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MONITORING AND CONTROL REQUIREMENT DEFINITION STUDY FOR DISPERSED STORAGE AND GENERATION (DSG)

FINAL REPORT

Volume I

October 1980

Prepared for

JET PROPULSION LABORATORY
CALIFORNIA INSTITUTE OF TECHNOLOGY

and

NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

Submitted by

GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT

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GENERAL ELECTRIC COMPANY
CORPORATE RESEARCH AND DEVELOPMENT
Schenectady, New York 12301

GENERAL ELECTRIC

FOREWORD

This Final Report is the result of a year-long effort on Monitoring and Control Requirement Definition Study for Dispersed Storage and Generation (DSG) conducted by the General Electric Company, Corporate Research and Development, for the Jet Propulsion Laboratory, California Institute of Technology, and the New York State Energy Research and Development Authority.

Dispersed storage and generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems such as those represented by solar thermal electric, photovoltaic, wind, fuel cell, battery, hydro, and cogeneration. To maximize the effectiveness of alternative energy sources such as these in replacing petroleum fuels for generating electricity and to maintain continuous reliable electrical service to consumers, DSGs must be integrated and cooperatively operated within the existing utility systems. To effect this integration may require the installation of extensive new communications and control capabilities by the utilities. This study's objective is to define the monitoring and control requirements for the integration of DSGs into the utility systems.

This final report has been prepared as five separate volumes which cover the following topics:

VOLUME I - FINAL REPORT

Monitoring and Control Requirement

Definition Study for Dispersed Storage and Generation

VOLUME II - FINAL REPORT - Appendix A

Selected DSG Technologies and Their General Control Requirements

VOLUME III - FINAL REPORT - Appendix B

State of the Art, Trends, and Potential Growth of Selected DSG Technologies

VOLUME IV - FINAL REPORT - Appendix C

Identification from Utility Visits of Present and Future Approaches to Integration of DSG into Distribution Networks

VOLUME V - FINAL REPORT - Appendix D

Cost-Benefit Considerations for Providing Dispersed Storage and Generation of Electric Utilities

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Throughout this study we have benefited greatly from the help offered by many people who are knowledgeable in specific areas of the dispersed storage and generation technologies studied and in the fields of communications, control, and monitoring. We particularly wish to acknowledge the efforts of and discussions with Dr. Khosrow Bahrami and Dr. Harold Kirkham, each of whom have served as technical manager in the Jet Propulsion Laboratory, and Dr. Fred Strnisa, project manager, New York State Energy Research and Development Authority.

We also wish to thank the various people with whom we met during our utility visits. The following utilities have provided useful information regarding DSG activities at their organizations:

Niagara Mohawk Power Corporation, Syracuse, New York

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Blue Ridge Electric Membership Corporation, Lenoir, North Carolina

Public Service Electric and Gas Company, Newark, New Jersey

In addition, we thank our many associates in General Electric Company who have helped so much in our understanding of the selected DSG technologies and in the integration of DSGs into the existing electric utility system. In particular, we thank J.B. Bunch, A.C.M. Chen, M.H. Dunlap, R. Dunki-Jacobs, W.R. Nial, R.D. Rustay, and D.J. Ward.

The help of Dr. Roosevelt A. Fernandes of Niagara Mohawk Power Corporation in several phases of the work covered in this report is acknowledged with thanks. Also, Dr. Fred C. Schweppe, consultant, has been of considerable benefit in the conduct of this project and his efforts have been appreciated.

Harold Chestnut

Robert L. Linden

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ABSTRACT

A major aim of the U.S. National Energy Policy, as well as that of the New York State Energy Research and Development Authority, is to conserve energy and to shift from oil to more abundant domestic fuels and renewable energy sources. Dispersed Storage and Generation (DSG) is the term that characterizes the present and future dispersed, relatively small (<30 MW) energy systems, such as solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration, that can help achieve these national energy goals and can be dispersed throughout the distribution portion of an electric utility system.

A study of trends reveals that the need for DSG monitoring and control equipment by 1990-2000 will be great, measured in tens of thousands. Criteria for assessing DSG integration have been defined and indicate that economic and institutional as well as technical and other factors must be included.

The principal emphasis in this report is on the functional requirements for DSG monitoring and control in six major categories. Twenty-four functional requirements have been prepared under these six categories and serve to indicate how to integrate the DSGs with the distribution and other portions of the electric utility system.

Although much work remains to be accomplished, the results indicate that there are no fundamental technical obstacles to prevent the connection of dispersed storage and generation to the distribution system. However, a communication system of some sophistication will be required to integrate the distribution system and the dispersed generation sources for effective control. The large-size span of generators from 10 kW to 30 MW means that a variety of remote monitoring and control may be required. Recent Federal Energy Regulatory Commission rulings under PURPA Section 210 are intended to encourage the use of dispersed generation. Continued emphasis on establishing a more definite set of conditions of agreement between utilities and customers' suppliers is required.

A strong impression from the results of this report is that an increased effort is required to develop demonstration equipment to perform the DSG monitoring and control functions and to acquire experience with this equipment in the utility distribution environment.

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Section 1

INTRODUCTION AND BACKGROUND

A major aim of the U.S. National Energy Policy, as well as that of the New York State Energy Research and Development Authority, is to conserve energy and to shift from petroleum to more abundant fuels and renewable energy sources. Dispersed Storage and Generation (DSG) is the term used to characterize present and future electric energy systems, such as solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration, that can help to achieve these national energy goals. Much of the national energy research and development effort is being devoted to energy systems of these kinds, which, because they can be generally small in size, may be located in the distribution portion of the electric utility system.

This study has been made to understand the character and need of the electric utility distribution system over the period from 1980 to 2000 in which increasing demands for electrical energy and increasing costs for centrally generated power will encourage the use of dispersed storage and generation. An effort has been made to determine the character of the DSGs that will be availab[illegible] and how they can be controlled and monitored remotely. The infl[illegible]nce of technical and operating issues, economic considerations, and institutional and regulatory factors have been investigated as they affect the integration of DSG into the distribution system. The major effort has been directed at preparing functional requirements in six major categories covering subfunctions that define how an integrated distribution-DSG system should operate.

The purpose of the survey of DSG technologies which was conducted was to provide an understanding of the special characteristics of each of these technologies in sufficient detail so that the physical principles of their operation and the internal control of each technology would be evident. In this way a better understanding was obtained of the monitoring and control requirements for these DSGs from utility control centers. Visits to representative utilities that are interested in using DSG were conducted to verify the survey results and to identify the problems associated with integrating DSGs into the electric utility distribution system.

The extent to which new electric power generation is required will have a major influence on the need for new energy capacity to be installed. Although the anticipated average growth rates for energy, GNP, and electric power generation will be less than their historic values, it is currently estimated that by 2000 there will be a demand for a much greater installed electrical generation capacity: and perhaps 4 to 10% may be supplied by DSG equipment. Further, because the sizes of DSG units tend to be smaller than those used for conventional generation, there may be many thousands of DSGs that must be monitored and controlled.

Concurrently with the introduction of new dispersed storage and generation into the electric distribution system, there has been an increasing trend to provide distribution automation and control of other distribution system functions. These distribution system functions include substation automation, distribution automation, communication systems, and load management systems. Thus, in addition to integration of DSG into the distribution system, the development of distribution automation and control and its possible implications for DSG and its associated equipment and functions must also be considered.

Consideration of the functional requirements of DSG in an electric distribution system must also include the influence of DSG on the major generation and transmission portions of the electric utility as well as on the persons and processes involved in planning, scheduling, operating, and maintaining the generation and power dispatching. Therefore, both equipment and operational implications of the DSG integration requirements must be taken into account.

To provide a coherent basis for judging both the control and monitoring requirements, as well as the suitability of specific DSGs in terms of size, cost, location, and time of installation, attention has been given to suitable criteria for assessing DSG integration with the remainder of the electric utility distribution system. Included in these criteria are such items as the following:

- Commercial availability of the DSG
- Cost-benefit economics
- DSG size, number of units, and total capacity
- Energy resources
- Operational features
- Technical factors
- Institutional and regulatory requirements

Emphasis on energy conservation has focused attention on the need for remote control and monitoring of dispersed generation sources to take advantege of their available energy. Where appropriate use of these sources is made, these DSGs should be scheduled; where scheduling is not possible, monitoring should be employed. A need exists for systematically handling the many potential DSG sources that may be remotely commanded and controlled. These several needs are further complicated by the different DSG technologies having different startup, operating, and shutdown characteristics.

In identifying the DSG control and monitoring requirements, it is desirable to have a limited number of categories of requirements for consideration. For this study, the following function requirement categories have been selected:

A. Control and monitoring requirements

B. Power flow and quality requirements

C. Communications and data handling requirements

D. Operational requirements for normal, abnormal, and emergency states

E. Failure and abnormal behavior detection and correction requirements

F. Special DSG control requirements

For each of these categories functions have been described including their inputs, outputs, interactions with other functions, and special requirements.

Section 2

EXECUTIVE SUMMARY

This monitoring and control requirement study for dispersed storage and generation is a systems definition effort that describes how the many new electrical generation sources and their means of control can be integrated into electrical distribution systems during the 1980-2000 time period. The use of dispersed storage and generation (DSG) will provide ways of saving nonrenewable energy and reducing electrical energy costs and will represent a major change in the way that electric utility distribution systems operate by the year 2000. It is important that efforts be undertaken soon to provide a smooth and orderly development of the monitoring and control required with the DSG.

A short description of the means for directly controlling each of seven different DSG types has been prepared. In parallel with this description an effort was made to identify the state of the art, trends, and potential growth of the DSGs as well as their role and penetration into electric utility power generation. Following this investigation of the types of DSGs, one-day visits were made to four separate and geographically distributed utilities to obtain their viewpoints and interests in DSGs and their present criteria for integrating DSGs into their distribution networks. Although different dispersed energy generation sources such as solar thermal electric, photovoltaic, wind, fuel cell, battery, hydro, and cogeneration operate on different principles, suitable monitoring and control means can be developed that will enable these sources to perform compatibly with the other portions of the distribution system.

A review was made of the feasibility of different types of DSGs for integration into distribution networks. As a result, a number of criteria for integration were identified from technical and other perspectives. These criteria served as a basis for identifying twenty-four functional requirements toward which this study has been principally directed. It is important that the control and monitoring philosophy employed be flexible so that it can handle DSGs of different sizes and ownership, ranging, for example, from small photovoltaic units (10 kW and up) owned by individual customers to larger hydroelectric generation (5 to 30 MW) largely owned and operated by the electric utility.

The relationships between the major monitoring and control categories and the distribution DSG system parts were established in a generic way, and the general descriptions of the functional requirements were defined. The time intervals for which monitoring and control data must be communicated to and from the DSGs to a central distribution dispatch center (DDC) range from 2 to 10 seconds for normal scan and load frequency control (LFC), to 15 minutes to an hour and longer for routine periodic data update from the DSGs. The inherent uncertainty regarding the scheduling of such DSGs as those depending on the sun, wind, or water availability is an area which will require attention in any detailed system design.

The monitoring and control functional requirements were related to specific scenarios for a Niagara Mohawk Power Corporation (NMPC) distribution composite to investigate the significance of the requirements to situations which might reasonably be encountered. These scenarios served as a means for checking the suitability of these requirements for use by a utility in integrating possible DSGs into their distribution network. Particular attention was given to unusual communication requirements that might be involved and to determine what scheduling difficulties might be anticipated at a distribution dispatch center, because many DSGs were controlled from distant locations.

The communications needs associated with monitoring and control for DSGs will have to be considered in conjunction with those needs associated with other remote control distribution automation functions. The combination of these requirements may produce some stringent communication needs at critical periods.

The results of this study indicate that a large number of individual DSGs are likely to be remotely controlled on electrical distribution networks and that there is a need for developing a way to monitor and control these DSGs as an integral part of the electrical generation, transmission, and distribution system. An interface at the distribution dispatch center (DDC) must be effective in coupling together the needs which stem from the energy management system (EMS) to the individual DSGs. This task is complicated by the fact that DSGs can be many in number and have a variety of characteristics.

This study points out that perhaps 4 to 10% of the electrical generation of the year 2000 may be supplied by DSGs, and that if their average size is on the order of 1 to 5 MW, then in the United States 10,000 or more of such units may be remotely controlled. If still smaller units are used, an even larger number will need remote monitoring or control; thus a large monitoring and control effort will be required.

Already some types of DSGs such as hydro, cogeneration, and wind are available for utility use. It is considered important by the study team that an expanded effort be made to bring to reality the recommendations set forth in this report. In particular, the following specific tasks should be undertaken to develop and to reduce to practice:

- Control and dispatching methods for large numbers of DSGs
- Operator interface means for scheduling various DSGs
- Design guidelines for integrating the operation of DSGs, load controls, and distribution automation using real-time distribution control and communication equipment
- Preliminary specifications for an integrated distribution DSG system design

2.1 RELATIONSHIP OF DSGs TO THE EXISTING ELECTRIC UTILITY SYSTEM

The distribution system is that segment of the electric power system that delivers energy from the bulk generation and transmission system to the customer's load. The major systems of the present overall utility system include the following:

- Bulk System - utility generation, transmission, and bulk substation primary and transformer
- Distribution System - bulk substation secondary bus, subtransmission, distribution substations, primary feeders and equipment, and secondary circuits
- Customer Load - elements and/or equipments owned by the customer that use electricity

These conventional energy portions of the electric utility system are shown on the right portion of Figure 2.1-1.

Dispersed storage and generation units can be considered as a fourth system that in the future must be operated compatibly with the other systems. At that time there will be more extensive monitoring, control, communication, and protection equipments as shown on the left portion of Figure 2.1-1. The DSGs also shown on the left may range in size from small (10 kW to 500 kW), to medium (0.5 MW to 5.0 MW), to large (5.0 MW to 30 MW). The ownership, operation, and maintenance of these DSG units can be entirely the utilities', entirely the customer's, or other possible joint arrangements.

The terms small, medium, and large as they pertain to DSG size are used for illustrative purposes and serve to indicate that there may be a ratio of DSG sizes of the order of 3000/1 from the largest to the smallest. Although there may not be this range of DSG sizes on any one utility, it is apparent that the nature of the specific energy management system, the distribution dispatch center, and the distribution communication may differ from one utility to the next depending on such factors as the size of the loads served by the utility and the nature of the DSGs including whether they are utility or customer owned.

Another aspect of the relationship of the DSGs to the remainder of the electric utility system pertains to the fashion in which the communication from the distribution dispatch center (DDC) is related to or connected to the dispersed storage and generation units.

Some utilities may find it desirable for the DDC to communicate to several different substations, feeders, or users' sites to monitor and control only the DSGs located at the site contacted. For purposes of this report, such a DSG communication arrangement is referred to as a centralized approach to monitoring and control.

In other cases utilities may find it more desirable for the DDC to communicate more extensively to each substation to perform

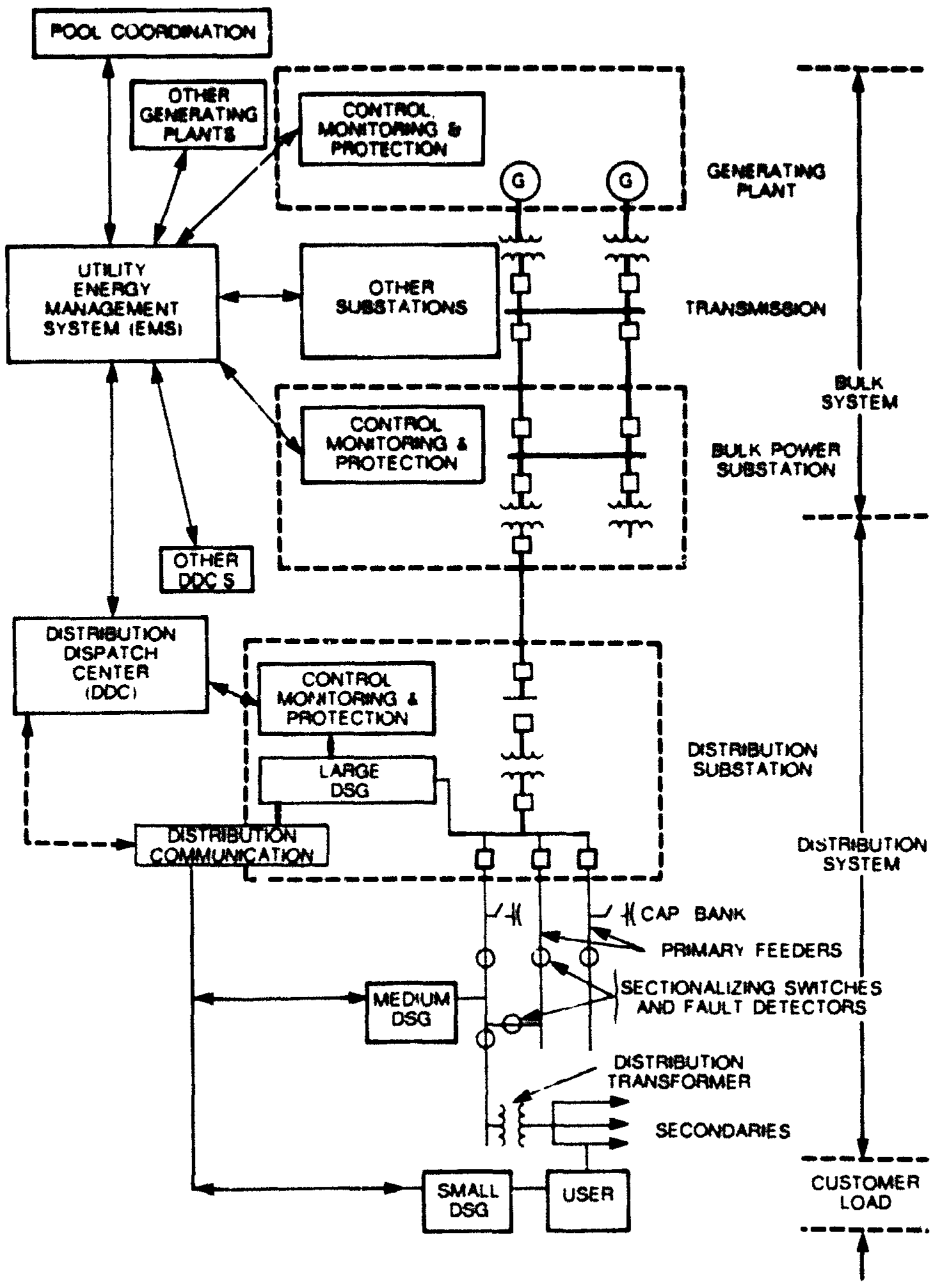

Figure 2.1-1. Representative Utility System and Control Hierarchy with DSGs

the distribution automation and control of many functions relating to that particular substation, only one function of which is the monitoring and control of a smaller number of DSGs. In this report, such a DSG communication arrangement is referred to as a decentralized approach to monitoring and control. Since there may be extenuating circumstances for a utility that may make either centralized or decentralized monitoring and control more desirable, it is worthwhile to recognize that both methods exist and may be used for different utility conditions.

The centralized communication approach, shown in Figure 2.1-2, refers to the monitoring and control of DSGs separately from the other distribution functions. With the centralized approach, communication is direct between the distribution dispatch center (DDC) and a number of DSG units that may be at the substation, the feeder, or the customer's location.

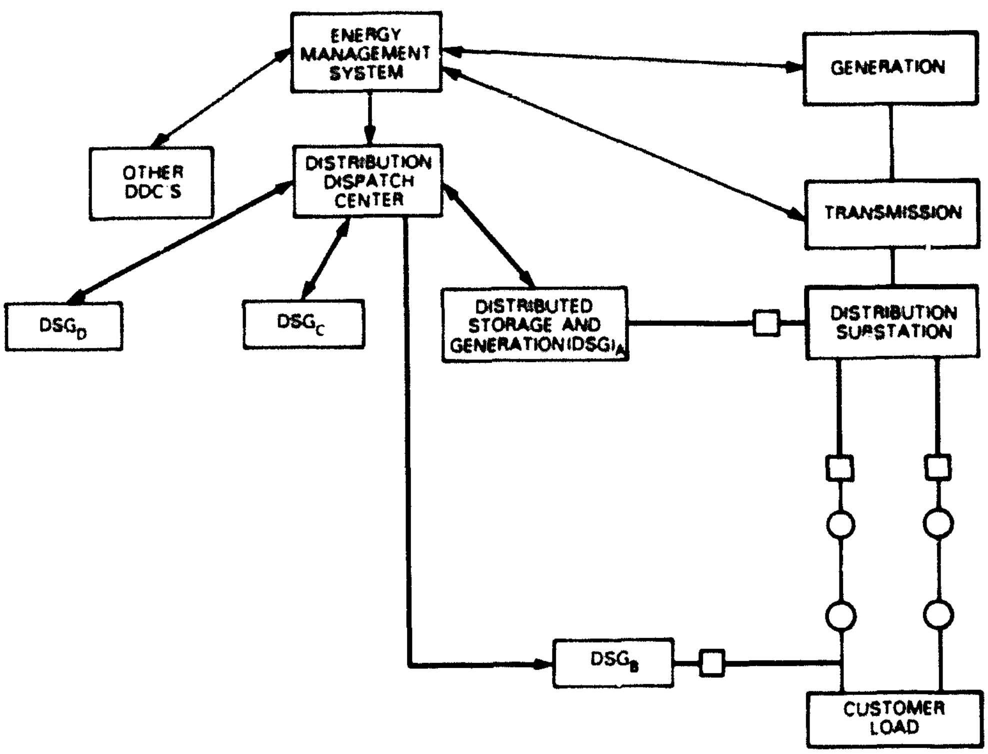

Figure 2.1-2. Centralized Approach Control and Monitoring - DSG Integration

The decentralized communication approach refers to the monitoring and control of both DSGs and other distribution automation and control (DAC) functions through a control and monitoring system for substations, their feeders, and customer's loads. Figure 2.1-3 shows how decentralized monitoring and control of other DAC functions and DSGs at the substation or feeder (or customer's locations) may be employed and have communication to the DDC.

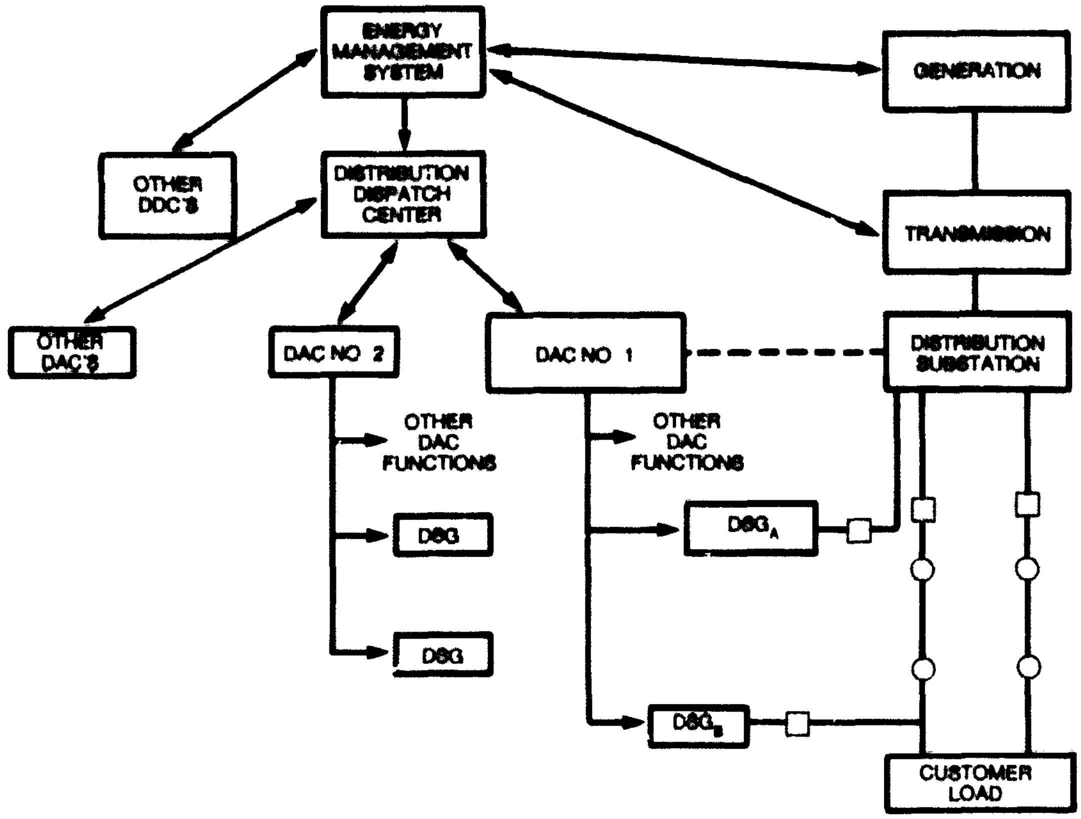

Figure 2.1-3. Decentralized Control and Monitoring for DSG Integration

In addition to, or independent from, centralized and decentralized utility DSG control, there may be local control of DSGs that customers may own and operate to optimize their financial return or other needs. The Public Utility Regulatory Policy Act of 1978 (PURPA) provides basic rules under which utilities and customers must interact in such a circumstance. It appears to be highly desirable that the utility operate with up-to-date knowledge of what is taking place at the customer's DSG as well as other DSG sources.

Many of the elements of the EMS and the DDC, as well as the DSGs, do not presently exist for most electric utility systems. The design of some of these equipments may be undertaken without a full awareness of the fact that in the future these different equipments may be required to operate compatibly with one another. A system control integration effort is required to enable the many parts of the control and energy systems to work together effectively.

It is highly desirable that this system integration work, i.e., the establishing of ways and means for accomplishing the incorporation of DSGs into the electric utility be started while there are relatively few parts of the new system yet in place. The DDC represents the top level of control of this new and improved distribution-DSG system.

2.2 CRITERIA FOR ASSESSING DSG INTEGRATION

Many factors enter into an evaluation of the feasibility of DSG alernatives. There are general criteria that pertain to the applicability of particular DSGs to specific utility distribution systems. There are functional characteristics and technical issues regarding general DSG integration into utility distribution systems. There are the economic aspects of feasibility where justification of a particular DSG must be according to cost-benefit considerations.

In addition to the issues noted above, each utility tends to have unique characteristics that have an important influence on the selection process. The utility's geographical location, size, bulk energy system composition and configuration, and expansion plans are illustrative of such characteristics.

