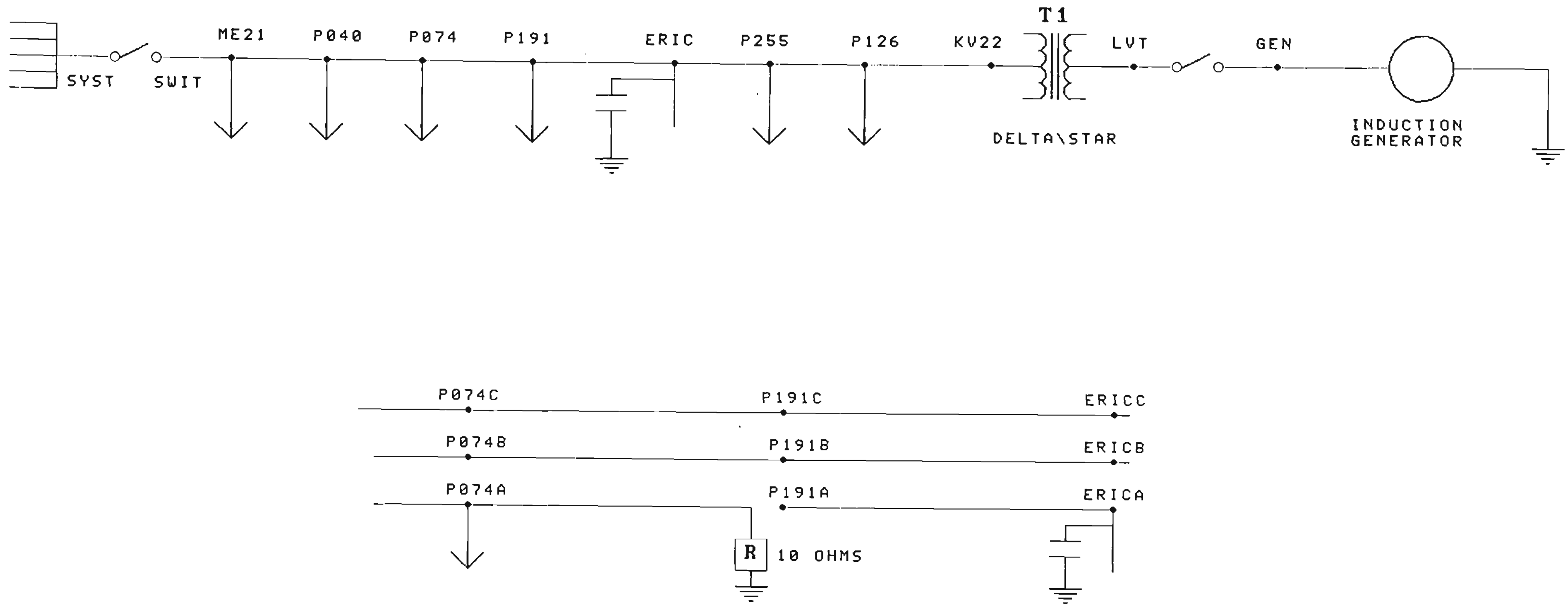
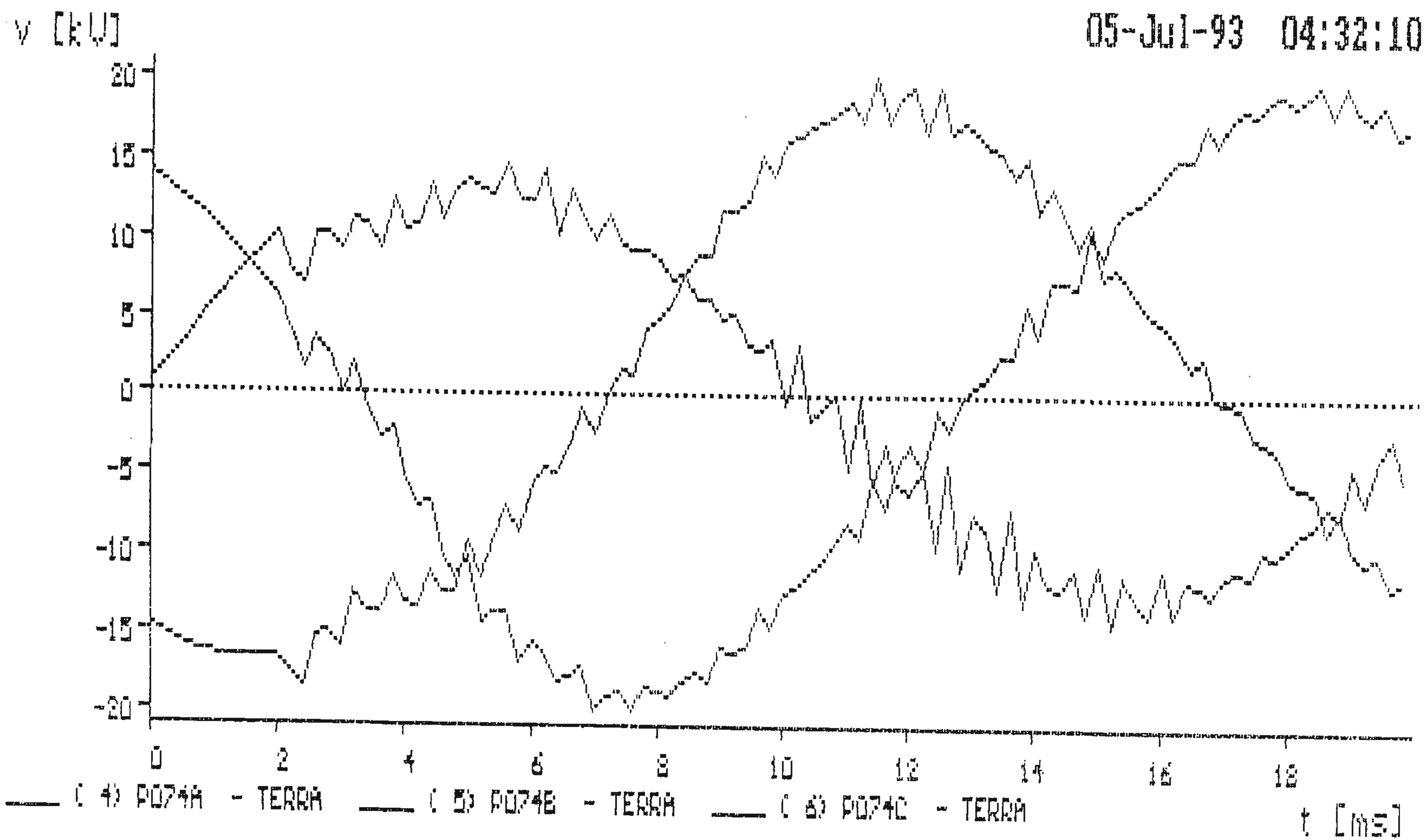
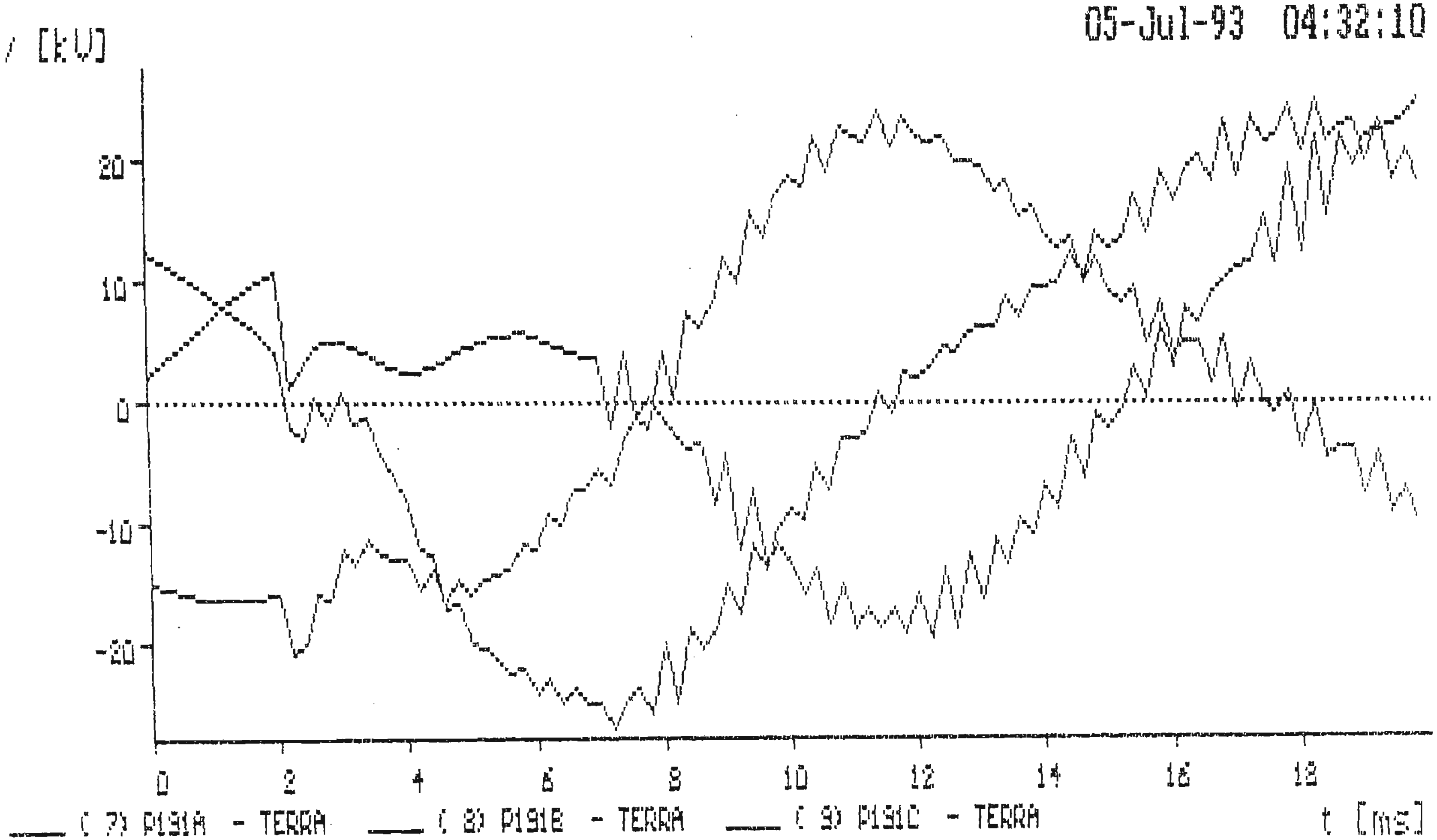


FIG. 4-5. BROKEN CONDUCTOR AT P191 ; SYSTEM SIDE OF BREAK GROUNDED.



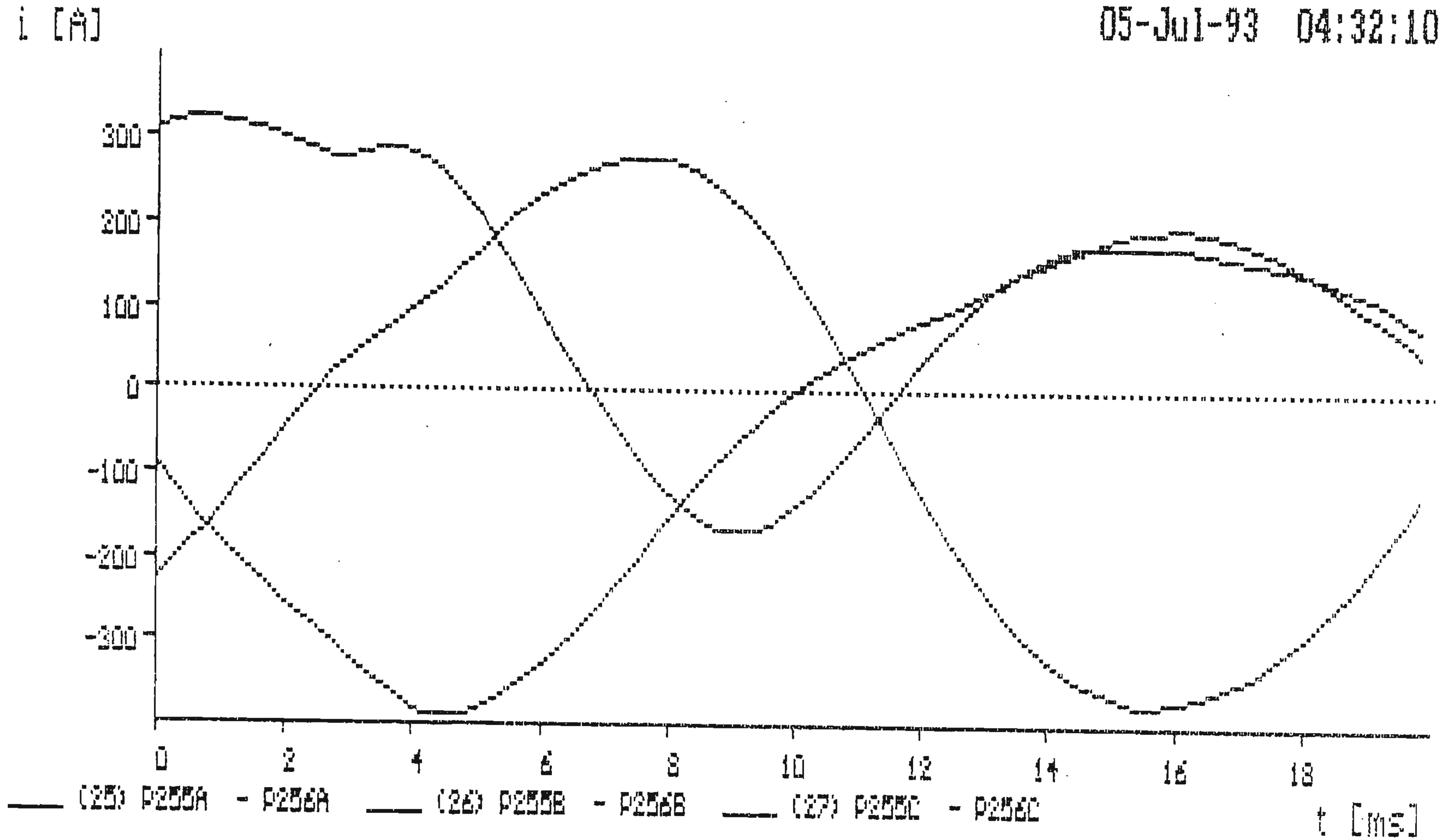
PLOT 18. TRANSIENT VOLTAGES AT NODE P074.

print date: 6. July 1993



PLOT 19, TRANSIENT VOLTAGES AT NODE P191.

print date: 6. July 1993



PLOT 20. TRANSIENT CURRENTS BETWEEN NODES ERIC & P255.

print date: 6. July 1993

slightly affected by this fault. Again, it is seen that the effect of this fault is not significant in these phases of the feeder.

4.6 Abnormalities at different points of a feeder when the generator is disconnected at the terminals by an ideal three phase device

This section describes the effect of switching off the induction generator on the voltages and currents at the terminals and on the feeders. In the ideal case it is assumed that all phases of the switch open simultaneously. In practice the three phases open sequentially. Both cases are considered in this section.

Fig. 4-6 shows the three phase switch connecting the terminals of the induction generator to the feeder. In this case, the generator is operating at -1.0 % slip and the switch is closed for a long time.

Plot 21 shows the transient voltage at the terminals of the generator, when the three terminal switches open simultaneously at 2 ms. It can be seen that the transients due to high frequency components are present. It is interesting to note that the reason for the presence of high frequency components is different from that of the feeders, as previously dealt in cases of Plots 4 and 5. The feeders are physically disconnected and cannot effect the voltage at the terminals of the induction

DISTRIBUTION CIRCUIT OF SECU

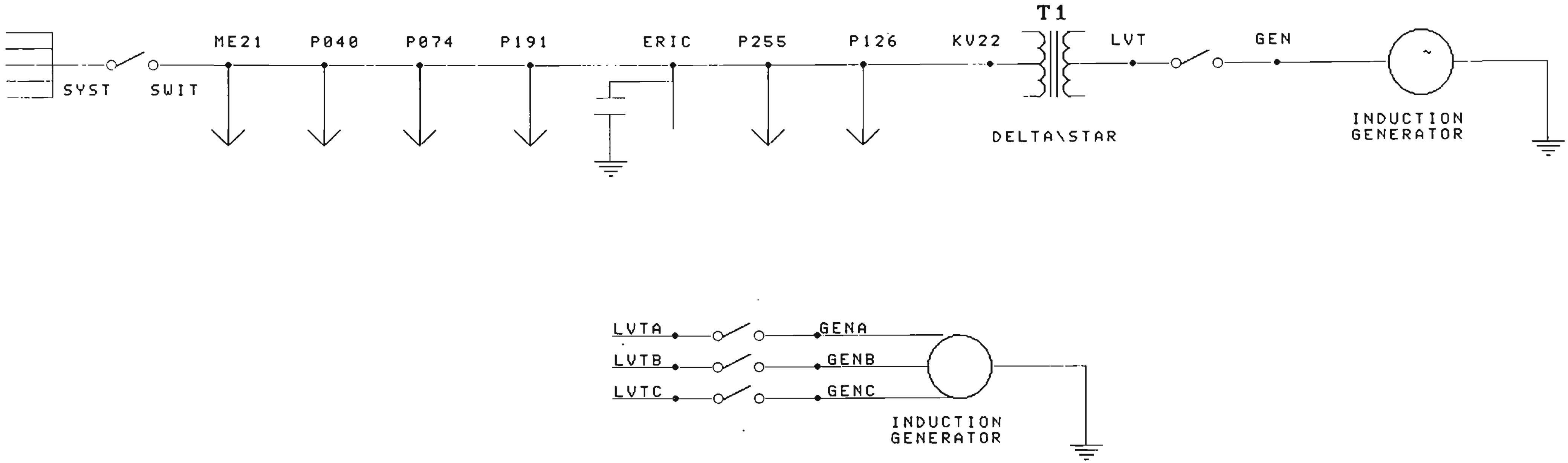
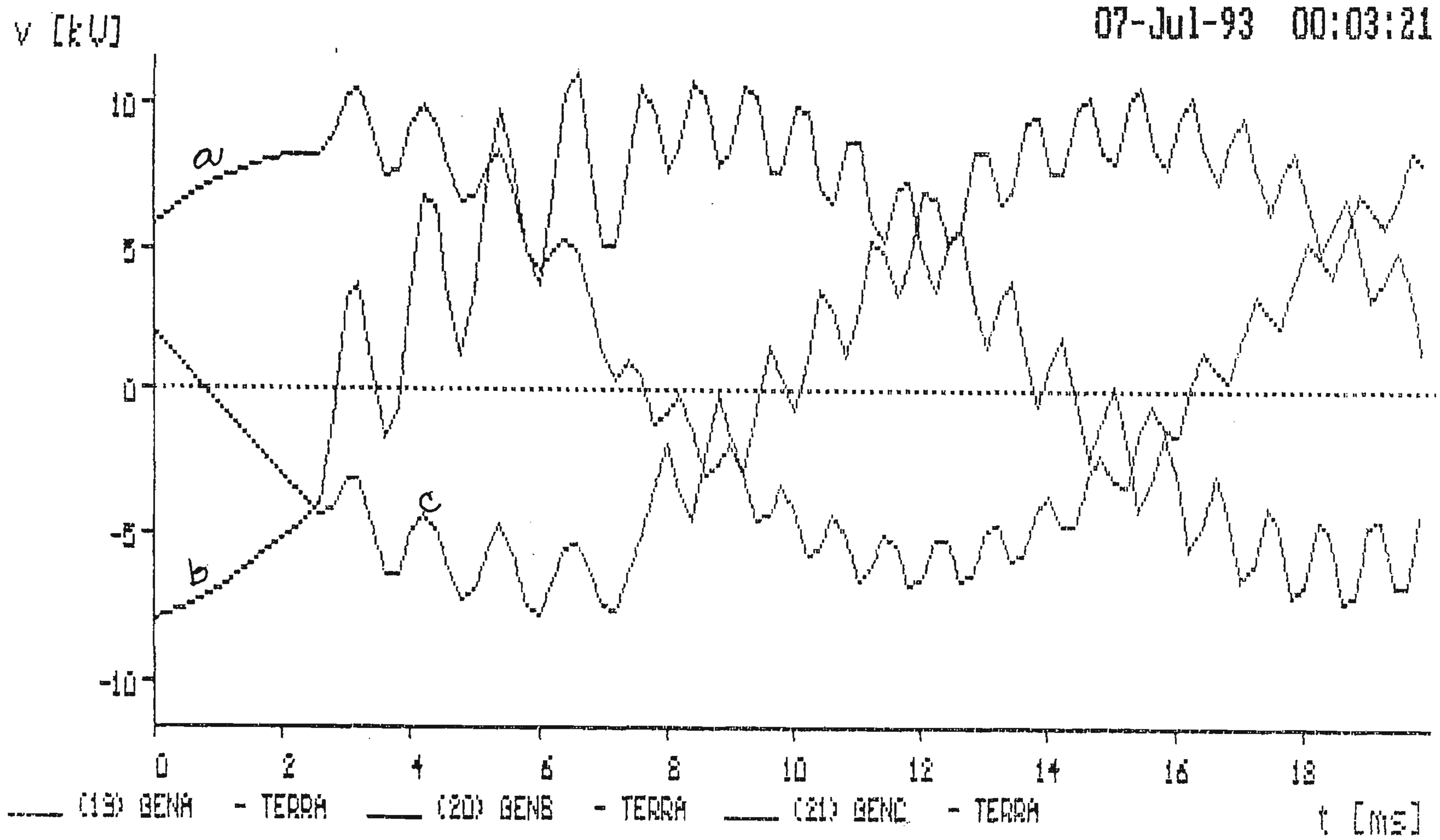


FIG. 4-6. GENERATOR DISCONNECTED AT TERMINALS
OF IDEAL 3-PHASE SWITCHING DEVICE.



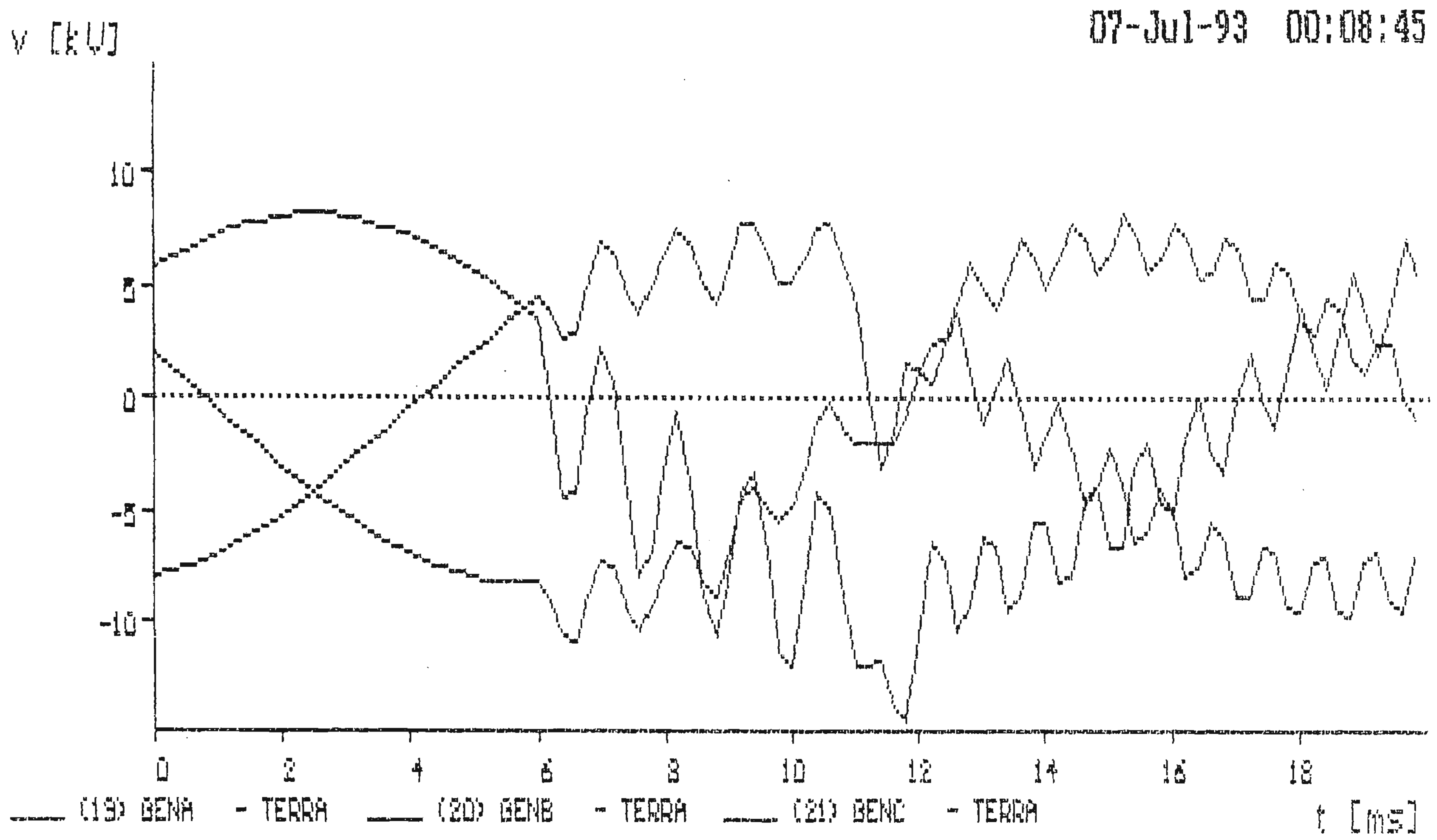
PLOT 21. TRANSIENT VOLTAGES AT NODE GEN WHEN THE THREE TERMINAL SWITCHES OPEN SIMULTANEOUSLY.

print date: 7. July 1993

generator. In fact, these high frequency components are produced by the capacitance representing the mass on the rotor shaft and the inductance of the stator. It can also be observed from the plot that there is a time lag of less than 1 ms following the opening of the switch and the first appearance of the transients. The reason for the delay is the inductance of the stator, which opposes any change in the current.

Plot 21B shows the transient currents in the stator windings when the terminal switches open sequentially. Phase A switch opens at 2 ms, phase B at 7 ms, and phase C at 12 ms. The effect of opening the switch in phase A is seen at 6 ms ; similarly, the effect in phase B is seen at 11 ms. A delay of 4 ms is seen in both phases because of the inductance of the stator. The currents in all phases nearly reach zero by 11 ms, hence the opening of the switch in phase C at 12 ms does not make any noticeable change in the waveforms.