The principal issues to be considered in selecting one or more DSG technologies include the following:

- Commercial availability of DSG
- Cost-benefit economics of utility system with DSG
- DSG size, number of units, total capacity
- Energy resources available to operate DSG
- Operational features of distribution system with DSG
- Technical factors regarding performance and utility operation
- Institutional and regulatory requirements influencing choice of DSGs

With DSG technologies progressing from experimental to commercial stages, and with fuel and equipment costs changing dramatically, the DSG integration process represents a rapidly changing activity that requires considerable additional effort.

A major finding in assessing DSG integration was that some DSGs such as hydro and cogeneration are essentially ready now for application to utility distribution systems. Although such DSGs may be commercially available, may have favorable economic benefits, and are of a size to contribute a significant energy savings, there are still important engineering design and construction efforts that remain to be done before a design is available that has already been well integrated into the remainder of the electric utility system.

A number of design choices of equipment and on-line control means exist to provide a basis for selecting among various alternative ways the achievement of DSG integration. In addition the effects of the specific agreements between a utility and the user-power generator, such as those associated with the residential solar photovoltaic and other programs, have yet to be firmly worked into the DSG integration process. Since these arrangements are frequently established under a set of conditions mandated by federal and state regulatory agencies, institutional factors such as these may strongly influence the technical design alternatives.

2.3 TYPES OF DSG

In this study the following seven DSG technologies were examined in detail: solar thermal electric, photovoltaic, wind, fuel cell, storage battery, hydro, and cogeneration. Other generation means such as fusion, magnetohydrodynamics, biomass/biofuels, geothermal, hydroelectric pumped storage, compressed air storage, and superconducting magnetic storage were also investigated but were later dropped from detailed consideration.

In identifying each of the seven DSG technologies, an effort was made to define the technology in a generic sense and to explain its functional, operational, feasibility, availability, and economic factors. A detailed report on each of the seven DSG technologies is contained in Appendix A, "Selected DSG Technologies and Their General Control Requirements."

In order to provide reference points for the seven DSGs that are discussed with most emphasis throughout this report, there follows a brief description of each. Such abbreviated descriptions by no means cover all forms of these DSG technologies adequately.

Solar Thermal Electric energy conversion systems collect solar radiation and convert it into high-temperature heat. The heat is transferred to a working fluid, which is often water or steam, for use in a mechanical-electrical generation system. Solar thermal electric energy may also be used in a total energy system providing both electricity and thermal energy. Energy storage may also be included as part of the system.

Photovoltaic generation systems convert light energy into electrical energy. This conversion takes place by the "photovoltaic effect" whereby a voltage is produced between dissimilar materials when their junction is illuminated (irradiated) by the light-band portion of the electromagnetic spectrum. There is a limited number of materials that exhibit photovoltaic properties. The relatively low-power intensity of sunlight (0.100 W per square centimeter), and the relatively low efficiency of photovoltaic conversion, (5 to 20%), inherently requires considerable area to obtain even low-power levels. Because photovoltaic power is in the form of direct current, dc-to-ac inverters are required to interconnect photovoltaic generation to the electric utility ac distribution system. The basic daily insolation cycle and variable weather conditions limit the availability and amount of photovoltaic energy in a 24-hour period. Thus photovoltaic generation systems must be used in conjunction with other firm power sources or storage on an electric utility system.

Wind Generation systems convert wind energy to electrical energy by means of a bladed propeller-driven shaft connected to an electric generator. Wind generation installations (plants) for electric utilities are likely to consist of one or more modestly sized units (0.2-3.0 MW) combined into an integrated installation. Wind generation is available only when the wind is blowing at speeds above a lower threshold and at speeds below a maximum at which damage to the installation might occur. Therefore, with wind generation additional firm generation capacity or storage are required by the utility.

Storage Battery energy systems have as their inputs dc electrical energy that is converted electrochemically to chemical energy during charging of the battery and is electrochemically converted to dc electrical energy during discharging of the battery. Operation of the storage battery with a conventional ac electric distribution system requires the use of power conditioning equipment. This equipment can accept the alternating current from the distribution system, convert it to the dc electrical energy that is required by the battery during charging, and invert the dc electrical energy provided by the battery to ac electrical energy suitable for use by the distribution system. Care must be taken to ensure that the periods scheduled for battery charging and discharging are economically beneficial to the overall electric power system operation.

Fuel Cell energy systems consist of an electric power generation device in which hot fuel gas is passed over a fuel electrode and heated air is passed over an adjacent air electrode, which is separated from the fuel electrode by an electrolyte, to produce a dc power output and an exhaust of carbon dioxide and water. The direct current electric power produced by the fuel cell is connected to a dc/ac inverter that in turn supplies the distribution system with an alternating current at the proper voltage and frequency. Although the hot fuel gas and heated air must be supplied whenever electric energy is desired, the fuel cell system power output is available on demand.

Hydroelectric generation converts the energy of falling water into electrical energy by means of mechanical-electrical machinery. Flowing water, pressurized by gravity, drives a hydraulic turbine that is coupled to an electric generator. The electric generator driven by the turbine produces alternating current electric power that is supplied to the electric utility power system.

Cogeneration is the combined production of process heat and electricity. Industries and/or utilities, which need both of these forms of energy, potentially have net operational cost savings available through an efficient coordinated facility that fully utilizes the heat of combustion of the fuel. Various manufacturing, commercial, and district heating applications utilize medium- and low-pressure steam. These comprise the largest percentage of potential cogeneration applications. For these applications the most common configuration for generating "process steam" and electricity has been to use fossil-fuel-fired steam boilers producing high-temperature, high-pressure steam to drive steam turbine-generator set(s). Electricity is produced directly by the turbine-generators; and the steam from the turbine, with its remaining energy, is extracted or exhausted to the "process."

In considering DSG technologies it is important to note that they represent different means of power conversion, i.e., ac or dc, and they have different scheduling characteristics, i.e., schedulable or nonschedulable, because of the availability of sun, water, or wind. Table 2.3-1 illustrates these DSG characteristics for the seven selected technologies.

Further, because not all of the technologies are in the same stage of development or commercial maturity, and the amounts of energy produced from each are not of equal magnitude, one needs to consider each technology from various considerations as shown in Table 2.3-2. In addition to the present status, the anticipated date of commercialization, and the total amount of power estimated to be added from 1980 to 2000 are shown. Further information on the state of the art, trends, and potential growth of selected DSG technologies is contained in Appendix B.

From a monitoring and control point of view, it should be noted that although the power supplied by some DSG technologies, such as solar photovoltaic at the residential user level, may not be large, a great number of equipments may be required.

Table 2.3-1

DSG CHARACTERISTICS

DSG Type	Power Conversion	Scheduling of Power
Solar Thermal Electric	ac	NS
Hydroelectric	ac	S
Wind	ac	NS
Fuel Cell	dc/ac	S
Storage Battery	dc/ac (Storage)	S
Photovoltaic	dc/ac (Renewable)	NS
Cogeneration	ac	S (Indirect)

NOTE: NS - Nonschedulable
S - Schedulable

Table 2.3-2

PROJECTED STATUS OF FUTURE DSG TECHNOLOGY

DSG Technology	Present Status	Anticipated Date of Commercialization	Total Power Added by 2000	
			GW	Number of units and assumed rating
Solar Thermal	Experimental	1990	2	2,000 @ 1 MW Avg.
Photovoltaic	Experimental	1990	2	2,000 @ 1 MW Avg.
Wind	Preproduction	1990	6	3,000 @ 2 MW Avg.
Fuel Cell	Preproduction	<1990	3	600 @ 5 MW Avg.
Battery	Experimental	<1990	15	3,000 @ 5 MW Avg.
Hydro	Mature	Now in Use	6	1,200 @ 5 MW Avg.
Cogeneration	Commercial	Now in Use	30	1,500 @ 20 MW Avg.
		TOTAL	64	13,300

Note: Inclusion of smaller residential units, such as photovoltaic, could raise to more than 300,000 the number of DSG units supplying power nationwide for distribution use (see Table 5.9-1).

2.4 CONTROL AND MONITORING SYSTEM ARCHITECTURE AND EQUIPMENT FOR DSG INTEGRATION

In addition to the DSGs operating satisfactorily as a source of power for the distribution system, it may be desirable to provide each DSG with communications, control, and monitoring equipment to enable it to be properly coordinated and integrated with the remainder of the distribution system. Depending on the nature and size of the DSG, its location on the distribution network, and the nature of other control means such as distribution automation being performed, there are various configurations or structures of the distribution DSG system equipment that may be used for integrating the DSG with the remainder of the system.

For small DSGs located at the customer, local control may suffice with little remote control and monitoring. With systems having more extensive distribution automation, the control and monitoring of DSGs may be considered as a part of a decentralized control in which the control and monitoring are a subset of the distribution automation functions. For larger DSGs a centralized control for each one may be required in which more monitoring and control equipment will be needed. Figure 2.4-1 shows how the DSG size and number of units may influence whether the control structure be local, decentralized, or centralized.

QUANTITY / SIZE	FEW (UNDER 10)	SEVERAL (10 - 50)	MANY (50 - 1000)
SMALL (0.01 - 0.5MW)	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY
MEDIUM (0.5 - 5MW)	CENTRALIZED CONTROL SOME INDICATION & DATA	CENTRALIZED OR DECENTRALIZED CONTROL SOME INDICATION & DATA	DECENTRALIZED CONTROL SOME INDICATION & DATA
LARGE (5 - 30MW)	CENTRALIZED CONTROL INCREASED INDICATION & DATA	CENTRALIZED CONTROL INCREASED INDICATION & DATA	CENTRALIZED CONTROL INCREASED INDICATION & DATA

Figure 2.4-1. Effect of DSG Size and Quantity on Control Structure

A major aspect of the control and monitoring requirements is concerned with the functions performed at the Distribution Dispatch Center. It is at this center where the operator is located and where human judgment can be brought to bear on an ongoing basis. It is also at this center where information can be made available about how much electrical generation is actually taking place at the various DSGs. Depending on the number of large, medium, and small DSGs as well as other factors, the amount of power generated in each size range will differ, and the amount of information that is required by the operator and can be afforded by the utility will also differ. The system architecture and equipment for DSG integration may be different in detail to accommodate for the number and size of the DSGs involved.

Another factor which may influence the system architecture is the ratio of unschedulable DSG generation that may be allowed by the utility. The utility may have to reserve the right to limit the amount of customer-supplied power to certain agreed upon aggregate quantities that will be monitored in order for the utility to be able to handle in a dependable manner the power shifts such as available sun, wind, or water that change abruptly. As of the present, the nature of such items of understanding has yet to be established on an industry-wide basis.

From the preceding it is evident that a flexible control and monitoring system architecture is required that can handle DSGs of different sizes and numbers of units which range from central to local control means. The hardware and software for specific DDC applications are not presently available, so that effort should be made to obtain the necessary knowledge and experience regarding DSG integration before its need is critical.

A general form for representing the distribution DSG system is represented by Figure 2.4-2 where the DSGs connected to the distribution system are shown to be made up of power, control, protection, and interface equipment. Also included as equipment are the communication connection to the DDC, the DDC interface, and the DSG equipment. Figure 2.4-2 also shows that the DDC equipment may be connected to other DSGs as well as having both operator and automatic inputs and outputs related to other needs of the system.

Depending on whether or not the communication control is centralized, decentralized, or local, the extent to which the different control functions are carried out will differ. Larger sized DSGs will warrant more monitoring and control and can justify higher costs for these functions. Smaller sized DSGs will not require as much control and monitoring and would have trouble justifying such large costs. Thus, control and monitoring system architecture and equipment that differ in detail may be required for different utilities.

There are six major categories of functional requirements that are performed primarily by the equipment indicated by the letters (A) to (F) on Figure 2.4-2. The nature of these major functional categories is discussed in Section 2.6 and in more detail in Section 8.

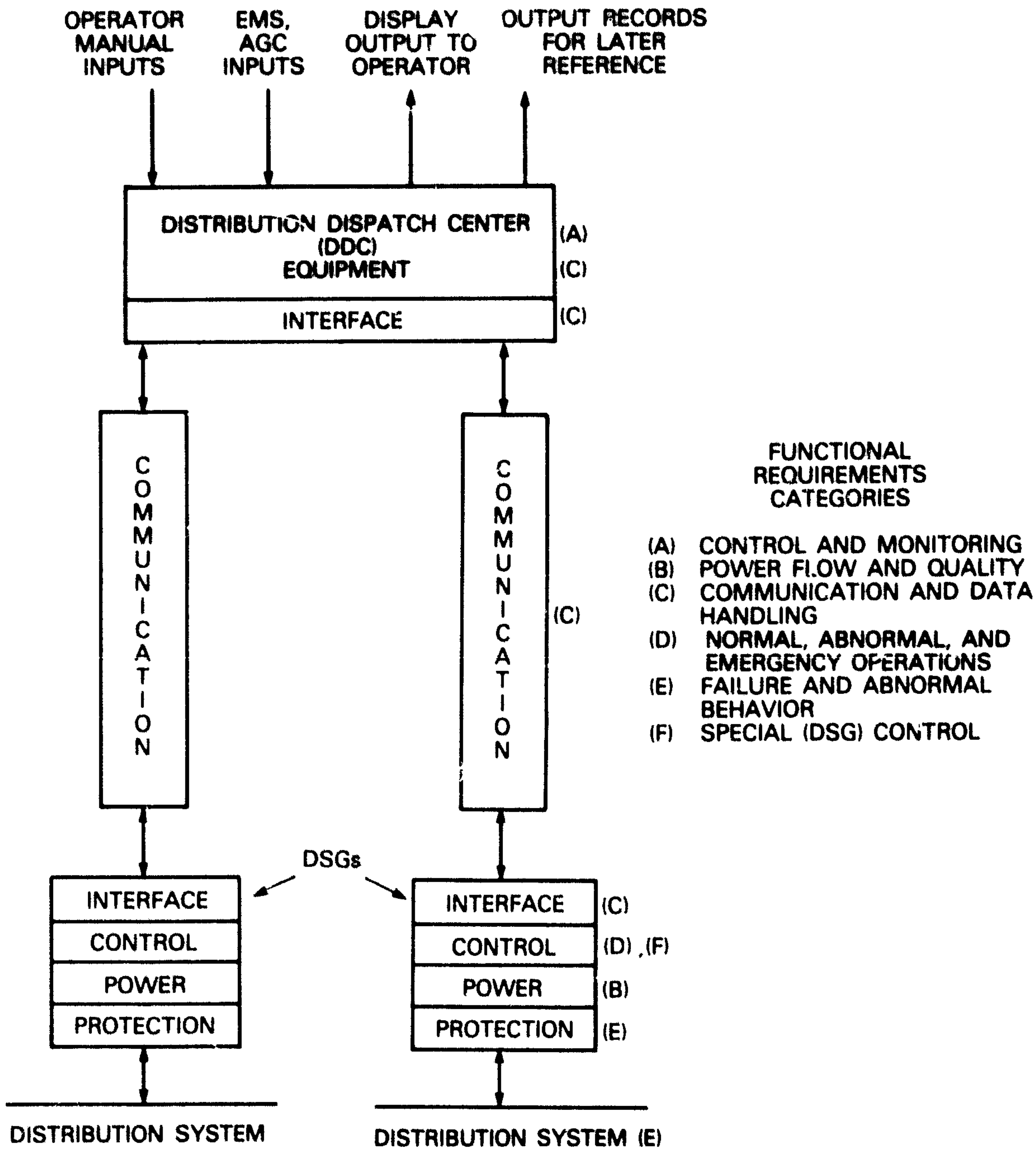

Figure 2.4-2. Categories of Distribution DSG System Equipment and Functional Requirements

2.5 DSG CONTROL REPRESENTATION AND MAJOR OPERATING MODES AND STATES

A representation of the multilevels of the hierarchical control system that a DDC uses to control one or more DSGs is shown in Figure 2.5-1. The DSG power generation process is shown to supply an electric utility distribution system and/or customer load through protective equipment. The DDC controls the DSG in the three major modes (on, off, and standby) and under the four DSG states (normal, abnormal, emergency, and inoperative).

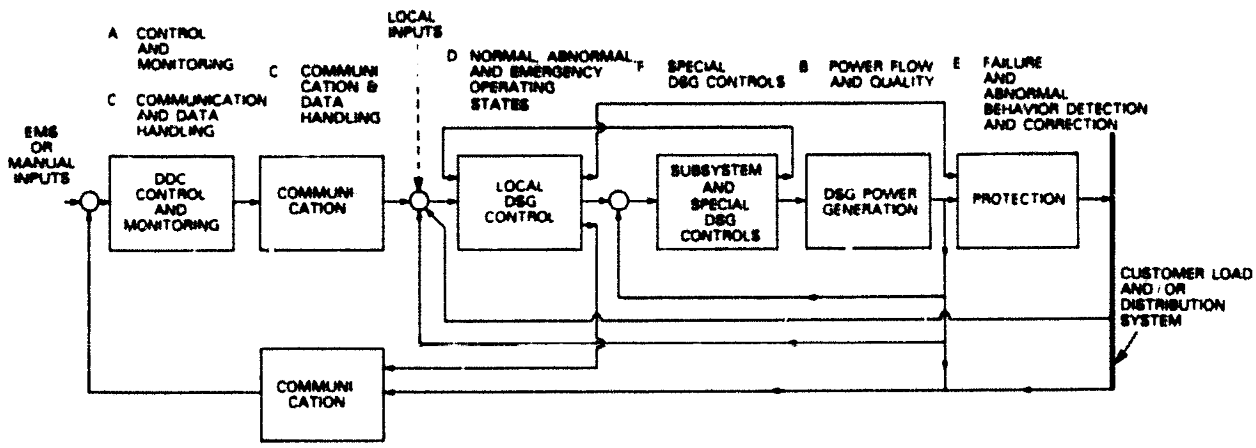

Figure 2.5-1. Schematic Representation of Monitoring and Control of DSGs Related to the Functional Requirement Categories

The DSG power process is controlled through special DSG controls that receive feedback from the DSG. The special DSG controls in turn have signals from the local DSG control as inputs which make sure that the various auxiliaries are properly sequenced and controlled and that the overall local DSG control is operating in the proper operational control mode. Feedback from the DSG power elements is again employed by local DSG control, and additional feedback from the distribution network may be used.

The top level of the hierarchy is the DDC control and monitoring that is connected through communication means to the local DSG control for command and control purposes and to the DSG power generation and local control for monitoring feedback. Inputs to the DDC control and monitoring equipment include those from the EMS and/or from the manual inputs of the DDC operator. It should also be noted that under local control to meet customer load needs, a local input control at the DSG site may represent the primary control means for the DSG power generation equipment, and the communication inputs to the DDC may enable the operator to monitor but not to control the local DSG power level.

Although Figure 2.5-1 presents a general representation of DSG with remote control from a DDC, this figure also helps to describe how a small dispersed generation source, for example, a photovoltaic unit, would operate. In this case the local inputs would be used to start up and control the power generation. Depending on the extent of the communication to the DDC which was warranted, the transmittal of data on power supplied to the distribution system or the communication of command and control data from the DDC to the local photovoltaic generation can range from very little to the same amount as for a larger sized DSG. It is highly desirable that operational experience be obtained soon on the effect on different aspects of DSG operation with different degrees of communication and control.

Regarding the distribution system operation, the DDC under centralized or decentralized control may command each DSG to be in one of the three operating modes: on, off, or standby.

On - The DSG is in operating condition and is running in synchronism with the power system and electrically connected to it. In this condition it will be normally generating or absorbing power (electrical energy).

Off - The DSG is disconnected from the power system at the DSG distribution system interface and is shut down (not running).

Standby - The DSG is in operating condition and running, but it is not electrically connected to the distribution system.

In addition to the DSG modes, the DSG may be in one of four different states that describe the overall conditions that can exist at the DSG unit or plant.

Normal - All systems, subsystems, and components of the DSG plant or unit are in operable condition within continuous design rating limits.

Abnormal - The DSG plant or unit system, subsystem, or component is in a condition wherein its continuous design rating is being, or would be, exceeded during operation.

Emergency - A DSG plant is in a condition in which continued operation will result in imminent failure or serious damage.

Inoperative - In this state the DSG is not available for useful operation.

The determination of the DSG plant mode is influenced and determined by a number of factors that include:

- DSG state
- Power system state

- DSG schedule
- DSG energy resource
- Private owner decision

A DSG will be called upon to change from off to on and on to off modes for the majority of its normal operational mode changes. These transitions will be dictated primarily by the DSG operating schedule and the availability of energy. Certain types of DSGs may have an intermediate mode between off and on called standby. This may be required by cogeneration or advanced battery systems to permit stabilization of process and/or energy system balances. This mode may also be used as a "spinning reserve" mode in providing generating margin for the power system.

These operational transitions are represented in Figure 2.5-2. Commands initiated at either the remote centralized control or local control to command a DSG to be placed on-line, taken off-line, or be placed on standby, will cause a startup, a shutdown, or a partial transition, as indicated by the arrows in Figure 2.5-2.

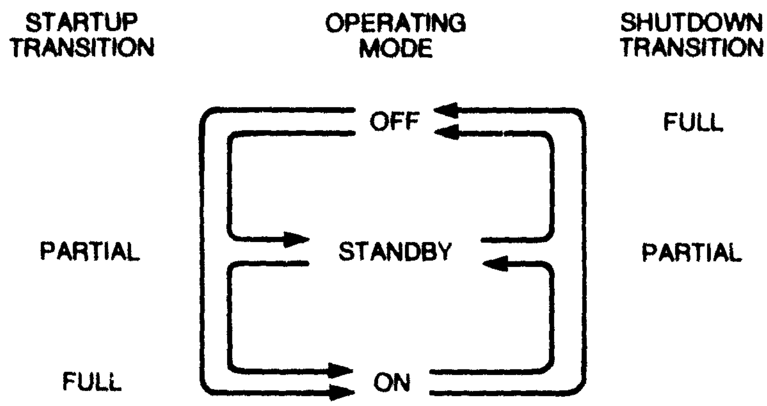

Figure 2.5-2. DSG Modes and Transitions

In the general case these mode changes will be possible from either the local DSG controls or remote control location. However, certain types of DSGs, e.g., cogeneration or wind, may for practical reasons preclude absolute remote control. The cogeneration will usually be closely interrelated with a heat process that places constraints on electric energy output variations. Wind turbine generators do not permit absolute control because of the variable (unpredictable) source, and control will be more of a permissive (or prohibiting) action.

2.6 FUNCTIONAL REQUIREMENTS

The six major categories of functional requirements associated with DSGs are:

A. Control and monitoring

B. Power flow and quality

C. Communication and data handling

D. Operational requirements for normal, abnormal, and emergency states

E. Failure and abnormal behavior

F. Special (DSG) control

Summary descriptions of the six categories of functional requirements are as follows:

A. The control and monitoring functions are associated with the DDC equipment and location and provide the centralized functions necessary for overall coordination of the DSGs assigned to the DDC. Control and monitoring functions incorporate DDC operator and EMS requirements for distribution DSG operation and control. DDC operator information and control inputs must be accommodated and information concerning the DSG's operation presented to the DDC operator. EMS information relative to overall power system generation scheduling, automatic generation control, voltage/var dispatch, and load management must be input to and incorporated by the DDC into its control strategies and logic operations for the specific DSGs and distribution system operations. The EMS will need feedback information pertaining to aggregate DSG data and characteristics to properly represent overall DSG power and energy in scheduling and control strategies.

B. The power flow and quality functions are DSG power-related functions that control power flow, provide appropriate instrumentation, and establish the quality and magnitude of voltage and current wave shapes including harmonic content. Each of these functions has requirements, related to the specific type of DSG, that must be reconciled with the general requirements of the DDC control and monitoring function. DSG power control, for example, must consider minimum and maximum power output levels, permissible rate of change, and power reversal characteristics for storage types of DSGs. These requirements involve both distribution system needs and DSG characteristics.

C. The communication and data handling functions provide the necessary information transfer and data handling between DDC and DSGs, the data transfer interfaces between these equipments and the communication links, and the associated information processing at the DDC. These functions are primarily involved in the transfer of command and control data from the DDC to DSGs and the return of monitoring (normal and alarm) data from the DSGs to the DDC.

Depending on whether the distribution DSG System uses a centralized or decentralized control structure, the communication and data handling requirements may differ in detail. Using a centralized approach, information transfer takes place directly between DDC and DSGs. With a decentralized arrangement, DSG control and monitoring information shares communication facilities with general distribution automation and control functions. For the decentralized configuration, in addition to the distribution automation and control functions, incremental loading is added to the communication and data handling for DSG requirements.

In addition to those DSGs for which power control is handled from the DDC, there may be some DSGs, especially small and customer-owned ones, that are locally controlled and for which more limited communication and data handling is warranted.

D. The operational requirements associated with DSG normal, abnormal, and emergency states relate to local functions at the DSG required for the control of the DSG operating modes, DSG stability, and personnel safety. These functions include the logic to determine whether normal, abnormal, or emergency conditions exist and the logic to adjust or change the DSG power production process and associated auxiliary equipment in response to changes in DSG state. The ability of the DSG to remain in step with the power system fundamental frequency is of utmost importance and thus DSG stability is a necessary requirement. For all states that the DSG may encounter, personnel safety is a primary consideration and requirement. This requires coordination of local DSG and distribution system operation especially during times of maintenance, outages, and service restoration.

E. The failure and abnormal behavior detection and correction functions are primarily associated with protection system equipments of both DSG and the distribution system. There is a mutually dependent requirement that the distribution system be protected from failure and abnormal behavior of DSGs and, conversely, the DSGs must be protected from failure and abnormal conditions on the distribution system. System protection philosophy dictates that protective systems be associated and physically located at DSG and distribution equipment facilities. Functional requirements define the protection needs in order to establish rules for protective system equipment design.

F. The special DSG control functions are associated with the local DSG control equipment. These functions involve controls that cause the DSG unit(s) to respond to remote start and stop commands from the DDC and other special functions. In a general sense this involves power actuation and control. Therefore, these functions and control equipment make it possible to carry out DSG scheduling directed by the DDC.

Because each type of DSG will have different power and energy system configurations, the logic and arrangement of controls for special DSG control functions will be different or unique for each type of DSG. However, the basic functions of automatic startup and synchronization to the distribution system and automatic shutdown will be a general requirement for most DSGs.

For the abnormal condition of major outages and isolation ("islanding") of portions of a distribution system, special consideration is required to utilize DSGs to restore partial power to the islands that contain DSGs capable of stand-alone operation.

Table 2.6-1 lists the DSG categories of functional requirements and their associated subfunctions. Each of these subfunctions are described in terms of the following characteristics:

- Functional description
- Input or processed data
- Controlled outputs and data
- Interaction with other functions
- Special requirements

Figure 2.6-1 presents a functional block diagram that highlights the DSG control and monitoring functions at the DDC for the case of centralized control. At the same time it does show a number of other functions associated with communication and data handling as well as with power flow and quality. The emphasis in this "top-down" figure is to show how the distribution dispatch center, where the DDC operator is located, is the site of many control and monitoring functions for the various DSGs that supply the power distribution system.