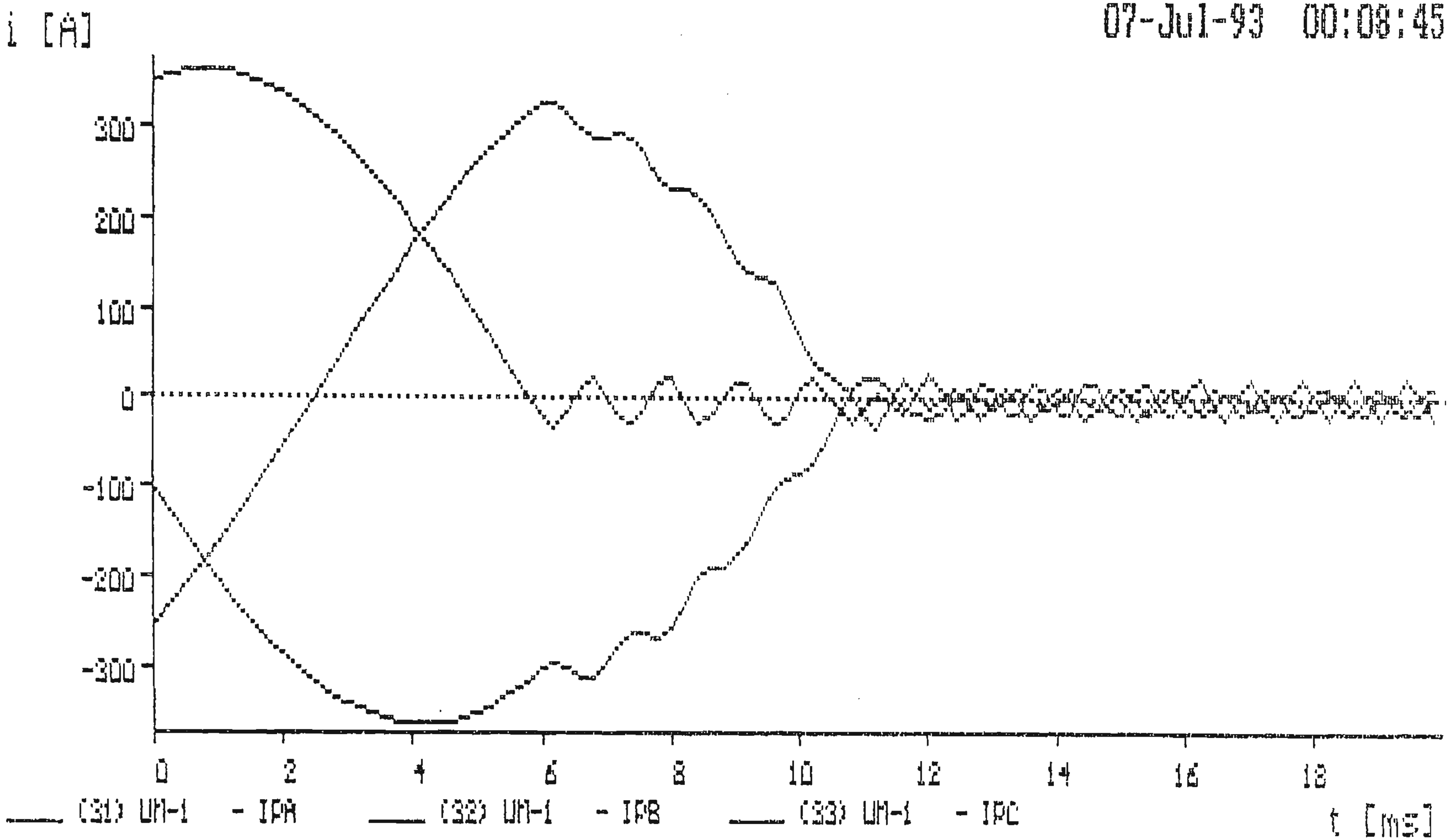
Plot 21A shows the transient voltages when the three phases of the switch open sequentially: phase A at 2 ms, phase B at 7 ms, phase C at 12 ms. The onset of transients in phase A starts at 6 ms, which is delayed by 4 ms from the instant the switch opens. The transients observed in phase B from 6 to 11 ms are due to the mutual inductances of the stator windings. The effect of opening the switch in phase B at 7 ms is seen at 11 ms as a considerable dip in the voltage. By 11 ms, the currents in all phases in the stator windings are nearly zero (Plot 21 B); when phase C switch opens at 12 ms, its effect on the



PLOT 21A. TRANSIENT VOLTAGES AT NODE GEN WHEN THE THREE TERMINAL SWITCHES OPEN SEQUENTIALLY: PHASE A AT 2 MS, PHASE B AT 7 MS, PHASE C AT 12 MS.

print date: 7. July 1993

07-Jul-93 00:08:45



PLOT 21B. TRANSIENT CURRENTS IN THE STATOR WINDINGS WHEN THE TERMINAL SWITCHES OPEN SEQUENTIALLY.

print date: 7. July 1993

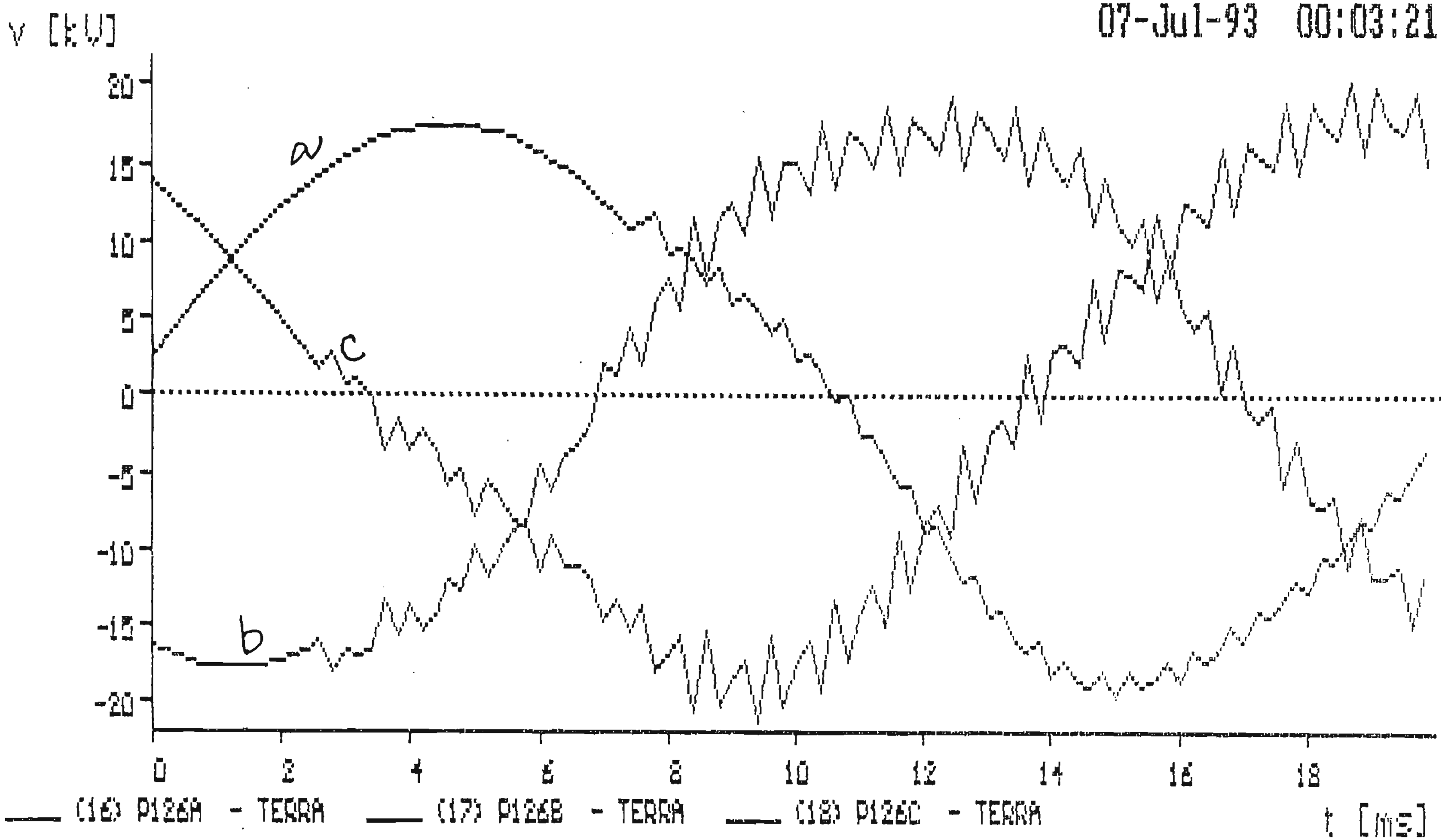
waveforms is not so sharp as those of phases A and B.

Plot 22 shows the transient voltages at node P126, when the terminal switches open simultaneously. The transients are of the same nature as that of Plot 21, but the spikes are not conspicuous because the observation is made at some distance from the switches; the line impedance smooths down the spikes.

Plot 22A shows the transient currents at the generator's terminals when the three switches open simultaneously at 2 ms. The effect of opening the switches is seen by the onset of transients in all three phases at a time-lag less than 1 ms. In cases of phases A and C these transients gradually subside to non-zero value by 7 ms, but phase B attains near-zero value at 3 ms.

Plot 23 shows the transient currents between nodes P126 and P255. After 2 ms the currents in all phases start decaying and practically become zero by 7 ms. Again, the line impedance causes this delay in decaying the currents to zero.

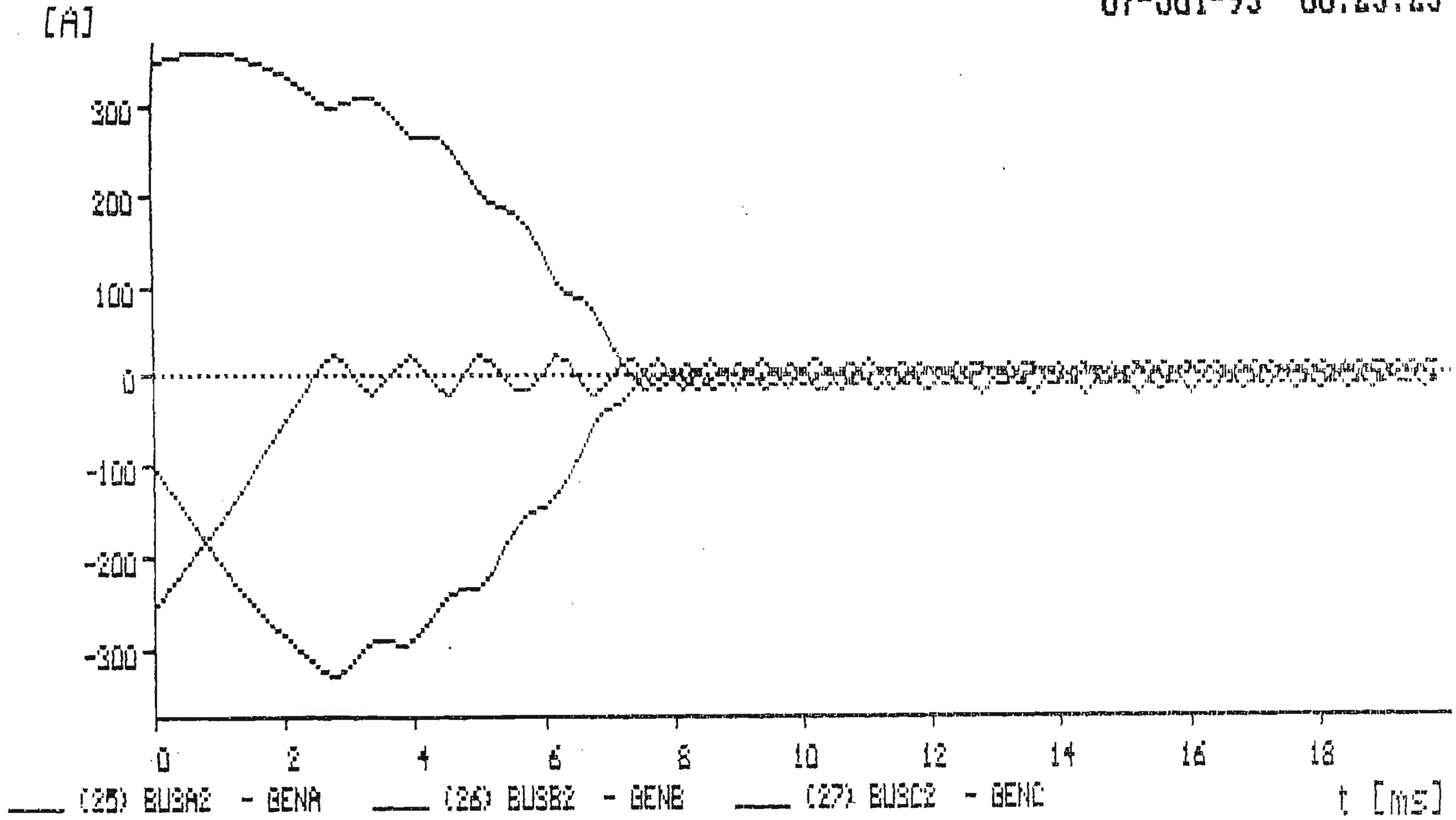
Plot 23A shows the transient currents between nodes P255 and ERIC when the three terminal switches open simultaneously. The effect of opening the switches does produce transients in this section of the feeder, but it does not reduce the currents to zero during 20 ms. It appears that the power supplied by the supply holds the current up in this section.



PLOT 22. TRANSIENT VOLTAGES AT NODE P126.

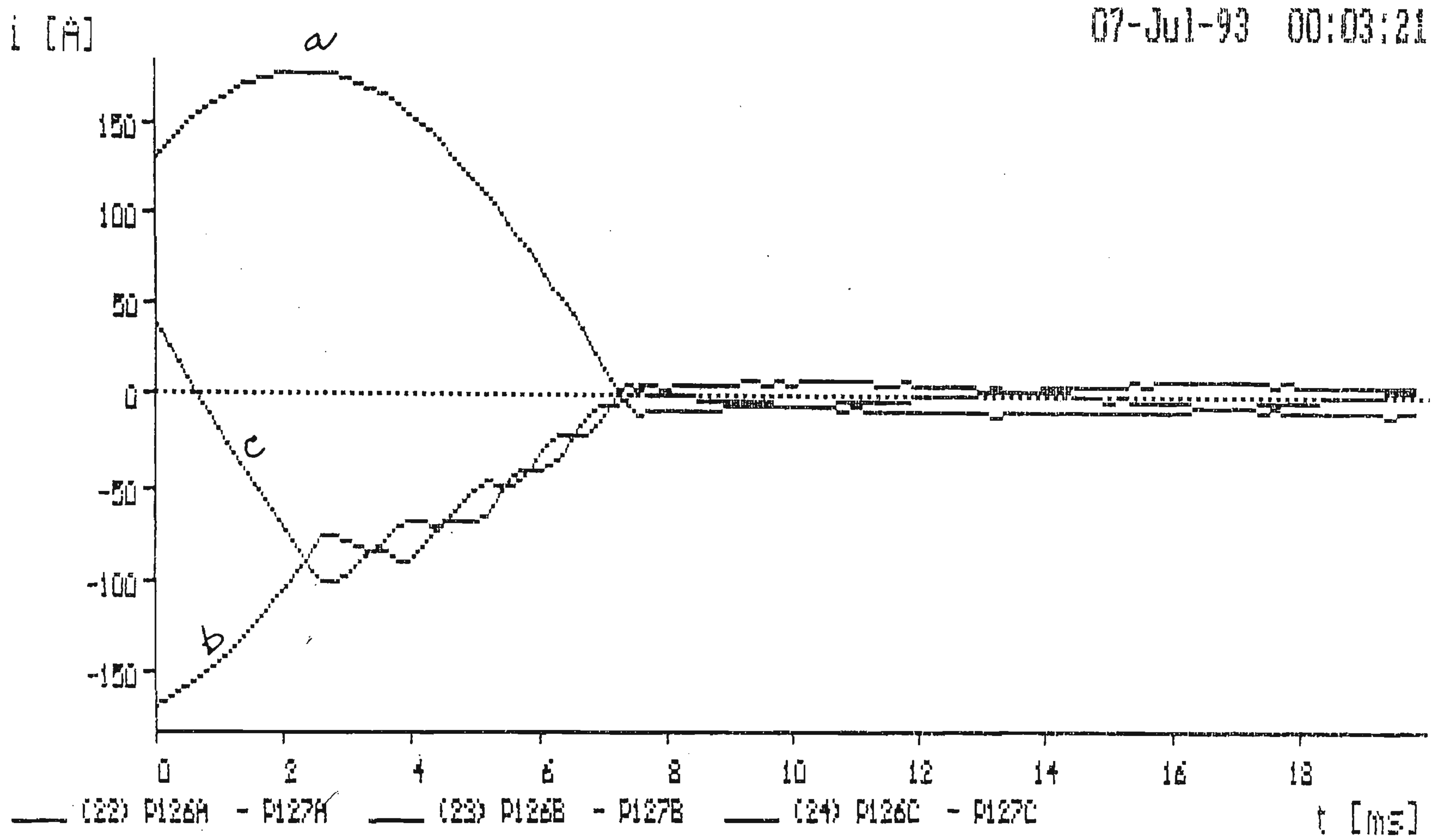
print date: 7. July 1993

07-Jul-93 00:25:23



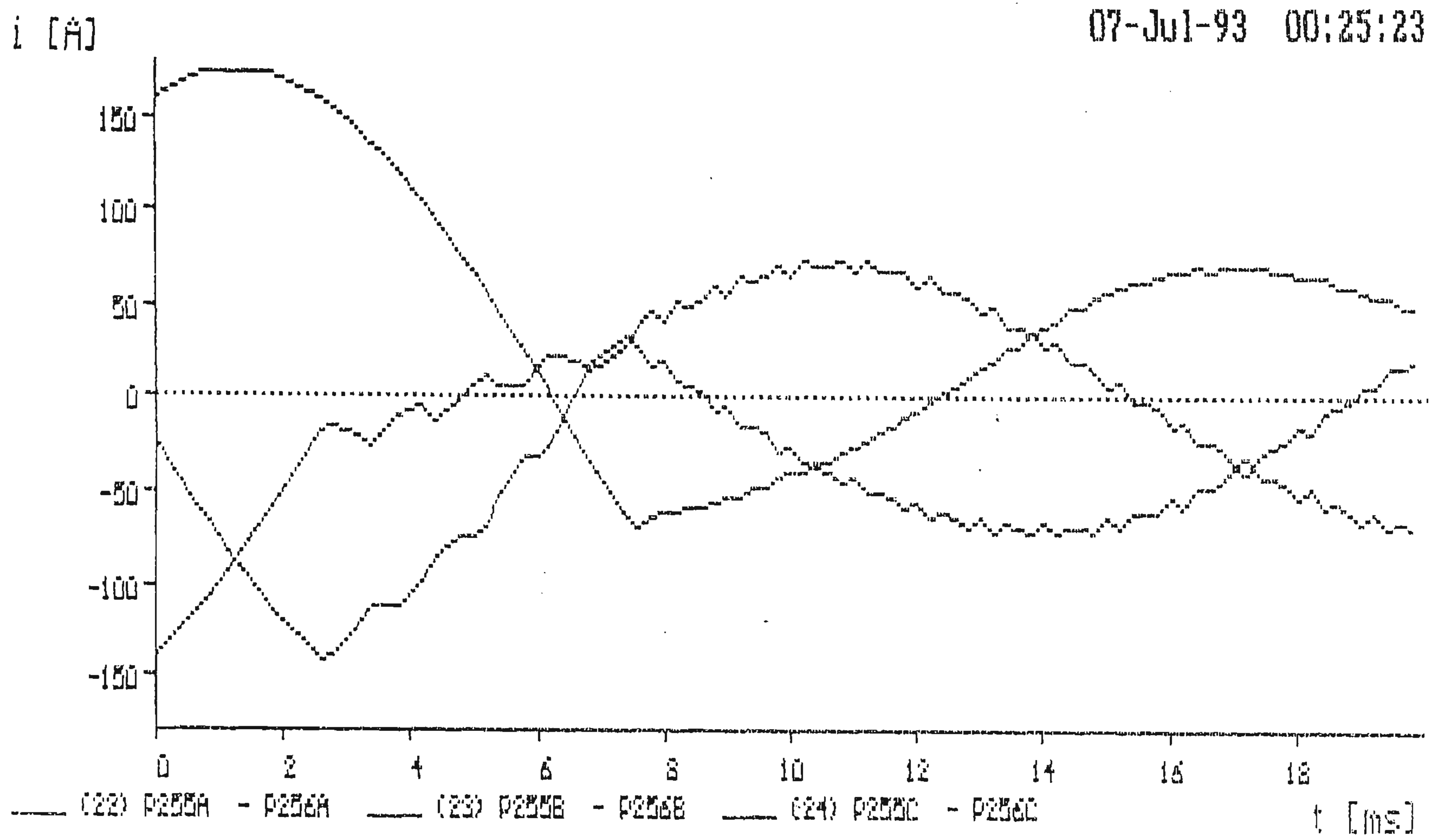
PLOT 22A. TRANSIENT CURRENTS AT THE GENERATOR'S TERMINALS WHEN THE THREE TERMINAL SWITCHES OPEN SIMULTANEOUSLY.

print date: 7. July 1993



PLOT 23. TRANSIENT CURRENTS BETWEEN NODES P126 AND P255.

print date: 7. July 1993



PLOT 23A. TRANSIENT CURRENTS BETWEEN NODES P255 AND ERIC WHEN THE THREE TERMINAL SWITCHES OPEN SIMULTANEOUSLY.

print date: 7. July 1993

4.7 Abnormalities at different points of the feeder when the generator is switched on to it by an ideal three phase device

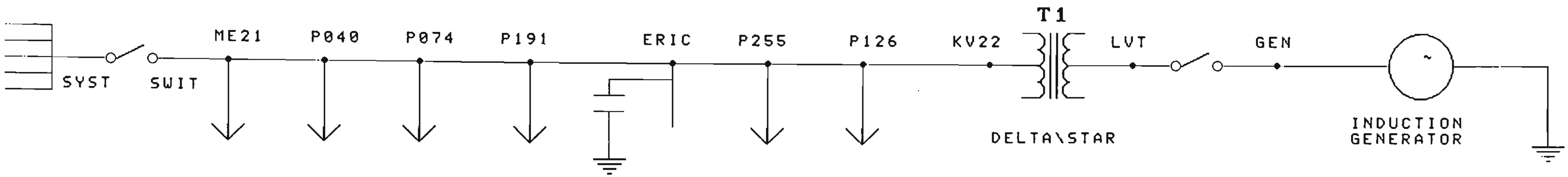
This section describes the effects of switching the generator on to the feeders voltages and currents. At the instant of switching the generator runs at -1.0 % slip. In this case it assumed that the switches of all phases close simultaneously.

Fig. 4-7 shows an ideal three phase switch connecting the terminals of the induction generator to the feeders.

Plot 24 shows the transient voltages at the terminals of the generator when the three phase terminal switches close simultaneously at 2 ms. The peak voltages of phases A and B are nearly 5 kV and 4.5 kV at 2.5 ms. Phase C at that instant is 0.5 kV. From the plot it appears that phase C has less conspicuous transients than phases A and B. However, the relative magnitudes of the transients depends on the time of opening of the switch. The scenario is different when the switch is opened at 4 ms.

Plot 25A shows the transient currents at the generator's terminals when the switch is opened at 2ms. The peak value of phase A is 1000A, which is the maximum of all peaks. As the current scale is very high on the plot, the transients are not as conspicuous as the voltage plots (PLot 24).

DISTRIBUTION CIRCUIT OF SECU



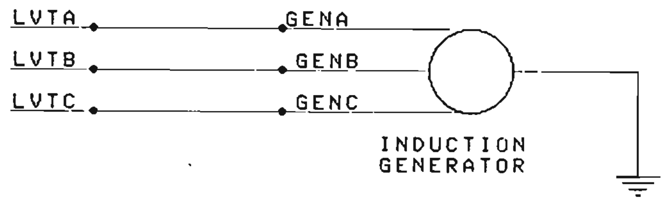
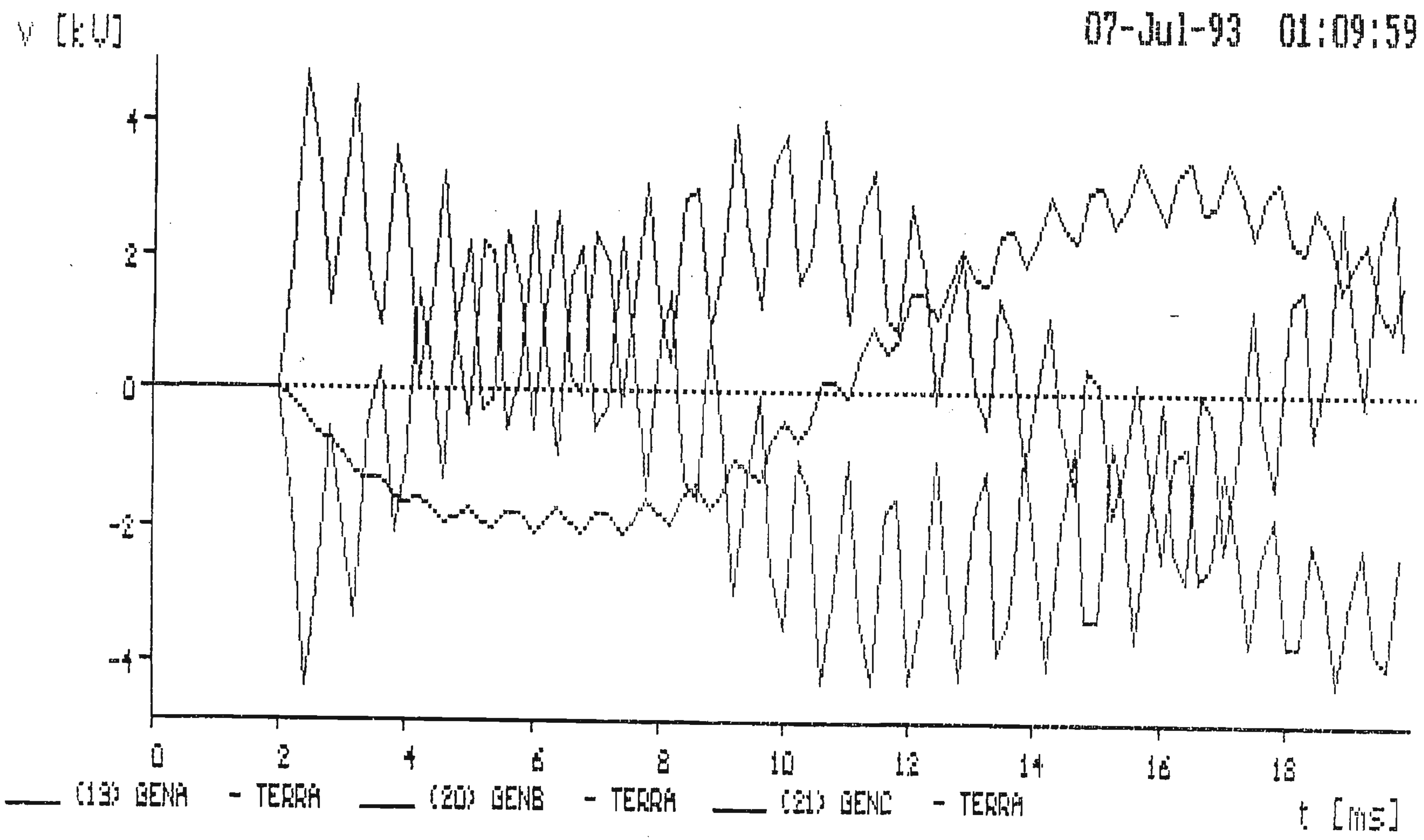


FIG. 4-7. GENERATOR ENERGISATION: TERMINALS OF IDEAL 3-PHASE SWITCHING DEVICE CLOSED.

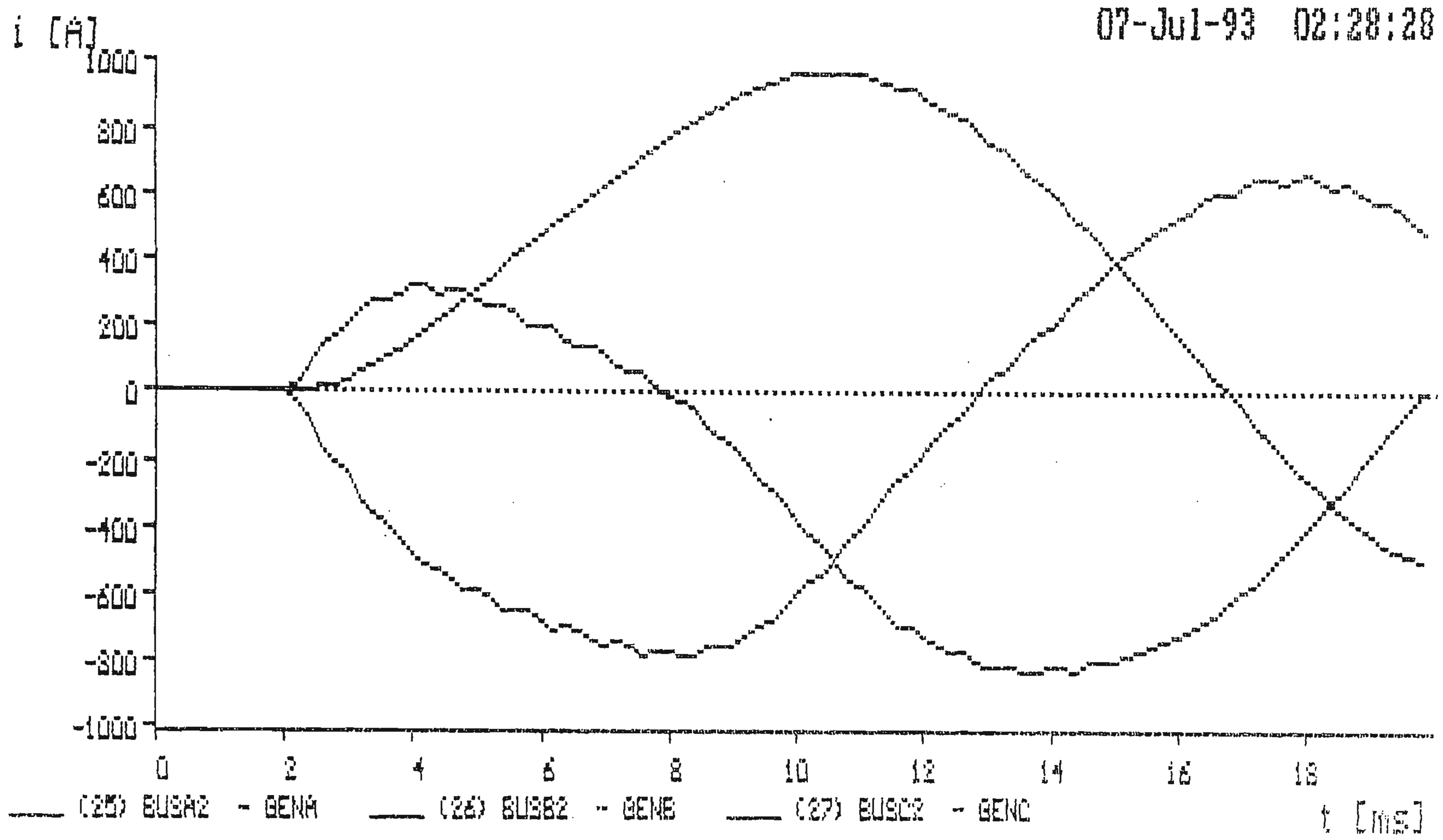


PLOT 24. TRANSIENT VOLTAGES AT NODE GEN.

print date: 7. July 1993

PLOT 25. TRANSIENT VOLTAGES AT NODE P126.

print date: 7. July 1993



PLOT 25A. TRANSIENT CURRENTS AT THE GENERATOR'S TERMINALS
WHEN IT IS SWITCHED ON TO THE FEEDERS AT 2 MS.

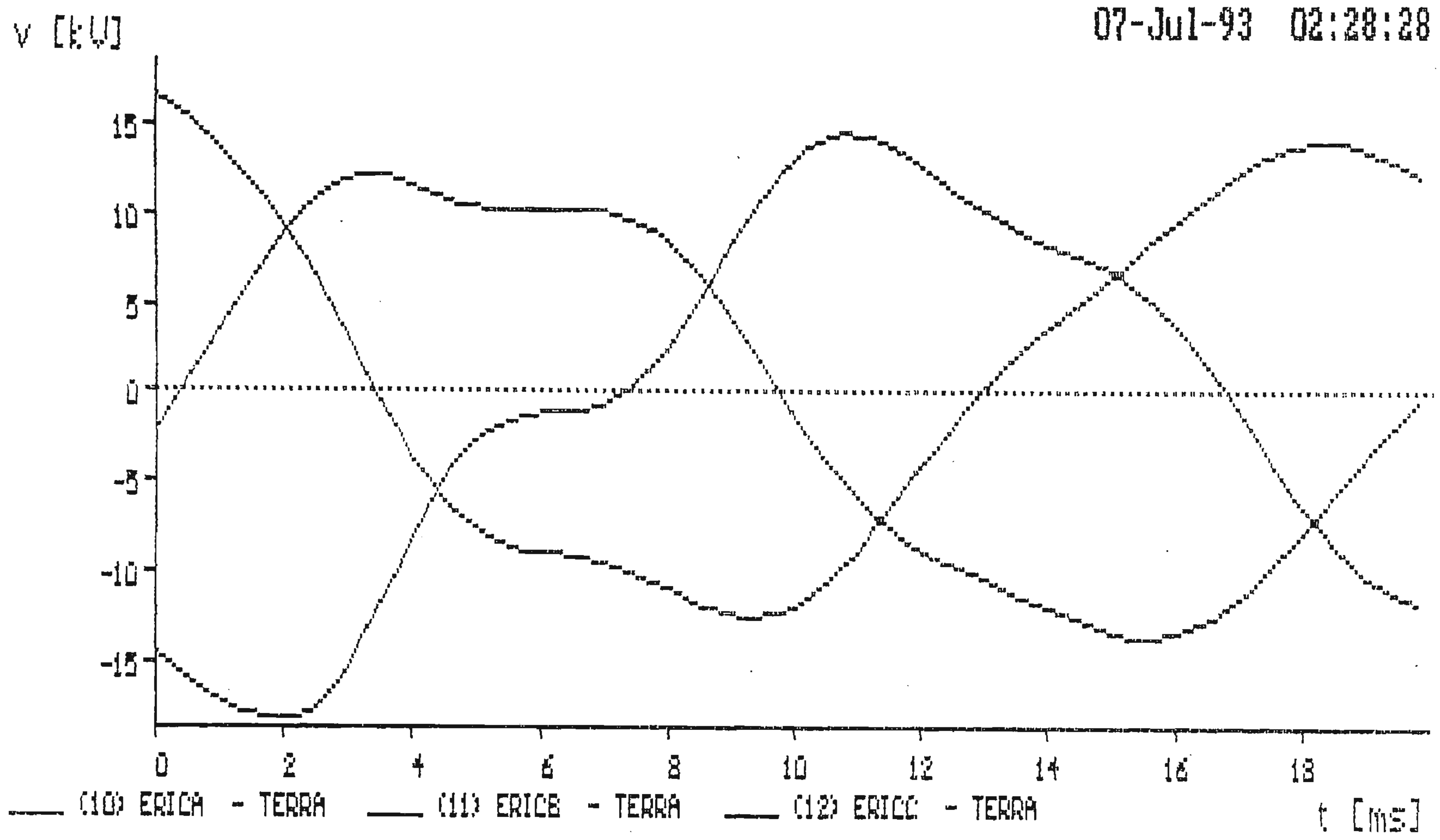
print date: 7. July 1993

Plot 25B shows the transient voltages at ERIC capacitors bank when the three terminal switches are opened at 2 ms. The plots are smooth, which shows that the capacitor bank has wiped out the transients. When the capacitor bank is switched off from the feeders, the transients appeared again (Plot 25E), which is very similar to the transient voltages at node P126 (Plot 25).

Plot 25C shows transient currents in ERIC capacitors bank when the generator is switched on to the feeders at 2 ms. The explanation given in the preceding paragraph also applies to the currents in this paragraph.

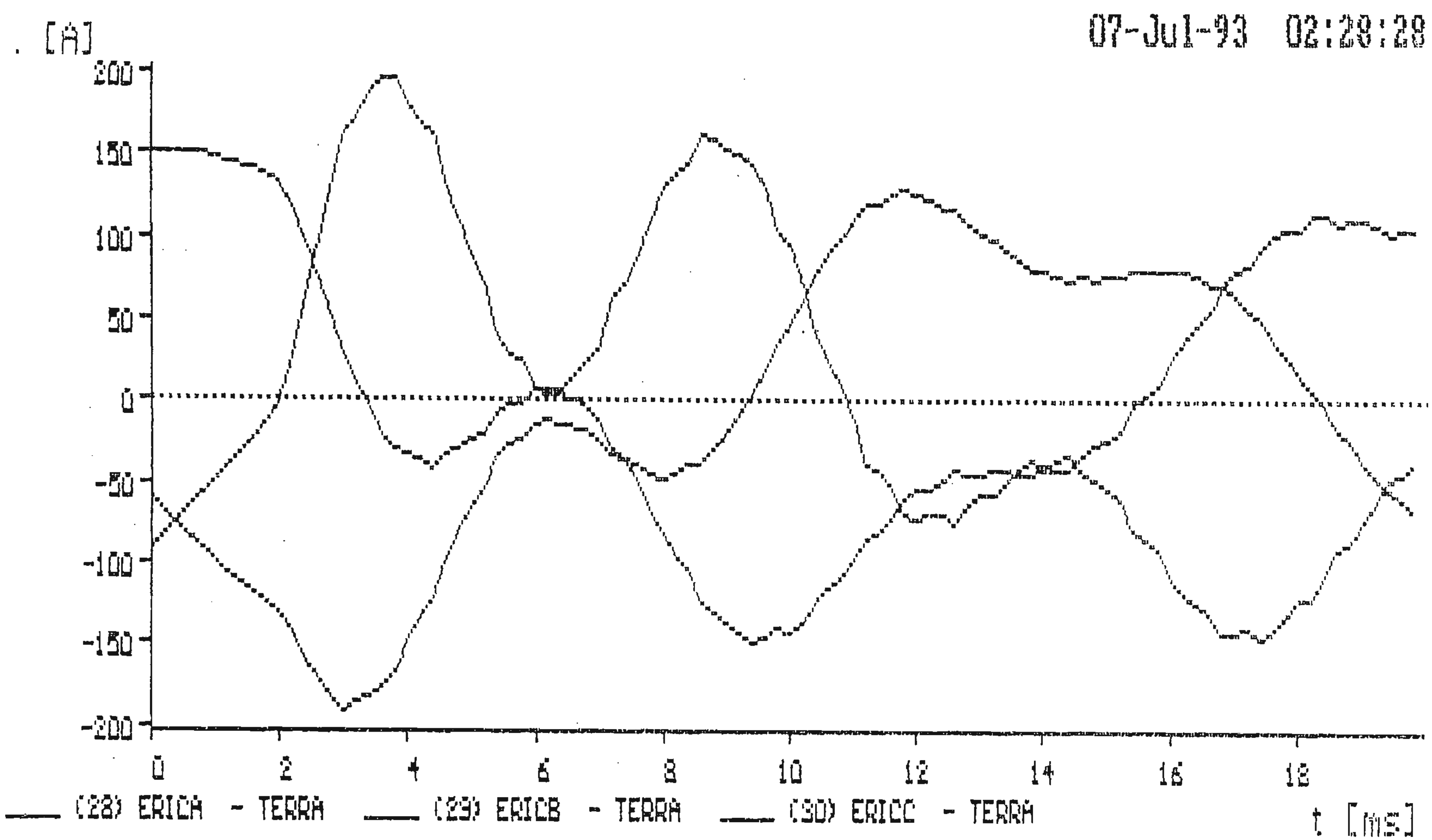
Plot 25D shows the transient ground currents at the system source flowing from node SYST into node ME21 when the generator is switched on to the feeders at 2 ms. Phase values of currents were measured at 10.4 ms and 16 ms. The currents in phases A, B, C at 10.4 ms were found to be -63.83A, 268.08A, -204.26A, which totals to zero. Similarly, the currents at 16 ms were -191.49A, 127.66A, and 63.83A, which again totals to zero. As this point is very far from the switching point and also the capacitor bank comes in the way, the transients are not visible.

Plot 26 shows the transient currents between nodes P126 and P255 when the generator is switched on to the system at 2 ms. The effect of transients here is not significant, because the line impedance smooths it down.



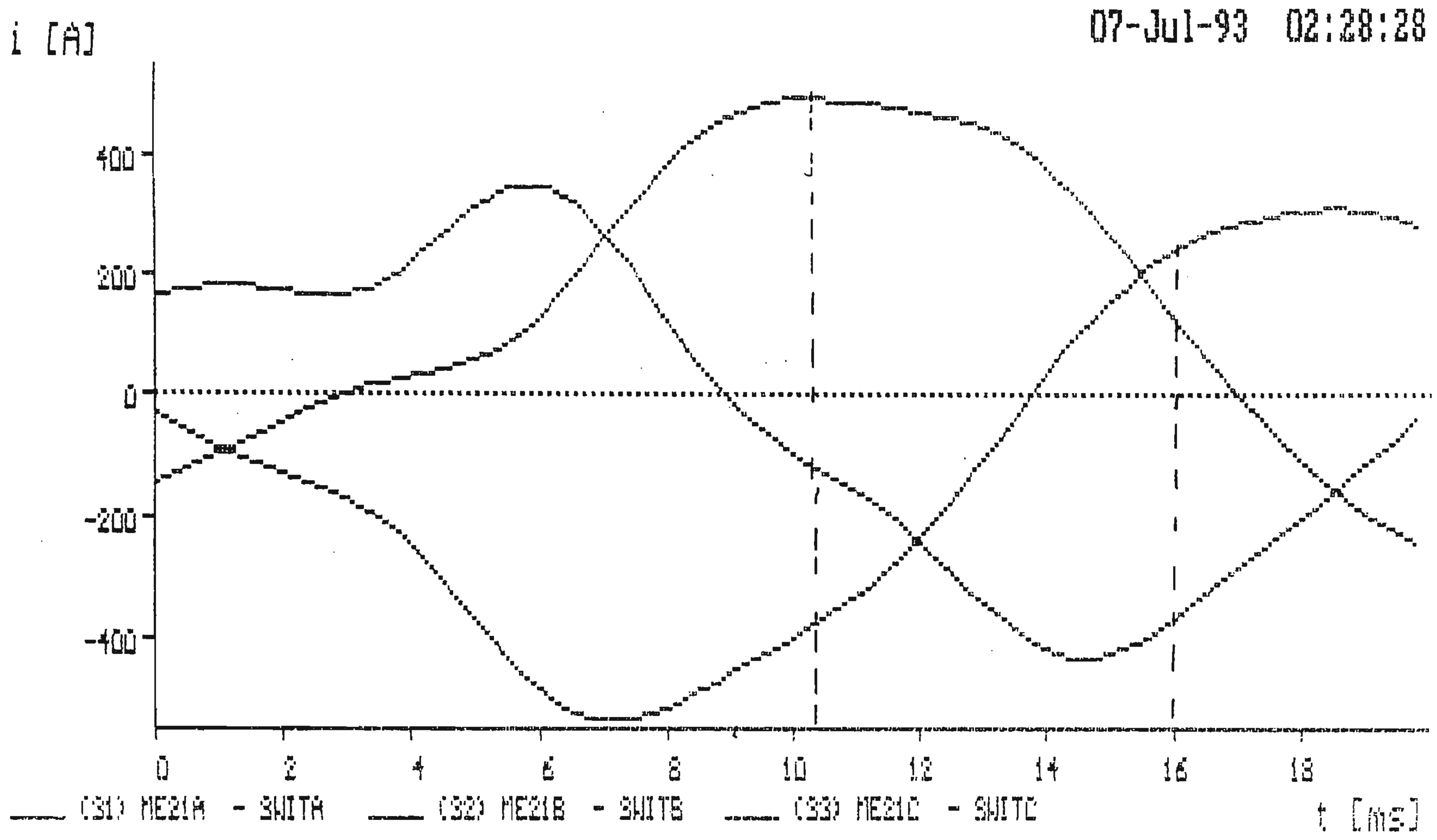
PLOT 25B. TRANSIENT VOLTAGES AT ERIC CAPACITORS BANK WHEN THE GENERATOR IS SWITCHED ON TO THE FEEDERS AT 2 MS.

print date: 13. September 1993



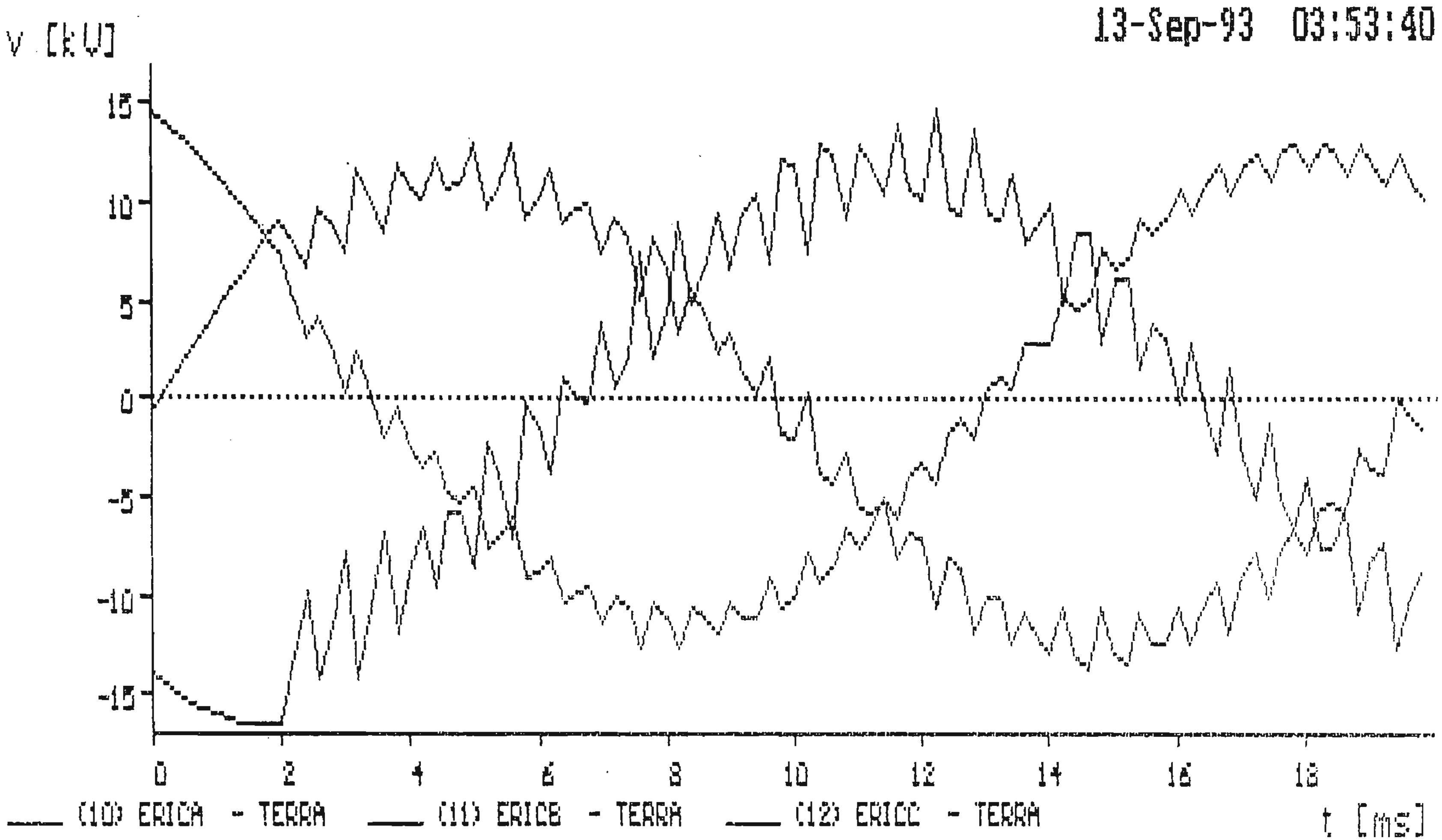
PLOT 25C. TRANSIENT CURRENTS AT ERIC CAPACITORS BANK
WHEN THE GENERATOR IS SWITCHED ON TO THE FEEDERS AT 2 MS.

print date: 7. July 1993



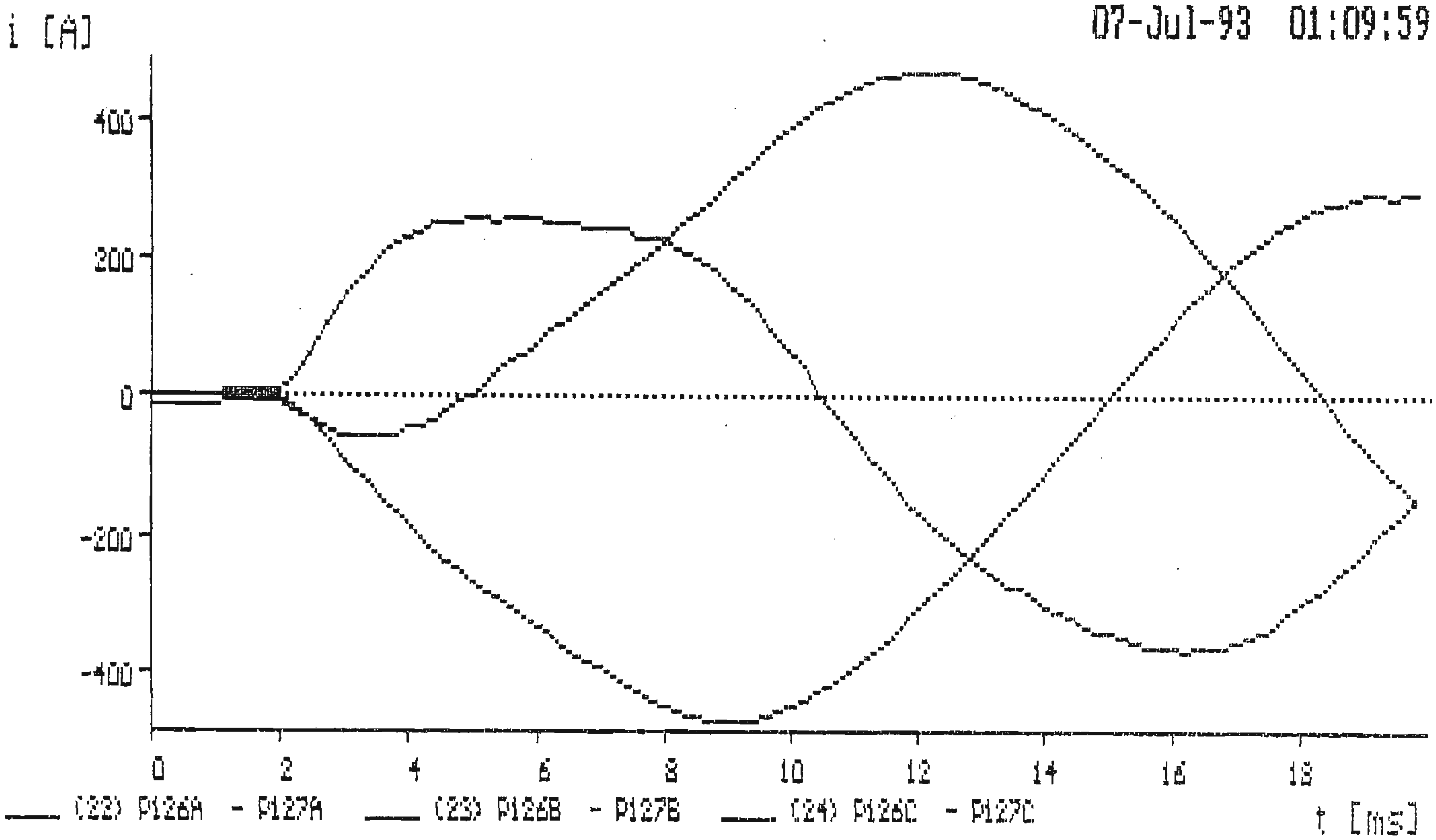
PLOT 25D. TRANSIENT GROUND CURRENTS AT SYSTEM SOURCE
FLOWING FROM NODE SYST INTO NODE ME21 WHEN THE GENERATOR
IS SWITCHED ON TO THE FEEDERS AT 2 MS.

print date: 7. July 1993



PLOT 25E. TRANSIENT VOLTAGES AT ERIC CAPACITOR BANK WHEN THE BANK IS SWITCHED OFF.

print date: 13. September 1993



PLOT 26. TRANSIENT CURRENTS BETWEEN NODES P126 & P255.

print date: 7. July 1993

4.8 Abnormalities at different points of the feeder when the section from the induction generator to ERIC capacitor banks is disconnected from the supply system

This section describes the effect of the induction generator with some portion of the feeder and some loads getting suddenly isolated from the supply system; this is also referred to as "islanding". It should be noted that the period of observation of transients is prolonged from 20 ms to 200 ms and also to 2 seconds for comprehensive conclusions.