Figure 2.6-2 presents a "bottom-up" functional block diagram which highlights the DSG power flow and quality control from the viewpoint of the DSG and shows the DDC to be a single block. Although communication, SCADA, and the DDC are referred to, the emphasis is on the several DSG controls that are required to achieve the desired DSG conditions for the electric utility distribution system. The operator interface shown permits local operator control at the DSG when an operator is present. However, operation of DSGs without an operator is the desired condition. Further discussion of these diagrams is to be found in Section 8 where all the functional requirements are presented in detail.

COMMUNICATION MISSION

The communication requirements can be considered in terms of a mission that consists of the transmission of data from the distribution dispatch center to the many DSGs and back to the DDC. This is a 24-hour-a-day, 365-days-per-year mission in which there are many activities or functions which take place with different periodicities ranging from seconds to hours. Other operator-originated, abnormal or emergency events, that take place on an unscheduled basis or infrequently, will occur and may require priority access to the communication usage at the expense of other more routine

Table 2.6-1

DSG CATEGORIES OF FUNCTIONAL REQUIREMENTS AND SUBFUNCTIONS

A. Control and Monitoring

- DSG Command and Control
- Display and Recording
- DSG Scheduling and Mode Control
- Distribution Volt/VAR Control
- Load Control Including Restoration
- Automatic Generation Control
- Security Assessment

B. Power Flow and Quality

- DSG Power Control
- DSG Voltage Control
- Harmonics
- Instrumentation

C. Communications and Data Handling

- Distribution SCADA
- Communication
- Revenue Metering
- Information Processing

D. Operational Requirements for DSG Normal, Abnormal, and Emergency States

- DSG Control
- Operating Mode Control
- Personnel Safety
- DSG Stability

E. Failure and Abnormal Behavior Detection and Correction Requirements

- Protection (Distribution Substation, Transformer, Feeder)
- Protection (DSG)

F. Special (DSG)

- Start Capability
- Synchronization
- Stand-alone Capability

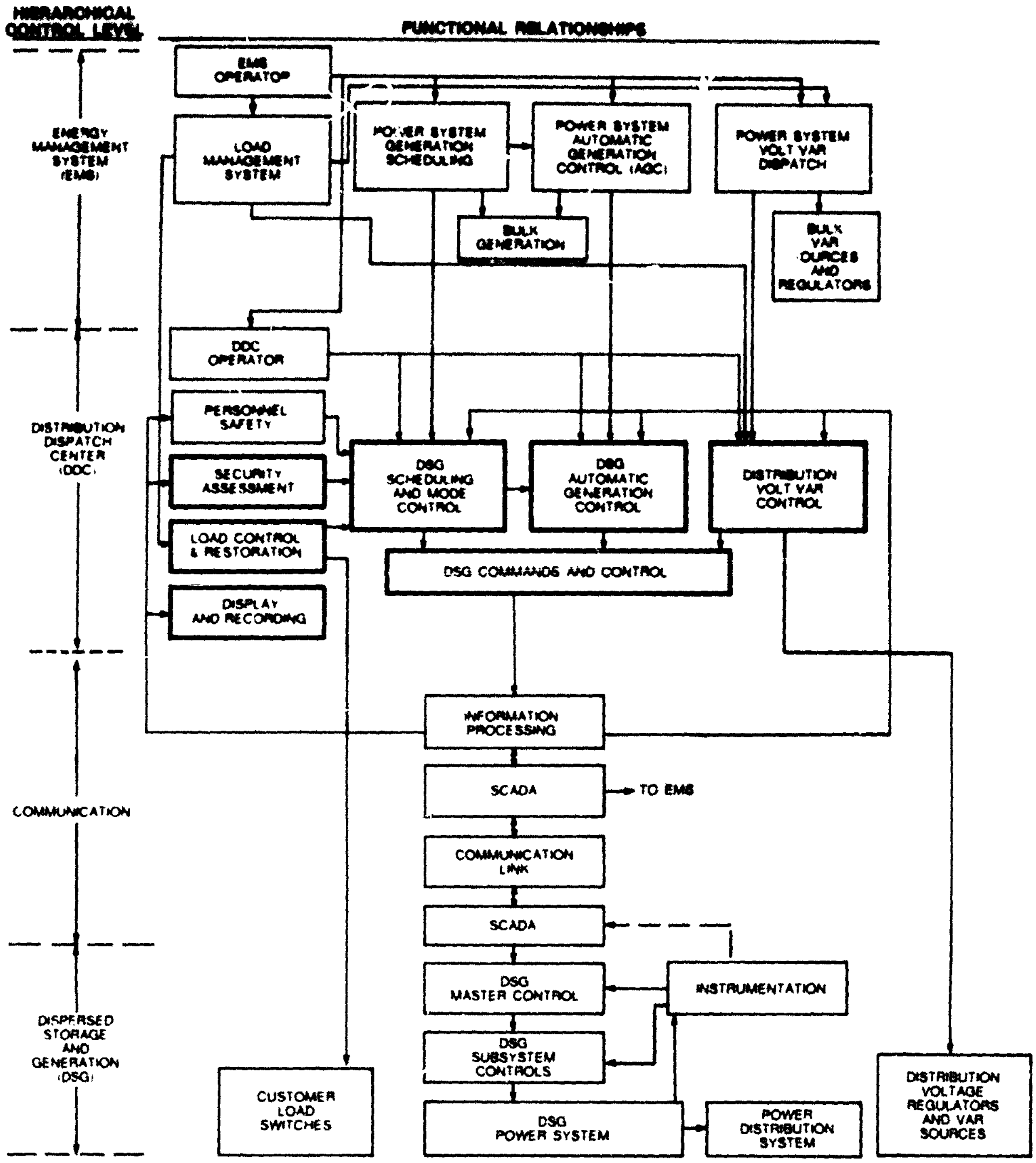

Figure 2.6-1. DSG Control and Monitoring Functional Block Diagram for Centralized Control (communication for control and monitoring of DSGs' functions primarily)

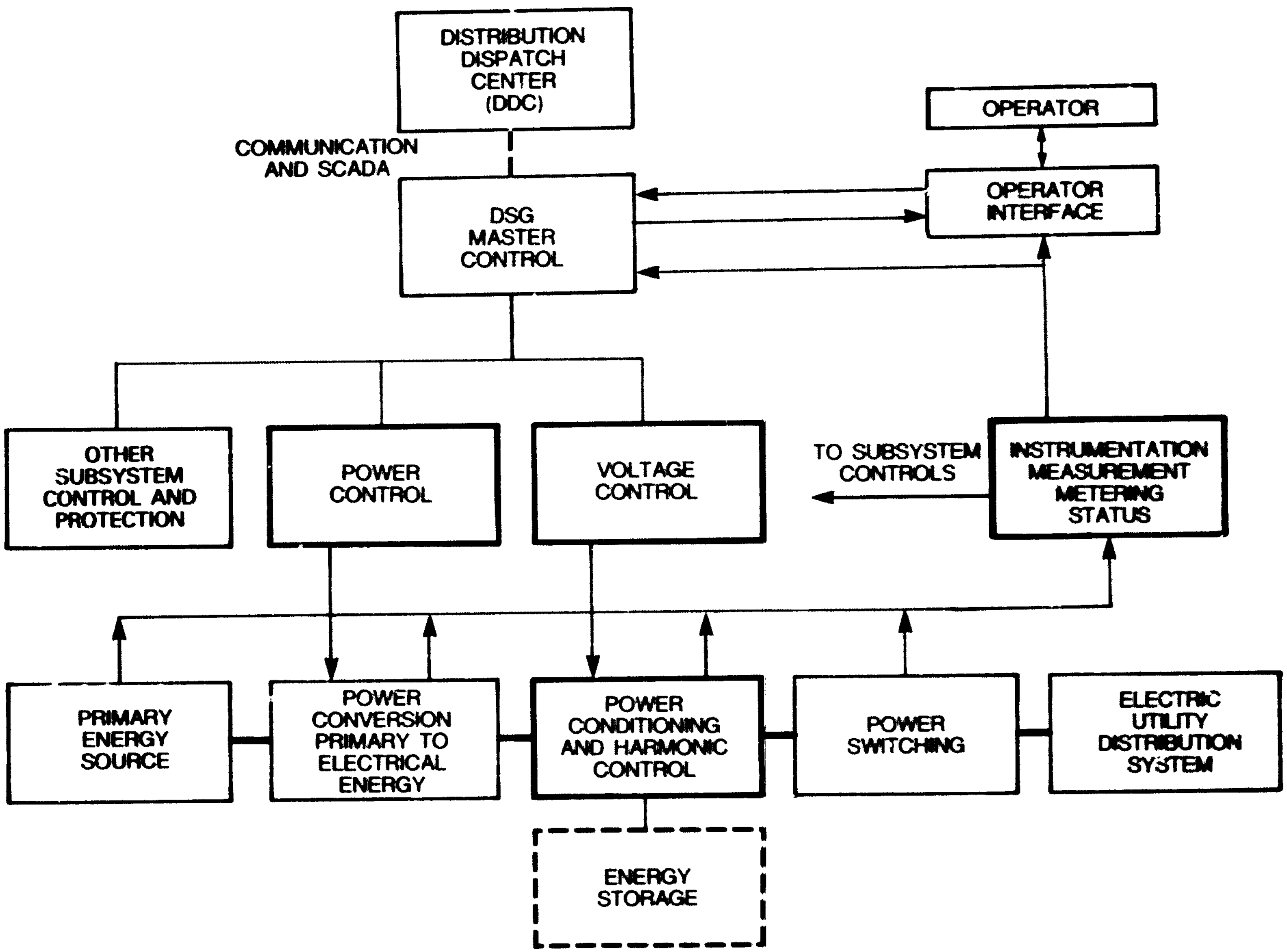

Figure 2.6-2. Power Flow and Quality Functional Relationships

requirements that may have to be preempted by priority events. Thus some flexibility must be provided in the identification of the communication mission requirements.

The functional block diagram of Figure 2.6-1 can be redrawn as in Figure 2.6-3 to emphasize the nature of the information inputs and outputs to the communication link between the DDC SCADA and the DSG SCADA. DSG command and control serves as a gathering point of information from several other DDC-located sources including the DDC operator and makes data available to information processing.

The DDC SCADA function prepares this information and other information at the proper time periods for communication to the various DSGs and to other information sources such as the EMS. At the DSGs, information relating to the periodic status of the various major elements of the DSG are prepared for transmittal by the DSG SCADA to the DDC information processing and output to the display and recording.

Table 2.6-2 shows by the column headings the approximate time periods at which information must be handled to accomplish the several DSG functions which are indicated. Also shown in the boxes of the matrix are representative values of the amount of information that must be handled for the function and time periodicity indicated. In general there are commands and schedules which are of an ON-OFF nature on a daily basis that are associated with one to four times a day period. Also revenue metering might be done on a 15-minute to one-hour basis. Periodic update of DSG status covering status and analog data might take place on approximately an hourly basis corresponding to the 15-minute to one-hour period. On a five to ten minute period, power and voltage commands are sent to the DSGs and data returned. Normal scan for alarms and load frequency control (LFC) information, where required, will be at a faster rate as associated with two to ten-second periods. Operator and EMS inputs may from time to time have need of a fast response (one to two seconds) associated with override requirements. On a priority basis these requirements may appear like a one to two-second period input. On a very occasional basis after the equipment is operating effectively, perhaps of the order of one per day to one per month, alarms and data by exception may occur.

Although the various DSG functions develop the basic information to be handled, the distribution SCADA function is responsible for the proper information coding and development of the complete message to be communicated and received and how it is to be interpreted. In many cases the data to be communicated are far more extensive and comprehensive than the particular basic information that it is desired to transmit or receive. This is especially true as several to many DSGs of different types are to be handled with differing degrees of information coverage required.

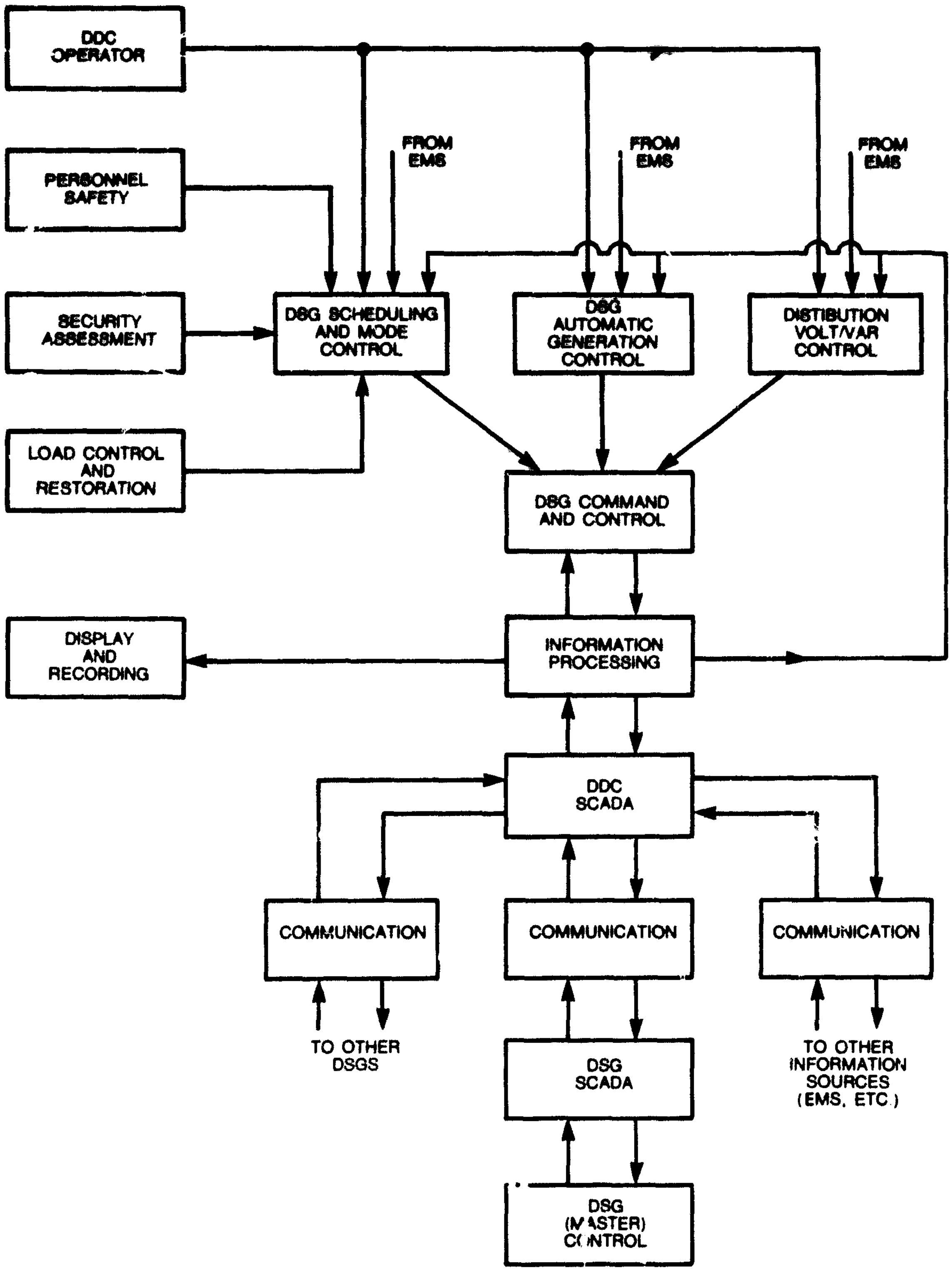

Figure 2.6-3. Block Diagram Showing Information Inputs and Outputs to Communication Links Between DDC and DSGs

Table 2.6-2

DDC-DSG VOLUME VERSUS TIME PERIOD, BY FUNCTION; APPROXIMATE TIME PERIODS AT WHICH DATA MUST BE HANDLED; AND QUANTITY (BITS) OF DATA PER DSG FUNCTION

DSG FUNCTION	1 day to 1 month	6 to 24 hours	15 min to 1 hour	5 to 10 min	2 to 10 sec
1. COMMAND AND CONTROL		2516*		820*	246*
2. DISPLAY AND RECORDING					
A. DISPLAYS					
1. Variables Update			276		
2. Single Value		164			
3. Monitor for Control		9840			
4. Alarms	156				
5. Data by Exception	358				
B. RECORDING					
1. Periodic Log			604		
2. Operator Mode Control		328*			
3. Operator R.L. Control		492*			
3. DSG SCHEDULING AND MODE CONTROL		712*			
4. DISTRIBUTION VOLT VAR CONTROL				164*	
5. LOAD CONTROL, INCLUDING RESTART		984*			
6. AUTOMATIC GEN CONTROL					
A. LFC and EDC					246*
B. EDC (Alone)				656*	
7. SECURITY ASSESSMENT	324				
8. DISTRIBUTION SCADA					
NORMAL SCAN					164
9. REVENUE METERING			164		

*Command and Control is a composite of functions 3,4,5,6,7 plus 2B2 and 2B3. The composite may not be cumulative.
Could be less frequently if data were stored at DSC. Quantity of data would increase inversely proportional to decrease in period.

Table 2.6-3 showing examples of the bits per second (BPS) data rate requirements for individual DDC-DSG functions involving a communication link to a single DSG, indicates that rates from 2 to 200 BPS may be required. The results indicated are of course affected by the nature of the many assumptions that went into their determination, and other data rates either higher or lower could be reasonably justified. For example, if ten seconds rather than two seconds were chosen for the time period of the most rapid functions, the maximum rate for the highest bit rate functions would be decreased by about five to one. It should be emphasized that the resulting rates for combinations of functions may not be determined by adding the bit rates associated with the individual functions.

Table 2.6-3

EXAMPLES OF DATA RATE REQUIREMENTS FOR INDIVIDUAL DDC-DSG FUNCTIONS INVOLVING COMMUNICATION LINKS

Function	Function Period	Allowable Transaction Time, s	Data Rate (bps)
Periodic Update of Variables	1 Hour	30	9.3
Alarm Reporting	1 Month	2	197
Scheduling and Mode Control	1 Day	300	2.4
Distribution Volt/VAR Control	10 Minutes	10	16.7
Automatic Generation Control, Load-Frequency Control Subfunction	2 Seconds	2	145
SCADA (Normal) Scan	2 Seconds	2	91

In considering the overall mission requirements of monitoring and control communications, one should include such factors as reliability, error rate, efficiency, as well as physical environment.

NMPC COMPOSITE

As a vehicle for helping to understand the detailed functional requirements for monitoring and control of dispersed storage and generation, use was made of a distribution system composite in the vicinity of Syracuse, New York, which represented about 1% of the total Niagara Mohawk Power Corporation (NMPC).

For many years Niagara Mohawk has been using dispersed hydrogeneration to help meet a portion of its electric power needs, and further additions of 16 new units with almost 200 MW of added capacity are planned by 1990. NMPC also has an interest in other DSG sources such as fuel cells and storage batteries for possible additions to its system.

Through the use of a few scenarios covering situations such as startup of DSG units, transient fault followed by successful reclose, and operation with the distribution system in the emergency state, it has been possible to identify a number of items that should be included in the detailed functional requirements. In particular these items have been included in the operational requirements for normal, abnormal, and emergency states; failure and abnormal behavior; and special control.

Since NMPC is NOT planning the specific DSG installations that were considered in these scenarios, it was primarily the discipline of using the scenarios and the insight to the functional requirements which was of greatest benefit in this evaluation. One of the principal insights that developed as a result of the NMPC composite-scenario effort was the fact that activities may be taking place at different times for the different DSGs so that separate status information may be required for each DSG.

COST-AND-BENEFIT ANALYSIS

The cost-and-benefit analysis effort in this DSG study has been of a general nature to identify the major issues involved. The costs considered have included those of the complete DSG unit or plant including the control and monitoring means. The benefits of DSG control and monitoring have been viewed in the perspective of the whole utility system including generation, transmission, and distribution.

The economic advantages for a particular DSG installation may vary broadly depending on a number of factors including size, cost, and available capacity factor of the DSGs; the availability of existing or planned communication means; the extent of system load growth and generation supply availabiltiy; and the environmental requirements. With the increasing costs for added central generation supply it appears that dispersed storage and generation installations should become more economically favorable in the future.

The intent of the cost-benefit study was not to answer the specific question as to whether a particular distribution DSG system design was cost effective. Rather the study was intended to provide sufficient cost and performance information insight to assist future designers of distribution DSG systems with an indication of which factors are of importance in evaluating alternative distribution DSG system designs.

2.7 CONCLUSIONS

1. The results of the DSG Monitoring and Control Requirement Definition Study indicate that there are no fundamental technical obstacles to prevent the connection of dispersed storage and generation to the distribution system although much work remains to be accomplished.

2. A communication system of considerable sophistication is required to integrate the distribution dispatch center to the many possible DSGs of differing sizes, energy characteristics, and types of owners.

3. The seven different DSGs that were studied appear to be capable of operation from a common control interface at the distribution dispatch center. However, a certain measure of customizing at the DSGs is required to accommodate the different DSGs to the DDC interface. A significant amount of advanced engineering applications work remains to be done to accomplish the desired engineering results for such integrated systems.

4. The functional requirements for DSG integration indicate the importance of the following factors:

   - Increased communication. In addition to providing the means for information flow, it is necessary to keep track of much data from many sources.
   - Utility control hierarchy. The organization of the monitoring and control structure to place proper emphasis on the power and control functions in an economical fashion.
   - Personnel safety. Utility operating personnel are required from time to time to work on the distribution system. With an increasing number of DSGs on the distribution system a greater effort is needed to ensure that there will be no degradation in the level of personnel safety.

   To achieve these requirements with low-cost hardware implies standardization of -

   - System architecture and interfaces
   - Communication protocols
   - Operator interface
   - DSG protective interface
   - DSG control interface

5. The selected DSGs that were studied varied in the detail of their local controls and in their input control requirements. In terms of their outputs, however, they have a relatively small number of different characteristics:

- Alternating current or direct current in terms of primary energy output
- Schedulable or nonschedulable in their energy availability

DSG size can have an important influence on the extent of central controllability required by the utility.

- Small DSGs need not have the power closely controlled and may be considered as a variable negative load.
- Larger units warrant greater control of their power and may be considered as an alternative to central generation.

Some DSGs that are owned by the customer may be of such a nature that the customer is unable or unwilling to let the utility control their power generation. For other customer-owned DSGs, arrangements may be made for the utility to obtain control of the scheduling of such units.

6. The 3000/1 size span of DSGs being considered, from 10 kW to 30 MW, is so great that appropriate monitoring and control means for the larger units may not be suitable for the smaller ones. For larger DSGs, i.e., greater than 5 MW, the cost of a rather complete DDC monitoring and control means seems to be a rather small portion (less than 3%) of the total DSG and control costs. For smaller DSGs, i.e., less than 0.1 MW and customer-owned, a much simpler, less expensive, monitoring and control means may be all that can be justified economically.

7. Several possible states, i.e., normal, emergency, and so forth, exist for a DSG as well as for its associated distribution system. A major effort is required to establish the control logic for the selection of the proper control mode for a DSG at each time period. Coordination of DSG and distribution protection means must be developed and implemented.

8. The six major functional requirements categories listed below provide a useful frame of reference for partitioning and describing the DSG monitoring and control requirements. These categories are helpful in establishing a useful hierarchy of control and in relating the DSGs to existing and planned distribution systems. As such, they can serve as a basis for future work on monitoring and control and provide a means for more ready exchange of information among utilities, suppliers, customers, and others in integrated DSG distribution systems.

A. <u>Control and monitoring</u> requirements that are associated with the way the DDC operator and/or EMS interact at the distribution dispatch center level to provide information about and to be able to command and control remotely those DSGs on the system. This function represents the overall, top-level control of the DSGs.

B. Power flow and quality requirements that relate primarily to the power characteristics of the DSG and as such serve to define what is physically possible from the DSG or what is essential from the point of view of the distribution network. This function pertains to the characteristics and control of the power generation or power storage process or equipment.

C. Communication and data handling requirements that pertain to the necessary information transfer and data handling between the DDC and DSGs, the data transfer interfaces between these equipments and the communication links, and the associated and necessary information processing at the DDC. These functions are primarily involved in the transfer of command and control data from the DDC to the DSGs and the return of monitoring (normal and alarm) data from the DSGs to the DDC.

D. DSG normal, abnormal, and emergency states whose operational requirements relate to local control of a DSG at its own site. Each DSG requires controls to start it up, to operate it under all of its operating states, to maintain it to stand by, to shut it down, and the ability to decide which condition or state should be ordered.

The requirements for these operational controls and the integration of these controls with commands from, and monitoring to, other portions of the distribution DSG system are included in the requirements of this category.

E. Failure and abnormal behavior detection and correction requirements that are associated with the DSG protection equipment and indicate what action is required of the protection equipment under the many possible DSG or distribution network states. This function takes place at the DSG site and represents very fast action to protect the DSG power and other equipment from damage to itself or other equipment.

F. Special DSG control requirements that are related to equipment at the DSG site and pertain to special controls such as those for startup, standby, and shutdown for each DSG technology. These controls tend to pertain to the carrying out of subordinate, but essential, functions that are actuated or initiated by other functional categories.

9. A large growth in the availability and use of the dispersed storage and generation is highly probable during the period from 1990 to 2000. Using conservative projections for electrical power demand for the year 2000 and assuming that, as an example, 5% of this is supplied by DSGs, one can estimate that,

13,000 DSG units 1 MW and larger, and

300,000 DSG units 10 kW and larger, may be required.

New and improved DSG equipments using lower cost energy sources are being designed and built, and the cost of non-renewable energy for conventional generation means continues to rise thus making dispersed renewable generation more attractive.

10. Recent Federal Energy Regulatory Commission rulings under PURPA Section 210 mandate the purchase by utilities of co-generation and power production from small facilities, i.e., under 30 MW, at price rates equal to what it would cost the purchasing utility to generate the energy itself. This ruling is intended to encourage the use of DSGs.

Continued emphasis on establishing a more definitive set of conditions of agreement, both technical and financial, between utilities and customers regarding DSG operation is required. The connection between the utility and the customer-owned DSG must be under utility control to ensure personnel safety.

11. The costs and benefits for monitoring and control of DSGs must be considered with respect to the whole system, including generation and transmission, and not on the basis of distribution alone. Likewise, scheduling and control of remote DSG units should be based on the need to make the overall system service, i.e., generation, transmission, and distribution, most effective.