Fig. 4-8 shows the section of the feeder and the induction generator, enclosed within dotted lines, disconnected from the supply system. This section gets suddenly disconnected from the supply system at 2 ms.

Plot 27 shows the transient voltages at node P191B when the islanding occurs at 2 ms. It can be seen from the plots that the transient voltages are much higher than the rated voltages and it takes a very long time to subside. An observation for a period of 2 seconds shows that the rate of decay of transients is very slow (Plot 30). It should be noted that this node is nearest to the islanded section of the feeder.

Plot 28 shows the transient voltages at node GENA when the islanding occurs at 2 ms. The transient voltages are much higher than the rated voltage of the generator but the decay is faster than that at P191B. An observation for a period of

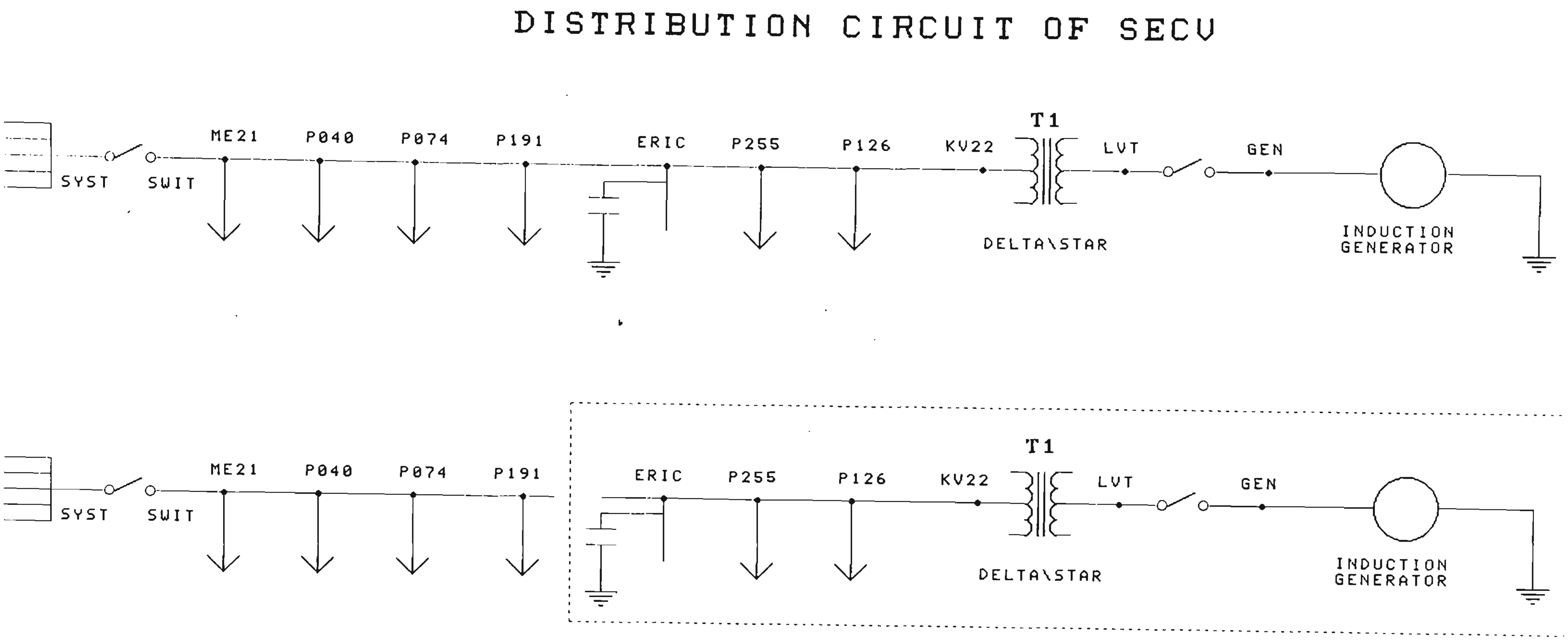
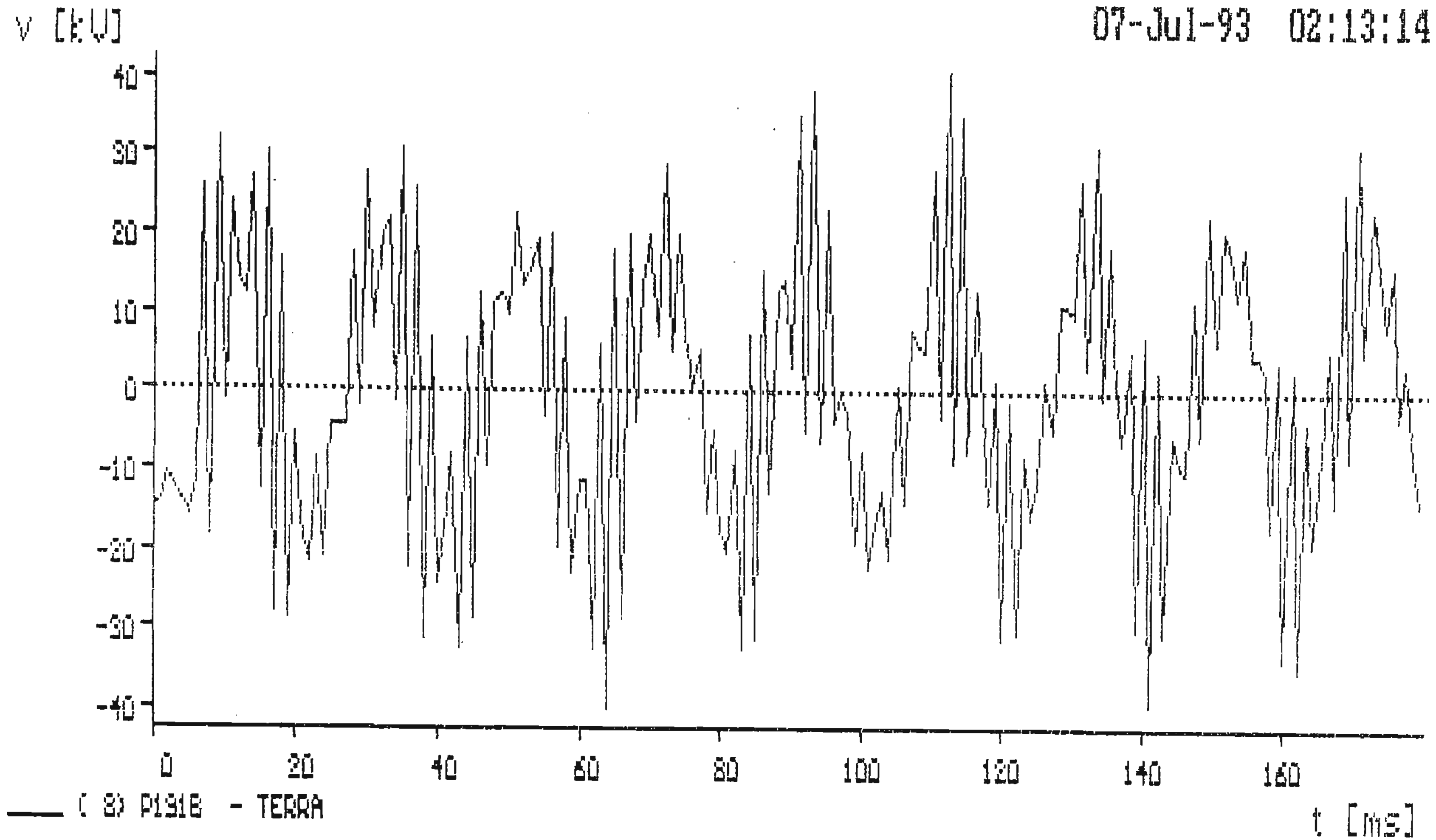
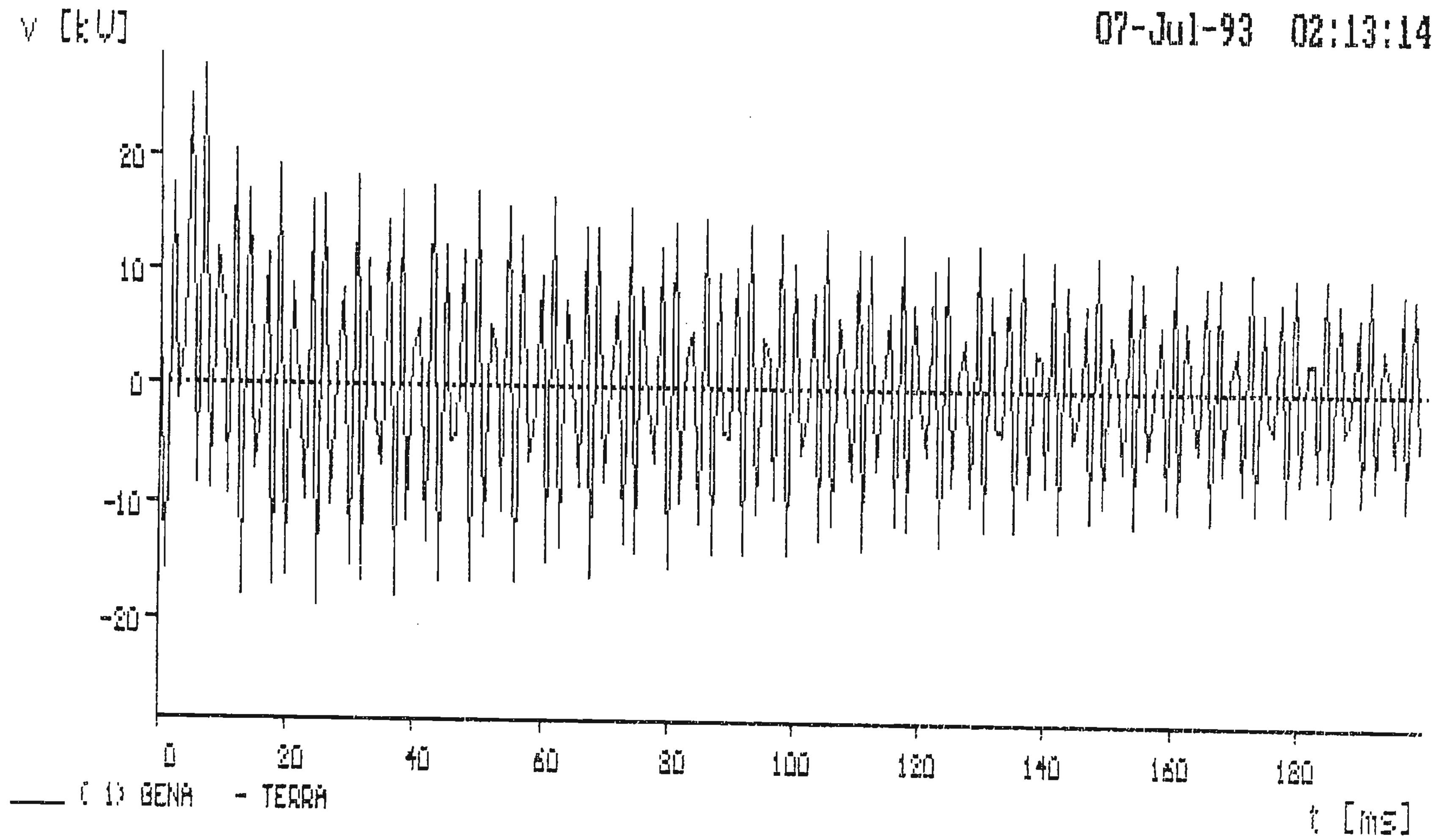


FIG. 4-8. ISLANDING SITUATION: SECTION WITHIN DOTTED LINES IS DISCONNECTED FROM SUPPLY SYSTEM.



PLOT 27. TRANSIENT VOLTAGES AT NODE P191B.

print date: 8. July 1993



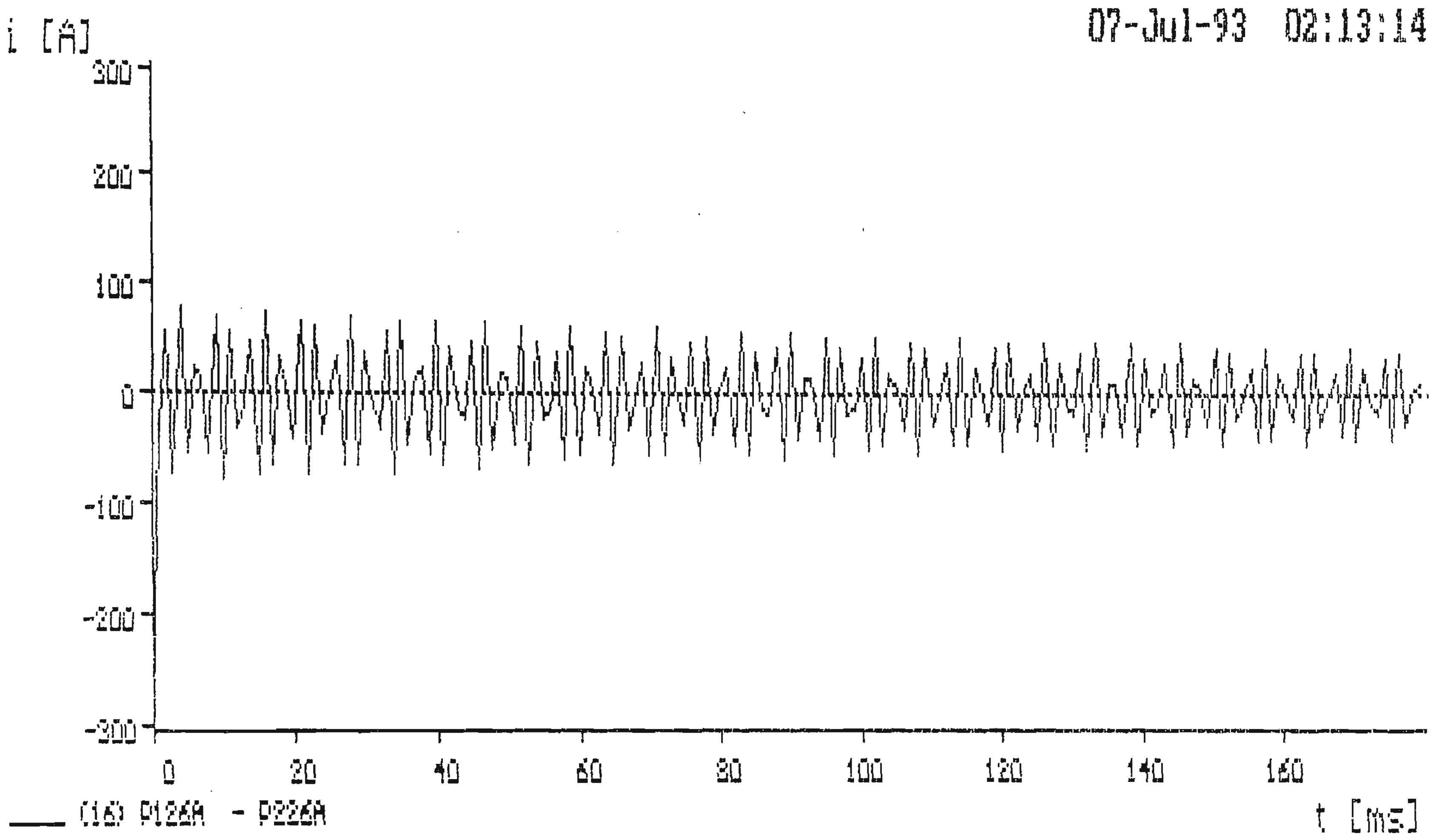
PLOT 28. TRANSIENT VOLTAGES AT NODE GENA.

print date: 8. July 1993

2 seconds shows a better picture (Plot 33).

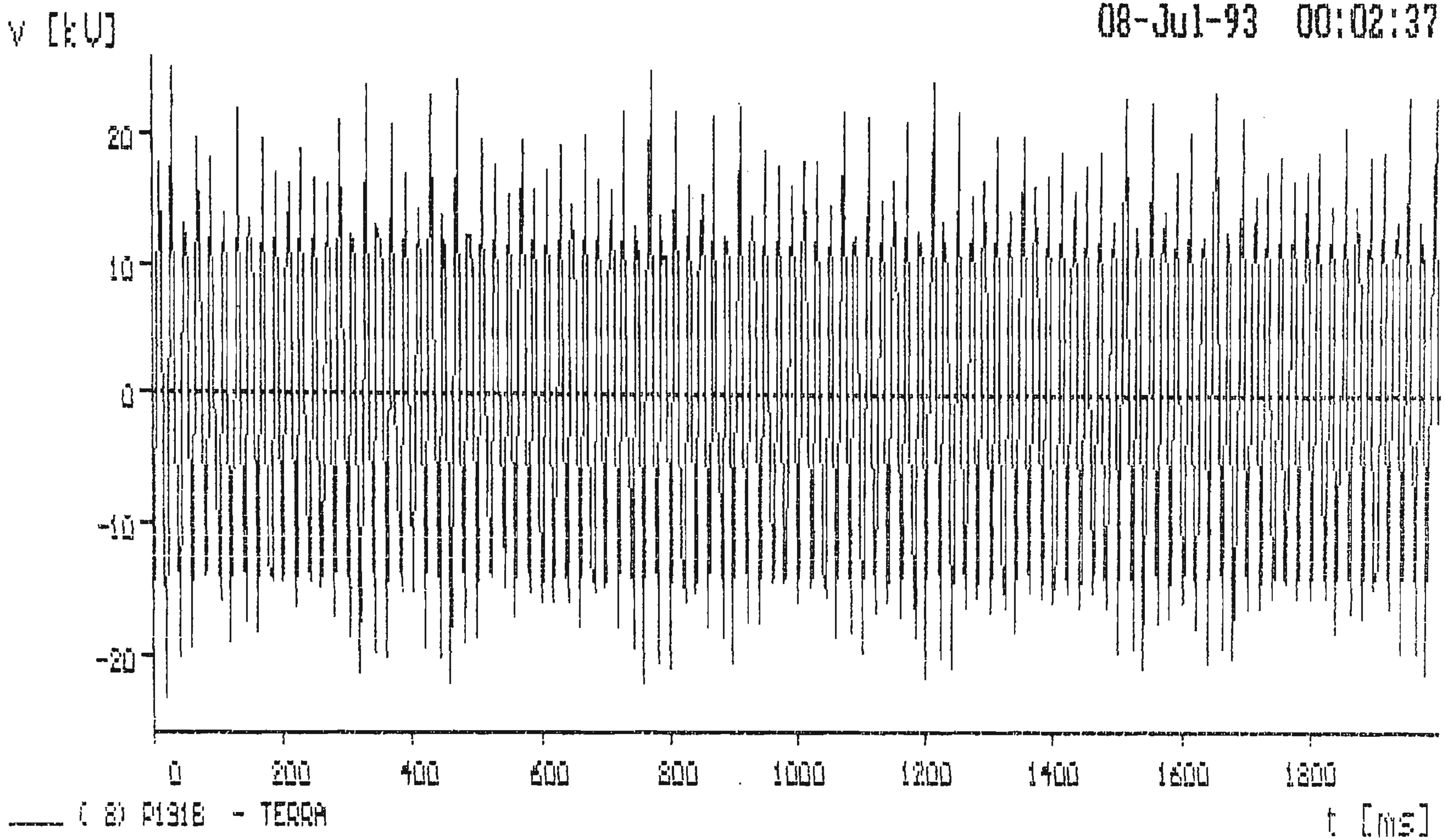
Plot 29 shows the transient currents between nodes P126 and P255 when the islanding occurs at 2 ms. The transients gradually subside, but takes a long time. An observation for 2 seconds is shown in Plot 34.

Plot 31 shows the transient voltages at node ERICB. Transient voltages are not seen here, because the capacitor bank smoothens them down. The transient voltages are very small at node P255 (Plot 32), which is nearest to the capacitor bank.



PLOT 29. TRANSIENT CURRENTS BETWEEN NODE P126A & P255A.

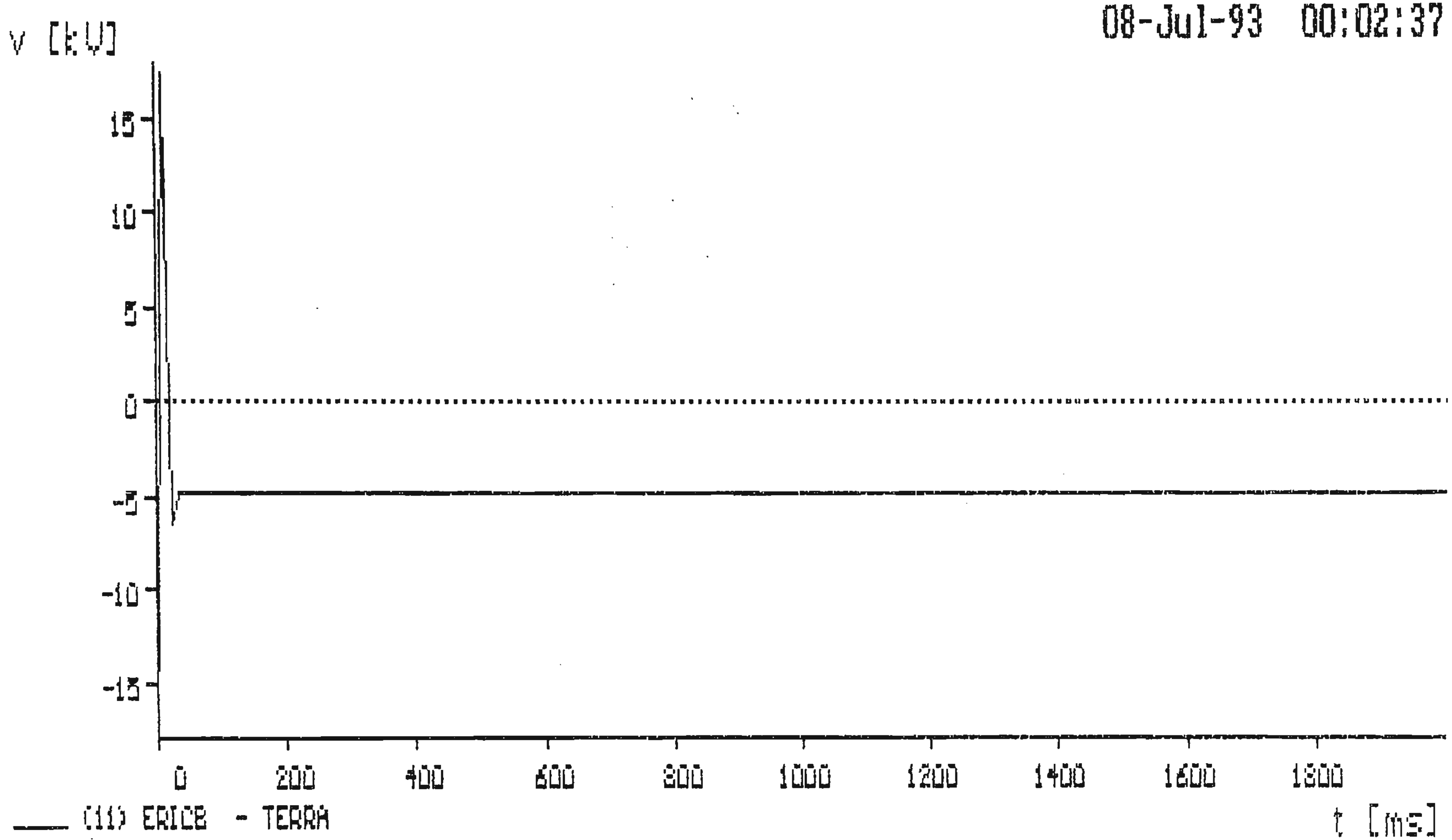
print date: 8. July 1993



PLOT 30. TRANSIENT VOLTAGES AT NODE P191B.

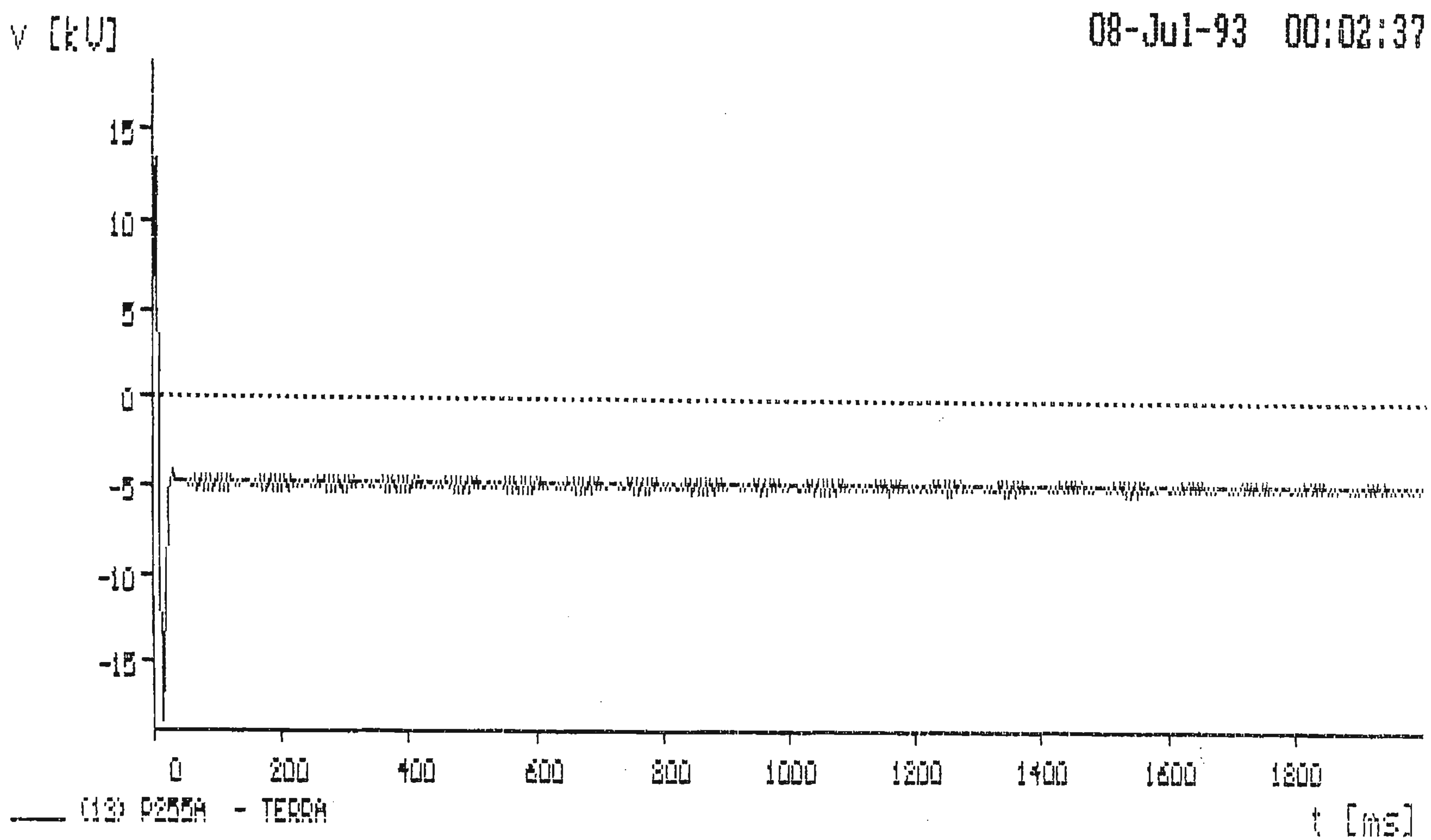
print date: 8. July 1993

08-Jul-93 00:02:37



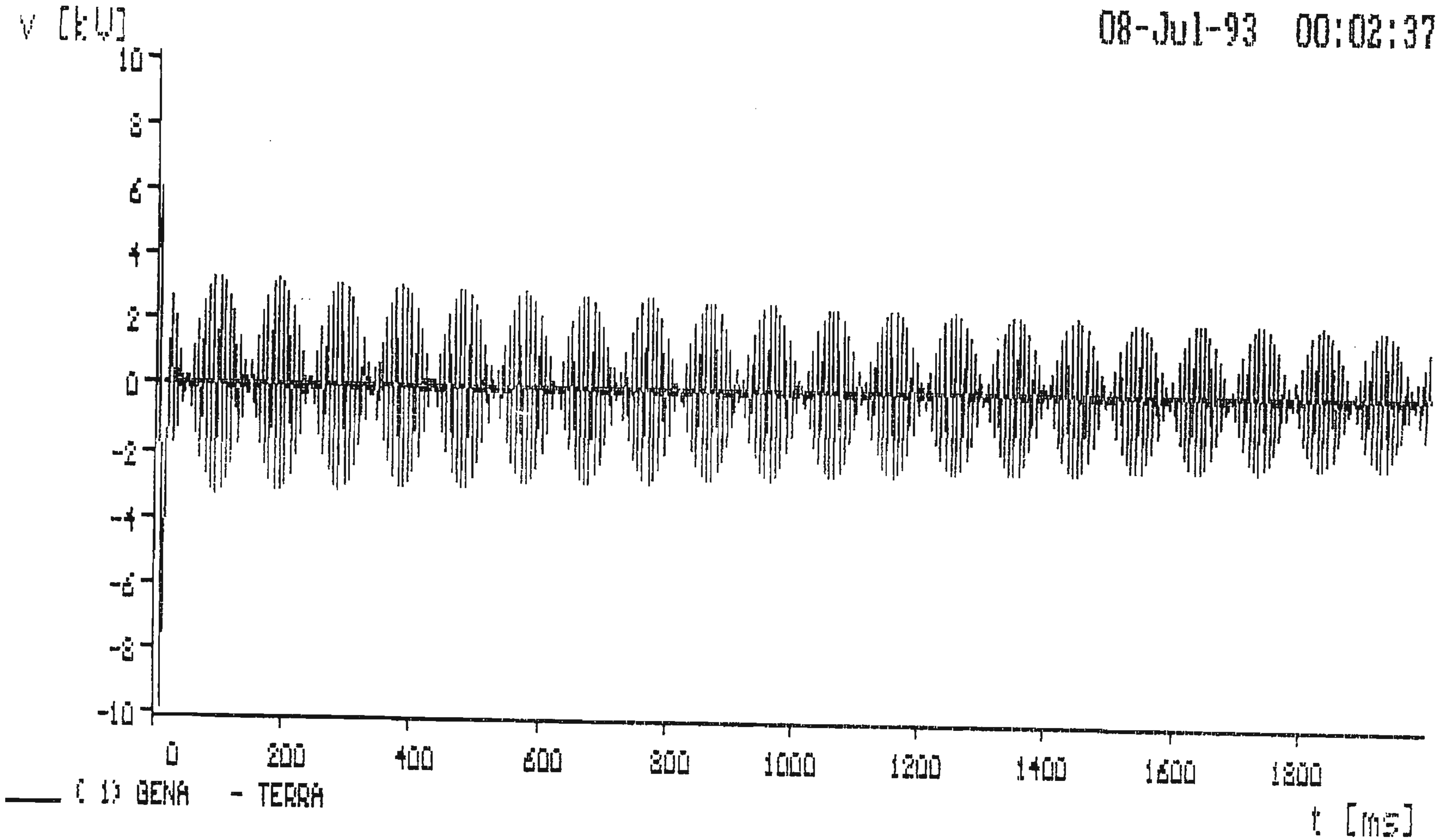
PLOT 31. TRANSIENT VOLTAGES AT NODE ERICB.

print date: 8. July 1993



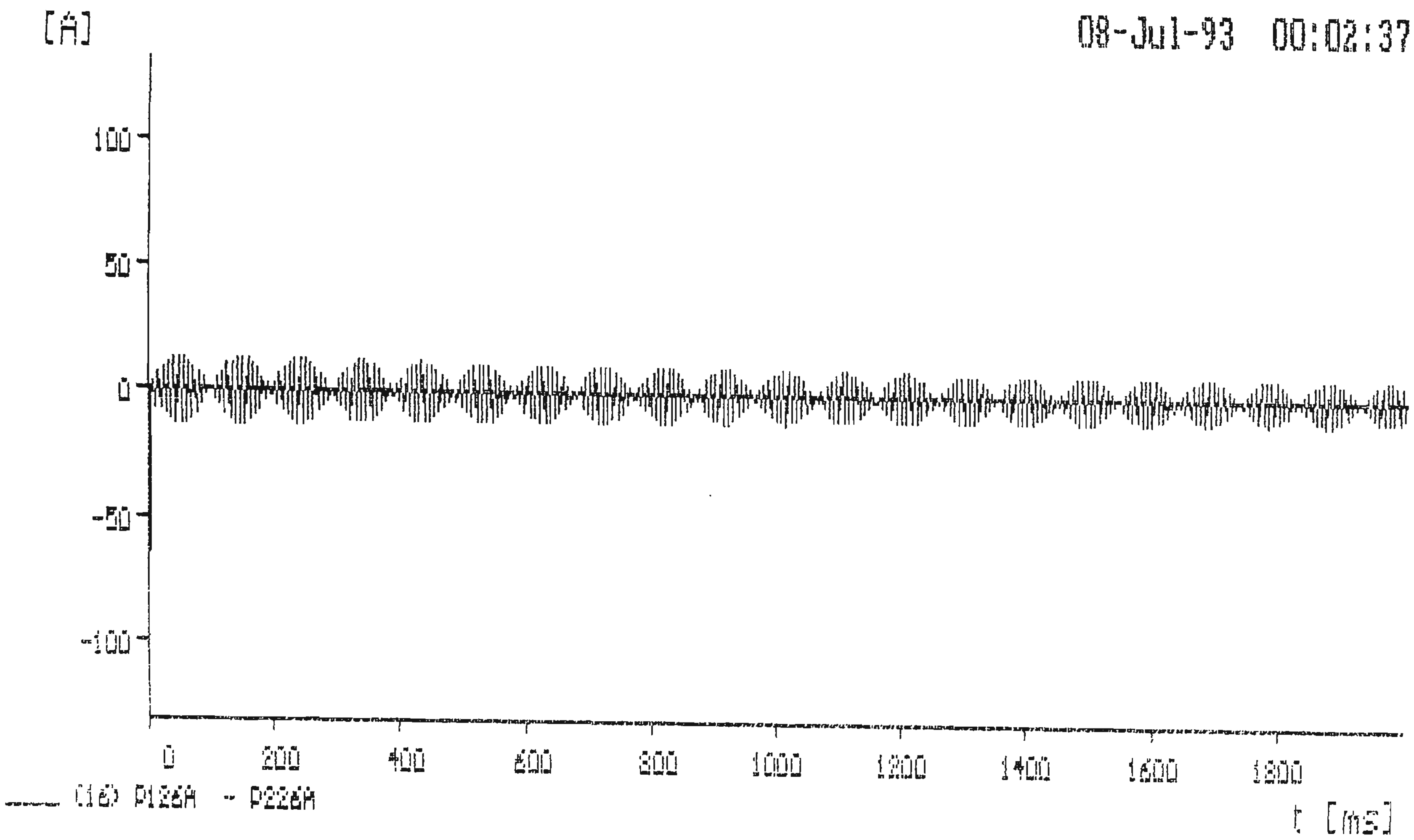
PLOT 32. TRANSIENT VOLTAGES AT NODE P255A.

print date: 8. July 1993



PLOT 33. TRANSIENT VOLTAGES AT NODE GENA.

print date: 8. July 1993



PLOT 34. TRANSIENT CURRENTS BETWEEN NODES P126 & P255.

print date: 8. July 1993

CHAPTER 5 PLANNING AND OPERATION OF DISTRIBUTION CIRCUITS WITH DISPERSED STORAGE GENERATION

5.0 Introduction

The introduction of DSG into distribution systems has significantly complicated the previous distribution planning and operating practices. It requires substantially greater data collection and analysis efforts. This chapter describes the salient features of the distribution characteristics and conventional distribution planning. It also includes the impact of DSG technologies in the planning process. Operational problems like voltage control, harmonics, earthing, reliability etc. are considered.

5.1 Delivery system characteristics

5.1.1 Reserve capacity

Reserve capacity exists throughout distribution systems. Some of this capacity provides useful reserves for future load growth and reliability, and some excess capacity protects against load growth uncertainties and daily load fluctuations. In general, reserve capacity increases as one progresses further down to the end users. Other reserve capacities occur because of trade-offs between economies of scale in equipment costs and high replacement costs due to labour costs. This reserve capacity characteristic, together with load diversity, means that the DSG placed at the lower part of the system may not result in simultaneous distribution capacity savings throughout the system in the short term. DSG can also be used as a temporary relief option to reduce excess capacity due to load uncertainties.

5.1.2 **Distribution reliability**

Though the individual equipment has high component reliability, distribution level outages still cause about 95% of all service interruptions to customers, only about 5% is caused by failures in the bulk-supply system [99]. This is due to the large number of components susceptible to outage occurrences caused by natural conditions or human interference. Generally, the cost of service continuity improvement is so high that brief periods of infrequent service interruption to a small number of customers can be tolerated. Usually, distribution outages, compared to bulk-supply failures, are significantly more frequent, have shorter duration, and affect a smaller number of customers at one time. Present distribution reliability performance reflects the balance between the value of service continuity to smaller customers and the cost of improvement of these kinds of outages. DSG as an option to improve distribution reliability should be evaluated to the extent it can be useful in these frequent, short-duration, and location-specific outages.

5.1.3 Distribution losses

Transmission and distribution systems together lose about 8 to 10% of the energy they deliver, about half of the total loss typically being in the distribution system. Dispersed generation can eliminate transmission losses and reduce distribution losses. Dispersed storage has negligible effect on transmission and distribution losses. To deliver the same amount of energy to end-users, dispersed devices require smaller power and energy capacities.

5.1.4 Radial operation

Most distribution systems are radially operated. This avoids the expensive capital investments in additional distribution equipment and reduces operating and protection complexity of loop systems. DSG could be operated to preserve the uni-directional current flow in a network operated radially, avoiding any additional capital investment and planning and operating complexities.

5.1.5 Thermal and voltage limitations

Thermally-limited systems require reinforcements to avoid current overloading of equipment. Voltage-limited systems serve areas with lower load density and long primary and secondary lines. Systems can be both thermal and voltage limited. DSG can be used to smooth down the loads higher up the system above the device location in a thermally limited system. It can help to increase the voltage level at the lower part of the system below the device location in a voltage limited system.

5.2 Distribution planning system characteristics

Distribution planning is determined by delivery system characteristics, integrating and reflecting the load, equipment, and service-area system characteristics. The planning includes designing subtransmission system, distribution substations, the primary system, and the secondary system.

5.2.1 Planning for peak load

The load forecast drives the distribution expansion planning process by defining the planning need. In most cases, distribution load is the most important quantity projected because the distribution system must be designed to carry the maximum load. Minimum load projections are sometimes needed for systems with excessive voltage differences between peak and minimum load conditions.

5.2.2 Planning objectives

Beginning with load forecasts, the distribution planner considers various options to satisfy the future demand at an appropriate service quality at a minimum cost over the planning horizon. Planning is performed under very stochastic conditions, with uncertainties and data scarcity increases as one moves further down the delivery system from substations down to end-user customers. Quality of customer service is defined by the performance and life span of customer electric facilities, and by the pattern of frequency and duration of service interruption. Standard voltage criteria exist to ensure proper performance of electrical facilities, but there is no common criteria for service interruption accepted by all utilities. Minimising the cost of delivered service includes capital cost of equipment, distribution energy losses, cost of maintenance, and loss of revenue from unserviced energy. In distribution planning, usually capital cost and the cost of energy losses are emphasised because these are the major cost elements and can be reduced by careful planning.

5.2.3 **Planning criteria**

Several procedures are used to achieve appropriate levels of planning objectives. Because it is difficult to measure service quality directly, planners have established distribution equipment performance criteria as surrogate to planning objectives. There are different planning criteria for normal and emergency operation. A system is in normal state if all distribution equipment are functioning properly. A system is in outage state if some distribution equipment has failed to perform properly. A set of emergency operating criteria -- different than those for the normal state -- are defined for some selected outage states. The states are selected on the basis of high expected costs arising from high probability of occurrence or excessive costs resulting from outages. For these selected outage states, planners select which customer loads are to be served under the relaxed emergency operating criteria. For example, planning to have all customers receive service under emergency criteria for those outage states with selected single equipment failure is called "single contingency planning". For some outage states, selected customer loads are dropped temporarily to protect the system from falling into more severe outage states with even greater outage cost as more customers lose service or equipment damage occurs.

5.2.4 **Voltage and current criteria**

Two fundamental criteria are used in the normal and emergency states to protect customer and utility equipment: current loading criteria and voltage criteria. Current overloading for extended period overheats the equipment, shortening life span or permanently damaging the equipment. Life span of all distribution equipment depends on the duration and magnitude of current loading as a percentage of their nameplate capacity. Current-loading criteria is established for each type of distribution equipment, allowing extended operation during normal peak period without damage. Voltage at the customer service entry must be maintained within certain range. Both excessively high and low voltage can damage customer electrical facilities and appliances. To maintain voltage within this range, voltage profiles at the sub-transmission and primary system must be kept within some range, allowing for the drop in the secondary system.

5.3 Planning for normal and emergency conditions

Emergency state criteria allow higher current overload and a wider range of voltage variation than are allowed in the normal state. This is because the duration of the emergency states are usually shorter than normal-state peak periods. The surrogate planning criteria usually evolve from the judgement and experience of planners familiar with the system; the surrogate criteria is much simpler to use in planning than the more fundamental service-quality and cost criteria. Occasionally, the surrogate measures are derived from empirical tests or studies, but usually the exact quantitative relationship between the surrogate and the fundamental service and the cost criteria are not known.

5.3.1 Use of judgement and experience

Judgement and experience are applied extensively to forecast loads, develop competitive options, select outage cases, establish normal and emergency criteria, and select customers to be serviced during emergency conditions. This informed judgement, when used iteratively with a set of planning models, determines the final planning decisions.

5.3.2 **Adoption of new technology**

The introduction of new technology as an option in distribution system planning is a long process because of the time needed to establish proven and reliable performance to a large number of potential users with widely different needs. This cautious approach stems from the substantial costs of repairing, maintaining, and removing a large number of widespread faulty units. This is true for conventional technologies and it will be true for DSG. The planning and operation of DSG will be subject to the same objectives and criteria as used to evaluate conventional technologies.

5.3.3 **Planning horizon**

The planning horizon, is the number of years various options, must be developed and evaluated so that the implementation decision for the first year is optimal. The distribution planning horizon for five to seven years is much shorter than the generation planning horizon of thirty to forty years. The planning horizon is related to the degree of uncertainty, the cost of forecasting demand, the cost of collecting and processing demand, the cost of information, the cost of finding the optimal expansion plan, and the expected benefit of extending the planning period. The distribution planning is short because of severe load uncertainties, the cost of forecasting demand at every part of the system, the cost of collecting and processing large amount of data, the planning effort needed to find the optimal expansion plan, and the dubious benefit of extending the planning horizon to more than five to seven years. An exception is the long-range planning for rapid growth areas where the expected benefits of longer planning horizons may be repeated. In these cases, hypothetical service area and load data, together with a simple heuristic expansion algorithm, substitute for detailed planning under uncertainty. The planning horizon for the secondary system is even shorter, usually less than three years, because of the aforementioned reasons.

5.4 Characteristics common to storage & generation

DSG technologies have many unique characteristics compared to conventional distribution components and generation equipment.

5.4.1 Impact on generation

Unlike all conventional distribution equipment, a DSG device stores or generates real power. It therefore affects requirements for bulk-supply generation. It may change both the energy and capacity of generation. For this reason, DSG devices may be controlled for bulk-supply objectives. If in addition, dispersed devices are to satisfy distribution objectives, they may have to be used for a longer duration. This may increase the production, capital, and operating and maintenance costs.

5.4.2 **Economy of scale capital cost**

DSG technologies considered for dispersion have characteristically no significant economy of scale above 10 MW. However, between 1 kW and 10 kW, there can be substantial economy of scale, depending on the technology employed.

5.4.3 Operating and maintenance

There is a diseconomy of scale in operating and maintenance costs for dispersed devices. The unit cost would be increased as devices which are geographically distributed must be maintained unit by unit. Total operating and maintenance cost depends increasingly on the number of units, rather than on the total cost of individual units.

5.5 **Communications and control**

DSG technologies require communication and control equipment. The cost of this equipment, for a large number of devices, depend on the number of units, not on the capacity. Communication and control costs could be an important part of the total capital and operation and maintenance cost, as the number of dispersed units increases.

5.6 **Interface**

For devices that inherently generate dc power, inverters are required to interface the units with the distribution systems. For storage, converters are required to change ac to dc power before storing.

5.7 **Reliability**

Individual dispersed unit reliability is expected to be comparable to peaking generators such as gas turbines. These generating devices are expected to have higher component outage rates than conventional distribution equipment. This may vary according to the extent the devices are operated and maintained.

5.8 **Planning & operation with DSG**

5.8.1 **Supply-side devices**

The general approach to planning with Dispersed Supply-Side Storage and Generation (DSSG) located on the supply or utility-side of the meter is to consider violations of distribution planning criteria. The same set of load forecasts, distribution planning criteria and models are used for planning both with and without DSSG. DSSG is not expected to be able to solve all distribution problems, nor it is expected to always be the least-cost or optimal solution. A strategy is defined by a selected application of DSSG to relieve specific distribution violations for a specified duration. In addition, different DSSG options which may implement a strategy, are identified according to: (1) device locations, (2) capacity sizes, and (3) operating modes.

New distribution expansion plans including DSSG may be preferred alternatives to the base-case plan defined using only conventional technologies. To determine their relative costs and benefits, conventional distribution planning procedures are used to identify the specific criteria violations relieved by the base-case expansion plan. Then each of the violations are analysed to determine whether DSSG can be used as a relief alternative. For example, the overloading of substation transformers during a single contingency outage of a neighbouring substation, relieved in the base plan by an additional transformer, might also be relieved by DSSG placed in the substation. Strategies are defined for relieving selected violations for a designated duration within the planning horizon.

To implement the strategies, alternate options are developed with DSSG of various sizes placed at various locations: (1) potential locations for DSSG vary from the high-voltage bus of the distribution substation to the end-user customer site. Environmental factors are included by the planner for specific application; (2) device capacities are limited by the need to preserve unidirectional current flow. The maximum capacity at any location is the sum of all loads supplied downstream of the device. Storage sizes are further limited by the conversion losses and characteristics of the charge/discharge cycle; and (3) operating modes can be either for meeting local objectives or both local and central objectives. The choices of operating modes become separate DSSG options in the strategy. The exact definitions of different operating modes are discussed in the next section.

No model exists for defining and selecting optimal DSSG options. The models used in conventional distribution planning are used also to develop feasible DSSG options. This is done by modelling the DSSG devices which decrease or increase the real load and reactive power. DSSG options are simulated to evaluate their feasibility. This approach to evaluating DSSG is consistent with how planners use models to evaluate options, whether they be conventional or new-technology options. Long-range planning models are not suitable, since they ignore many short-range details necessary for evaluating DSSG. Two new models are needed, however, to help the planner identify feasible options; a new load model containing 24-hour load information and a new model for simulating the operation of DSSG option.

5.8.2 **Customer-side device**

Supply-side DSG (referred as DSSG) and customer-side DSG (referred as DCSG) have different impacts on distribution systems planning and operation. DSSG technologies may be used by utilities as a planning alternative to satisfy distribution needs. For DCSG, a distribution planning and operating procedures must account for changes in the real distribution loads. Distribution planners can plan with DSSG with certainty, but plan for DCSG since the locations, capacities, and perhaps operation of DCSG may be beyond the utility's influence and control.

When applied to DSSG, planning and operating for bulk-supply needs means siting the devices in the bulk-supply system. Planning and operating with consideration of distribution needs mean siting the devices in the distribution system. The approach then measures the net costs and benefits of dispersion of DSSG at different levels of the distribution system. The net value of dispersion is termed the dispersion credit of DSG.

When applied to DCSG, planning and operating from the bulk-supply perspective means introducing and operating the devices on the customer-side of the meter to achieve bulk-supply needs. Planning and operating with distribution objectives means operating the customer-side of the meter devices to satisfy the distribution needs. The result of the approach gives the net costs and benefits of accommodating distribution-level needs and the impact on distribution systems.

5.9 **Interconnection**

The cogenerators are connected with the centralised electric grid, so that the cogenerator may supply power to the grid and use backup power from the grid. However, interconnection with the grid may create problems for the utility system's operations or for the cogeneration equipment itself. Because interconnected cogeneration will involve power flows in both directions, utilities' and regulatory commissions' tasks in these areas will be more complicated.

If cogenerated power is of a different quality from that distributed on the grid, it may damage the utility's and its customers' equipment. Moreover, large number of utility-dispatched dispersed generators could make central load dispatching more difficult. Utilities are also concerned about properly metering the power consumption and production characteristics of grid-connected cogeneration systems, and about the effects of such systems on the safety of utility workers. Finally, out of all the above concerns arise the question about liability for employee accidents or equipment damage that may result from interconnection. Utility rates for purchases of power from and sales of power to cogenerators must take into account the net increased costs of interconnection, including the reasonable costs of connection, switching, metering, transmission, distribution, and safety provisions, as well as administrative costs incurred by the utility. Each qualifying cogenerator must reimburse the utility for these interconnection costs. The state regulatory commissions are responsible for ensuring that interconnection costs and requirements are reasonable and non-discriminatory, and for approving reimbursement plans (e.g., amortising the costs over several years versus requiring one lump-sum payment).

5.10 **Power quality**

Utility customers expect electric power to meet certain tolerances so that electric appliances will function efficiently and not be damaged under normal operating conditions. Power supplied to the grid by an interconnected cogenerator also is expected to be within certain tolerances, so that the overall power quality of the utility system remains satisfactory. Electric utilities are concerned about three types of power quality: correcting the power factor to keep the voltage and current in phase, maintaining strict voltage levels, and minimising harmonic distortion.

5.10.1 **Power factor correction**

A power factor different from 1.00 means that the voltage and current are out of phase, and can be either leading or lagging. Because the most useful power is delivered when voltage and current are in phase, it is important that the power factor be as closed to 1.00 as possible.

Phase shifts are one consideration in setting the demand component of rate structures. Thus utilities will have one rate for power with a power factor of 1.00 sold to other utilities, another rate for power sold to industrial customer which may have power factors much less than 1.00 and require the utility to install special monitoring devices, and another rate for power sold to residential customers, where power factor is not measured individually.

Synchronous generators have power factors of approximately 1.00 but can be adjusted to slightly leading or lagging while induction generators always have lagging power factors because they have more inductive than capacitive elements. Also, synchronous generators are more efficient than induction generators [87]. These two points can cause synchronous generators to be preferred for units above a certain power level (about 500 kW), although the precise value depends on individual situation.

As the penetration of these induction generators increases, more inductive elements are added to a particular distribution substation's circuits, resulting in a more lagging power factor, this creates three potential problems for the utility: the capacity of both transformers and switching equipment in the transmission and the distribution system may have to be increased to handle the out of phase signals; the efficiency of the transmission network may decrease; and equipment and appliance may overheat and may need more frequent overhaul.

Utilities normally improve lagging power factors by using capacitors, which may be sited either at the distribution substation or near the customer's load or generator, depending on the cause of the poor power factor and its magnitude. If the poor power factors are caused by smaller customers' equipment, utilities usually pay for the correcting capacitors, while large customers often are required to pay for their own power factor correction. Most utilities have guide-lines that state the minimum power factor allowed, usually 0.85 lagging. If a customer fails to maintain this minimum, utilities may ask the customer to install and pay for the necessary corrective capacitors. Traditionally, few utilities have leading power factors, because most utility circuits (and most appliances and motors) have more inductive elements than capacitive elements.

Similar policies will apply to cogenerators. Thus many utilities supply capacitors for smaller cogenerators, while requiring larger ones to pay for their own capacitors under the theory that there will be fewer substations with significant cogeneration penetration. Thus, the avoided substation capacity becomes part of the utilities's avoided cost and is credited to the cogenerator.

5.10.2 **Voltage regulation**

Utilities have many concerns about variations in voltage cycle from the standard cycle, both over long and short time intervals. While some customers can tolerate voltage outside of specified range for very brief intervals less than a second), any longer term variation will cause motors to overheat and will increase maintenance costs. Voltage cycle variations are minimised through the proper design and operation of generators. However, generators do not always function perfectly, and protective "over/under voltage" relays generally are necessary to disconnect the generator if its voltage falls outside of a certain range.

The state regulatory commissions [92] normally require a steady supply of 240 V (±5%) for residential customers. Large commercial and industrial customers often receive their voltage directly from substations or distribution lines, with much higher voltages and different tolerances.

Two major analyses are available if potential voltage regulation problems caused by improperly interconnected dispersed generators. One study considers a sample utility with 50% of its customers generating power with wind machines [86]. This study must be considered a "worst case" analogy for cogeneration because the output from the wind machines will change more often than the output of typical (either induction or synchronous) cogenerators. Even with this 50% penetration, the study indicates that substation voltage levels would remain within 5% of standard levels.

In the second study, which installed a transformer on its 37.5kV distribution circuits and connected it to two residences (both unoccupied), one of which uses a photovoltaic array, in order to test the effect of the photovoltaic system on other residences connected to the same distribution transformer [88]. The study also concluded that voltages would remain within 5% of standard.