2.8 RECOMMENDATIONS

The conclusions have indicated that there will be a large growth during the 1980-2000 period in the use of DSGs in connection with electric utility systems. It is important that the research and development be started now on the critical tasks noted below and that are required for the success of DSG integration. The time for this effort is now before the DSGs are commercially available on a large scale, and while development demonstrations of integrated distribution DSG systems can be used to gain valuable operating experience.

The present study program should be extended to accomplish the following tasks:

1. Scheduling/Dispatching Methods for DSGs

   Define, develop, and demonstrate effective scheduling and dispatching control of specific DSGs with near-term potential.

2. Standard Dispatching Operator Interface for Various DSG Technologies

   Define, develop, and assess a standard monitoring and control interface for utility operators to remotely control various DSGs. Particular emphasis should be given to developing means for use of common hardware and software elements for the integration of different DSGs.

3. Design Guidelines for the Integrated Operation of DSGs, Load Controls, and Distribution Automation Using Real-Time Distribution Control and Communication Equipment

   Define and categorize the conceptual framework for the operation of future utility distribution systems that contain DSGs, load control devices, and distribution automation and control systems.

4. Preparation of a Preliminary Specification for a Utility Integrated Distribution DSG System Design

   This specification for hardware and software should incorporate the recommendations from the preceding three tasks into the basis for a system design that will carry out the DDC control and monitoring and the communication and data processing functions for DSG integration into a combined DSG load control and distribution automation control system.

Section 3

RELATIONSHIP OF DSG TO EXISTING ELECTRIC UTILITY SYSTEMS

3.1 INTRODUCTION

Major elements of the overall electric utility system include the bulk generation-transmission system, the distribution system, and the customer load system. Dispersed storage and generation units can be considered as a fourth element which must be operated compatibly with the other elements of the utility system.

Overall responsibility for the bulk generation-transmission system generally rests with a company dispatching center. At present, this center is often called the energy management system (EMS). EMS directs the control of bulk generation to maintain tie-line schedules and area frequency and is responsible for minimizing the cost of power generation within security constraints. This center normally has access to telemetered values of major tie-line flows, output of generating units or plants, and system frequency. Automatic generation control is one of the major functions at the EMS and it is responsible for sending raise-lower control signals to each generator under control. For some large DSG units, control may be from the bulk level (EMS).

Many utilities have transmission divisions. Division operators are responsible for switching operations within the division. Transmission substations may be manned or unmanned. Unmanned transmission substations will be controlled and monitored via supervisory control such as the modern supervisory control and data acquisition (SCADA) systems. Manned transmission substations may also include SCADA remote units.

The distribution system is the component of the electric utility system which delivers energy from the transmission system to the customer load. The distribution system includes the distribution substations that reduce voltage to a level suitable for distribution and the distribution primary feeders and secondary circuits which connect to user load.

Figure 3.1-1 represents a typical electric utility system of the sort described above and indicates a utility system without the benefit of dispersed storage and generation.

Distribution substations have generally been operated unmanned for many years using separate subsystems for control, protection, and monitoring. SCADA remotes are becoming more prevalent at distribution substations for control and for communication of necessary information back to distribution dispatch centers (DDC). A number of DDCs may report to an EMS. Each DDC can have responsibility for a number of distribution substations, up to 50 or more in some utilities. Interest is growing in further automation of

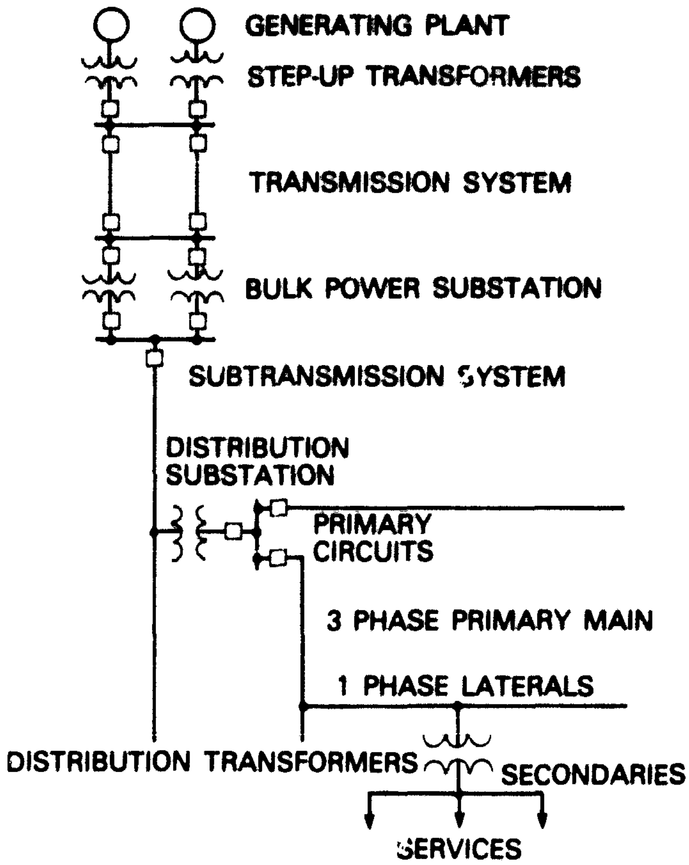

Figure 3.1-1. A Typical Electric Utility System

the distribution system to obtain benefits of better utilization of the power system and equipment, improved operation, reduced outage duration, and better information for planning.

The bulk generation-transmission system, distribution system, and customer load are shown in Figure 3.1-2 together with the major elements of a representative electric utility control hierarchy. Different utilities use differing control hierarchies depending on their own particular requirements. Power pool coordination, shown in Figure 3.1-2, is responsible for improving overall economics and has control over generation, maintaining net pool tie flow, and frequency.

Other major elements of the representative control hierarchy shown in Figure 3.1-2 include the EMS and the DDC. The full coordination between the EMS, the DDC, and the load management system (LMS) has not been fully resolved by the industry. Load management may include load control or automatic meter reading, or both.

Figure 3.1-3, patterned after the Typical Electric Utility System of Figure 3.1-1, indicates in a schematic fashion how different dispersed storage and generation equipment could be located

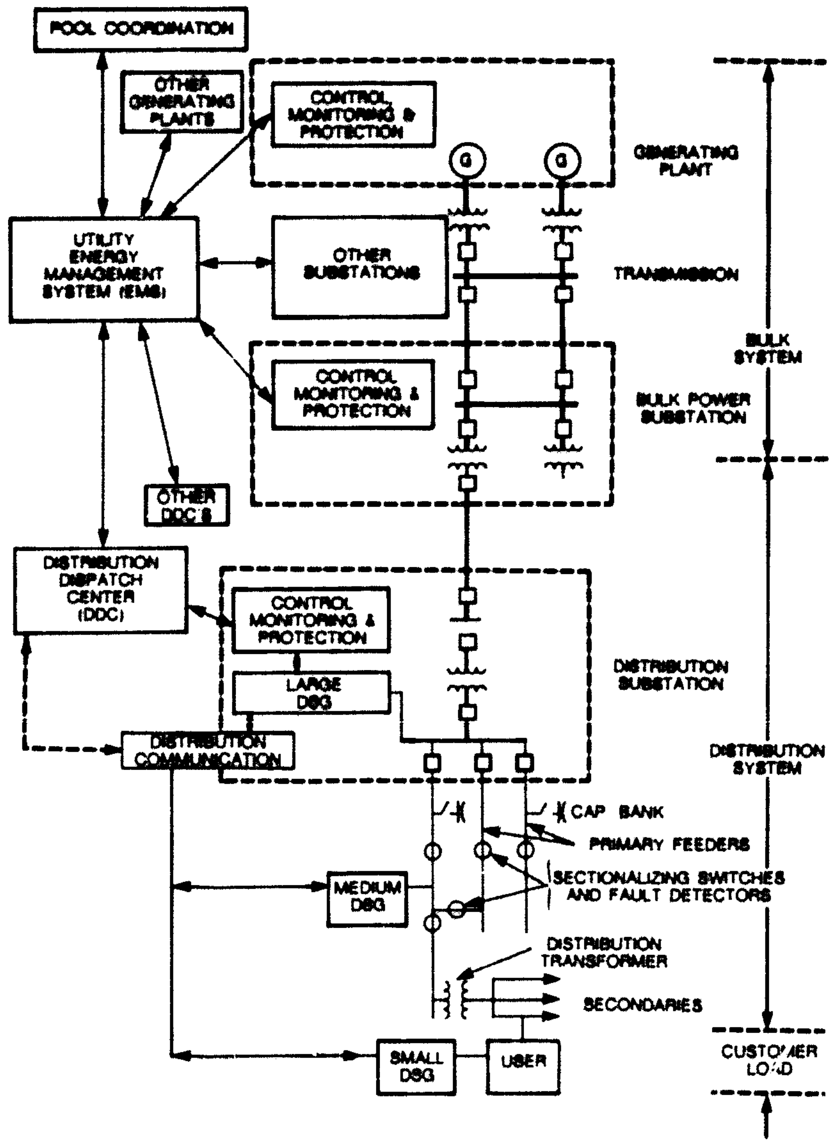

Figure 3.1-2. Representative Utility System and Control Hierarchy

at the distribution substation, the distribution feeders, or even at the customers' homes, depending on the size and ownership of the DSG source. It is anticipated that operation of DSG units of medium and large size will generally be scheduled from distribution control centers such as a DDC. In some cases control and monitoring will be direct between the DDC and the DSG units. With automated distribution systems, control and monitoring of DSG units may utilize distribution automation equipment at the distribution substation level.

Three basic methods that must be considered for DSG units to be interconnected with the utility distribution system and/or customer load are:

- DSG-Distribution System Interconnection: Utility owns and operates DSG.

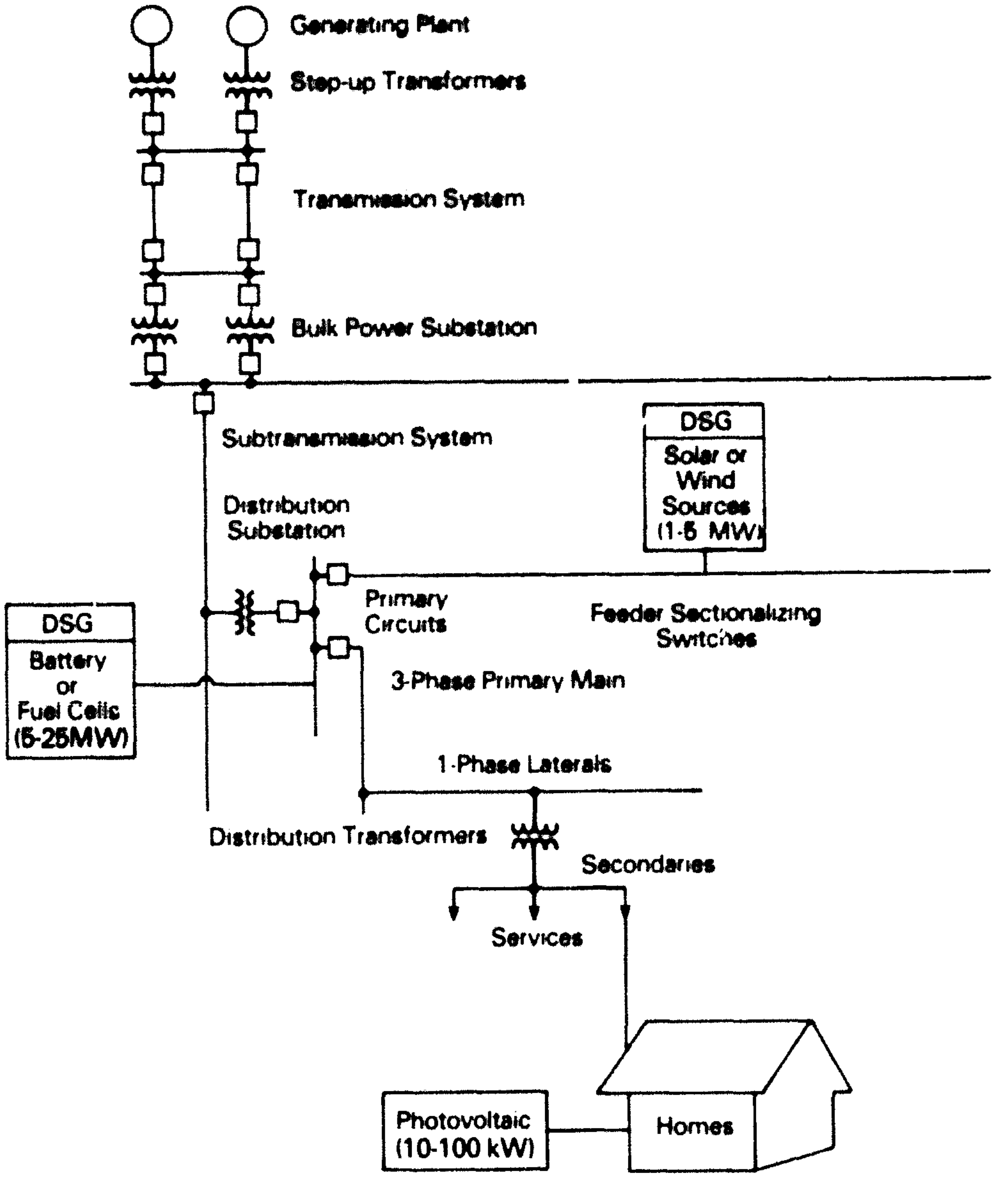

Figure 3.1-3. Typical Electric Utility System with DSG

- DSG-Distribution System Interconnection: DSG unit is connected directly to distribution system but it is owned and operated by nonutility personnel.
- DSG-Customer Load Interconnection: DSG unit is connected internally to customer load and is owned by the customer. The DSG is not tied directly to the distribtuion system except via the customer load system and the metering point.

3.2 SITING AND OPERATION OF DSG WITHIN THE UTILITY SYSTEM

Most of the DSG technologies presently being used or developed are expected to be less than 50 MW and are thus naturally matched to the distribution systems of the utilities. The DSG sources such as load leveling battery systems or fuel cell systems of approximately 25 MW, naturally interface to the utility systems at the distribution substations where the electric power is stepped down to the primary distribution voltage (e.g., 13 kV) and where an enclosed area is available for these systems. Medium dispersed sources (1 to 5 MW) such as wind or solar could also be installed within the substation or along the main feeders (e.g., 13 kV) which provide power to about 500 homes. For small sources (up to 100 kW) such as solar or wind which can provide power for a family, the natural location appears to be adjacent to the house.

Figure 3.1-3 depicts conceptually where dispersed sources may be integrated with the electric distribution system by virtue of rating. To assure reliable and efficient operation of these sources in conjunction with the traditional bulk power provided by the electric utility, the control of these sources must be integrated with that of the distribution system. Understanding of the control and integration of dispersed energy sources into the nation's utility network is needed to appreciate the research and development efforts needed to implement dispersed energy sources on a broad scale.

From an energy source siting and improved customer services point of view, DSG technologies naturally fit with the utility system in the power distribution system. From a utility operational control point of view, DSG sources must be coordinated with the operation of the total utility system. Thus, the DSG sources must be coordinated through control and communication systems on the distribution system.

3.3 POWER SYSTEM OPERATING STATES

Power system operating conditions can be described by five operating states:* normal, alert, emergency, in extremis, and restorative. The industry has not developed precise definitions for these operating states. The characterization into these five states was developed for the overall power system but the operating states have been considered primarily in relation to the bulk system. A brief description of the five operating states follows and the states and transitions between the states are shown in Figure 3.3-1.

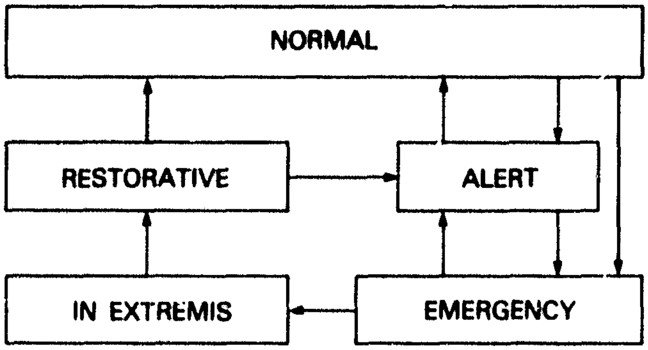

Figure 3.3-1. Power System Operating States

In the normal operating state, generation is adequate to meet existing total load demand. No equipment is overloaded and reserve margins for generation and transmission are sufficient to provide an adequate level of security for the stresses which may be imposed on the system.

The alert state is entered if the probability of disturbance increases or if the system security level decreases below a particular level of adequacy. In this state, all constraints are satisfied such as adequate generation for total load demand and no equipment is overloaded. However, existing reserve margins are such that a disturbance could cause overloads or other levels to be exceeded corresponding to physical limitations of equipment. In this state, preventative action can be taken to restore the system to normal.

In the emergency state, which is caused by a severe disturbance taking place before preventative action is taken, the system is still intact; but overloads exist, or other physical limitations of equipment are exceeded; system security is reduced, and emergency control measures are required to restore the system to the alert or to the normal state. If the action is not taken in time, and the disturbance or a subsequent disturbance is sufficiently severe, the system begins to disintegrate.

*L.H. Fink and K. Carlson, "Operating Under Stress and Strain," IEEE Spectrum, March 1978.

When system disintegration is occurring, the power system is in the in extremis state. Generation and load equalities are not satisfied and major portions of system load are lost. Physical equipment overloads are occurring and equipment limitations are exceeded. Emergency control action is necessary in this state to keep as much of the system as possible from collapse.

In the restorative state, control action is taken to pick up lost load and reconnect the system.

In the discussion of the above operating states, security is considered to be an instantaneous time varying condition that is a function of the robustness of the system relative to imminent disturbances. Security is determined by the relationship between system reserve margin and the contingent probability of disturbances. Stability is a factor in security and is related to the continuance of parallel, synchronous operation of all operating units.

3.3.1 DISTRIBUTION SYSTEM OPERATING STATES

All five power system operating states apply to the distribution system. In considering the normal, alert, emergency, in extremis, and restorative operating states in the context of the distribution system and DSG integration, the following examples of these states are suggested.

Normal - All customer loads are being served and no overloads exist on distribution substations, feeders, or equipment. Feeders are in their typical configuration. Voltage levels at all points are within specified limits. No equipment limitations are being exceeded. DSG equipment may or may not be in service depending on scheduling.

Alert - All customer loads are being served and no element of the distribution system is overloaded. "Reserve" distribution capacity is reduced in this state; however, e.g., feeder reconfiguration has occurred with load transfer to a different feeder leaving less capability to transfer load in the event of a subsequent disturbance. This state is entered when major distribution system equipments; e.g., substation transformer, or some DSGs, are out of service and result in increased vulnerability in the event of a subsequent disturbance. In the alert state, no physical equipment limitations are exceeded, but specified alarms may be occurring indicating that limits are being approached. Examples of this state are transformer LTC at maximum raise or minimum lower tap position, ratio of feeder or transformer actual current to normal rating exceeds specified limit, and so forth. As indicated, all customer loads are being served in this state. However, load management (load control) may be occurring on direction from the Energy Management System or Distribution Dispath Center to achieve a reduction in system load.

Emergency - In this state, substation or feeder overloads are occurring, or distribution equipment or DSG limitations are being exceeded. This state is entered also when underfrequency conditions are detected or when emergency load shedding is in progress by the energy management system or distribution dispatch center.

The distribution system is in the emergency state during storm or other conditions with numerous customers out of service because of lines being down and/or loss of major transmission facilities serving the distribution system.

In Extremis - Power system operational disintegration is occurring. This state can be reflected in DSG units operating in island conditions on the distribution system. Communications facilities (for control and monitoring of DSG units) to control centers may be reduced because of the conditions causing this state.

Restorative - Control action is taken to pick up customer load which has been lost. Examples of this state include load restoration with cold load pickup following load shedding, service restoration to unfaulted feeder zones on a feeder which has experienced a persistent fault, and so forth. Other examples include cases when DSGs are being reconnected to the distribution system after this system may have been operating in an islanding condition under DSG power.

3.4 DISTRIBUTION SYSTEM DESIGN AND OPERATION CONSIDERATIONS

In the integration of DSG units into the utility distribution system, it is important to study the significant design and operation considerations of the distribution system. These can be divided into three categories: general, distribution substation, and distribution feeder. Major considerations in each category are listed in Table 3.4-1.

Table 3.4-1

DISTRIBUTION SYSTEM MAJOR DESIGN
AND OPERATION CONSIDERATIONS

<u>General</u>
Economics
Load Growth Rate
New Loads
Operating Problems
Personnel Safety
Protection of Equipment
Quality of Supply
Siting
Reactive Power Supply
New Concepts
Utility Control Hierarchy
<u>Distribution Substations</u>
Transmission Availability and Loading
Future Transmission Plans
Substation Transformer Size
Load Transfer Capability to Adjacent Substations
Number of Feeder Circuits that Can Be Installed
Protection and Control
<u>Distribution Feeders</u>
Adequate Voltage to Users
Feeder Loading
Feeder Reconductoring
Sectionalizing Guidelines
Protection and Control
Fault Current Available

3.4.1 GENERAL

The electric utility distribution system has the objective of economically supplying electrical energy at satisfactory voltage to its users. The users include industrial, commercial, and residential customers and may be located in either urban, suburban, or rural areas. An important characteristic of the utility system load is that it is constantly changing. The load varies according to the daily load curve for each utility and it may have a different load shape for different weekdays and different seasons of the year. The peak load also varies.

Dispersed storage, for example that obtained from the use of storage batteries or hydrogeneration, can help meet these changing load needs. Some dispersed generation, such as solar, can have a fortunate coincidence of peak generation occurrence at approximately the same time as when high air conditioning loads occur. Thus DSGs can help meet the distribution system's changing load needs.

Increased load requires adequate capacity at each system level: generation, transmission, and distribution. At the distribution system level, anticipated load growth must be considered in planning of substation transformer ratings, breaker ratings, feeder ratings and routing, and so forth, and will affect timing of the addition of new substation and feeder capacity. Similarly, the addition of new spot loads must be considered in the design of the system.

Operating problems include maintaining the quality of supply to users, e.g., voltage magnitude, reliability of service, restoration of service after outages, load transfer to adjacent feeders and substations, and so forth.

Personnel safety considerations affect both distribution system design and operation in establishing operating and maintenance procedures for both normal and emergency conditions. Protection against faults and overloads must be provided for both the distribution substation and feeder equipments.

Siting is increasingly important both for substations and feeders. New distribution substation sites will be affected by a number of factors, e.g., availability of transmission or subtransmission supply, lack of new sites in suburban and urban areas, regulatory approvals for certain areas, proximity of load area, and so forth.

Quality of supply includes voltage magnitude, frequency, balance between phases, harmonic content of voltage and current waveforms, and reliability of service. With the trend to higher distribution voltages and longer and more heavily loaded feeders, more users are affected by a fault on the feeder. The result has been that maintaining service reliability at levels comparable to earlier 4 kV system reliability, e.g., average outage of 30 to 60 minutes per year per customer, has not been achieved generally. New concepts, such as computer control of feeder automatic sectionalizing, offer the potential to improve reliability for these longer, more heavily loaded feeders. A significant characteristic to be considered also is that while primary distribution feeders are three-phase circuits, a sizable fraction of the load is single-phase. The utilities distribute these single-phase loads among the three phases to minimize unbalance, but the actual degree of unbalance between phases is continually varying and unbalances of 10% or more are not uncommon.

Reactive power supply, or VAR supply, is another important design and operating consideration of the distribution system. In addition to the reactive power requirements of the distribution system, substation and/or feeder shunt capacitors are often used to supply reactive power to the subtransmission or transmission system.

New concepts, such as automated distribution systems, will have significant impact on future design and operation of the distribution system. Distribution substations have been operated unattended for many years; in most cases by individual separate subsystems including protective and control relays, supervisory controls, recorders, and so forth. Technical and economic advances in digital electronics technology are making possible new opportunities for integrated control, protection, and instrumentation of the distribution system and offer potential advantages such as:

- Improved utilization of power system facilities
- Improved system operation
- More complete and timely information for system planning
- Reduced outage duration

Automated distribution application areas include the distribution substation, feeder, and user level, and also distribution communications. Automated feeder sectionalizing is one of a number of distribution functions which are being considered or implemented in automated distribution systems. Improved utilization of substation and feeder facilities with opportunities for deferring new system investment offer the potential for significant economic savings through improved monitoring and control. Load management and dispersed storage and generation offer opportunities for significant savings in possible deferral of new generation and/or transmission capacity.

The utility control structure is another significant characteristic. An example was shown in Figure 3.1-2 which indicated a number of distribution dispatch centers (DDCs) which communicate upward to the energy management system (EMS) and downward to distribution substations and/or feeders and users. Each DDC, in turn, would have responsibility for a number of substations; e.g., up to 50 or more substations per DDC.

In considering the technical and operational issues of DSG integration into the distribution system, three approaches were chosen: a centralized control and monitoring approach, a decentralized control and monitoring approach, and a local approach. These are discussed in more detail in Section 6

3.4.2 DISTRIBUTION SUBSTATIONS

Distribution substations are fed from the transmission or the subtransmission system of the utility. These substations vary in size and complexity from a simple arrangement supplying one distribution feeder to highly automated substations supplying many feeders. The substations may be in urban, suburban, or rural areas; and the location will be affected by a number of factors including the load area served, the substation site availability, the regulatory considerations, and the availability of transmission or subtransmission facilities.

Several representative distribution substation configurations are shown in Figure 3.4.2-1. The number of substation transformers and distribution feeders varies according to individual electric utilities. Some substations may have only one transformer while others may have up to 4 or more with 20 to 25 feeders.

Different substation transformer kVA ratings are used by various utilities. These transformer ratings may vary from as small as 1000 to 2500 kVA for small rural applications up to 50,000 or 60,000 kVA for the larger substation transformers. For example, the typical transformer ratings used by Commonwealth Edison for their fully implemented TDC substation in Figure 3.4.2-1 is four 40,000 kVA transformers, or 160,000 kVA for the substation.

The principal components in the distribution substation are the transformers, high- and low-voltage switching equipment, and the associated protective relays and control and communications equipment. The switches, circuit breakers, and relaying and control equipment are necessary for system operation, detection of abnormalities, and the rapid isolation of faulted circuits or equipments.

Distribution substations are usually unattended. The control, monitoring, and protection functions are generally performed by separate devices at the substation; e.g., voltage control, protective relaying, chart recorders, and so forth. Utility service personnel are scheduled from a control center, such as a distribution dispatch center (DDC), for maintenance and inspection of the substation. An increasing trend is to install supervisory control and data acquisition (SCADA) systems with remote SCADA terminal units at distribution substations. These systems provide the traditional supervisory control functions of control, indication, and data and act under the direction of computer-directed master stations. Larger distribution substations may also include sequence of events recorders and fault recording systems.

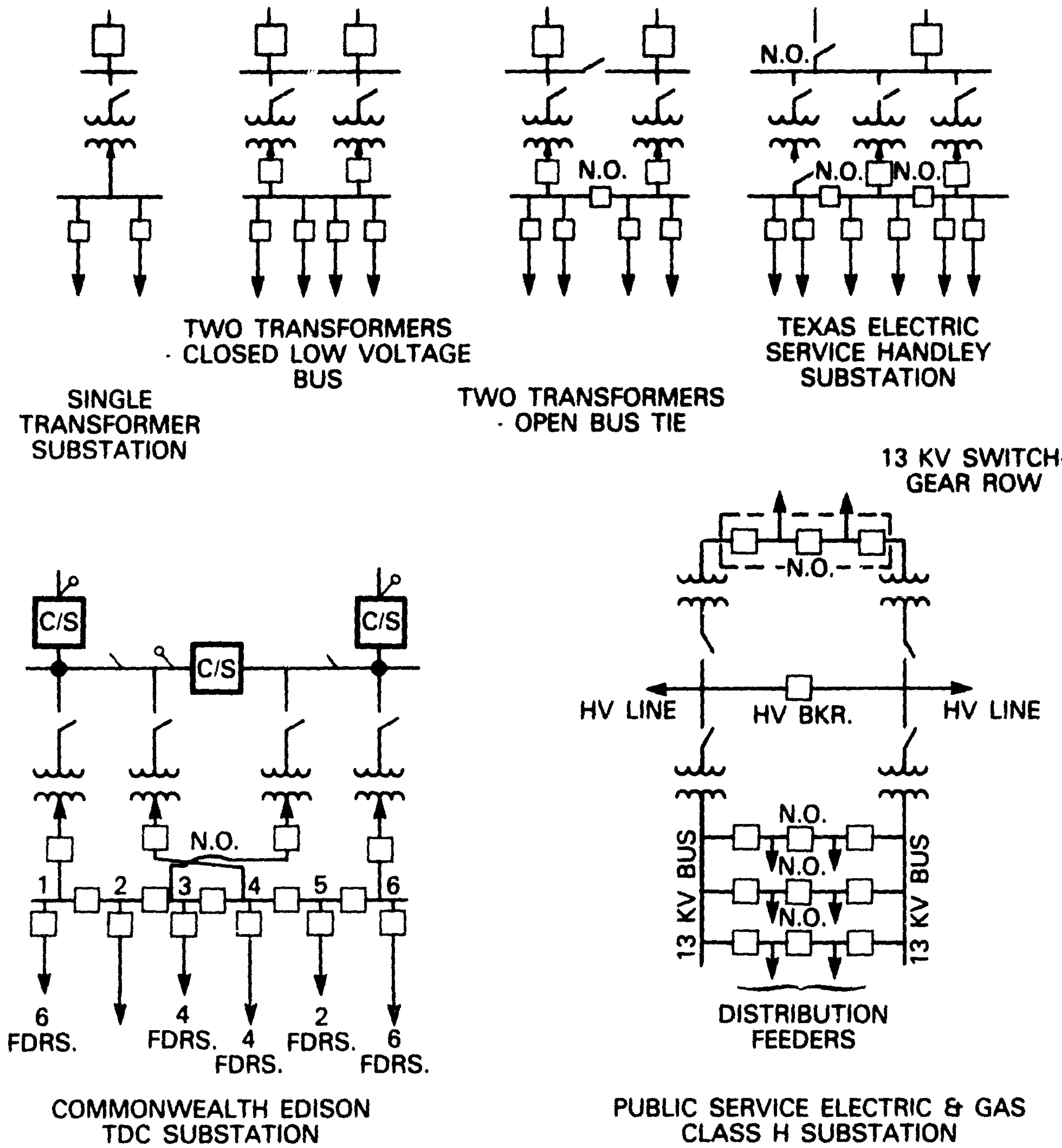

Figure 3.4.2-1. Some Representative Distribution Substation Configurations

At the substation, the voltage may be automatically regulated by using transformers equipped with tap changers that operate under load (LTC), by regulators and/or capacitors that maintain the desired voltage level on the substation bus, or by separate regulators for each feeder. LTC transformers or bus regulators may be used when all feeders connected to a transformer have similar load and voltage drop characteristics.

Control and protection functions for a distribution substation depend upon the substation configuration and size. A listing of the more common functions is shown in Table 3.4.2-1.

Table 3.4.2-1

DISTRIBUTION SUBSTATION

Representative Control and Protection Functions
Automatic Bus Sectionalizing
Automatic Breaker Reclosing
Breaker Failure Protection
Bus Differential Protection
Overcurrent Protection
SCADA Remote
-Control
-Indication
-Data
Transformer Differential Protection
Subtransmission Line Protection
Underfrequency Relaying
Volt/VAR Control
-Capacitor Bank
-Transformer Load Tap Changing (LTC)
-Voltage Regulators

These functions are shown in Figure 3.4.2-2 with a representative substation configuration, and principal equipments in the substation with which these functions act are identified.

3.4.3 DISTRIBUTION FEEDERS

The distribution circuits that carry power from the distribution substations to the local load areas are known as primary circuits or feeders. They generally operate at voltages between 2,400 and 34,500 volts. These circuits may be overhead or underground, depending on the load density and the physical conditions of the particular area to be served. The distribution system design and operation must result in the primary voltage at any point along the feeder being within prescribed limits.

As an example, one utility's voltage criteria are that the primary feeder voltage will be within the range of 98.8 to 105% during normal conditions, and this voltage must not be less than

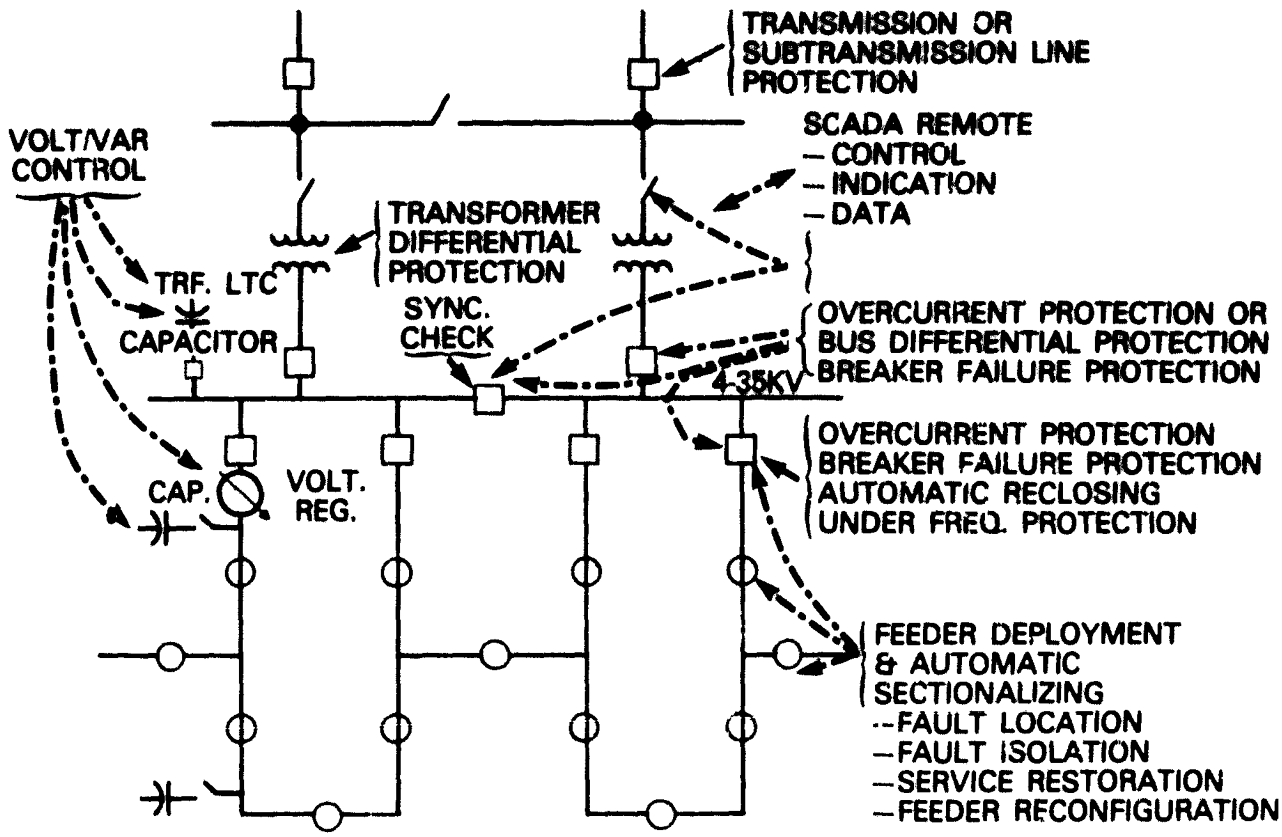

Figure 3.4.2-2. Substation Control and Protection

95% during emergency conditions. Feeder voltage regulators sometimes supplement transformer LTC for voltage control, and fixed and switched feeder capacitor banks are also used for voltage/VAR control.

A simplified diagram of a radial feeder circuit is shown in Figure 3.4.3-1. Radial feeders are generally used in distribution systems, but network systems are also used by some utilities particularly in urban areas. As shown in Figure 3.4.3-1, peak load for a 15 kV feeder will normally be in the range of 6,000 to 10,000 kVA but may be greater for some utilities. For higher voltage distribution, feeder loadings will be higher. It is also necessary to check the transformer to feeder connection current ratings for normal and emergency operating conditions. Most utilities assign a normal and emergency current or kVA rating to their feeders.

In the radial feeder arrangement of Figure 3.4.3-1, main primary feeders from a substation serve the surrounding area. Each feeder is connected to the substation through an automatically controlled circuit breaker. The remote ends of the main feeder often terminate in normally open switches to provide an alternative source of supply. Sectionalizing switches may be installed at intervals along the main feeder so that segments may be isolated to facilitate restoration of service following an outage or for

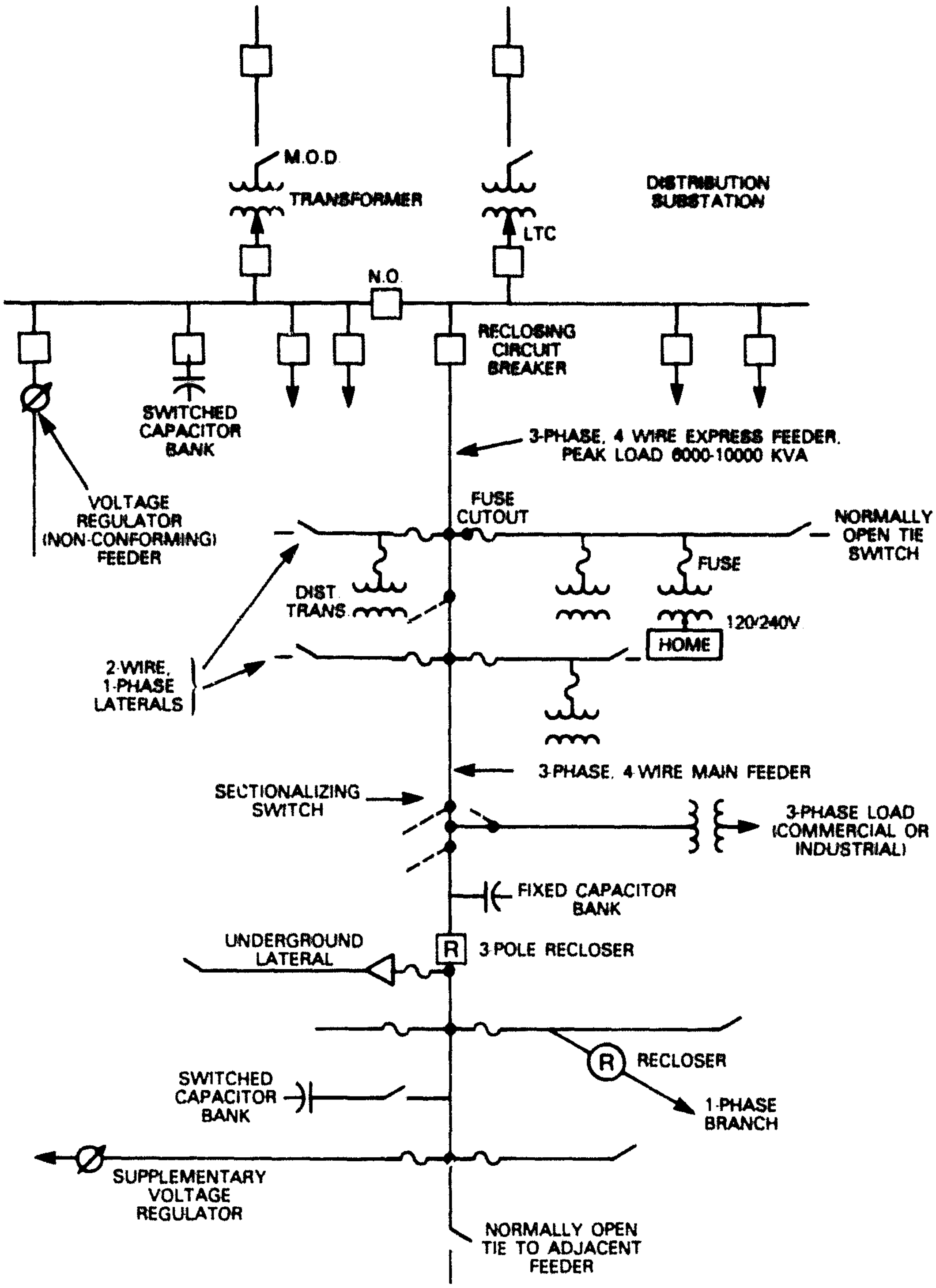

Figure 3.4.3-1. Representative Sketch of Distribution Feeder

maintenance of facilities. Laterals branch from the main feeder at intervals to serve the surrounding area. These laterals are usually connected to the main feeder through a fuse or automatic sectionalizing device. The laterals may in turn have a number of branches that are connected through fuses, switches, or other sectionalizing devices.

A representative circuit diagram is shown in Figure 3.4.3-2 showing several main primary distribution feeders, with ties between feeders from the same and from different substations. Sectionalizing switches are shown that divide the feeder into several sections or zones and that tie to adjacent feeders. For 15 kV class distribution feeders, a guideline is three or four zones (or sections) per feeder. For higher distribution voltages, 25 kV and 35 kV class, there may be four or five zones per feeder.

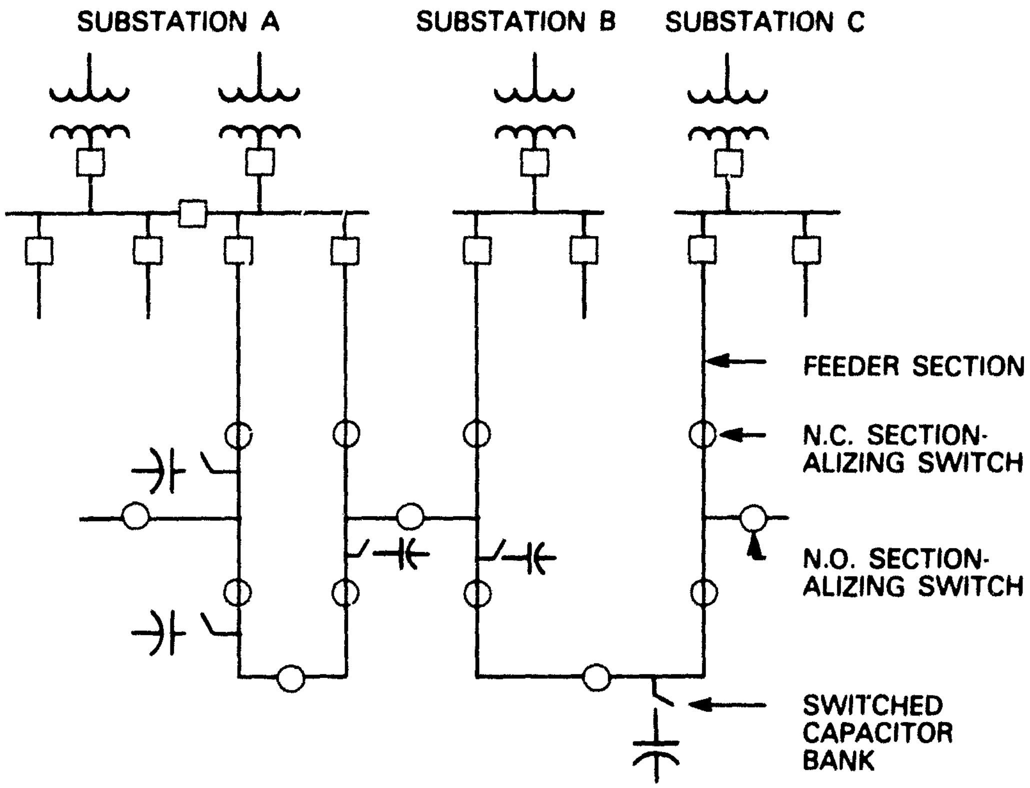

Figure 3.4.3-2. Representative Feeder Configuration Illustrating Ties Between Feeders-Load Transfer Capability and Protection and Control with Feeder Deployment and Automatic Sectionalizing

The relaying for the feeder circuit breaker at the substation is coordinated with the fuses or automatic sectionalizing devices associated with the primary laterals. In most arrangements, the feeder circuit breaker is tripped by feeder overcurrent relays and will reclose within a few cycles or after a time delay of a few seconds for a fault on the feeder. If a feeder fault is of a transient nature, such as a lightning flashover, all service will be restored and the only effect to the customers served by this feeder will be a momentary interruption. In the event the fault is persistent, a fuse or automatic sectionalizing device will isolate a faulted lateral, and the faulted lateral will be without service until the trouble is repaired or isolated. All other customers served by the feeder will experience only a momentary interruption.

In the event that a persistent fault is on the main feeder, the entire area served by the feeder will be without service until the faulted feeder zone is isolated. Service may be restored to the remaining zones by switching to alternate sources, if available. If alternate sources are not available beyond the point of trouble, service cannot be restored in and beyond the faulted zone until repairs can be made. In Figure 3.4.3-2, only the main primary feeders are shown. The sectionalizing switches are manually operated for nonautomated systems. Automated distribution systems are controlled from a remote point utilizing a distribution communication system. Depending on the degree of automation, such a system may be controlled by an operator or automatically controlled by the automated distribution system. In an automated implementation of feeder deployment and automatic sectionalizing, fault detectors would be located at each sectionalizing switch location. For a faulted radial feeder, all fault detectors between the substation feeder breaker and including the switch on the source side of the feeder will be picked up providing an indication of the fault location. An automated distribution system can then open the appropriate switches automatically to isolate a faulted feeder zone and to close the proper switches to restore service to unfaulted zones on the affected feeder.

With the addition of DSG on the distribution feeder, the above automatic fault location technique becomes more complex since additional fault detectors may be picked up depending on the DSG location and on the fault location.

Similarly, distribution recloser and fuse coordination on the feeders and laterals with the feeder breaker at the substation will be affected by the addition of DSG on the feeder. Another factor to be considered is the fact that with both distribution feeder reclosers and automatic breaker reclosing for the feeder breaker, and depending upon reclosing sequences and operations, there may be either too much or too little load remaining for a DSG located remotely on a feeder to carry the isolated load by itself. Another effect could be the out-of-synchronism reclosing between the system and the DSG with resulting higher transient torques. Conditions such as these can be associated with DSGs operating under the situation of "islanding."

The distribution feeder breaker and feeder reclosers are selected on the basis of voltage class and of fault current available. The addition of DSG units, either at the substation or remotely on the feeder, may affect the available fault current and this must be considered in choosing interrupting ratings.

Listed in Table 3.4.3-1 are some of the more significant distribution feeder characteristics or requirements that must be considered in integration of DSG with the feeder.

Table 3.4.3-1

SOME DISTRIBUTION FEEDER CHARACTERISTICS OR REQUIREMENTS TO CONSIDER WITH DSG

Communications to/from DSG
Fault duty
Fault location determination
Feeder loading capability
Feeder phase unbalance
Feeder reactive power requirements
Feeder reclosing
Feeder protection
Quality of service
Personnel safety

3.4.4 CUSTOMER LOAD INTERCONNECTION

There will be some cases where DSG units are connected within user load systems. In those events the DSG is most likely to be controlled by the user. It is not tied directly to the distribution system except through the user connection to the utility distribution system and metering point. Many of the factors listed in Table 3.4.3-1 will apply with the DSG unit connected in the customer load system.

3.5 TRANSITION OF DSGs INTO WIDESPREAD ELECTRIC UTILITY SYSTEMS USE

The previous portions of this section have stressed the nature of the current electric utility systems in the United States and have indicated in a general way the location at which DSG plants may be placed in future distribution DSG systems. Subsequent sections of this report will present information on planning for integrating DSG plants into the distribution system, and on determining the criteria for deciding how much of what type of which DSG technology should be purchased when and located where.

It is worthwhile at this time to comment briefly here about what is likely to be the nature of the transition from the present condition where few DSGs exist, to a condition in the next 5 to 10 years when there will be some significant number of DSGs installed and in operation, to the years 1995 to 2000 when there will be many DSGs in operation. What will be described represents simply an educated guess as to what may happen rather than any authenticated plan of some official planning group.

3.5.1 FEW DSGs

The present situation where a relatively small number of DSGs, principally small hydro, are being operated, represents what happens when there are only a few DSGs on a utility system. This situation causes a small enough impact so that the DSGs can be handled as a minor adaptation of past practices.

For scheduling purposes, the few small generating units are treated as are other scheduled units. The dispatcher, by phone or other means, is in touch with the people who look after each unit or who set the clock timers that can start or stop any automatically controlled generators.

Automatic remote control or monitoring is limited, and telephones and manual control and monitoring of chart data at the site are the accepted procedures. Thus, experience is being obtained with the operation of the DSGs on the power distribution system, but there is a very limited amount of control and monitoring in a remote control sense. The power scheduling is done at the EMS or the top utility level.

3.5.2 SOME DSGs

The situation visualized for the next 5 to 10 years has one or two DDCs operating on an experimental basis monitoring and controlling 10 to 20 preproduction or commercial DSGs. Remote control and monitoring are handled by automatic control equipment, but there is a fair amount of manual control for backup purposes. Scheduling of the DDCs is done at the EMS level on a computer basis using algorithms which have been developed and which are being evaluated for their effectiveness and possible change if required.

DDC scheduling and automatic generation control are being employed and the communication and data handling proposed for full automatic control operation are operating. Considerable manual supervision of the automatic equipment at the DDC and the DSG levels is taking place to ensure the proper operation of automatic equipment and the smooth functioning of the system.

3.5.3 MANY DSGs

Successful tests at a few utilities and demonstration projects by the DOE and the New York State ERDA in the next few years will encourage much more extensive use of DSGs. By 1995 to 2000 there will be many DDCs and DSGs and the distribution DSG systems will be as described in Sections 6 to 9 which follow. Fully automatic operation of DDCs and DSGs will be well established, and the scheduling of DSGs will be carried out at the DDC level. Ways of handling many small-sized, customer-owned-and-operated DSGs will be well established and more than one way of communicating between DDC and DSG may well be operating.

Thus there is visualized a gradual transition in the amount and character of the DDC, DSG, and communication equipment with time and experience as the DSGs become more of an accepted portion of the distribution system. Throughout this transition period there will be the basic electric distribution system which the public will interface with and which will appear to remain relatively unchanged in terms of the quality of the service provided to the customer.

Section 4

CRITERIA FOR ASSESSING DSG TECHNOLOGIES FOR INTEGRATION INTO UTILITY DISTRIBUTION SYSTEMS

4.1 INTRODUCTION

From the perspective of the electric utility, there are several major issues that must be considered and evaluated in the process of selecting DSG technologies to be integrated into utility distribution systems.

From technical evaluations alone it may be possible to apply more than one DSG technology for a particular application. However, other considerations such as economic, energy characteristics, or institutional regulatory issues may dictate the use of certain specific DSG technologies more than others.

In addition to general issues, each utility tends to have unique characteristics that directly influence and have an important impact on the selection process. Examples of such unique characteristics are the utility's geographical location, size, energy resources, bulk energy system composition and configuration (generation and transmission), interconnections with other utilities, system load characteristics, expansion plans, and utility type (public or private). Thus, the factors influencing the selection process have to be examined on an individual utility basis.

4.2 MAJOR ISSUES

The major issues considered in assessing DSG are:

- Commercial availability of the DSG
- Cost-benefit economics
- DSG size, number of units, and total capacity
- Energy source characteristics
- Operational and technical characteristics
- Generic operational and technical features
- DSG interaction with power system
- Institutional and regulatory requirements

4.2.1 COMMERCIAL AVAILABILITY

In the context of electric utility system planning for generation and transmission expansion, it is fundamental that any DSG included in expansion plans be commercially available. It is necessary to have assurance that a DSG will be available in the period for which it is being planned; therefore, several DSG technologies are considered in this study even though their commercial availability is not foreseen until the 1990's.

Table 4.2-1 presents a list of the technologies that have been considered most extensively in terms of their control characteristics as well as their present status and anticipated commercial availability during the period 1980-2000. These data were described in Appendix B under the heading "Maturity of Selected DSG Technologies" and indicate that each of these DSGs should be commercially available by the year 1990. Although some technologies like hydro and cogeneration are commercially available now, each of the others appear sufficiently close to commercial availability by 1990 to warrant their consideration.

4.2.2 COST-BENEFIT ECONOMICS

The economics of any proposed system generation, transmission, or distribution expansion is of vital concern to an electric utility company, because it directly affects the company's revenue requirements and the cost of producing electric energy. In analyzing the overall economic viability of a DSG, the total cost of producing electrical energy, including the total installed cost of the equipment as well as the total operating and maintenance costs, is fundamental in comparing the DSG to alternative means of supplying the needed energy.