Both these studies indicate that cogeneration should not present any longer term (i.e., lasting longer than 1 minute) voltage regulation problems for utilities. However, sudden and more brief changes in power system voltages can also occur in utility systems -- especially when large power consuming equipment is turned on and off. These changes are caused by the large amount of current that is needed to start-up these motors, thereby removing some power normally used for the remaining load on the circuit. Because these large surges of power can temporarily dim lights, these changes are called "voltage flicker".

Utilities usually confine voltage flicker problems to the customer's own system by requiring some large commercial and industrial customers to use a "dedicated" distribution transformer that connects the customer's load directly to a higher voltage distribution line, substation, or, in some cases, the higher voltage transmission network. Because of this policy, voltage flicker and regulation effects of cogenerators are extremely site and circuit-specific and it is difficult to make any general statement except that most of the commercial and industrial facilities that are potential cogenerators probably already have a dedicated transformer. Therefore, there would be no additional cost for voltage regulation if these customers were to install cogenerators. One way for cogenerators to get around this problem is to install synchronous generators, which already include voltage regulators.

However, if a potential cogeneration facility does not have a dedicated transformer and uses an induction generator (e.g., smaller commercial and residential customers), the cost involved in installing a transformer could be equal to all other interconnection equipment costs combined, and therefore could be a major disincentive to cogeneration.

Even though dedicated transformers may not be an issue for many cogenerators, most utilities protect themselves by including a clause in their interconnection agreement that says: If high or low voltage complaints or flicker complaints result from operation of the customer's cogeneration, such generating equipment shall be disconnected until the problem is resolved [89].

The interim guidelines state that "no induction generators larger than 10 kW should be permitted on single phase secondary services ... due to possible phase unbalances and voltage flicker" without the electric cooperative first studying the situation to ensure that adequate and reliable service to all members will be maintained [90].

5.10.3 **Harmonic distortion**

A third utility concern related to power quality is harmonic distortion. Occasionally, other frequencies beside the standard 50 Hz are transmitted over the power system, usually due to inverters. These cause harmonic distortion. These distortions may be made up of several harmonic frequencies or a single strong frequency. A 50 Hz power signal accompanied with many other harmonic signals may cause several problems for the utility. Excessive harmonic voltages and currents may cause increased heating in motors, transformer relays, switchgear/fuses, and circuit breaker ratings, with an accompanying reduction in service life, or distortion and jitter in TV pictures, or telephone interferences. Also, excess harmonics may produce malfunction in systems using digital and communication equipment. Other possible problems caused by excessive harmonics are the overloading of the capacitors, malfunctioning of computers, and errors in measuring power at the customer's kilowatthour meter.

What constitutes "excessive" harmonics is not well defined. There is no agreement on the exact ratio of distorted signals to the standard signal, a great deal of research is underway to determine this ratio precisely. While further research is underway, both the Electric Power Research Institute (EPRI) and American Public Power Association (APPA) have recommended maximum percentage limits for total systemwide harmonic distortions for both current and voltage signals. EPRI suggests 5% for current harmonics, and 2% for voltage [91]. APPA suggests 10% for current and 2% for voltage [92].

Australian Standard 2279 (1979) defines limitations adopted by SECV in respect of the allowable harmonic voltage distortion produced at any point on the system [97]. In the general case, harmonic voltage distortion produced at the point of common coupling (PCC) by any purchaser installation will be limited to one-third of the values quoted in Table 1 [97].

In the past, most of the major problems of harmonics have occurred with the normal operation of inverters, rather than any malfunctioning of conventional induction or synchronous generators. Since inverters have a high capital cost, they rarely are used and their present impact on utility systems is small in most cases. Because cogenerators produce power at the standard power system frequencies and, therefore, do not use inverters, and because these generators are not normally a significant harmonic source, most engineers feel that harmonic distortion will not increase when cogenerators are interconnected to utility systems.

5.10.4 **Earthing**

Earthing is necessary for safety, to prevent electric shock and to operate devices which disconnect faulty equipment. Earthing is the process of connecting both the metalwork of electrical apparatus and equipment and, in certain cases, the star or neutral of such apparatus to the general mass of earth in order to ensure that there will be an immediate and safe discharge of energy when necessary.

Where h.v. and l.v. equipment are to be connected to a common earth electrode, its value must not exceed 1 Ω [37].

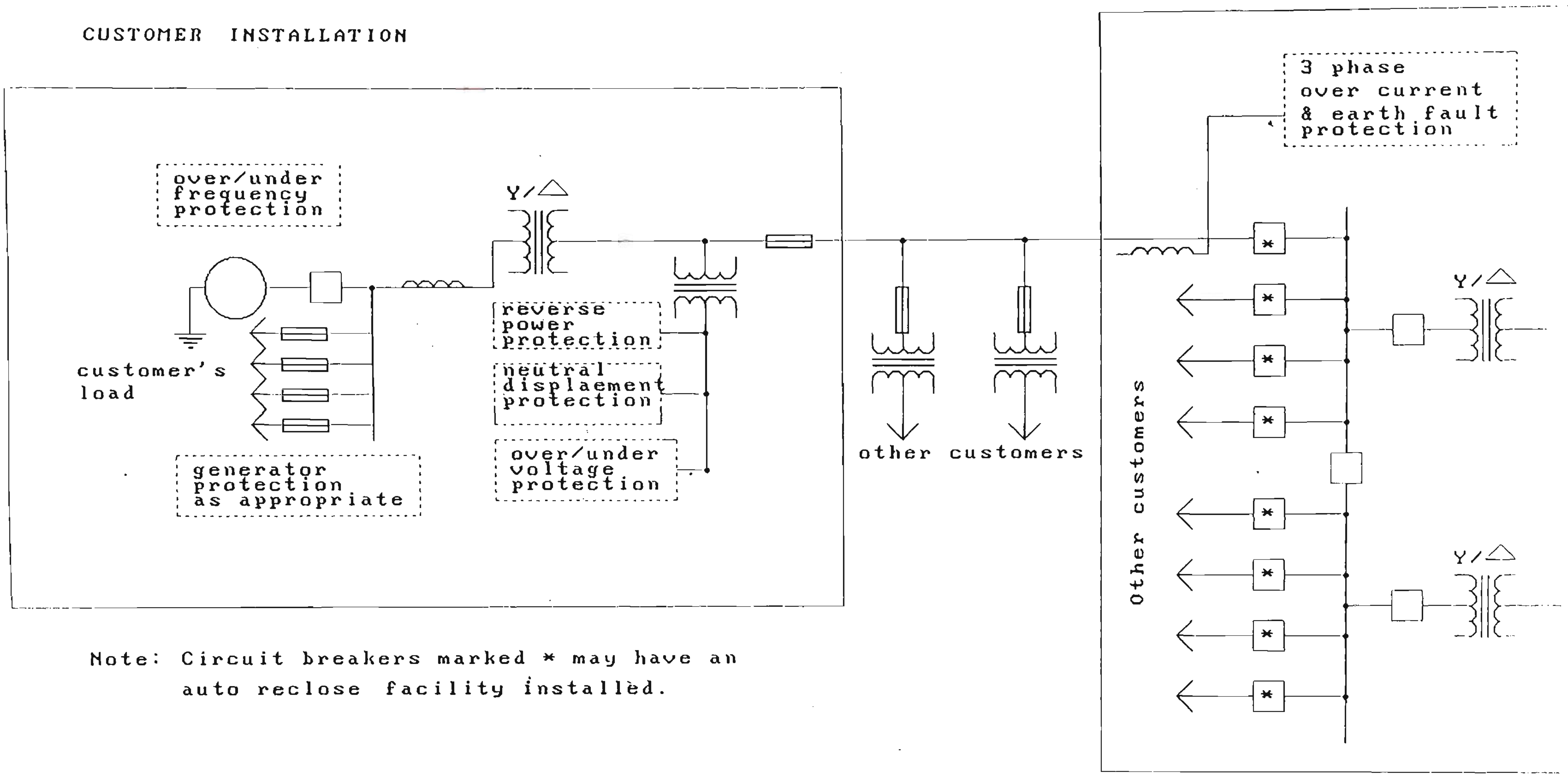
For high voltage system neutral earthing, the utility may use solid or resistor methods. The magnitude of the possible earth fault current will vary widely according to which of these methods is used.

The earthing method employed for the cogenerating plant must provide approximately twice the operating current of the earth fault current protection relay.

Arrangement for earthing of the neutral or star point of the generators will be dependent on the number of generators in use and whether they are to be operated in parallel with each other or the utility's system.

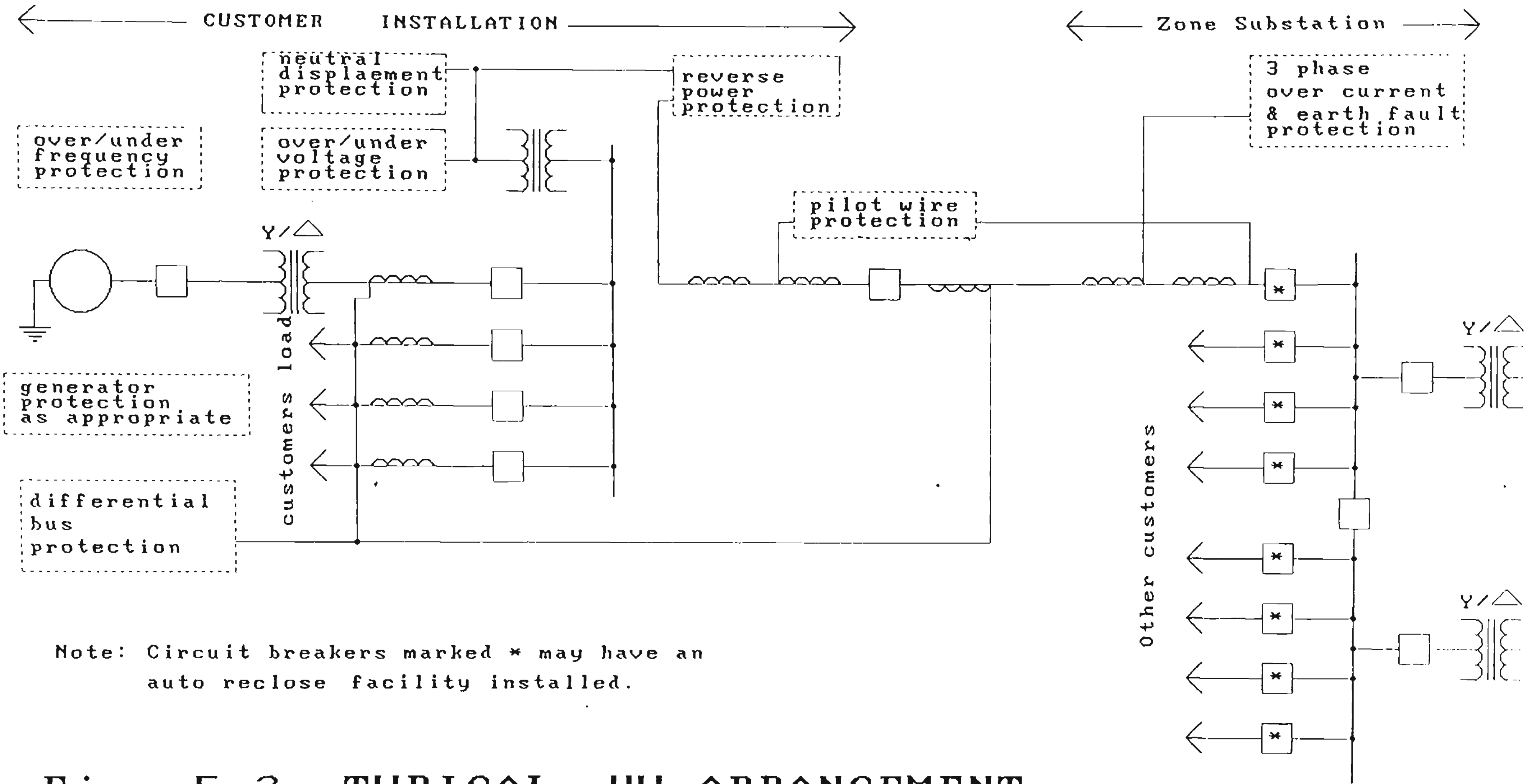
A generator operating independently at h.v. will normally be connected as a three-phase, three-wire machine with its generator star point earthed.

Where a number of generators are being operated in parallel with one another, the h.v. star point of only one machine should be earthed to avoid the risk of circulating third harmonic currents. Arrangements should be made for the provision of automatic transfer of the generator star point earth to another machine if the selected machine is tripped, so as to ensure that the generator installation remains continuously earthed. This is achieved by connecting an automatic switch to the generator star point so that it is opened automatically when the system is earthed on the utility's system. In the event of the loss of the utility's system, the generator's star point can be arranged to close, thereby maintaining an earth on the cogenerator's system. An arrangement which avoids the need for automatic star point earth switching is the use of a busbar connected h.v.



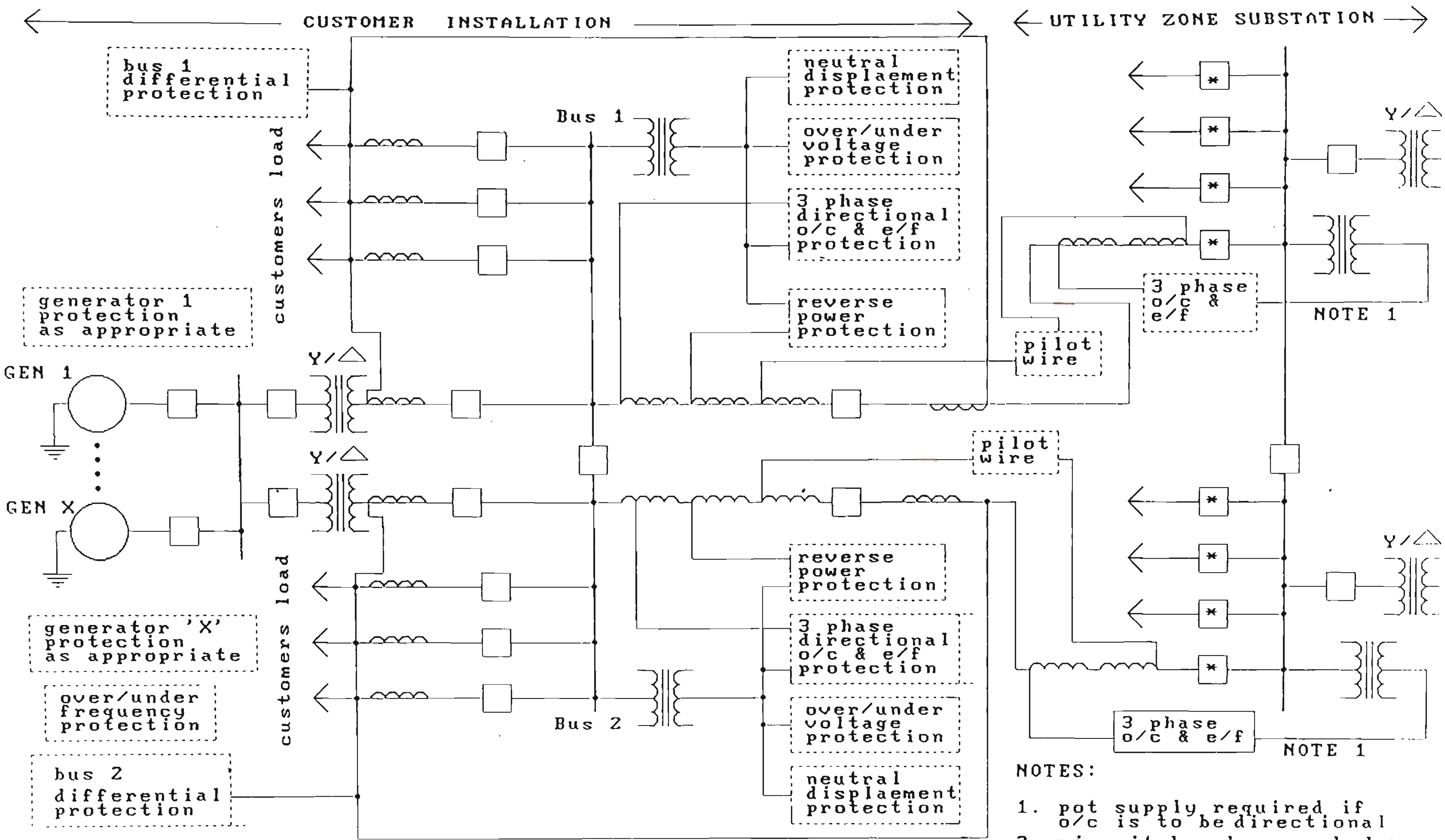
Note: Circuit breakers marked * may have an auto reclose facility installed.

Fig. 5-1. TYPICAL HV ARRANGEMENT – SHARED ZONE SUBSTATION FEEDER



Note: Circuit breakers marked * may have an auto reclose facility installed.

Fig. 5-2. TYPICAL HV ARRANGEMENT - DEDICATED ZONE SUBSTATION FEEDER



NOTES:

1. pot supply required if o/c is to be directional
2. circuit breakers marked * may have an auto reclose facility installed.

Fig. 5-3. TYPICAL HV ARRANGEMENT — DUPLICATE ZONE SUBSTATION FEEDERS

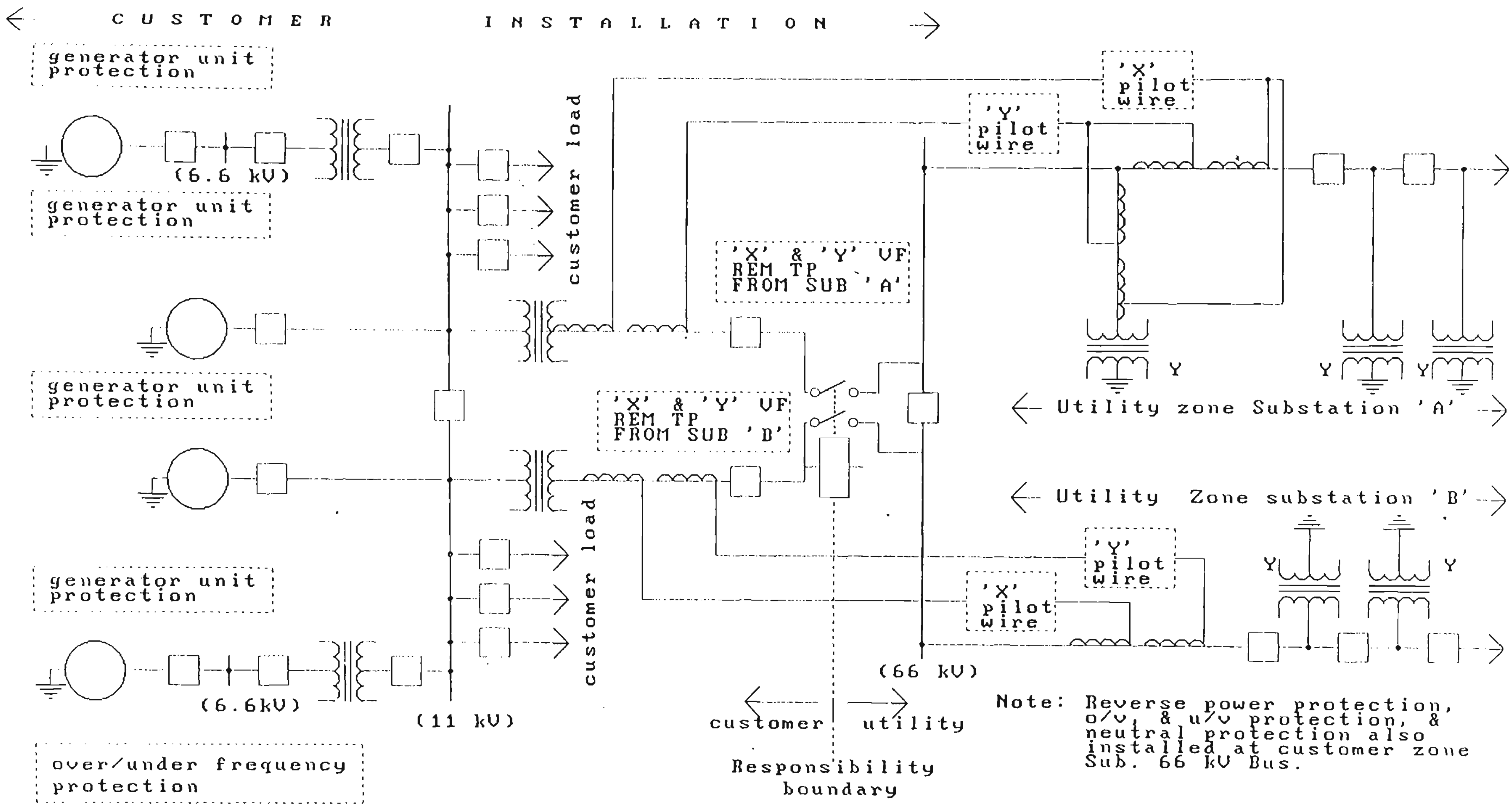


Fig. 5-4. CUSTOMER ZONE SUBSTATION — TYPICAL HV ARRANGEMENT

earthing transformer with all generators connected as three-phase, three-wire machines, the star point earth being derived from the earthing transformer.

For l.v. system neutral earthing, the utility uses solid earthing, but variations in possible earth fault current can be expected due to the sizes of the h.v./l.v. distribution transformers and the earthing electrodes employed.

It is essential to ensure that the neutral busbar is continuously connected to a source of supply, or to a balancer, as well as being earthed. The decision to couple the neutrals of l.v. generators operating in parallel will be dependent on the amount of third harmonic circulation current which would result if all the machine neutrals were coupled. With smaller rated sizes of generator, the harmonic problem increases due to laminations in the machine design which result in the production of non-sinusoidal waveform.

The use of a static balancer to provide the neutral and earth connection for the l.v. four-wire system will mean that neutral of the four-wire will be maintained and earthed irrespective of the number of generators operating on load. The static balancer must be solidly connected to the l.v. busbar. The generators are then connected as three-wire machines.

Manual or automatic switching of the connection between generator star points is not permitted. In some circumstances, the l.v. secondary of a h.v./l.v. transformer may provide this connection, but there is usually a risk this might become disconnected under fault conditions and result in voltages on the neutral which might cause damage to equipment.

5.11 **Protection of cogenerator's plant**

Each generator should be equipped with protection arranged to trip the generator circuit breaker, and where appropriate, suppress the excitation and shut down the prime mover. This protection should operate for all faults between the generator circuit breaker and the generator windings and should provide back-up protection for the customer's installation side of the generator circuit breaker. The installation of additional generator unit protection should be included according to the size and importance of the installation. Where a number of generators operate in parallel, each machine should be equipped with reverse power protection to prevent motoring.

The installation of protection schemes to prevent abnormal voltage and frequencies being generated in the event of disconnection of the utility's system or other abnormal conditions is essential. If more than one generator is installed then under and over voltage, and, under and over frequency protection should be installed on each machine in addition to an overall scheme at the interconnecting tie. Depending upon the generator and transformer connection, neutral displacement protection on the customer's installation may be advisable. The customer is responsible for the design, installation, setting and commissioning of all generator protection equipment.

All faults on the interface between the cogenerator's plant and the utility's network must be cleared rapidly and automatically from all sources of supply.

The protection installed at the cogenerator's end of the interconnecting system shall provide back-up protection for h.v. faults on the utility's network. Similarly, the protection installed at the utility's end of interconnecting system will be capable of providing back-up protection for h.v. faults in the customer's plant.

5.12 Protection of the Private Generation - Supply Network Interconnection Circuits [20]

5.12.1 Interconnection Circuit Protection Requirements

All faults on the interface between the customer's private generating plant and the Supply Authority's network must be cleared rapidly and automatically from all sources of supply.

Fig. 5-1 shows the protection scheme for a shared zone substation feeder for a typical high voltage arrangement. Fig. 5-2 shows a dedicated zone substation feeder for a high voltage arrangement. Fig. 5-3 shows duplicate zone substation feeders for a typical high voltage arrangement. Fig. 5-4 shows customer zone substation for a typical high voltage arrangement.

The protection installed at the customer's end of the interconnecting systems should also provide backup protection for faults on the Supply Authority's network. Similarly, the protection installed at the Supply Authority's end of the interconnecting system will need to be capable of providing backup protection for faults in the customer's plant.

Where there is no agreement to supply the Authority with energy, reverse power protection must be installed by the customer to prevent the private generator supplying the Authority's network.

Where there is an agreement to supply the Authority with energy, reverse power protection must be installed by the customer to ensure that the level of generation is restricted to the agreed export limit. The installation of such protection will enable quicker restoration since tripping due to excess power flow will be confined to the customer's plant.

The Supply Authority may install similar protection at its end of the interconnecting system as backup.

The private generator installation must be able to detect faults on the supply system and open the appropriate circuit breaker(s).

There are no special protection schemes developed for application to the interconnecting circuits to a private generation installation but the presence of generation running in parallel with the supply network frequently requires more complex protection than would otherwise be used. For example, a 22kV distribution supply to a customer without generation would be protected by inverse time overcurrent protection, sensitive earth fault protection and if the circuit is of overhead line construction, autoreclose would be used. Consider now if the customer has private generation operating in parallel with the network. High speed protection such as pilot wire may be required to ensure clearing times are fast enough to meet transient stability critical switching times for the private generator(s). Overcurrent protection may need to be directionally controlled because of the possibility of bi-directional fault current flow and so also the sensitive earth fault protection need the same feature. Earth fault protection requirements will be influenced by the connections and neutral earthing of the interconnecting transformers, the generators or both.

5.12.2 **Autoreclose**

Overhead distribution feeders are generally fitted with autoreclose. If there is a feeder fault and the installation is not isolated from the system in the dead time of the autoreclose, the substation circuit breaker will reclose onto the feeder with the generator out of synchronism. This could result in substantial damage to both the customer's installation and the Supply Authority's equipment.

The generator must not form an island that is supplying other customers. This creates the same problem of reconnecting the generator to the system with the circuit breaker at the substation, which is not intended for this purpose.

5.12.3 **Islanding Operation**

Traditionally, Supply Authority distribution protection schemes are designed on the basis that the zone substation is the only source of power. However, with the advent of distributed generation sources along the distribution feeder, private generation sources can naturally back-feed energy towards the substation. In the case of loss of the zone substation as an energy source, private generation sources will attempt to supply the distribution feeder load.

Several scenarios are then possible. Firstly, the load may exceed capacity of the private generation sources and hence supply will not be maintained. In the ensuring voltage collapse situation, the load consuming plant may be shut down, as well as the generation. In cases where the customer is operating a continuous production process, this is clearly undesirable. Another possibility is that a stable load/generation "island" is formed with the private generation, customer's generation, load and the load of other customers. In this situation, control of voltage and frequency of the energy delivered to customers during the period is determined by the private generator. If there are frequency and voltage excursions outside of acceptable limits, third party customers could suffer damage to their equipment and installations.