Because electrical power is needed to meet the customer's load demands, it is essential that there be sufficient installed electrical generation capacity to provide the required power. Some DSGs represent sources of generation that are available only at certain times, i.e., when the wind is blowing, the sun is shining,

Table 4.2-1

PROJECTED COMMERCIALIZATION DATE OF DSG TECHNOLOGIES
(1980 - 2000)

DSG Technology	Present Status	Anticipated Date of Commercialization	Total Power Added by 2000 GW	Number of units and assumed rating
Solar Thermal	Experimental	1990	2	2,000 @ 1 MW Avg.
Photovoltaic	Experimental	1990	2	2,000 @ 1 MW Avg.
Wind	Preproduction	1990	6	3,000 @ 2 MW Avg.
Fuel Cell	Preproduction	<1990	3	600 @ 5 MW Avg.
Battery	Experimental	<1990	15	3,000 @ 5 MW Avg.
Hydro	Mature	Now in Use	6	1,200 @ 5 MW Avg.
Cogeneration	Commercial	Now in Use	30	1,500 @ 20 MW Avg.
		TOTAL	64	13,300

Note: Inclusion of smaller residential units, such as photovoltaic, could raise to more than 300,000 the number of DSG units supplying power nationwide for distribution use (see Table 5.9-1).

the water flow is available, or the battery is sufficiently charged. If these times are not the same as when the electrical energy is needed by the customer, it may be necessary for the utility to have additional reserve or standby generation capacity. Such standby capacity in turn may require generation capacity costs for the utility system to provide assured electrical generation. The use of renewable energy source DSGs may result in the utility requiring some additional standby generation capacity costs, resulting in a somewhat higher total cost, including energy and equipment capital charges.

Thus, for specific applications a complex cost-benefit analysis must be performed that compares total benefits and costs to the entire lifetime of the plant. The principal benefit will sometimes be the displacement of conventional (fossil) energy by the renewable energy source. Some of the DSGs will have capacity factors of 0.25 to 0.50. The availability and dependability of the renewable energy source will determine what amount of system generation capacity credit can be assigned to the particular DSGs in the cost-benefit evaluation. At present there seem to be no generally accepted methods for performing cost-benefit analyses of DSG applications.

There are additional factors of system costs and benefits that also must be considered. All benefits directly derived from DSG application, such as reduced generation capacity, reduced generation energy costs, reduced bulk transmission and distribution system losses and investment, should be credited to the DSGs. Added costs, such as those required for monitoring and control, as well as those for increased reserves, should be charged to the DSGs.

4.2.3 DSG SIZE

Dispersed storage and generation has been defined as being located in and connected to the distribution portion of the electric utility system. Thus it is connected to the distribution system at some point between the secondary side of transmission substations and the customer's premises. There will also be cases where it is connected to the user's load bus. Generally, the point of electrical connection will relate to the size (MW rating) of the DSG unit, although some large cogeneration units are customer owned. DSGs may range in size from a few kilowatts, located on single residences or farms, to large units of many megawatts, which may have their own substations connected to the subtransmission circuits in the utility systems. A wide range of electrical ratings is possible for DSG application and, to some degree, relates to the nature and characteristics of the type of DSG plant. The DSG size range in this study is considered to be from 10 kW to 30 MW.

A factor of some importance that is related to size is the extent to which a DSG is integrated into the utility distribution system. Integration refers "(1) to a DSG connection to a utility system in which provisions are made for the protection of the DSG as well as the system, and (2) to the operation of the DSG as a managed component of the total utility supply system."* In the sense of this usage of the term "integration," generation or storage size alone will not be the sole criterion of a DSG; also of importance will be the extent to which the energy source is operated as a managed part of the total utility supply system.

In general the DSGs will be plants capable of automatic or semiautomatic unattended operation. This will be necessary to keep the operating costs low to achieve economic viability. However, certain DSGs, such as a cogeneration plant, will have operating personnel present for other portions of the plant and process, and the generation equipment would incur only incremental personnel operating costs. In contrast, central station generation plants connected to the bulk power transmission system are large complex plants that require continuous-duty operating personnel and staff and tend to be from 50 megawatts to several thousand megawatts in size.

4.2.4 ENERGY GENERATION CHARACTERISTICS

DSGs may be characterized by the type of energy they utilize in generating electricity. The type of energy in turn will have a major effect on DSG operational characteristics as well as the other selection issues. There are two basic categories of DSG generation. They are identified by the energy being nonrenewable (fossil fuels) or renewable (sun, wind, or water). A third DSG category is that of energy storage, whereby electric energy is withdrawn from the system at a time of low incremental cost and returned at a time of high incremental cost.

Regarding nonrenewable energy sources, fossil fuels inherently have the property of energy storage and thus can provide for variation in electric energy production upon demand. In contrast, renewable sources tend to be periodic and/or variable in supply and are less predictable in time as a source for a utility system. Typical periodic source examples are: solar (used in solar thermal electric and photovoltaic plants, which are only partially available on a 24-hour cycle); water (available on a variable seasonal, monthly, and weekly basis with surges due to storms); and wind (available according to seasonal variations as well as more random occurrence). Other renewable energy sources, such as geothermal and biomass/biofuel, can provide a continuous energy supply. Biomass/biofuel, however, represents a form of stored energy that is quite similar to fossil fuels, and plants tend to be larger than DSG size.

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*K. Bahrami and R. Caldwell, Electric Utility Systems Application of Dispersed Storage and Generation, Summer Power Meeting, Institute of Electrical and Electronics Engineers, 1979.

The constancy and predictability of an energy supply source for electric energy production has a significant effect on its value to a utility with regard to the overall system generating capacity. Energy storage has the basic role of reducing energy production costs by more effectively utilizing large central station units, which have low incremental cost of energy production, returning (supplying) the electric energy to the power system during times of peak load to replace energy that would be produced by higher incremental cost (less efficient) peaking generation units. Storage can also be used as generation reserve to replace units that are out of service due to an unscheduled outage. Thus, the inherent characteristics and supply quantity of the energy supply source is a major issue in selecting DSGs for application on a specific utility.

To satisfy their load requirement in the most economical way, electric utilities control generation output on an equal incremental cost basis.* Figure 4.2.4-1 illustrates the increasing incremental cost as generating unit output is increased. From this figure one can visualize that the process of storing energy at times when the energy costs are low and using the energy when the energy cost is high represents an effective way of obtaining economic benefits.

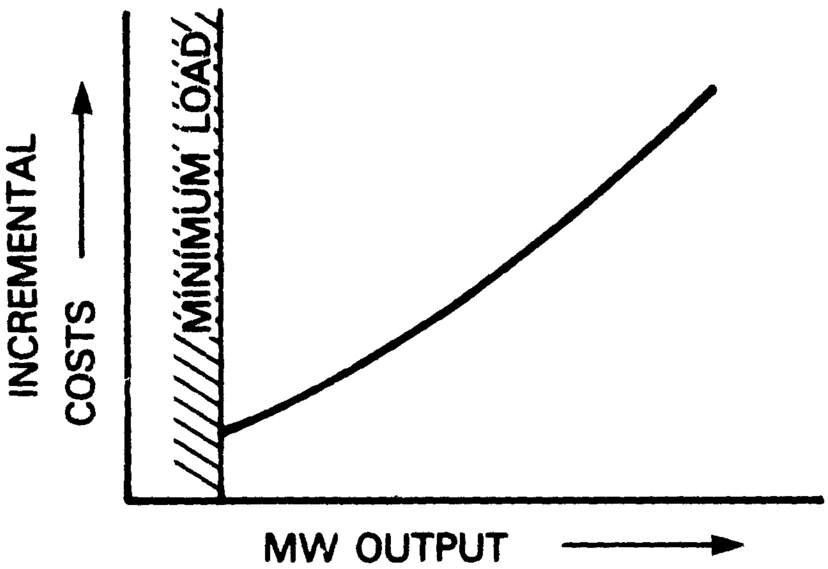

Figure 4.2.4-1. Incremental Costs

*Leon K. Kirchmayer, Economic Operation of Power Systems, John Wiley and Sons, 1958.

In addition to renewable and nonrenewable categories, DSGs may be characterized also in terms of ac or dc primary output and whether they are schedulable or nonschedulable. Their characterization is represented on Table 4.2.4-1. Illustrative examples of DSGs that are representative of renewable/nonrenewable, and schedulable/nonschedulable types are also shown in Table 4.2.4-1.

Table 4.2.4-1

DSG CHARACTERIZATION

Type of DSG	Power Conversion	Scheduling of Power	Examples
Nonrenewable or Renewable	ac	Schedulable	Cogeneration Hydro (with storage)
Renewable	ac	Nonschedulable	Solar Thermal Electric Wind Hydro (Run-of-River)
Nonrenewable or renewable	dc/ac	Schedulable	Fuel Cell Storage Battery
Renewable	dc/ac	Nonschedulable	Photovoltaic

4.2.5 OPERATIONAL AND TECHNICAL CHARACTERISTICS

Operational and technical characteristics can have a significant influence on the value of specific DSGs for application on an electric utility system. Two important operational characteristics regarding overall system operation are the availability and the reliability of the DSG source. The ability to schedule the power generation source, either continuously or periodically, with a high degree of dependability relates to its availability. Not only does the availability of a DSG influence its generation capacity value, but also the nature of its availability can affect the logic procedure necessary to estimate its operational capability. If the electrical output of a DSG is quite random with time, the dependability and value of the DSG nominal capacity may be reduced from its rated capacity.

The reliability of the DSG equipment also affects the availability of the overall DSG system. Because the reliability or operability of the DSG system can be checked in a reasonably systematic fashion, and generally the reliability can be designed to be in the order of 80-90%, the reliability may be far greater than the availability of some DSG technologies.

Other operational issues relate to system operation and scheduling regarding DSG startup and shutdown time requirements. These will vary widely for different types of DSGs and have an influence on their flexibility for systemwide energy management functions. Some types of DSGs, like photovoltaic, have a short startup time.

Others, like solar thermal electric, have relatively longer startup times.

Complexity represents another technical issue that is an important factor in the assessment of a particular DSG. Some DSGs have relatively few elements that must be controlled, or have few moving parts. Others involve many separate parts, each controlled independently, such that the probability of all parts working properly and well is greatly reduced.

Complexity not only affects performance but may influence operation and maintenance requirements, and therefore it impacts the cost of operations and maintenance. If the plant is extremely complex, it may require full-time operators and thereby tend to force a larger plant size in order to be economically viable.

Application issues include power quality and control, physical and electrical location within the distribution system, and integration of the DSGs into the distribution system. These application issues concern technical matters such as power flow, voltage level, stability, and protective coordination. The application of a DSG requires consideration of the conditions and characteristics of the particular part of the distribution system to which the DSG will be connected, and with which it must be compatibly integrated. Voltage, power flow, and system protection are of primary importance and require coordination for a successful DSG application.

4.2.6 GENERIC OPERATIONAL AND TECHNICAL PROBLEMS

There are five generic operational and technical problems to consider in defining control and monitoring requirements for integrating DSG into the electric utility distribution system. These problems are:

- Economics of operation
- Quality of supply
- Security of supply
- Protection of equipment
- Protection of personnel

4.2.6.1 Economics of Operation

After an electric utility has justified and installed generating equipment, it is concerned primarily with incremental costs. Economics of operation is concerned with minimizing fuel, operating, and rescheduling costs of customer load. Different criteria may be used by different control systems. The utility will be concerned with total fuel costs, losses, and revenues; while an individual customer will be concerned with fuel costs, electricity bills, and effects of rescheduling use of electricity.

4.2.6.2 Quality of Supply

Quality of Supply is maintained if the following quantities are maintained within respective bounds for each customer and if sufficient real power is available to meet the customer's demand for power: reliability of supply, voltage magnitude, balance between phases, frequency and system time, harmonic content of voltage, and current waveforms.

4.2.6.3 Security of Supply

Security of supply is concerned with predicting whether the given quality of supply will be available in the future.

4.2.6.4 Protection of Equipment

Equipment on the system (bulk, distribution, DSG, and customer) must be protected from damage. There are four basic concerns:

(1) Voltage magnitudes must be kept within bounds because of insulation.

(2) Current/power flow must be kept within bounds because of heating.

(3) Frequency must be kept within bounds to prevent damage that is due to overspeed or underspeed.

(4) Harmonic content must be kept within bounds because of its impact both on equipment and control-monitoring systems.

4.2.6.5 Protection of Personnel

Personal safety of both utility personnel and customer personnel must be protected. A prime concern is to make certain that the presence of DSG systems does not result in a distribution system being energized accidentally while utility personnel are working on it.

4.2.7 DSG INTERACTION WITH POWER SYSTEM

It is important to recognize phenomena that involve interactions between the DSG unit and the rest of the power system (bulk, distribution, customers, and other DSGs). Obviously such interactions depend on the characteristics of both the DSG and the rest of the power system. DSG characteristics of concern include:

- Harmonic generation
- Startup/shutdown time requirements
- Synchronism with system
- Voltage/VAR abilities
- Real power economics
- Dynamic response when interconnected

One possible list of phenomena is given in Table 4.2.7-1.

Table 4.2.7-1

SYSTEM PHENOMENA

- Harmonic Generation, Propagation
- Switching
- Transient Stability
- Dynamic Stability
- Slow-Speed (Long-Term) Dynamics
- Automatic Generation Control (AGC)
- Real-Power Scheduling
- Voltage-VAR Scheduling
- Restoration
- Island Operation

Harmonics generated by a DSG can have an adverse effect on the rest of the power systems. Two key issues of concern are the effect of harmonics and the propagation of harmonics. Harmonics may be undesirable because of heating or energy losses produced by them in power equipment, or because of the noise or other objectionable interactions that harmonics produce on communication or information-handling equipments. Losses in power equipment represent added cost for the energy loss, or for the reduced efficiency of the power process. Harmonics in communication networks may produce higher error rates or objectionable visual, auditory, or other environmental effects. On some occasions the effects of harmonics are propagated to equipments that are quite remote from their place of origin so that the unfavorable results appear to be unrelated to the source.

Switching is concerned with both fast automatic circuit breaker switching and slower sectionalizing actions. Switching actions of concern are those between DSG and distribution, DSG and customer, and customer and distribution depending on types of interconnection; on distribution system; and on bulk transmission system.

Transient stability refers to the dynamic behavior of the system immediately following major disturbances such as faults or major switching operations. The phenomena could be caused by problems events on the bulk system that influence the distribution system or by events on the distribution system that cause interaction between various local DSGs, et cetera.

Dynamic stability refers to sustained low-amplitude oscillations between elements on the system. Such oscillations could occur between DSGs and the bulk system; could be caused by interactions between elements on the bulk system that are affecting the DSGs; or could occur between DSG units and customer loads without impacting the bulk system.

Long-term dynamics (time scale seconds to minutes) refer to slow-speed variations in voltage, frequency, line flows, et cetera. Voltage and/or line-flow problems could occur either on just the distribution system or could also involve the bulk transmission system. Frequency involves both the bulk system and the DSG.

AGC is the conventional function presently being performed by the bulk power system control centers. The dynamics of concern involve interactions between the bulk generation, DSG units, and load fluctuations.

Real power scheduling can be divided into three main areas following existing bulk system terminologies:

- Economic dispatch: readjustment of real-power levels every five minutes
- Unit commitment: determination of hour-by-hour schedules of real-power generation and storage for the next week
- Maintenance scheduling: determination of a maintenance schedule on a weekly basis for the next year.

The problem is to minimize cost as defined in terms of losses, fuel used, and rescheduling costs while considering security constraints such as maintenance of satisfactory reserve.

Voltage/VAR scheduling will probably be done on an hourly basis or perhaps slower if past history from bulk power systems is applicable. The problem is to maintain the voltage magnitudes within an acceptable range and to adjust voltages and reactive power to minimize distribution losses.

System restoration after major outages such as loss of distribution lines, feeders, and/or customer's load is a special concern, because the loss of distribuiton lines and feeders through storm damage will often be coupled with loss of communication.

Island operation occurs when portions of the load are served entirely by DSG units even though there is no electrical interconnection with the main power system.

4.2.8 INSTITUTIONAL AND REGULATORY ISSUES

Institutional and regulatory issues can have a major impact on DSG selection. If relatively small generating sources are subjected to complex operating rules and procedures, lengthy and costly licensing procedures, and environmental constraints, then the institutional and regulatory issues may place disproportionate costs on these plants. By contrast, if large plants having much larger capacity and capital investment are subjected to the same issues, they may be able to bear the same costs but at a lower percentage of total plant cost.

Conversely, strict environmental or space constraints on bulk generation and transmission may practically force a predominantly urban utility to utilize small or medium-sized environmentally acceptable DSGs, regardless of economics.

In addition, other institutional factors such as favorable tax policies regarding write-off/depreciation and investment tax credit can have major impact on economic incentives and decisions regarding DSG technologies. The influence of such factors is to make some DSGs appear to be more or less attractive than would be the case without the institutional factors included.

All of these issues are important and must be considered in the application of DSG.

4.2.8.1 FERC and PURPA

On February 25, 1980, there was an official clarification of the regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with regard to small power production and cogeneration.

> *The Federal Energy Regulatory Commission (FERC) has issued its final rules that require utilities to buy power from qualifying cogeneration systems or from small generating facilities. Subpart B, which defines "qualifying facility" under Section 201 of the Public Utility Regulatory Policies Act (PURPA), is RESERVED and will be the subject of a separate rule making "in the near future." However, Section 201 of PURPA defines a small power production facility as one that generates no more than 80 MW and uses biomass, geothermal, waste, or renewable resources, including wind, solar and water, to produce electric power. A cogeneration facility is defined as one producing electricity and any other form of useful energy used for industrial, commercial or heating purposes. Implementation of these rules is left to the State regulatory authorities.*
>
> *Under the new regulations, electric utilities must purchase the electric energy and capacity made available by qualifying facilities at rates equal to what it would cost the purchasing utility to generate the electricity itself, or to buy the energy or capacity from other suppliers. This is called "avoided costs." The rules also provide that electric utilities must furnish the qualifying facilities with supplemental, or back-up power "on a nondiscriminatory basis and at a rate that is just and reasonable." It exempts all qualifying cogeneration facilities and certain qualifying small power production facilities from certain provisions of the Federal Power Act, from all provisions of the Public Utility Holding Company Act of 1935 and from State laws regulating electric utility rates and financial organization as follows:*
>
> 1. *Federal Power Act - All qualifying cogeneration facilities and those small power production facilities that do not exceed 30 MW generation capacity.*

2. Public Utility Holding Company Act of 1935 - Cogeneration facilities and small power production facilities of 30 MW or less generation capacity, with the exception that any qualifying small power production facility with a power production capacity over 30 MW (up to 80 MW) that solely uses biomass as a primary energy source, is also exempted.

3. State laws and regulations concerning utility rates and financial organization - same as (2) except that a facility may not be exempted from State law and regulation implementing this rule.

The utilities will have to pay to the generating facilities the full amount they save by purchasing this power and not generating it themselves. FERC notes that, "in most instances, if part of the savings from cogeneration and small power production were allocated among the utilities' ratepayers, any rate reductions will be insignificant for any individual customer. On the other hand, if these savings are allocated to the relatively small class of qualifying cogenerators and small power producers, they may provide a significant incentive for a higher growth rate of these technologies." FERC also says in the Preamble that it "recognizes that the translation of the principle of avoided capacity costs from theory into practice is an extremely difficult exercise, and is one which, by definition, is based on estimation and forecasting of future occurrences." Therefore, the States, who must implement these rules, are given the "flexibility for experimentation and accommodation of special circumstances" and will have one year to issue detailed procedures and/or regulations."

In determining "avoided capacity costs," utilities must account for both fixed and operating costs saved by buying power from these facilities, at the true value (not some average) of the purchased power. FERC gives as an example, the case where power output from a photovoltaic facility would be maximum at the same time as the system peak when purchased by a summer peaking system. The facility's capacity coincidence with the system peak should be reflected in the purchase price being based on the utility's costs of running its peaking units not on its average system cost.

FERC further says that the prices paid by utilities must take into account the costs of new construction that would be avoided by these power sources. "If a qualifying facility offers energy of sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rates for such a purchase will be based on the avoided capacity and energy costs."

Edison Electric Institute commented on the proposed rules that the avoided cost approach provides no incentives to utilities to seek electricity from these facilities and that a lower, share-the-savings rate should be used. FERC concluded, however, that this full avoided cost approach is required to encourage new, and risky, technologies.

Congress has mandated that cogeneration and power production by small facilities will be encouraged through PURPA. Whether these rules, which force utilities to buy this power, will in fact encourage cogeneration remains to be seen. There are some advantages, other than cost, to be gained by the utilities in promoting cogeneration facilities as a means of adding capacity, while at the same time avoiding the costly and time consuming permitting process, certain oil use restrictions of the Fuel Use Act, and exemption from certain Federal and State regulations.*

*M.M. Schorr, internal GE communication, February 29, 1980.

Section 5

TYPES OF DSGs AND TRENDS IN THEIR USE

In order to be able to remotely control and monitor a DSG, it is necessary to understand how that DSG operates under its own local control. Since Appendix A on "Selected DSG Technologies and Their General Control Requirements" describes in some detail each of the seven types of DSG technologies mentioned below, the emphasis in this section will be primarily on the nature of control systems associated with the local control of each DSG technology.

In the following descriptions of the individual DSG technologies, the primary attention will be on how a master control for each DSG relates the control and monitoring from a remote distribution dispatch center (DDC) to the various subsystem controls of modes and other subfunctions that are necessary for the DSG to perform its dispersed storage or generation function.

It should be noted that smaller dispersed DSGs, which may be similar in principle to the types of DSG described below, may be operated under the control of the customer. In this event the decision-making process involved in establishing the control of power level, schedule, and so forth may be different, since it is the customer and not the utility who has the primary monitoring and control responsibility. Nevertheless the same underlying physical principles and constraints of the DSG technology may be overriding. When and how many DSGs are likely to be available for control is an additional matter of interest. Although this subject is discussed more completely in Appendix B, "State of the Art, Trends, and Potential Growth of Selected DGS Technologies," mention of the time of commercial availability as well as the extent of generation by the year 2000 is included in this section.

5.1 SOLAR THERMAL ELECTRIC

Solar thermal electric energy conversion systems collect solar radiation and convert it into high-temperature heat. The heat is transferred to a working fluid, often water or steam, for use in a mechanical-electrical generation system. Solar thermal electric energy may be used in an energy system providing both electricity and thermal energy. Energy storage may also be included as part of the thermal energy system.

Common to all of the solar thermal electric systems are control subsystems for collectors, power conversion, energy transport, and energy storage. Also common to all of the solar thermal electric systems is the fact that sunlight is available for only a limited amount of time. One alternative to this problem is to generate electrical energy from the sun and store it to meet customer needs when the sun is not shining. Another alternative is to use the output from the solar thermal electric system when available and to use other energy sources such as coal, nuclear, or oil when the solar energy is not available.

Representative of one form of solar thermal electric generation is the design concept shown in Figure 5.1-1. Two types of collectors are shown:

- A saturated steam field (approximately 80% of the collectors - about 200 in number)
- A superheated steam field (approximately 20% of the collectors - about 50 in number)

The two fields are connected by a steam accumulator as shown schematically in Figure 5.1-1. Basically, the system operates by generating saturated steam, collecting this saturated steam (quality varying with insolation) in a steam accumulator, and then superheating the steam from the accumulator in the superheated field prior to entry into the steam turbine. This concept requires only the turbine control valves for controlling the collector field.

The master control subsystem directs and monitors all control functions within the solar plant using a fully automatic control technique. A computer system performs process calculations, interfaces with other plant subsystems, coordinates control action, and monitors and records data, thus allowing automatic unattended operation of the plant. This control concept is especially suited for a solar thermal electric power plant where variations in the heat source intensity during the course of the day require continuous adjustments to the process flow rates. The use of a master computer control minimizes the length of time that the plant operates in less than an optimum condition. Figure 5.1-2 shows a master control functional diagram which relates the utility monitoring control (DDC) to the subfunctions of the solar thermal electric DSG.

The primary objective of the small solar power plant is to maximize the plant's energy output. Therefore, after warmup,

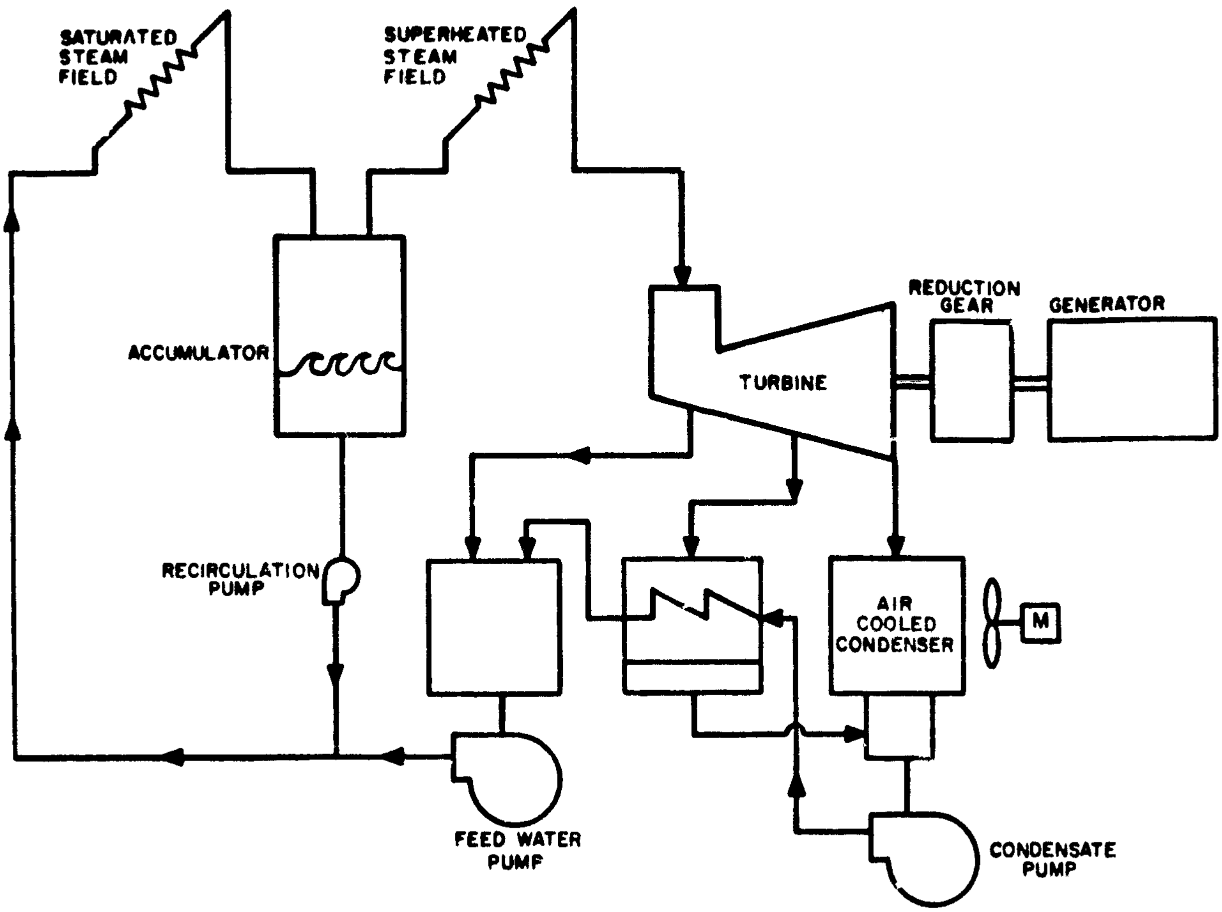

Figure 5.1-1. Basic System Schematic

electrical power generation commences as soon as, and continues as long as, insolation levels permit. If insolation levels become too low to support power generation, the plant is placed in a standby mode and electrical power generation recommences when insolation levels increase sufficiently. The generator is disconnected from the grid as soon as it stops producing power. No-load operation to maintain synchronization is not utilized, and the generator is not allowed to "motor" on battery power. The plant is shut down only if an end-of-day or emergency condition exists, or if so directed by the utility or local operator.

Within the master control subsystem, as shown in Figure 5.1-2, the operating mode control establishes the necessary valve positions and switches pumps, fans, and breakers on and off for the various operating modes of the plant. This control function also determines, by sensing key plant parameters, when to switch from one mode to another.

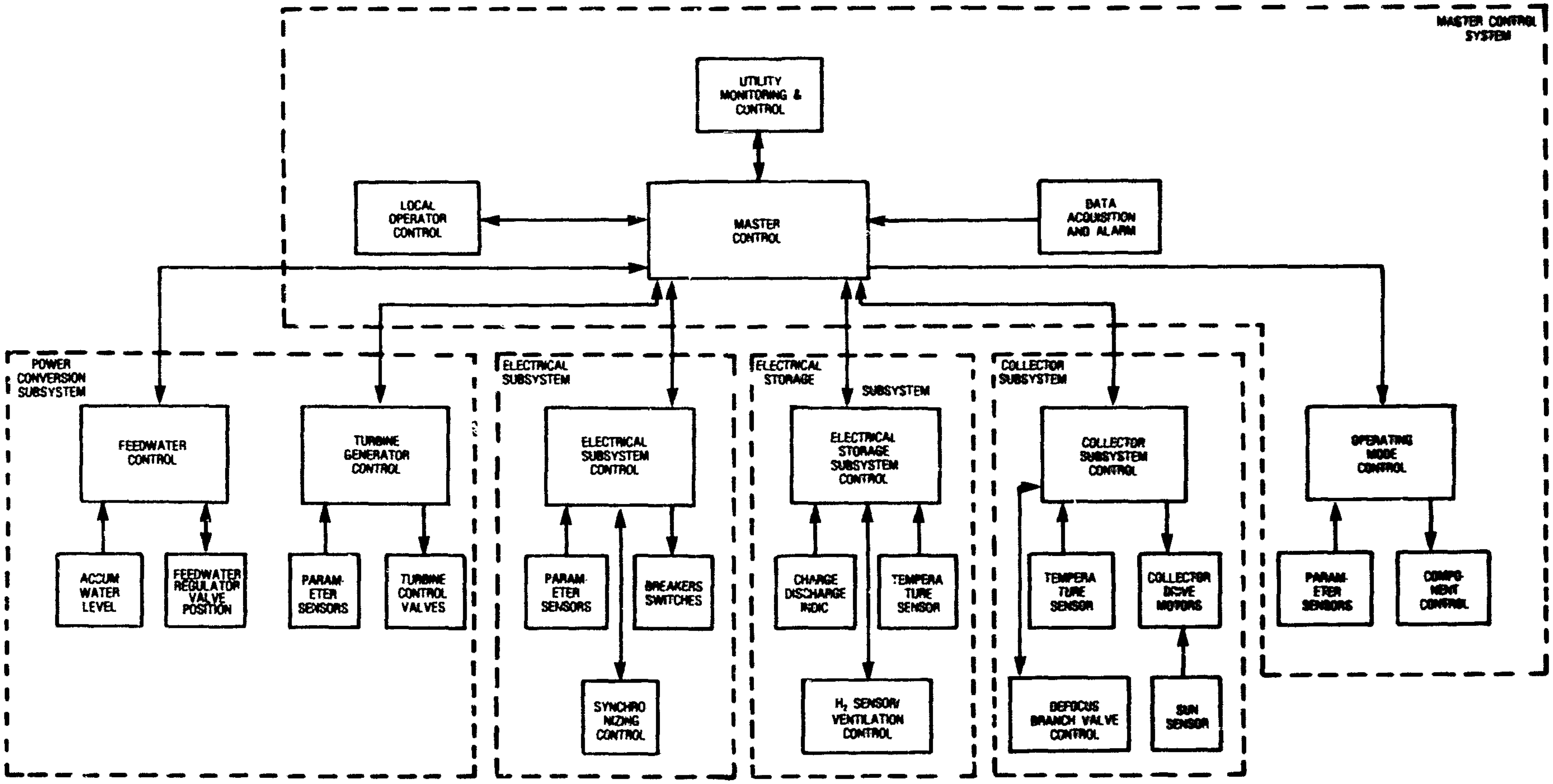

Figure 5.1-2. Master Control Functional Diagram

Data acquisition and alarm, local operator control, and utility control and monitoring are three other interfaces within the master control subsystem. The data acquisition/alarm function is provided by a standard data acquisition/alarm system. The system monitors and records identified key operating parameters periodically and records certain signals when they exceed a predetermined value. The local operator control panel is an on-site console where manual operation of the plant may be established, plant parameters monitored, and system checkout and troubleshooting performed. Normally, however, the local operator control is unmanned, with supervisory control being provided by the utility. The utility control consists of a relatively few overall plant control functions and the monitoring of certain key parameters. Alarm signals require dispatching of troubleshooting personnel to the power plant site for the necessary checkout and repairs.

The master control subsystem interfaces with the power conversion, electrical, electrical storage, and collector subsystems in implementing automatic control of the power plant. Further details of the various solar thermal electric controls can be found in Appendix A.

The preceding description of the control and monitoring functions has emphasized the DSG controls from such viewpoints as the operational modes, power flow and quality, failure and abnormal behavior detection and correction, and special requirements. It is of interest to note that although these features are embodied in the design of the DSG itself, they must be integrated with the control and monitoring, and communication and data handling functions that are controlled from the DDC that is referred to above and in Figure 5.1-2 as the utility monitoring control.

5.2 PHOTOVOLTAIC

Photovoltaic power generation systems convert light energy to electrical energy. This conversion takes place by the "photovoltaic effect" whereby a voltage is produced between dissimilar materials when their junction is illuminated (irradiated) by the light-band portion of the electromagnetic spectrum. There are a limited number of materials that exhibit photovoltaic properties. The relatively low power intensity of sunlight (0.100 W/cm^2), and the relatively low efficiency of photovoltaic conversion (5 to 20%), inherently require considerable land area to obtain kilowatt or megawatt power levels. Since photovoltaic power is in the form of direct current, dc-to-ac inverters are required to interconnect photovoltaic generation to an electric utility ac distribution system. The basic daily insolation cycle and variable weather conditions limit the availability and amount of potential photovoltaic power generation. Thus, photovoltaic generation systems must be used in conjunction with other firm power sources on an electric utility system.

In general, utility-size photovoltaic power plants should be designed for unattended automatic operation. However, on occasion (startup, testing, or maintenance operations) the plant will be controlled by a local operator. During unattended operations, the plant automatically performs normal startup and shutdown and emergency shutdown and is self-protecting from all types of electrical and mechanical failures. Protective subsystems detect faults, protect and isolate equipment which has incurred a fault, and if required, initiate plant shutdown. Control commands from the distribution dispatch center (DDC) are executed through and by the plant control equipment which also monitors plant conditions. The type, amount, and degree of monitoring are related to the rating of the plant. Larger plants have more components and require some means of identifying normal and abnormal conditions in circuits and equipment to assist in operation and maintenance activities.

Because of their lesser impact on an electric utility system, small plants require less monitoring and basically only have to identify major generic malfunctions and basic measurements or conditions.

Larger plants, especially as the number installed on a utility system becomes appreciable, require that normal and abnormal conditions be reported to the distribuiton dispatch office.

Protection, control, and monitoring requirements for photovoltaic plants require a hierarchy of plant protection control and monitoring equipment. Figure 5.2-1 is a simplified block diagram of protection, control, and monitoring for a photovoltaic plant of megawatt size.

The plant control, monitoring, and display equipment is a small computer-based system. It provides plant sequencing operations; control instructions to the major subsystem control equipment; coordination between various control and protection subsystems;

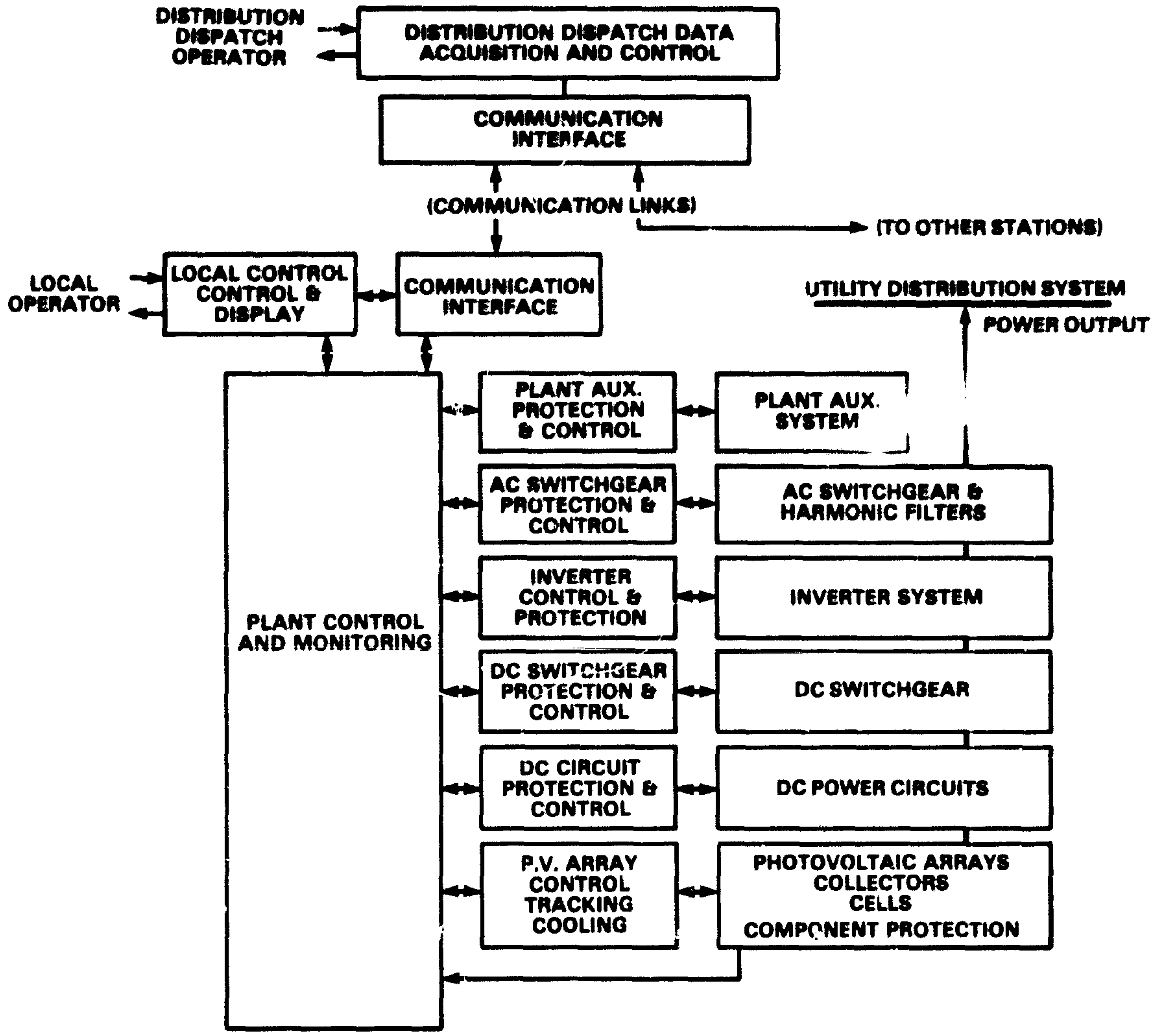

Figure 5.2-1. Block Diagram for a 5 MW Photovoltaic Power Plant

monitoring of important status and operating parameters; display of plant status and conditions; and a means of communicating with local and remote operators.

The other control and protection subsystems perform control and protective functions with only basic inputs from the plant control equipment. Examples of such subsystems are:

- Auxiliary power
- AC switchgear and filters
- Inverter
- DC switchgear
- DC power circuits
- Photovoltaic array

The major control subsystems are the photovoltaic array control and the inverter control.

If the photovoltaic array is a tracking system, its control system acts to optimize the use of the available insolation unless it receives override commands from the plant control equipment.

The inverter control system normally adjusts ac current flow to achieve maximum power output. If other than maximum power output is desired by the local, or remote operator, or utility dispatch system, a modified setpoint is imposed on the inverter control via the plant control equipment. Sequencing of inverter equipment for normal startup and normal and emergency shutdown is performed by the inverter control equipment.

Other subsystem controls provide the usual functions for the type of equipment involved by means of relatively conventional electromechanical controls.

Considering the photovoltaic generation plant in terms of the six monitoring and control requirement categories, we may group the controls as shown below:

A. Control and Monitoring	- distribution dispatch, data acquisition, and control
B. Power Flow and Quality	- inverter control and protection - PV array control tracking and cooling
C. Communication and Data Handling	- communication interface - communication links
D. Operational Requirements	- plant control and monitoring - plant auxiliaries protection and control
E. Failure and Abnormal Behavior	- ac switchgear protection and control - dc switchgear protection and control - dc circuit protection and control
F. Special DSG Requirements	- plant control and monitoring - PV array control - automatic startup and shutdown

5.3 WIND

Wind generation systems, by means of a bladed rotor, convert wind energy to shaft mechanical energy to electrical energy via a conventional electric alternator. Wind generation systems for electric utilities are likely to consist of one or more modest sized units (0.2 to 5.0 MW) making up an integrated installation. Wind generation is available only when the wind is blowing at speeds above a certain threshold velocity and at speeds below a certain maximum velocity at which point damage to the installation might occur. Therefore, with wind generation, additional generation by other means is generally required by the utility.

A wind turbine generator (WTG) control system should be designed for operation at a remote, unattended site. The system must be fail-safe and self-monitoring. It must be capable of detecting any failure within the WTG which may cause secondary damage to associated equipment. It must also be able to take the appropriate protective action. The control equipment must be capable of maintaining proper operation of the WTG under extreme environmental conditions such as wind gusting and wide temperature ranges. Safety and protective functions must be capable of being executed without external power. The WTG control system must be conservatively designed to maintain high reliability and to be properly protected against induced transients from the power line or from lightning strikes.

In addition to a number of individual controls for various portions of a wind turbine generator, there is also the need for a master control which will integrate the separate controls and make them responsive to the local control, the utility dispatch, and the data and alarms as shown in Figure 5.3-1 for a horizontal-axis propeller type WTG.

Another function of the master control may be to serve as a common control point for several wind-driven generators to operate in parallel when such a grouping of generators exists in close proximity. The local control station is required because the WTG must be capable of being operated locally as well as remotely.

The sequencing control of the WTG during startup and shutdown, and the signals for the synchronizing and normal operating modes are contained in the operating mode control. Critical sequencing functions may be provided by redundant signal sources so that a suitable reliability capability is available.

There are two primary control requirements for a horizontal axis WTG. The first requirement is to control the yaw orientation of the rotor to maintain the plane of the rotor disc perpendicular to the average wind vector. The rotor disc is normally positioned downwind of the rotor to allow the rotor to be operated as close as possible to the tower, and hence to reduce yawing moments on the tower.

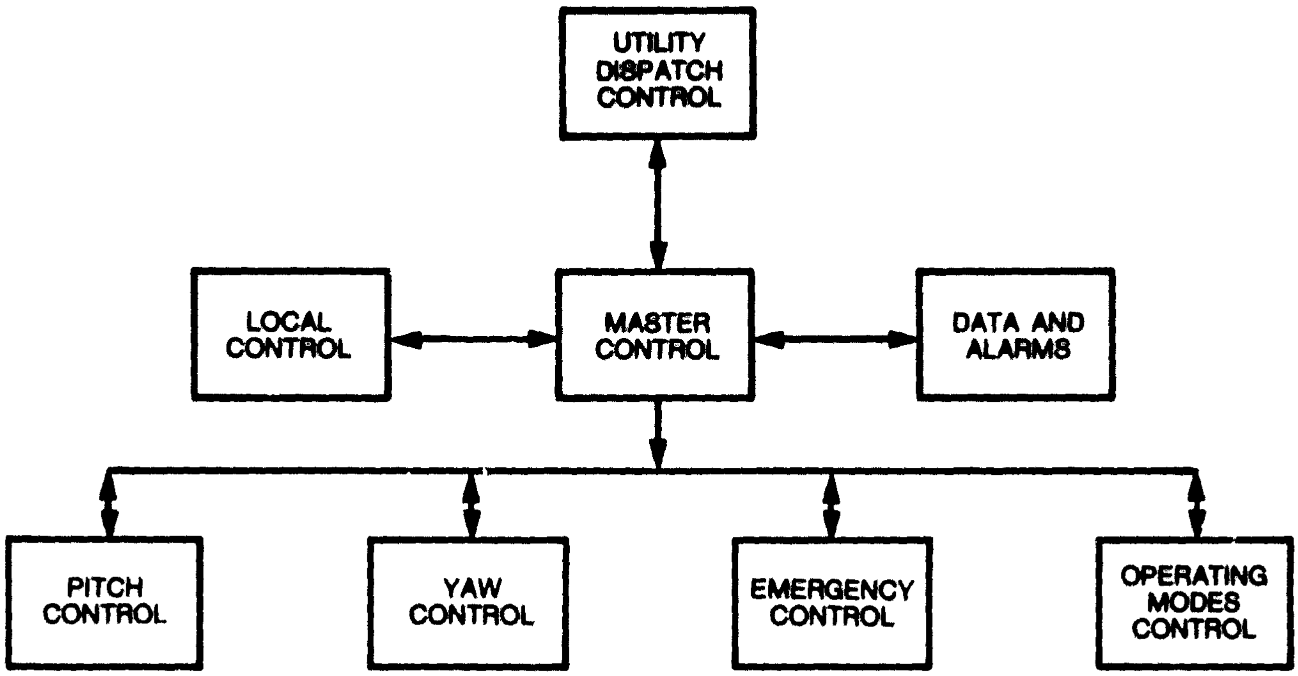

Figure 5.3-1. Wind-Driven Generator Control System

The second requirement is to control and limit rotor revolutions per minute and power output under varying wind conditions. This control is most readily provided by varying the pitch angle of the rotor blades around their longitudinal axis. The WTG can be operated at relatively constant rpm under varying wind conditions by control of the rotor blade pitch. This same control can be used to synchronize the generator with the utility network. Once the generator has been synchronized with the network, the blade pitch control is used to limit power output of the WTG under high wind conditions and to limit the adverse effects of wind gusts on the system.

Figure 5.3-2 shows a control block diagram for the yaw position control and the rotational speed control, each of which is provided with signal information from wind sensors. In addition, the rotational speed control is provided with utility load data from the electrical load on the alternator.

The pitch control system must operate in a satisfactory manner during the following operational modes of the WTG system:

- Startup: programmed pitch change for rotor acceleration
- Standby/Synchronize: pitch controlled to regulate shaft rpm
- Operate: pitch controlled to regulate power output
- Normal Shutdown: programmed pitch change for rotor deceleration

Continuous fault monitoring of the pitch servo during the startup, standby/synchronize, and operate modes is required to prevent possible overspeed/underspeed and/or reverse thrust on the

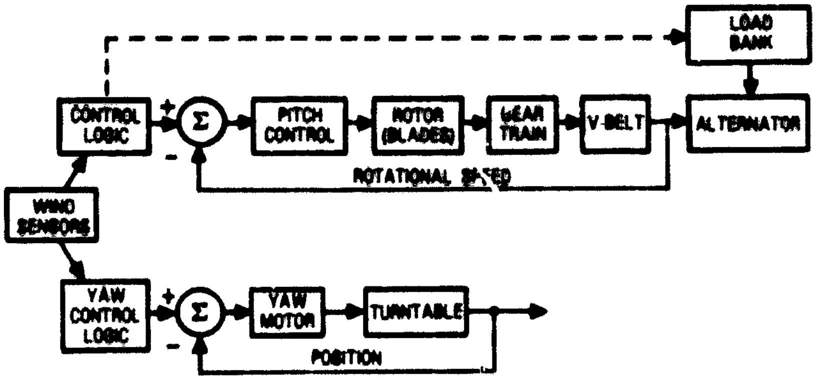

Figure 5.3-2. Rotor Control Block Diagram

rotor due to pitch servo failures. The monitoring device must be capable of differentiating between pitch control failures and sudden or unusual motion of the controls because of wind gusts.

Overspeed of the WTG in high winds because of control failure or a sudden loss of load is of concern because of the potential equipment damage which could occur. Alternative speed controls to the normal ones should be available, and a completely redundant mechanically actuated rotor blade feathering system to dump excess rotor energy, backed up by a parking brake of moderate capacity, may be employed for emergency conditions.

Turntable yaw orientation is accomplished by means of a hydraulic motor driving through a gear train. The worm gearbox is irreversible so that the turntable will be rigidly held against wind load, unless the wind load is assisting the hydraulic motor. This arrangement provides yaw restraint for the rotor even if the hydraulic supply should fail. The yaw servo is intended only to trim the system to the average wind direction, not to follow sudden wind direction changes.

Continuous fault monitoring of the yaw servo during WTG operation is provided by independently monitoring the average wind direction error and checking for proper servo response to changes in the average direction of the wind. Backup fault sensing is also provided for the yaw servo, as in the pitch system described above.

Data and alarms are needed locally and at the remote utility dispatch control. A limited amount of routine information should be available on a periodic or on an as-required basis remotely when all is operating well. When operation is abnormal, more detailed information should be available to the remote operator to help in the decision process to restore the WTG to normal operation.

The wind-driven generator control system shown in Figure 5.3-1 may be described in terms of the monitoring and control requirement categories in the following manner:

A. Control and Monitoring - utility dispatch control
- data and alarm

B.	Power Flow and Quality	- pitch control and - yaw control
C.	Communication and Data Handling	- utility dispatch control - master control
D.	Operational Requirements	- operating modes control - master control
E.	Failure and Abnormal Behavior	- emergency control - data and alarms
F.	Special DSG Requirements	- operating control - pitch control - yaw control

5.4 FUEL CELL

Fuel cell energy systems consist of an electric power generation device in which hot fuel gas is passed over a fuel electrode and heated air is passed over an adjacent air electrode, separated from the fuel electrode by an electrolyte, so as to produce a dc power output and an exhaust of carbon dioxide and water. The direct current electric power produced by the fuel cell is connected to a dc/ac inverter which in turn supplies the distribution network with alternating current at the proper voltage and frequency.

Fuel cell control systems differ from some other dispersed storage and generation sources in that the fuel can be made available on demand within a reasonable time interval, so that the scheduling of fuel cells is better under command of the utility dispatcher. As such, this element of availability uncertainty can be greatly reduced although a fuel gas supply control is needed which may introduce an element of time delay. Also necessary is a control system for input elements of the fuel cell itself.

As shown in the fuel cell master control functional diagram on Figure 5.4-1, the master control for the fuel cell serves as the interface between the utility dispatch control center and a number of other controls located at the fuel cell itself. Typical of these other controls are the following:

- Operating Mode Control. To coordinate the startup, standby, on, off, and other possible conditions of operation. Since the fuel cell operation requires that a suitable temperature be maintained and that adequate fuel gas be available, a proper sequencing and set of interrelationships among the various controls must be established. An important part of this coordination function is performed by the operating mode control.
- Fuel Gas Supply Control. To provide the fuel cell with the proper amount of fuel gas and air to handle the required electrical output. For the case of an oil-fired gas source shown in Figure 5.4-1, control of this gas supply is required.
- Fuel Cell Control. To provide the necessary flows of fuel gas and air to the fuel cell to develop the desired voltage and current for the inverter to meet the distribution network needs. Although the inverter and the gas source have their own controls, control of the fuel cell inputs and outputs is also required.
- Inverter Controls. To control the necessary match between the electrical energy output from the fuel cell and the electrical energy required by the utility distribution network.

C-2

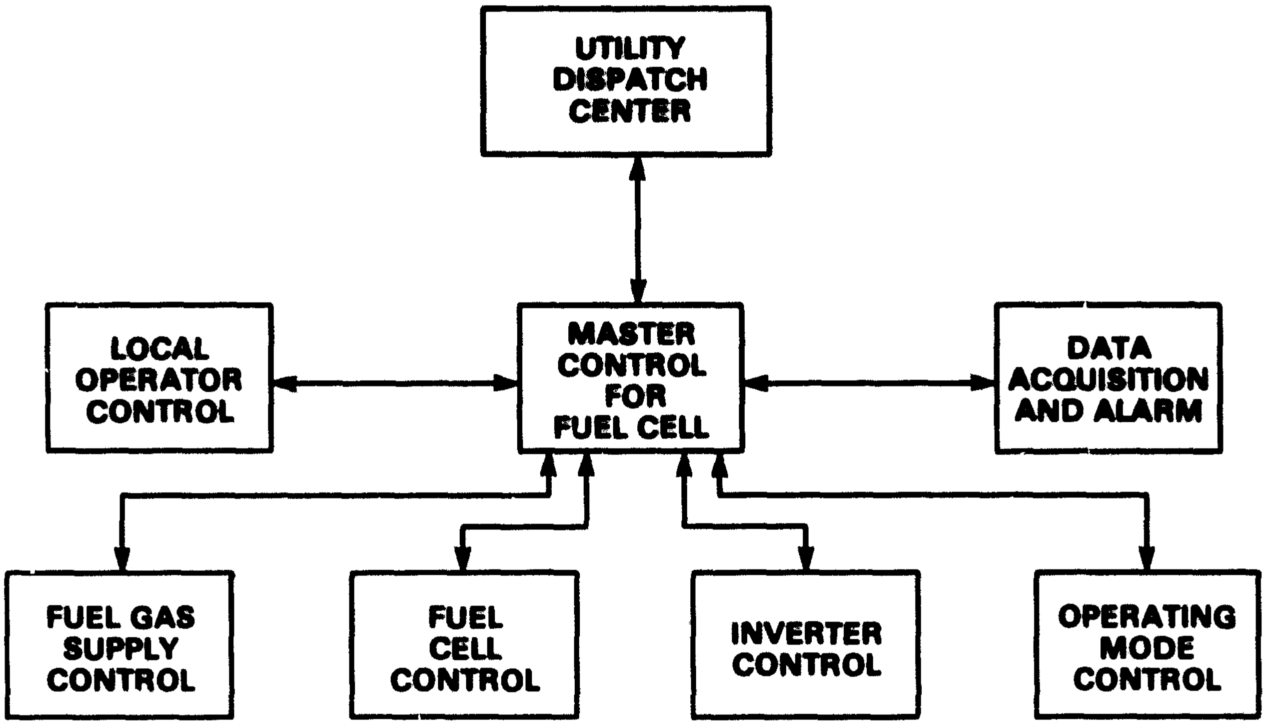

Figure 5.4-1. Fuel Cell Master Control Functional Diagram

Although not shown as a separate set of controls, emergency controls to serve in a protective role will also be required to handle the emergency and routine switching functions. As previously noted for the DSG technologies already considered, the plant master control must be capable of local control and operation of each electrical power generation source. Local alarms and data acquisition at the fuel cell site are also desirable control and monitoring functions.