Clearly, islanding operation involving third party customers is not acceptable; various techniques are used to prevent it occurring. This can be done either by direct logic using a signalling link between the Supply Authority source zone substation or substations and the private generator, ie via supervisory cable, etc, or by installing suitable relays on the interconnection to detect the islanded situation and initiate isolation of the private generator(s). Relays responding to voltage, frequency, power and reactive magnitude and direction can be used but are not always capable of being set to detect all possible islanding operation situations.

5.12.4 Supply Network Protection Requirements to Allow for Private Generation

It may be necessary for the Supply Authority to carry out protection modifications on its network to allow parallel operation of private generating plant. Each private generating plant installation will require investigation to determine the extent of such modifications. Considerations such as faster operating times to ensure stability, need to convert non-directional schemes to directional and possibly modify earth fault protection to take account of customer installation generator or transformer neutral earthing.

5.12.5 Customer Plant Protection

As for the supply network, adding generation to an existing customer plant will usually require upgrading plant protection schemes to give high speed and selective response for faults within the installation.

5.13 Safety

A major concern with interconnection of dispersed generators is the safety of utility's employees working on transmission and distribution lines. During routine maintenance or repairs to faulty lines, lineworkers must disconnect the generation source from the service area, and establish a visible open circuit. Also, before starting any repairs, they must ground the line and test it to ensure that there is no power flowing in the line.

Disconnecting and grounding the lines is relatively simple when the generation system is centralised and there are few sources of supply. However, with numerous sources of power supply, as with grid-connected cogenerators, the disconnect procedure becomes more complicated and extra precautions may be needed: the utility must keep clear accounts of what dispersed equipment is connected to the system, where that is located, what transmission lines and distribution substation it uses, and where the disconnecting switches are located. To simplify these procedures, many utilities have asked cogenerators to locate their disconnect switches in a certain place, such as the top of the pole for the distribution line going into the customer's building.

Disconnecting and reconnecting a cogenerator is not so simple as just turning the switch off and on, because the cogenerator must be synchronised and brought up to the standard frequency before coming back on-line with the centralised system. Without the synchronisation, both the cogenerator and the customer's appliances could be damaged.

However, the normal operation of circuit breakers that have disconnected a line to clear a fault is to reclose automatically after a fraction of a cycle. If a problem on the line is still present, a cogenerator also will need to be concerned about this reconnection. Most utility's require protective equipment that can disconnect the cogenerator from the line before any reclosing can occur [89].

Another problem with disconnecting cogeneration equipment is self-excitation of the generators. When an induction generator is isolated from the rest of the grid, the absence of the grid-produced power signal usually will shut down the generators. However, if there is sufficient capacitance in the nearby circuits to which the generator is connected, the induction generator may continue to operate independently of any power supplied to the grid. The power signal produced by the isolated self-excited induction generator will not be regulated by the grid's power signal and the customer's electricity-using equipment may be damaged. More importantly, an isolated induction or synchronous cogenerator that reenergised on the customer's side of a downed transmission or distribution line, could endanger utility workers. Self-excitation is less of a problem with synchronous generators.

There are two ways to prevent self-excitation problems. First, the utility can put the corrective capacitors in a central location, in which case disconnecting a cogenerator also will disconnect the capacitors and reduce the possibility of self-excitation [89]. Alternatively, voltage and frequency relays and automatic disconnect circuit breakers can be used to protect both the customer's equipment and utility workers.

5.14 **Metering [90]**

Three types of metering configurations can be used to measure the amount of energy consumed and produced by dispersed generators. The first uses the simple watthour meter that is commonly found outside the homes of today. When a cogenerator is producing power that is sold back to the utility, the watthour meter simply runs backward. As a result, the meter will measure only net power use, thus assuming that there is no difference between the utility's rates for purchasing cogenerated power and its retail rates. If these rates are different (as they are likely to be with most utility systems) then two watthour meters can be used, one that runs in the reverse direction of the other, with the first meter to measure power produced by the cogenerator and the second (equipped with a simple detente or rachet that prevents the reverse rotation of its induction disk) to measure the customer's power consumption. This configuration is recommended by the National Rural Electric Cooperative Association interim guidelines, unless the individual electric cooperative prefers a different metering system.

The third configuration uses more advanced meters to measure a combination of parameters, including power factor correction, energy and time-of-use. Some utilities are asking customers to install these advanced meters in order to understand the relationship between the cogenerator and the central power system better, and to collect the best data possible to help determine future interconnection requirements (such as information on power factor requirements and peak demands) and to decide how to price buyback and backup power. In some cases the utility is supplying the advanced meters and paying for the collection and analysis of data.

CHAPTER 6 CONCLUSIONS AND FUTURE WORK

6.0 Introduction

This chapter offers the main conclusions derived from the observed results. Further it also points out the direction of future work out to enhance this research.

6.1 Conclusions

Transients are caused by faults on the feeders and switching actions of generators. There is a change in the voltage and current wave forms on application of faults. The magnitude of the phase values may suddenly be high in some phases and low in others. It could be nearly zero voltage in a grounded phase and several times full load current flowing into the ground. As all phases are mutually coupled, the presence of any abnormal behaviour is reflected on the other phases. The transient voltages and currents are associated with high frequency, which is caused by parallel resonance of the line inductance and capacitance between lines. The onset of transients may be instantaneous or delayed for a few milliseconds. The delay is associated with high inductive component like the stator windings of an induction generator.

In case of 2-phase to ground fault, the voltages on the faulted phases collapsed to nearly 50%, but the voltage on the unfaulted phase increased markably with its wave shape changed to non-sinusoidal form. The reasons for this unusual behaviour have been mentioned in Section 3.0, Chapter 4.

The magnitude of transients is more spectacular near the fault than at a point far away on the feeder. The impedance of the line causes the transients to diminish.

When transient passes through a Δ/Y transformer, there is phase shift like any sinusoidal wave.

When the induction generator is switched off from the feeders, so that all phases open simultaneously, the magnitude of the transient voltage is more than when the phases open sequentially.

The capacitor banks smooth out the spikes of the transients; as seen from plots 25B and 25E (Chapter 4), which are the plots at Node ERIC with the capacitor banks connected to the feeders and the capacitor banks disconnected respectively.

The relative magnitudes of transients among different phases will vary depending upon the time of the fault occurrence or time of switching of the generator. The scenario of transients is different at the instant the switch is opened at 2 ms than at 4ms.

When the induction generator was switched on to the feeders, the transient ground currents at system source, ie, $\Sigma(i_a + i_b + i_c)$ was found zero on measurement. There was appreciable voltage drop at node P126 (Plot 25, Chapter 4) due to the machine switching on. The customer loads will be subject to this transient voltage drop which can disturb the operation of the equipment. The transient inrush currents at the generator's terminals reaches 1000A (peak), which is much higher than the normal operating current (Plot 25A). Again the capacitor bank wiped out the current spikes at node ERIC (Plot 25C).

In the case of islanding, the transients are of higher values than those caused by faults or switching actions. Also, the rate of decay is very small; it takes several seconds for the transients to subside to normal values.

The induction generator continues to operate, even being disconnected from the power supply system, because there is sufficient capacitance in the nearby circuits. The power produced thus will not be controlled by the grid power signal. It could endanger the utility workers and damage the customer's equipment. Voltage and frequency relays and automatic disconnect circuit breakers can be used to protect both the customer's equipment and utility workers.

Supply-side DSG can be used by utilities as a planning alternative to satisfy distribution needs. For a customer-side DSG, a distribution planning and operating procedures should account for changes in the real distribution loads.

6.2 Future Work

The induction generator in this study is used as a DSG in a radial system; it could also be used in a loop type distribution system. Only one DSG is used in the distribution system; there could be more than one connected at other points.

With increasing penetration of DSGs in utility, studies are required to integrate distribution system with dispersed energy sources, with regard to system planning, operation, and control.

A system consisting of dispersed generation sources should be identified as dispatchable or non-dispatchable. Similarly, it could be categorised based on varying power output level, as in the case of solar cells. Still another way to look upon them is to see the possibility of being switched independently as in case of fuel cells. These will form the basis for requirement analysis and conceptual design.

A study of the current and future generation and storage technology needs to be assessed. Control aspects for the operation of the technology for the above sources with respect to communications, sensors, computer and control hardware, and software needs to be defined.

These two studies could be combined to define a dispersed generation system incorporating power availability, reliability and cost considerations. Thus different systems could be designed and relative cost evaluation could be performed.

The aforementioned studies can be developed into system requirements, operational planning and software tools for integration of dispersed generation to the entire electrical system, taking into consideration all aspects of distribution including control centre, customer systems and billing. The influence of transmission interface to the dispersed generation is also a critical area, as utilities have very stringent requirements. This area requires considerable effort, as the future of all such independent generations is very much dependent on the interface with the main transmission system.

APPENDIX A ALTERNATIVE TRANSIENTS PROGRAM (ATP)

1.0 ATP Formats for putting in the data for computation

Resistances, capacitances, inductances, voltage or current sources, transformers, switches, motor parameters, etc.and the required results are keyed in prescribed format and are entered according to certain rules, which are described below [62]:

1.1 Floating point miscellaneous data cards

This is the first non-comment card which will be assumed to be the floating-point miscellaneous data card, which has the following format (Table 1):

	1	2	3	4	
345678	90123456	78901234	56789012	34567890	12345678
E8.0	E8.0	E8.0	E8.0	E8.0	E8.0
DELTA	TMAX	XOPT	COPT	EPSILN	TOLMAT

Table 1.

DELTAT (cols. 1-8) is the size of the time step of the numerical integration, in seconds. A simulation will be calculated at times that have this separation.

TMAX (cols. 9-16) is the end time of the study, in seconds.

XOPT (cols. 17-24) is a value that indicates whether it is inductance in millihenries or inductive reactance in ohms that is to be keyed on linear branch cards. (1) If XOPT = 0, inductances are to be keyed in millihenries. (2) if XOPT > 0, then the values are to be in at frequency XOPT (in Hertz). In any case, this choice of the miscellaneous data card can be changed at any point of data input by means of a $UNITS card.

COPT (cols. 25-32) is a value that indicates whether it is capacitance in microfarads or capacitive reactance in micromhos that is to be keyed on linear branch cards. (1) If COPT = 0, capacitances are to be keyed in microfarads. (2) If COPT > 0, then the values are to be in micromhos at frequency COPT (in Hertz). In either case, this choice of miscellaneous data card can be changed at any point of data input by means of a $UNITS card.

EPSLIN (cols. 33-40) is the near-zero tolerance that is used to test singularity of the real coefficient matrix within the time-step loop. A blank or zero value means that the value of the STARTUP file will be used. For 64-bit computation which is the most common, a default value of 1.E-8 is typical.

TOLMAT (cols. 41-48) is the near-zero tolerance that is used to test singularity of the complex admittance matrix [Y] of the steady-state, phasor solution. A blank or zero value means that a value equal to that of EPSILN will be used.

The just-described floating-point miscellaneous data card is to be followed by an integer miscellaneous data card shown in (Table 2):

	1	2	3	4	
345678	90123456	78901234	56789012	34567890	12345678
I8	I8	I8	I8	I8	I8
IOUT	IPLOT	IDOUBL	KSSOUT	MAXOUT	IPUN

CONTINUED BELOW . . . .

5	6	7	8
90123456	78901234	56789012	34567890
I8	I8	I8	I8
MEMSAVE	ICAT	NENERG	IPRSUP

Table 2.

IOUT (cols. 1-8) gives the frequency of LUNIT6 (printed) output within the time-step loop, e.g. a value of 3 means that every third time step will be printed. A value of zero or blank is changed to unity, and any even value is increased by one to make it odd. An even output frequency is not allowed because of the likelihood of deception: a saw-toothed oscillation would go unnoticed.

IPLOT (cols. 9-16) gives the frequency for saving solution points of time-step loop for purposes of later plotting, e.g. a value of 3 means that every 3rd timestep will be saved. A value of zero or blank is changed to unity, and any even value is increased by one to make it odd.

IDOUBL (cols. 17-24) controls the LUIT6 output of a table showing network connectivity. A value of zero or blank will suppress such output, whereas unity will produce it. For each node there is shown a list of other nodes to which there are physical connections. Mutual coupling between phases of multiphase elements is ignored in this output, as is the capacitance to ground of π-circuits and distributed-parameter lines. The name "TERRA" is used for ground instead of six blank characters, to improve readability. Ordering of the rows is in order of input, except for the final row, which applies to ground (node number one, which is labelled "TERRA FIRM").

KSSOUT (cols. 25-32) controls the printout of the steady-state phasor solution. There are three basic types of outputs: branch flows, switch flows, and nodal injections. These can be controlled by the value of KSSOUT as follows:

0 ===> No steady-state solution printout.

1 ===> Print the complete steady-state solution: branch flows, switch flows, and source injections.

2 ===> Print switch flows and source injections, but not branch flows.

3 ===> Print branch flows by requested by column 80 punches, switch flows, and source injections.

MAXOUT (cols. 33-40) controls printout of extrema at the completion of the simulation. Keying a zero or blank will suppress such computation and output, whereas the value unity will produce it.

IPUN (cols.41-48) is used to request the input of an extra, following card to vary the printout frequency. Use a value of "-1" to request such an extra card, or zero or blank if no such extra card is wanted. Alternatively, use "CHANGE PRINTOUT FREQUENCY" to accomplish the same thing.

MEMSAV (cols. 49-56) controls the dumping of EMTP memory onto disk at the end of the simulation for subsequent use with the "START AGAIN" request. Key "1", if such memory saving is desired, or zero or blank if it is not. For the single, deterministic simulation, the table saving is done at time TMAX (floating-point miscellaneous data parameter). For Monte Carlo ("STATISTICS") studies, this is upon completion of energisation number NENERG (integer miscellaneous data parameter). Memory saving is a powerful and useful tool of the production user.

ICAT (cols. 57-64) is to be left blank (or zero) if there is to be no parameter saving of raw plot data points that might be written to I/O channel number LUNIT4 during the simulation. But should such parameter be desired, then a positive value is required:

1 ===> Save the points, but ignore any batch-mode plot cards that might be present.

2 ===> Save the points, and also honour any batch-mode plot cards that might be present.

For most computers, the disk file in question will be internally named, based on the date and the time of day when the simulation began. See the plot file heading for such details. Such details are controlled by installation-dependent SUBROUTINE SYSDEP, so it is not possible to be much more specific.

NENERG (cols. 65-72) is to be left blank (or zero) for single, deterministic simulations. But for "STATISTICS" or "SYSTEMATIC" data cases, this is to be the total number of energisations (exclusive of any possible, extra, base-case solution). Append a minus sign if "SYSTEMATIC" usage is involved --- a flag to distinguish such a case from Monte Carlo studies. Also, an extra "STATISTICS" or "SYSTEMATIC" miscellaneous data card must follow.

IPRSUP (cols. 73-80) is normally left blank or zero. If keyed as a positive value, this is the diagnostic printout control that is to be applied to each UTPF overlay. But since the user normally will want to control such output overlay by overlay, he should instead use the "DIAGNOSTIC" special-request card.

1.2 **Branch card for uncoupled, lumped, series R-L-C branch**

The following rules must be observed in entering data for the above-type branch:

(1) Punch the branch-type "ITYPE" of columns 1-2 as zero or blank.

(2) specify the two terminal nodes of the branch by 6-character alphanumeric node, using fields of cols. 3-8 and cols. 9-14. One node of the branch may be grounded (field for node name left blank).

(3) At least one of the values R, L, C of the branch must be $\neq 0$.

(4) When series branch has no R or L, then the set R = 0 or L = 0. When no capacitance, set C = 0 (program regards this as $1/\omega C = 0$).

(5) If branch data R, L, C are identical with those on a preceding branch card, then the following storage saving option may be used:

Repeat node names of that preceding reference branch in the provided columns 15-26 in the same sequence and leave R, L, C blank.

If the reference branch has other branches in parallel, it is not clear which of them should be the reference branch. Therefore, the first branch among parallel branches with identical node-name pairs shall always be the reference branch. It should be noted that two branches "NODE-A" to "NODE-B" and "NODE-B" to "NODE-A" do not have identical node-name pairs (order is reversed) and can therefore be used as two distinct reference branches.

(6) The numerical values for parameters R, L, and C are in the following units. Recall that variables "XOPT" and "COPT" come from the floating-point (first) miscellaneous data card.

(a) Specify R in ohms.

(b) Specify L as (i) inductance L in mH if XOPT = 0.

(ii) reactance ωL in ohms at frequency $\omega/(2\pi)$ = XOPT, if XOPT $\neq$ 0.

(c) Specify capacitance C_{ij} as

(i) capacitance C in μF if COPT = 0.

(ii) susceptance ωC in μmhos at frequency $\omega/(2\pi)$ = COPT, if COPT $\neq$ 0.

(7) Output options for printing/or plotting:

Punch "1" in column 80 to get branch current;

Punch "2" in column 80 to get branch voltage;

Punch "3" in column 80 to get both branch voltage and current.

Punch "4" in column 80 to get branch power and energy consumption.

1.3 **Branch cards for Pi-equivalents**

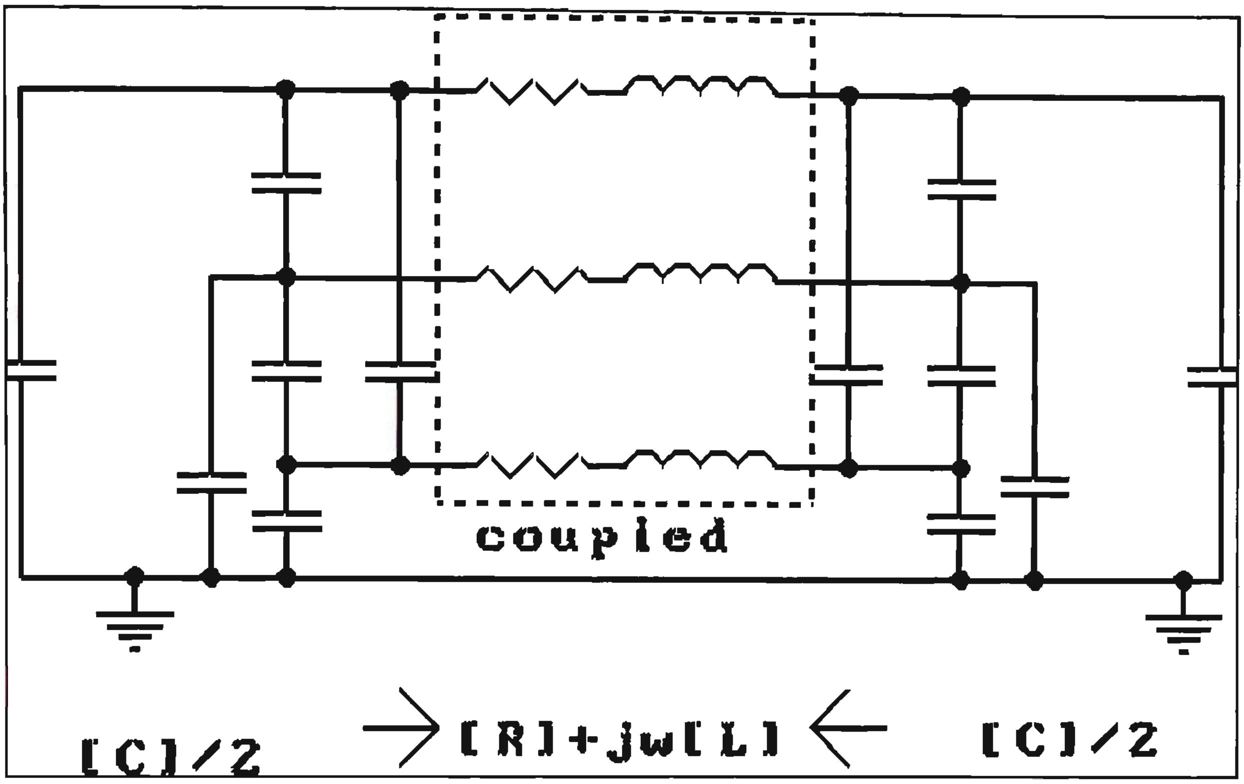


Fig. A-1. Short section of distribution feeder

This class of branches provides for the representation of lumped-element resistance, inductance, and capacitance matrices. All matrices are assumed to be symmetric, and it will be noted that [C] is split in two, with half of the total on each end of the branch. By connecting many such short sections in series, keeping track of the actual transpositions (if any), a model can be automatically calculated by "LINE CONSTANTS". Yet, because of increased running time and memory requirements, this modelling should generally be used only as a last resort, where distributed-parameter lines are believed to be inadequate.

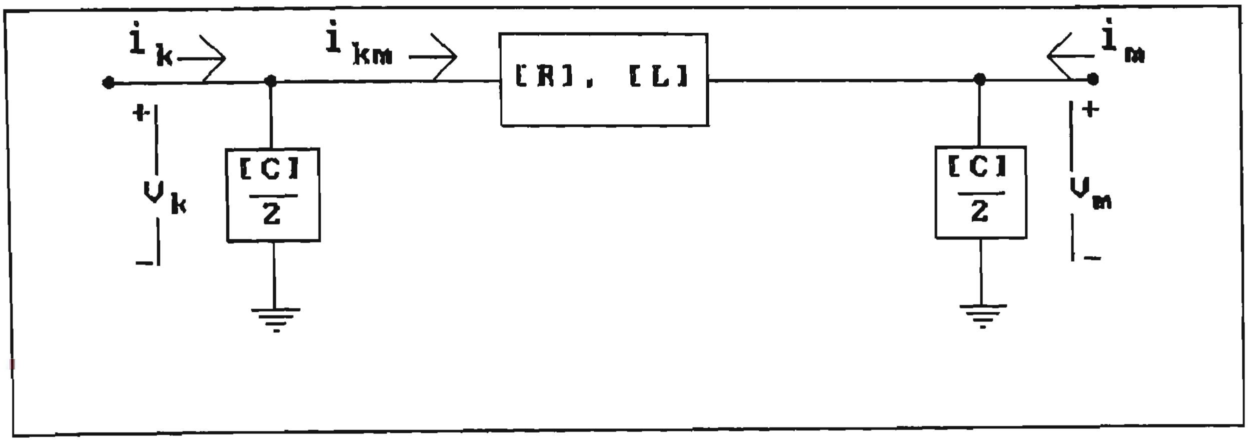


Fig. A-2. Pi-Equivalent circuit for the circuit of Fig. A-1

For N conductors the associated differential equations are:

$$v_k - v_m = [L]\,\frac{d_{im}}{dt} + [R]\, i_{km} \tag{41}$$

$$i_k = \frac{1}{2}\,[C]\,\frac{dv_k}{dt} + i_{km} \tag{42}$$

$$i_m = \frac{1}{2}\,[C]\,\frac{dv_m}{dt} - i_{km} \tag{43}$$

Elements of the matrices [R], [L], and [C] have the following meaning in the sinusoidal steady state at frequency ω:

diagonal $R_{ii} + j\omega L_{ii}$ = self impedance of branch i (impedance of loop "branch i--ground return"); off-diagonal $R_{ik} + j\omega L_{ik}$ = mutual impedance between branches i and k. ($R_{ik} \neq 0$ with nonzero ground resistivity.) diagonal C_{ii} = sum of capacitances connected to the nodes at both ends of branch i; off-diagonal C_{ik} = negative value of capacitance from branch i to branch k.

To enter data for N-conductor Pi-equivalent branch the following rules are to be observed:

(1) Number the phases 1, 2, ..., N. Make out one branch card (plus possible continuation cards) for each phase, and stack them in this sequence. Indicate this sequence by punching 1,2, ..., N in columns 1-2 of these cards. The value of N should not exceed 40.

(2) Specify each of the phases 1,2, ..., N by the names of the nodes at both ends; use cols. 3-8 and 9-14. Nodes may be grounded (indicated by blank field name) if desired.

(3) At least one of the matrices [R], [L] must be nonzero. Matrix [C] may be zero.

(4) If branch data are identical with those on a preceding set of N branch cards, then the following storage-saving option may be used:

Repeat node names of the first branch of that preceding set of branch cards in the provided columns 15-26 of the first branch in the same sequence and leave R, L, C blank. On the 2nd, 3rd, ..., N-th branch card only the information in column 1-14 is used.

(5) The numerical values for [R], [L], and [C] are in the following units. Recall that variables XOPT and COPT come from the floating point miscellaneous data card.

(a) Specify R_{ij} in ohms.

(b) Specify inductances L_{ij} as

(i) inductance L in mH if XOPT = 0.

(ii) reactance ωL in ohms at frequency $\omega/(2\pi)$ = XOPT if XOPT $\neq$ 0.

(c) Specify capacitance C_{ij} as

(i) capacitance C in μf if COPT = 0.

(ii) susceptance ωC in μmhos at frequency $\omega/(2\pi)$ = COPT if COPT $\neq$ 0.

(6) Matrices [R], [L], and [C] are symmetrical, so only need be specified on and below the diagonal. When one card is not sufficient for all required R-L-C values (for the fourth and later phases), then "continuation cards" are used, with cols. 1-26 left blank.

(7) No branch current output is possible for this branch type. However, the branch voltage can be obtained on the first two phases (where column 80 of the card is not being used) by punching a "2" in column 80.

1.4 Rules for entering data for three-phase transformer

(1) The first data card for the component is to be punched according to the following format:

"Special-request-word" field is punched with the 12 characters "TRANSFORMER " in columns 3-14.

(2) BUS3 (cols. 15-20) to be left blank, unless using reference-component procedure.

(3) i_{steady} (cols. 27-32) shows the magnetising component of the current at a certain point in the flux-current plane used to define the linear inductance.

(4) ψ_{steady} (cols. 33-38) is the flux corresponding to the above current.

(5) BUSTOP (cols. 39-44) is a 6-character alphanumeric name

for the internal bus at the top of the magnetising branch. This name uniquely identifies the transformer.

(6) R_{mag} (cols. 45-50) is the constant linear resistance which parallels the magnetising reactance, accounting for core loss. The specification is in ohms, with a value of zero or blank taken to mean $R_{mag} = \infty$.

(7) Assuming the reference name BUS3 is left blank, the above card is followed by cards that define the saturation characteristic of the magnetising branch. In this card the origin is an implied point, not to be input explicitly. Current and flux pairs are punched in columns 1-16 and 17-32 respectively. Only one pair of values are input in the monotone-increasing order (movement away from the origin).

(8) The final point on the characteristic merely defines the slope of the final segment, which is assumed to extend to infinity. The last card is followed by a terminating card with "9999" punched in columns 13-16.

(9) For each transformer winding k (k = 1,2,..., N), a winding card is input using the following format:

(10) Winding numbers (1,2,...) must be placed in natural order in columns 1-2, with winding 1 first, winding 2 next, etc.

(11) Six character node names of the busses to which the winding in question is connected in columns 3-8 and 9-14 respectively. As usual, a blank field is taken to mean ground.

(12) Resistance of the winding in ohms and leakage reactance in ohms are entered in columns 27-32 and 33-38.

(13) Rated winding voltage of the winding in kV is entered in columns 39-44.

(14) Only for winding 1, a 1-punch in column 80 will make branch current i_1 an output variable.

1.5 **Rules for entering data for switching**

These rules apply to conventional time-controlled switches.

(1) The switch type code (cols. 1-2) is zero. Either the zero may be punched, or the field may be left blank.

(2) Specify the two terminal nodes by names in cols. 3-8 and 9-14 respectively. One of the nodes may be ground, indicated by a blank field for the associated name.

(3) No switch is permitted between two voltage sources, or between one voltage source and ground.

(4) If a switch connects a voltage source to a current source, then the current source is ignored whenever the switch is closed.

(5) If transients start from a non-zero ac steady-state condition, make closing time less than zero for time-controlled switches which are closed in the ac steady-state condition.

(6) Closing time of the switch, T_{close}, in seconds, is entered in columns 15-24.

(7) Opening time of the switch, T_{open}, in seconds, is entered in columns 25-34.

(8) The "MEASURING" switch is used to monitor current, or power and energy in places where these quantities are not

otherwise available. This is a different card from the one described above. The terminal nodes of the switch are entered as described above in (2). To request a measuring switch, the key word "MEASURING" is punched in columns 55-64 of the switch card. The 80-th column is punched for output purposes.

1.6 **Modelling induction generator and rules for entering data**

The system used for the simulation of a three-phase induction generator is shown in Fig. 3. The connection to a three-phase supply system is shown at terminals BUSA2, BUSB2, BUSC2; marked A2, B2, C2 on the diagram.

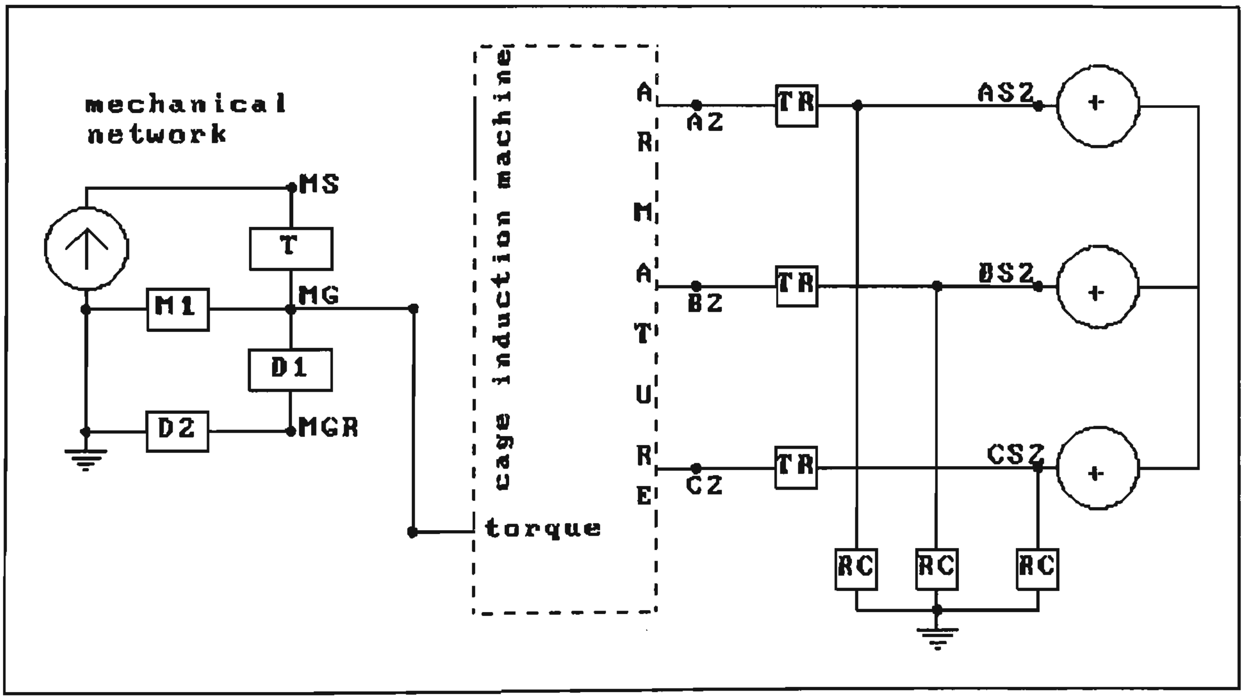


Fig. 3: System diagram of a 3-phase induction generator

The mechanical network is the equivalent circuit for the induction generator and is shown on the left side of Fig. 3. The source of torque is shown by a current source, the lumped shaft masses by a capacitor and the viscous damping load by resistors.

The equivalent torque source is specified to be a current source by the entry of "-1" in columns 9 and 10. The frequency of the source is set to 0.00001 Hz; so, over the interval of 0.02 second, covered by the simulation, the amplitude is essentially constant; and the mechanical torque (node MS) is constant. The network elements are defined as follows:

(a) D1, D2,---resistor equivalents of the viscous load;

(b) M1 -------capacitive equivalent of the mass on the rotor shaft;

(c) RC -------large resistors which provide the connectivity required by the EMTP;

(d) T --------resistor used for torque sensing;

(e) TR -------terminal-current sensing resistors.

Machines modelled in the U. M. (Universal Machines) algorithm are defined to be the sources of EMTP Type 19.

The rules for entering the data are:

(1) Enter 19 in columns 1-2 and UM in columns 4-5.

(2) In the next card enter a blank in col. 1 and 1 in col. 2.

The latter shows that automatic initialisation is to be carried out.

(3) A blank appears in col. 15, indicating that compensation, rather than prediction, is to be used in interfacing the 3-phase network.

(4) A blank card is required for termination of the General Specification group.

The data in the machine table conveys the following information:

(a) <u>Record one:</u>

3 in cols. 1-2 implies work with U.M. Type ;

1 in cols. 3-4 implies one d-axis field coil;

1 in cols. 5-6 implies q-axis field coil;

1 in col. 7 implies output, the electromechanical torque, TQGEN;

1 in col. 8 implies output, the absolute rotor speed, OMGEN;

1 in col, 9 implies output, the angle of the rotor relative to the stator, THETAM;

BUSMG in cols. 10-14 implies as the connection point of electromagnetic torque to the mechanical network;

4 in cols. 22-23 implies a 4 pole-pair machine;

0.1885 in cols. 52-65 implies convergence margin for rotor speed;

50.0 in cols. 66-79 implies default system frequency used.

(b) <u>Record 2:</u>

Blank in cols. 1-14 implies initial condition on the mechanical speed is not used;

0.17952 in cols. 15-28 implies the value of the unsaturated d-d-axis inductance;

blank in col. 29 implies no d-axis saturation.

(c) Record 3:

Blank in cols. 1-14 implies initial condition on the torque angle is not used;

0.17952 in cols. 15-28 implies the value of the unsaturated q-axis inductance;

blank in col. 29 implies no q-axis saturation.

(d) Record 4:

-2.5697 in cols. 1-14 shows the initial percent slip and the minus sign implies that the induction machine is generating, not motoring.

Blanks in cols. 15-34 imply an induction machine is simulated;

BUSMS in cols. 35-40 implies the node of the mechanical network where electromagnetic torque is connected and the type-14 source is adjusted to meet the initial condition of -2.5697 percent slip.

(e) Record 5:

BUSA2 in cols. 29-34 implies the network node to connect the winding of armature phase A of the U. M. model;

blanks in cols. 35-40 imply the ground for connecting the other terminal of phase A;

blanks in cols. 1-14 and 15-28 imply that zero-component calculations will not be carried out, otherwise values of resistance and inductance would be entered respectively.

(f) Record 6:

BUSB2 in cols. 29-34 implies the network node to connect the winding of armature phase B of the U. M. model;

blanks in cols. 35-40 imply the ground for connecting the other terminal of phase B;

0.087 in cols. 1-14 implies the direct-axis armature-coil resistance;

0.00709 in cols. 15-28 implies direct-axis armature coil leakage inductance in henry.

(g) Record 7:

BUSC2 in cols. 29-34 implies the network node to connect the winding of armature phase C of the U. M. model;

blanks in cols. 35-40 imply the ground for connecting the other terminal of phase C;

0.087 in cols. 1-14 implies the quadrature-axis armature coil resistance;

0.00709 in cols, 15-28 implies quadrature-axix armature coil leakage inductance in henry.

(h) Record 8:

0.238 in cols.1-14 implies direct axis field-coil resistance;

0.00378 in cols. 15-28 implies field coil leakage inductance in henry.

blanks in cols. 29-34 and 35-40 imply the direct-axis field coil is short-circuited to ground .

(j) <u>Record 9:</u>

The quadrature-axis values are identical to the direct-axis values and are entered in the same way. Also, they are short-circuited to the ground like the direct-axis coil.

(k) <u>Record 10:</u>

The blank record following the coil-table records terminates the input for machines modelled through the U. M. algorithm.

1.7 **Rules for entering sinusoidal voltage sources**

(1) Enter 14 in cols. 1-2, which implies the sinusoidal voltage source.

(2) SYSTA in cols. 3-8, which implies the node name of phase A of the sinusoidal source connected to the network.

(3) A blank or -1 in columns 9-10 implies a voltage or current source respectively.

(4) 17962.9 in cols. 11-20 implies the peak value (amplitude) in volts of the sinusoidal source.

(5) 50.0 in cols. 21-30 implies the frequency of the sinusoidal source.

(6) -90.0 in cols. 31-40 implies the phase angle of the phasor A in degrees. For phases B and C these values are respectively -210.0 and 30.0.

(7) -1 in cols. 61-70 implies the program will automatically

precompute the correct phasor conditions, and will use these as initial conditions to begin the ensuing simulation.

(8) The above entries are repeated for phases B and C, where SYSTB and SYSTC are entered in place of SYSTA. The phase angles for these phases are entered as mentioned in (6).

BIBLIOGRAPHY

1. BAUGHMAN, MARTIN L., EISNER NEIL A., MERRILL, PAUL S.: "Optimizing cogeneration and thermal storage systems: An engineering economics approach", IEEE Transactions on Power Systems, Vol. 4, No. 3, August 1989.

2. JASKE, MICHAEL R.: "Comparison criteria for use in long run resource planning.", IEEE Transactions for Power Systems, VOl, No. 3, August 1988.

3. NATRAJAN, R., GENTZLER, DAVID B.: "Adoption of electromagnetic transient program (EMTP) on personal computers", IEEE Transactions on Power Systems , Vol. 4, No. 4, October 1989.

4. WHIPPLE, D. P., TREFNY, F. J.: "Current electric system operating problems from a cogenerator's viewpoint", IEEE Transactions on Power Systems, Vol. 4, No. 3, August 1989.

5. KIRKHAM HAROLD, KLEIN JOHN.: " Dispersed storage and generation impacts on energy management systems", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 2, February 1983.

6. STYS, RUDOLPH D., QUADE, ARTHUR W.: "A cogeneration overview by a large electric and gas utility", IEEE Transactions on Education, Vol. E-24, No.3, August 1981.

7. MELIOPOULOS, SAKIS,P.: "Computer-aided instruction of energy source utilisation problems", IEEE Transactions on Education, Vol. E-24, No. 3, August 1981.

8. HARMON, ROBERT A.: "The keys to cogeneration and combined cycles", Mechanical Engineering, February 1988.

9. KERN JOHN G. AND FELDMAN, STEPHEN : "Fuel cell system produces power and steam from coal", Journal of Energy Engineering, Vol.110, No. 1, March 1984.

10. REASON JOHN : "Making Interconnection work", Power June 1982.

11. HALL, MARK : "Cogeneration : The Promise Is Now", Mechanical Engineering, August 1981.

12. Kirkham, H., Nightingale, D., Koerner, T. : "Energy Management system design with dispersed storage and generation", IEEE Transaction on Power Apparatus and Systems, Vol. PAS-100, No. 7, July 1981.

13. GISH, W.B., FERRO, W.E., GREUEL, S. : "Ferroresonance and loading relationships for DSG installations", IEEE Transactions on Power Delivery, Vol. PWRD-2, No. 3, July 1987.

14. PARK, GERALD L., ZASTROW, ORVILLE W. : "Interconnection Issues Concerning Consumer-owned wind electric generators", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 7. July 1982.

15. DUGAN ROGER C.,RIZY DWIGHT T.: "Electric distribution protection problems associated with the interconnection of small, dispersed generation devices", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-1, No. 6, June 1984.

16. DUGAN, R.C., THOMAS, S.A., RIZY, D.T. "Integrating dispersed storage and generation (DSG) with an automated distribution system", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 6, June 1984.

17. McINTYRE, R.J., WATTS,K.W., CULLEN, R.N. "Cogeneration and sugar factory", Journal of Electric and Electronics Engineering, Australia -- IE Aust. & IREE Aust., Vol. 5, No. 1.

18. FEERO W.E., GISH, W. B. : "Overvoltages caused by DSG operation: Synchronous and induction generators", IEEE Transactions on Power Delivery, Vol. PWRD-1, No. 1, January 1986.

19. GISH, WILLIAM B., : "Small induction generator and synchronous constants for DSG isolation studies", IEEE Transactions on Power Systems, Vol. PWRD-1, No. 2, April 1986.

20. Kalam, A., Coulter R., Gubbins, J., Klebanowski, A., McDonald, H., : "Protection and control of private generation", 1992 ESAA short course on power system protection, pp 13.1 - 13.40.

21. THOMAS R.J., WANG, XIFAN : "The control of large wind-farm-induced voltage fluctuations", IEEE Transactions on Energy conversion, Vol. EC- 2, No. 1, March 1987.

22. DESROCHERS G., BLANCHARD M., SUD S. : "A Monte-Carlo simulation method for economic assessment of the contribution of wind energy to power systems", IEEE Transactions on energy conversion", Vol. EC-1, No.4, December 1986.

23. IRISA T., TAKATA, S.,UEDA R.: "Dynamic performance of self-excited induction generator with voltage controller", IAS annual meeting 1980, part 2, Published by IEEE, New York.

24. CHEN MO-SHING, DILLON WILLIAM E. : "Power System Modelling", Proceedings of the IEEE, july 1974.

25. DUGAN C., JEWEL WARD T., ROESLER DIETRICH J. : "Harmonics and reactive power from line-commutated inverters in proposed photovoltaic subdivision", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-102, No. 9, September

1983.

26. ONG C.M. : "Operational behaviour of line-commutated photovoltaic systems on a distribution feeder", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 8, August 1984.

27. GIBBONS JOHN H. : "Industrial and commercial cogeneration", Office of Technology Assessment, Washington D.C.

28. RIZY D.T., JEWEL W.T., STOVAL D.T. : "Operation and design considerations for electric distribution systems with dispersed storage and generation (DSG)", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-104, NO. 10, October 1985.

29. MERRILL HYDE M., SCHWEPPE FRED C., WHITE DAVID C.: "Energy strategy planning for utilities, Part 1, Smarte Methodology", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 2, February 1982.

30. APERJIS DIMITRIOS, WHITE DAVID C., SCHWEPPE FRED C., MATTLER MATHEW, MERRILL HYDE M. : "Energy strategy planning for electric utilities part 2, Smarte Methodology case study", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 2, February 1982.

31. PRINCE, W. R., COMFORT, R. W., FINLEY, L. A., KRITIKSON, J. G., MEYER, F.J., ROSENBERG, L. D., TREFNY, F. J.: "Current operating problems associated with non-utility generators", IEEE Transactions on Power Systems, Vol. 4, No. 4, October 1989.

32. BURKE WILLIAM J., SCHWEPPE FRED C., LOVELL BRYNE E. : "Trade off methods in system planning", IEEE Transactions on Power Systems, Vol.3, No. 3, August 1988.

33. SODERHOLM, LEO H.: " Cogeneration interface update", Proceedings: 1984 Rural Electric Power Conference, Nashvillo, TN, USA conference, May 1984.

34. PHADKE ARUN G. : "Digital simulation of electrical transient phenomena", IEEE Tutorial Course, 81EHO173-5-PWR.

35. MERRILL, H.M., SCHWEPPE F.C. : "Strategic planning for electric utilities: Problems and analytic methods", INTERFACES 14:1 January - February 1984.

36. JACKSON RONALD M., YUEN MOON H. : "Integrating of utility distribution system into a refinery plant generation/distribution system network at UNOCAL Los Angeles refinery", Industrial Applications Society, 35th Annual Petroleum and chemical industry conference, Dallas, Texas, USA, Sept. 1982.

37. WOODBURY F. A. : "Grounding considerations in

cogeneration", Proceedings of Petroleum and Chemical Industry Conference, September 1984.

38. TOMSIC MIHA, AL-MANSOUR FOUD. : "Optimal operation of cogeneration plants in industry", Energy Vol. 14, No. 8, pp. 483- 490, 1989.

39. MANZONI G., SALVADERI L., TASCHINI A., VALTORTA M. : "Cogeneration and renewable sources : their impact on the electric system", International Conference on Large High Voltage Electric Systems (CIRGE), Proceedings of the 28th Session.

40. COOPER D., GRAVES A. : "Should you cogenerate electricity today?", Hydrocarbon processing, July 1988.

41. POWELL LOUIE J. : "An industrial view of utility cogeneration protection requirements", IEEE Transactions on Industry applications, Vol. 24, No.1, January/February 1988.

42. LEWIS P.A., MALLARD S.A., WOOD W., : "Experience of a large north-eastern utility in assessing and applying dispersed energy technologies", Public Service Electric and Gas Company, United States.

43. McGRANAGHAN, M. F., DUGAN, R.C., KING, JACK A., JEWEL, W.T.: "Distribution feeder harmonic study methodology", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-103, No. 12, December 1984.

44. MERRILL, H.M., BHAVARAJU M.P. : "Transfer capability objectives: A strategic approach", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-104, No. 5, May 1985.

45. PRINCE W.R., NIELSEN E.K., McNAIR H.D. : "A survey of current operational problems", IEEE Transactions on Power Systems, Vol.4, No. 4, October 1989.

46. KIRBY KEVIN A., RICH JOHN F., MAHONEY PAUL J. : "Cogeneration system evaluation: a case study", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-100, No. 6, June 1981.

47. MERRILL HYDE M. : "Cogeneration -- A strategic evaluation", IEEE Transactions on Power Apparatus and Systems, Vol, PAS-102, No. 2, February 1983.

48. VACHTSEVANOS G.J., KALAITZAKIS K.C. : "A methodology for dynamic utility interactive operation of dispersed storage and generation devices", IEEE Transactions on Power Systems, Vol. PWRS-2, No. 1, February 1987.

49. CHANDRA KRISHNA, PALLEY JAY N. : "Cement plant cogeneration opportunities", IEEE transactions on industry applications, Vol. IA-19, January/February 1983.

50. BILLINTON R., CHOWDHURY A. : "Generation adequacy impacts of cogeneration sources", IEE Proceedings, Vol. 137, Pt. C, No. 2, March 1990.

51. POWER SYSTEM RELAYING COMMITTEE : "Intertie protection of consumer- owned sources of generation, 3 MVA or less", IEEE Transactions on Power Delivery, Vol. 5, No. 2, April 1990.

52. KIRKHAM H., DAS R. : "Effects of voltage control in utility interactive dispersed storage and generation systems", IEEE transactions on Power Apparatus and Systems, Vol. PAS-103, No. 8, August 1984.

53. PUTTTGEN HANS B., MACGREGOR R. PAUL : "Optimum scheduling procedure for cogenerating small power producing facilities", IEEE Transactions on Power Systems, Vol. 4, No. 3, August 1989.

54. DIALYNAS E.N. : "Impact of cogeneration and small power producing facilities on the power system reliability indices", IEEE Transactions on Energy Conversion, Vol. 4, No. 3, September 1989.

55. DALEY JAMES M. : "Design considerations for operating on-site generators in parallel with utility service", IEEE Transactions on Industry Applications, Vol. IA-21, No. 1, January/February 1985.

56. HOGWOOD EDWARD E. JR., RICE DAVID E. : "The electrical aspects of cogeneration system design", IEEE Transactions on Industry Applications, Vol. IA-23, No.4, July/August 1987.

57. BONNARD G. : "The problems posed by electrical power supply to industrial installations", IEE Proceedings, Vol. 132, Pt. B, No.6, November 1985.

58. KNIGHT U.G., BOOTH ROBERT R., MALLARD S.A., LEWIS DAVID M. : "Computers in Power System Planning", Proceedings of the IEEE, Vol. 62, No. 7, July 1974.

59. OONG B.J., JEANS T. E. : "Waveform distortion in Electricity Distribution Systems", Electric Energy conference, Sydney, September 1977.

60. NAGEL THEODORE J.: "Operating a major electric utility today", Science, Vol. 201, 15 September 1978.

61. POWER SYSTEM RELAYING COMMITTEE : "Considerations in protecting the consumer-utility interconnection", IEEE transactions on Industry Applications, Vol. IA-20, No. 3, May/June 1984.

62. "Alternative Transient Program Rule book", K. U. Leuven EMTP Center.

63. CHESTNUT HAROLD, CHEM ARTHUR C.M., KIRKHAM HAROLD, BAHRAMI KHOSROW A., STRNISA FRED V. : "Monitoring and control requirements for dispersed storage and generation", IEEE Transactions on Power Systems, Vol. PAS- 101, No. 7, July 1982.

64. DISTRIBUTION ENGINEERING DEPARTMENT, STATE ELECTRICITY COMMISSION OF VICTORIA. : "Technical conditions for the operation of private generators with the SECV system".

65. STATE ELECTRICITY COMMISSION OF VICTORIA : "Guide to cogeneration in Victoria".

66. DOMMEL HERMANN W., BHATTACHARYA SUBROTO, BRANDWAJN VLADIMIR, LAUW HIAN K., MARTI LUIS : "Electromagnetic transients program reference manual", Bonneville Power Administration, Portland, U.S.A.

67. Power Talk, First issue of newspaper published by SECV.

68. National Energy Advisory Committee (1983). Electricity in the Australian Energy Market. report No. 19.

69. TSAO T. C., TSANG N. F. : "The squire-cage induction generator for power generation", Electrical Engineering, Sept. 1951.

70. Public Utilities Regulatory Policy act of 1978, Public Law 45-617, 16 U.S.C. 2601.

71. 18 CFR 292.205

72. 45 Federal Regulation 12214 (Feb. 25, 1980).

73. 18 CFR 292.304

74. 18 CFR 292.305

75. 10 CFR Parts 503-506.

76. 45 Fed. Reg. 38302 (June 6,1980).

77. Resource Planning Associates: "The potential for Cogeneration Development by 1990", Cambridge, Mass., Resource Planning Associates, July 1981.

78. Casten, Thomas: "Cogeneration Technologies 200 kW to 70 kW, Environmental Supplement", Contractor Report to the Office of Technology Assessment, 1981.

79. Nevitt, Peter K.: "Project Financing, report prepared for Bank AmeriLease Group Companies", Advanced Management Research, Inc. (2nd ed.).

80. Huyck, Philip M. : "Financial Aspects", Paper presented at The Energy Bureau Conference on Cogeneration, Washington

D.C., Oct. 13-14, 1981.

81. L. W. Borgman & Co.: "Finacing and Ownership of Dispersed Electrcity Generating Technologies", Contractor report to the Office of Technology Assessment, February 1981.

82. Federal Energy Regulatory Commission: " Appendix to Draft Environmental Impact Statement, Small Power Production and cogeneration Facilities -- Qualifying status/Rates and exemptions", FERC/EIS-019/D (Washington D.C.: U.S. Government Printing Office, June 1980).

83. Office of Technology Assessment, U.S> Congress: " Energy Efficiency of Buildings in Cities", OTA-E-168 (Washington D.C.: U.S. Government Printing Office, March 1982).

84. Bahrami K.A., Calwell R. W.: "Electric Utility Systems Application of Dispersed Storage and Generation ", Paper A79 494-6 presented at the PES Summer Meeting, Vancouver B.C. July 19-20, 1979.

85. Frey W., Althammer P. : "The calculation of transients on lines by means of a digital computer ", Brown Boveri Revue, Vol. 48, pp. 344-355, 1961.

86. Curtice, David and Patton, James. :" Operation of Small wind Turbines on a Distribution System," Final report (Palo Alto, Calif.: Systems Control, Inc. RFP-3177-2, UC-60, March 1981.)

87. Geller, Howard S.:" The Interconnection of Cogenerators and Small power Producers to a Utility System", (Washington D.C.: Office of People's Counsel, Feb. 1982).

88. Cummings, A. B., and Morris, J. A.:" Technical Support to the American Public Power Association Report on Cogeneration and Small Power Production", Phoenix, Ariz.: Salt River Project, March, 1981.

89. Southern California Edison Co.:" Guidelines for Operating, Metering, Protective Relaying for Cogenerators and Small Power Producers", Rosemead, Calif. : Southern California Edison Co., june 1981.

90. Theodore Barry & Associates, :"Guidelines to Assist Rural Electric Cooperatives fulfil the Requirements of section 201 and 210 of PURPA for Cogeneration and Small Power Production", Washington D.C.: National Rural Electric Cooperative Association, March 1981.

91. Electric Power Research Institute and Jet Propulsion laboratory,:"Interim Working Guidelines and Discussion Concerning the Interface of Small Dispersed Photovoltaic Power Producers With Electric Utility Systems", Palo Alto, Calif.: Electric Power Research Institute and Jet Propulsion Lab., draft, August 1981.

92. American Public Power Association,:" Cogeneration and Small Power production Guidelines", Washington D.C.: American Public Power Association, Nov. 1980.

93. Hassan, M. and Klein, J. :"Distributed Photovoltaic Systems", Utilities Interface Issues and their Present Status, Washington, D.C.; U.S. Department of Energy, DOE/ET-20356-3, Sept. 1981.

94. California Public Utilities Commission,:" Standards for Operating Reliability," ch. 14 in Final Staff Report on Cogeneration Small Power Production Pricing Standards, Order Institution Rulemaking No. 2 , California Public Utilities Commission, January, 1981.

95. Berlin, Edward, Ciccinetti, Charles J., and Gillen, William J.: "Perspective on Power", Cambridge, Mass.: Ballinger Publishing Co., 1974.

96. 45 Fed. Reg. 17959 (March 20, 1980).

97. Australian Standard 2279, 1979: "Limitations Of Harmonics caused by Industrial Equipment" Part 2, Table 1.

98. Prinz, H.,Zaengl, W., and Volcker, O. :"Solving Travelling Wave Problems with Bergerons Method", Bulletin Schwez. Elektr. Verein, vol. 53, 1962, pp. 725-739.

99. Ma, Fred S., Isaksen, Leif: " Impacts of Dispersed Storage and Generation on Distribution Planning and Operating Practices", 7th IEEE/PES Transmission and Distribution Conference and Exposition, April 1-6, 1979.