The remote utility dispatch center control may send reference commands or signals to establish the desired power generation level and mode of operation. Remote monitoring capability must also be available at the utility dispatch center so that the remote power dispatcher has knowledge of when the fuel cell is able to generate power and how much power it is generating.

Comparing Figure 5.4-1 for a fuel cell control system with Figure 5.3-1 for a wind-driven generator, a number of similarities are noted; for example, there will be a number of comparable functions to be identified for the control and monitoring categories for the two different DSG technologies. However, in the case of the fuel cell, the power flow and quality control and the special DSG requirements will relate to such controls as the fuel gas supply control, the fuel cell control, and the inverter control instead of to the pitch and yaw controls previously noted for the case of the wind-driven generator.

5.5 STORAGE BATTERY

Storage battery energy systems have as their inputs dc electrical energy which is converted electrochemically to chemical energy during charging of the battery and is electrochemically converted to dc electrical energy during the discharging of the battery. Operation of a storage battery with the conventional ac electric distribution system requires the use of power conditioning equipment that can accept the alternating current from the distribution network and convert it to the dc required to charge the battery and invert the dc electrical energy provided from the battery to ac suitable for the distribution network. Care must be taken so that the timing of battery charging and discharging is economically and operationally beneficial to the overall electric power system operation.

Storage battery systems, like those for fuel cells, have the advantage that they are not dependent on the sun or wind for their primary energy and thus they may more readily be scheduled in advance. On the other hand, storage battery systems have losses associated with the charging and discharging operations so they may be less efficient from an energy point of view than some other DSGs. Thus, the battery scheduling operation will represent an important aspect for control.

A storage battery system for load-leveling, as shown in Figure 5.5-1, can be represented as being made up of four parts: the battery, the switchgear and protection, the power conditioning equipment, and the electric utility network. Each of these parts has its own individual control system, and there is an integrated battery control system which combines all the various individual controls. Although early installations of the battery system will doubtless be under local manual control, it is anticipated that future battery systems and their tie with the electric utility network control, e.g., the distribution dispatch control, will be automatic.

Referring to Figure 5.5-1, one notes that the integrated storage battery control serves as a master control to coordinate the other controls which serve as subcontrols in a control hierarchy. Included in these subcontrols to the master control are the following functions:

- Operation Mode Control. To organize the startup, on, off, standby, and other conditions of operation, the battery operating conditions should include:
  - Battery Off
  - Battery Startup
  - Battery Cool Standby
  - Battery Warm Standby
  - Battery Charging (on)

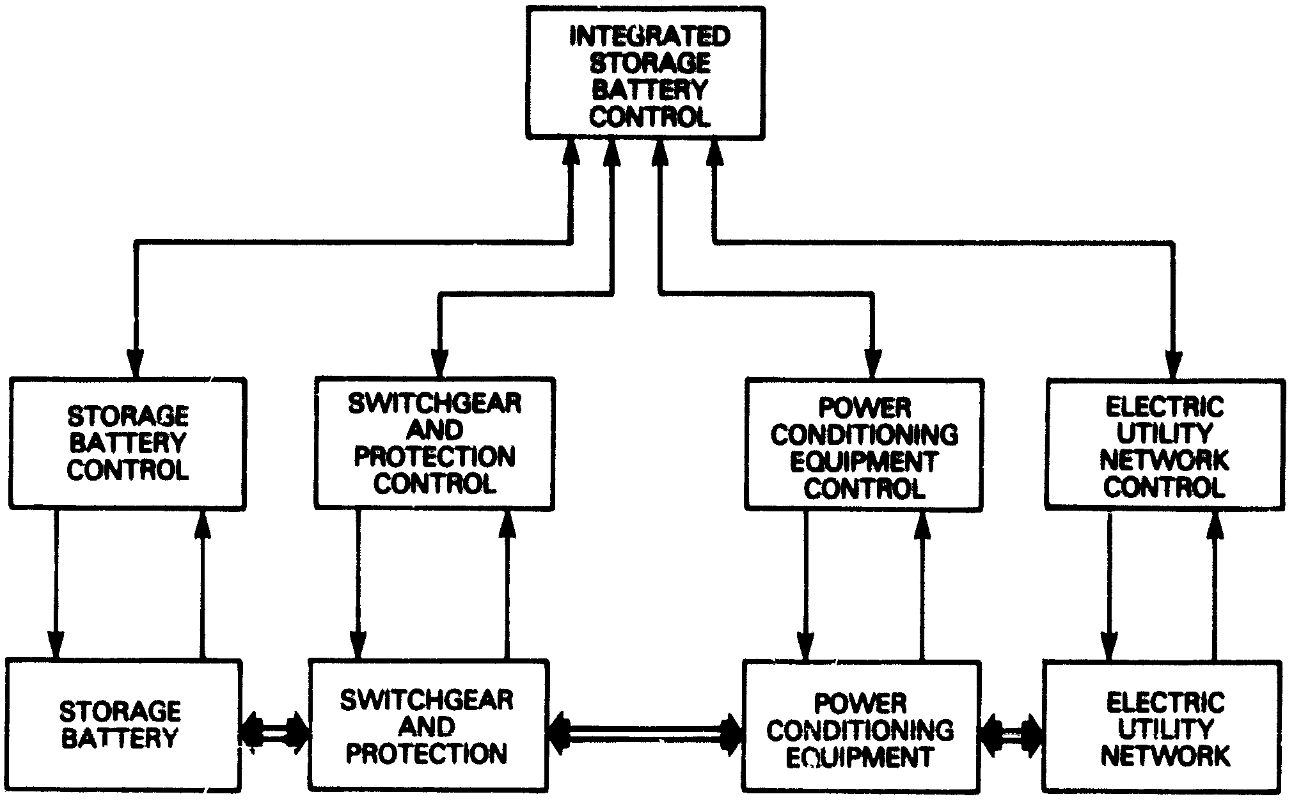

Figure 5.5-1. Storage Battery System with Controls

- Battery Discharging (on)
- Battery Module Replacement
- Battery Shutdown

- Power Conditioning Equipment Control. To prepare and control the power conversion equipment to match the battery dc characteristics and the ac network load needs as indicated by the distribution dispatch center commands.
- Switchgear and Protection Control. To permit the power equipment to change satisfactorily from battery charge to discharge and to reduce the danger of battery damage because of faults in the power conditioning equipment.
- Battery Control. To control the battery temperature, and other auxiliaries, to achieve suitable environmental conditions for the battery under the appropriate operating mode and state.

The correlation between the six DSG control and monitoring categories and the storage battery system with controls shown in Figure 5.5-1 is perhaps less evident than for some of the preceding cases for DSG technologies. Nevertheless it is possible to carry out this correlation in the following fashion.

The control and monitoring function category will be centered at the electric utility network control where the distribution dispatch center is considered to be located. The power flow and quality requirements will pertain to the control of power conditioning equipment. The communication and data handling requirements are relevant to the communication between the electric utility network control and the integrated storage battery control which also serve as a master control for the battery, switchgear, and power conditioning control equipments.

The operational requirements would be performed at the integrated storage battery control since this control represents a central point for coordinating the several equipments involved. The failure and abnormal behavior category will take place at the switchgear and protection control, pertaining to conditions within the DSG, as well as at the power conditioning equipment control for failures and emergencies between the electric utility and the storage battery. The special DSG requirements category will be handled by the storage battery controls as well as by the integrated storage battery control. Startup and shutdown procedures are important for batteries operating at elevated temperatures.

5.6 HYDROELECTRIC

Hydroelectric generation converts the kinetic energy of falling water into electrical energy by mechanical-electrical means such as a water turbine coupled to an electric generator. The electric generator driven by the turbine produces alternating current which is fed into an electric utility power system.

In general, hydroelectric plants of the size associated with dispersed storage and generation (DSG) projects are normally unattended. During periodic maintenance, testing, or repairs, an operator controls the plant locally. Thus, provision for automatic plant operation with either remote or local control initiation may be required for DSG hydro plants. Operating conditions which may be involved are:

- Automatic operation - startup/shutdown initiated by local sensor (water level) or device (timer)
- Automatic operation - startup, loading, and shutdown initiated by remote dispatch center (or dispatcher)
- Automatic operation - startup, loading, and shutdown initiated by local operation
- Manual operation - all functions initiated by local operator

Existing DSG-size hydroelectric plants have a wide range of control and data acquisition equipment, from local operator-controlled only, to remote automatic-controlled. Data acquisition may include: (a) local indicators, recorders, and meters, (b) same as (a), plus a few analog-telemetered quantities, or (c) digital data and status acquisition and transmission.

As the number of DSG stations on a utility system increases, it is anticipated that DSG data and control will become more important to the dispatch center. Thus, existing hydro stations may have to be converted from local manual control to automatic remote-control. For discussion purposes, unattended operation with its associated automatic operation and data acquisition are assumed. This type of operation requires interfacing local plant control and data acquisition with the remote dispatch center. Functional relationships are shown in the block diagram of Figure 5.6-1.

Basically, the plant must be provided with automatic control equipment which can safely and reliably perform startup, run, and shutdown functions. Equipment or control abnormalities must be detected and safe action (i.e., shutdown if necessary) initiated. Data acquisition will be performed, presented, and/or recorded locally, and transmitted to the dispatch center.

The functional block diagram of Figure 5.6-1 provides for the operating conditions described above, with overall control and data

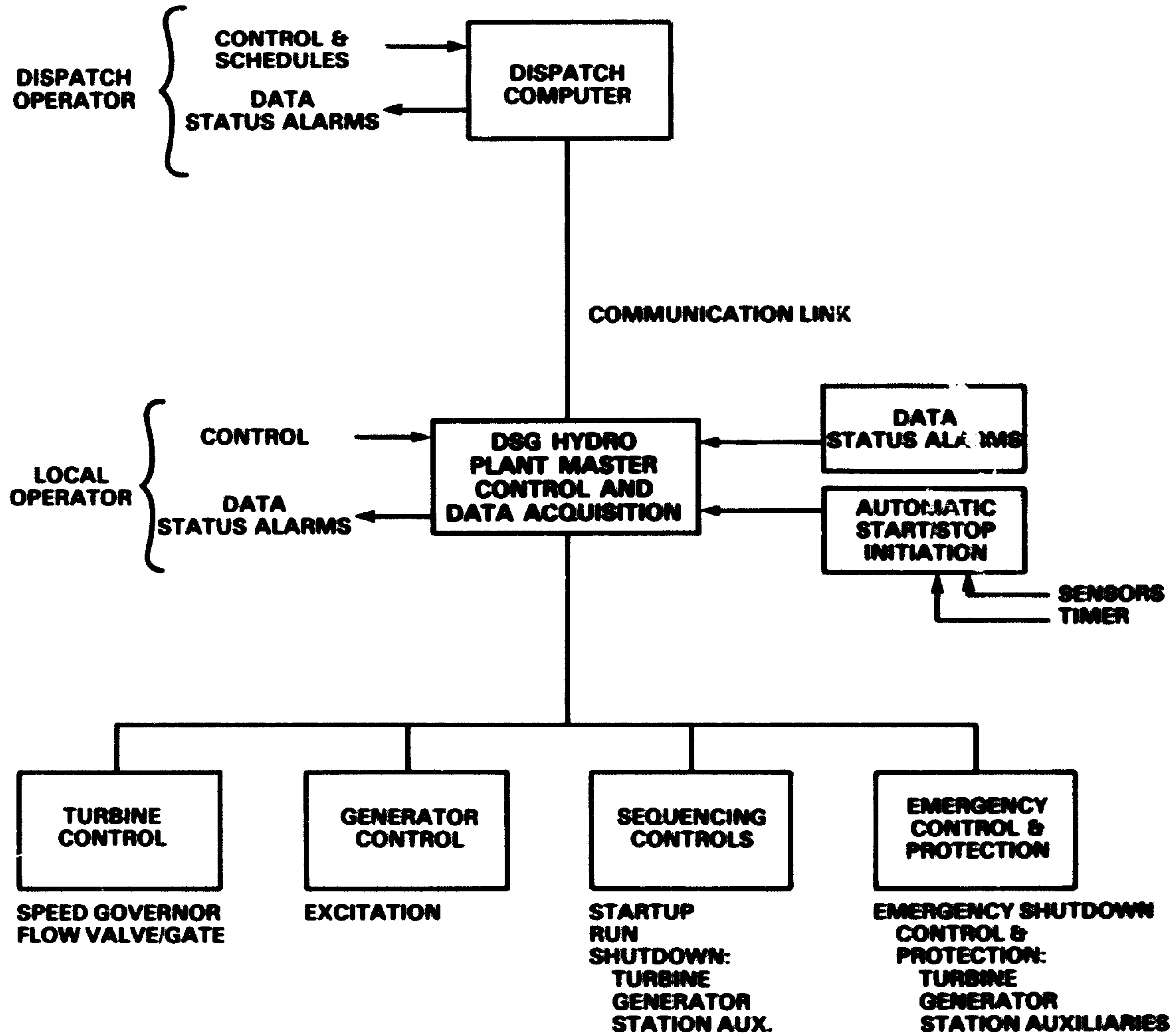

Figure 5.6-1. Block Diagram - Hydroelectric DSG Control and Data Acquisition

acquisition concentrated at the plant master control (PMC). The specific type of control and data acquisition equipment determines the degree of modularity and/or commonality. Figure 5.6-1 identifies only major functional control and data areas. Existing plants may have some degree of automation such as automatic startup and shutdown sequencing implemented with electromechanical relay logic. This could involve coordination, modification, and retrofitting if the station is to be included in an overall system DSG control and data acquisition system.

The plant master control, which serves as the nerve center, directs (or possibly performs) local automatic control and data acquisition functions. As shown in Figure 5.6-1, the plant master control interfaces with the following major subsystems:

- Turbine governor and gate control for controlling water flow, speed, and/or power output. These controls are furnished as part of the turbine and hydraulic system.
- Generator control (excitation system) for controlling synchronous generator voltage/reactive volt amperes/ power factor. This excitation system is usually furnished by the generator manufacturer.
- Sequencing controls basically provide step-by-step action-initiation, checking logic, for automatic startup and shutdown operations. Sequencing controls direct and coordinate all of the major and minor systems and equipment operation in the plant in response to startup/shutdown commands from either local or remote sources. For normal conditions, a hydroelectric turbine-generator unit is automatically sequenced through its startup steps, synchronized with the power system, and then the water flow is adjusted to achieve the desired power output. When normal shutdown is required, the load is reduced to zero and then the shutdown sequence is performed.
- Abnormal and emergency control and protection provide sensing, action initiation, and sequencing to protect against conditions which could damage equipment. For abnormal or emergency conditions requiring immediate disconnection and shutdown, the emergency shutdown sequence is initiated. This can be initiated by protective relay or sensor devices in the plant which detect serious problems.
- Data and status acquisition functions include the collection, processing, presentation, and transmission of measured data and status information, both normal and abnormal. The amount of data obtained locally is more than that transmitted to the dispatch center. Local data provide records and information to operating and maintenance personnel. Data and status transmitted to the dispatch center may be of a more basic and general nature.

- When alarm conditions exist, the category and nature of the alarm are recorded locally and transmitted to the dispatch center to permit the dispatchers to determine the urgency of the problem and to determine what type of maintenance personnel are needed to correct it.

- Normal data (and status) are scanned at regular intervals to detect trends. Selected normal data are transmitted periodically to the dispatch center. Abnormal conditions are logged and transmitted to the dispatch center immediately.

5.7 COGENERATION

Cogeneration is the combined production of process heat and electricity. Industries and/or utilities which need both of these forms of energy potentially have net operational cost savings available through an efficient coordinated facility that fully utilizes the total heat of combustion. Various manufacturing, commercial, and district heating applications utilize medium and/or low-pressure steam. These comprise the largest percentage of potential cogeneration applications. For these applications, the most common configuration for generating electricity and "process steam" has been to use fossil-fuel-fired steam boilers producing high-temperature, high-pressure steam to drive steam turbine-generators. Steam from the turbine, with its remaining energy, is delivered to the "process," and is called a topping cycle. Electricity is produced at the highest temperature portion of the steam cycle. Additional electric power and heat can be obtained by superimposing gas turbine-generators on the cycle. In some cases, diesel engine-generators producing electric power and relatively low-temperature water and steam provide a good match of power and heat to certain processes. Bottoming cycles, obtaining electric power from the low-temperature process "waste heat" or exhaust, are also possible configurations for cogeneration. However, bottoming cycles have higher investment costs and often require mor complex equipment. Processes requiring the direct heat of combustion can occasionally use the high-temperature exhaust gas of oil- or gas-fired gas turbines. The combustion turbines also drive electric generators in a topping configuration.

There are basic functions which make up a cogeneration plant control system. With regard to the production of electric power, however, it must be recognized that the cogeneration plant control system has primary responsibility for the correct, safe, and economic control of the plant's process heat needs. The electric power produced may be adjusted only insofar as the cogeneration plant configuration, equipment, and process permit. Cogeneration plant controls, within constraints, operate to meet power and heat needs.

System control functions included in a cogeneration plant system control are illustrated in Figure 5.7-1. This diagram is simplistic and does not show interrelationships between functions. Further, the functional block diagram should not be assumed to imply that hardware-oriented, completely integrated and coordinated, automatic control systems are common. Cogeneration plant system control functions and their descriptions follow:

- The tie-line power flow control function is the on-line control interface between the utility electric power system and the cogeneration plant. The tie-line controller adjusts the turbine governor speed control to change generator output. In the event of the tie-line interruption, the load-frequency control can control the isolated cogeneration system, perform turbine governor control mode switching and, if necessary, perform process plant electrical load shedding to balance available generation with load, to avoid system collapse.

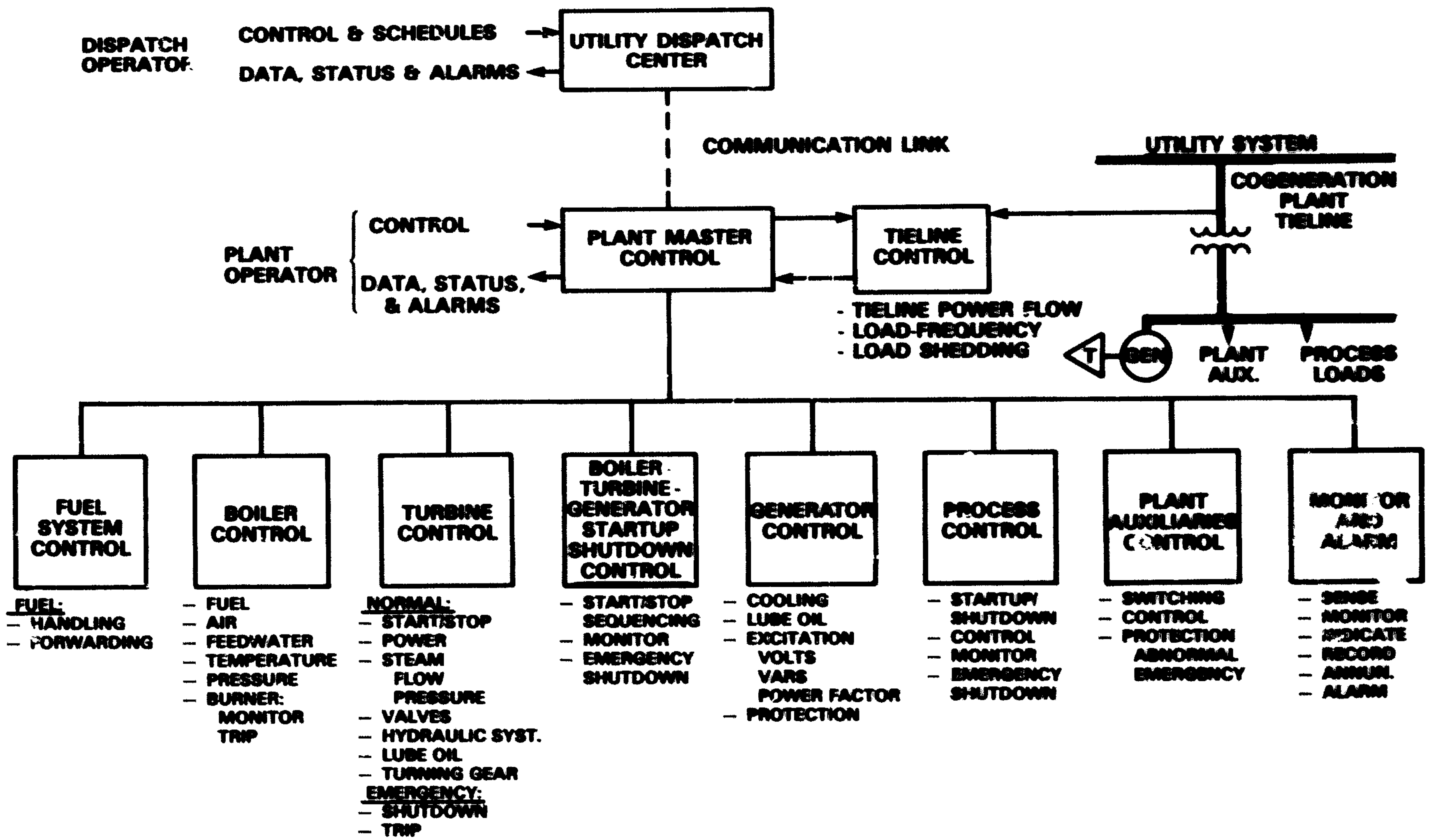

Figure 5.7-1. Cogeneration Plant System Control Functions

- Fuel system control can be relatively simple when the fuel is oil or gas, or it may be complex when the plant uses coal or other solid fuels. The primary function of the fuel system is to monitor and control fuel storage, handling, forwarding, and supply to the boilers, gas turbines, or diesel engines.

- The boiler control subsystem responds to disturbances internally and externally generated, in a manner which satisfies system demands, within limits of the boiler capability. The boiler control subsystem must perform in a fast, accurate, stable, safe, and reliable manner.

- Turbine control and governing subsystems play an important part in control of the cogeneration plant's overall steam and power system. Industrial steam turbine governors can control many variables in the plant, including electrical (or mechanical) power output, speed, and pressure.

- Boiler-turbine-generator startup/shutdown control provides the means of coordinating the startup and shutdown of these major plant subsystems. Depending on the design and implementation, this control may include both normal and emergency startup and shutdown functions.

- Generator control primarily includes the monitoring and control of basic generator cooling, lubrication, and excitation conditions. The excitation subsystem which controls the generator voltage, reactive volt-amperes, and power factor is complex. If the cogeneration plant is under joint utility-industrial ownership with an excess of electric power, the utility will probably want to exercise some degree of control over the generator excitation to assist in utility system voltage and reactive volt-ampere control.

- Process control implies discrete mechanical-electrical control of the process startup, shutdown, normal process operation, and emergency control. Since this is also specifically oriented to the process and in the domain of the plant control, further elaboration is not considered appropriate in this discussion.

- Plant auxiliaries control involves the actual control and switching of the plant electrical distribution system. In addition to normal switching and control, abnormal and emergency control and protection are included. These safeguards apply to all circuits supplied by the plant auxiliary electrical subsystem.

- Monitor and alarm functions for both boiler-turbine-generator and process conditions have been implemented with a wide range of equipment and subsystems. Modern computer-based plant controls have combined this function into overall master plant control, monitor and alarm, operator interface, and (where required), data transmission functions.

In summary, a modern cogeneration plant control system is a complex, integrated, coordinated arrangement of many control subsystems, which operates to maintain the plant integrity during normal operation and also during emergency or abnormal conditions. External control, such as might be exercised by a utility dispatch center, is limited to the degree provided by the basic cogeneration plant design and the constraints required by the associated process.

5.8 OBSERVATIONS REGARDING DSG TECHNOLOGIES AND THEIR CONTROL

Consideration of the DSG technologies as well as other information contained in Appendix A, "Selected DSG Technologies and Their General Control Requirements," serves to bring out a number of significant observations which are of importance regarding DSG technologies and their control.

5.8.1 Each DSG technology is a complicated system that has to be controlled locally to achieve satisfactory results.

Each DSG system has several control subsystems that must be integrated under a local master control and must be responsive to normal and abnormal conditions as sensed locally.

For proper stability and safety of each DSG, it is important that the DSG be controlled locally. However, for each DSG to be able to contribute power to the electric distribution system as needed, it is desirable that remote supervisory control of the DSGs from the distribution dispatch center be available.

The remote monitoring and control of the DSG tend to be of a supervisory character. This establishes setpoints, monitors DSG conditions so that reasonable setpoints may be established, identifies when conditions are normal or abnormal, and anticipates what to expect from the remote DSG unit. Although the nature of the specific commands from the distribution dispatcher may be different in detail for each type of DSG technology, the resulting power input from each of the DSGs to the electric distribution network can be comparable in kind.

5.8.2 Since each technology has its own particular subsystems and characteristics, the communications to and from the DSG must be tailored to the needs of each DSG technology and may, therefore, differ in detail.

It may be necessary to have monitoring and control information in several categories: those of low, medium, and/or high precision, as well as those of slow-, medium-, and/or fast-time response. The definition of low, medium, and high precision, and of slow-, medium-, and fast-time response has not yet been finalized. This matter is referred to again in Section 8.4.

An effort should be made to develop an appropriate modular approach to the hardware and software of the monitoring and control links to the various DSGs so that communicating to them appears the same to the distribution dispatcher, and yet each DSG component can have the specific instructions it requires.

5.8.3 From the power dispatch center's point of view, the aggregate of DSGs in a distribution system appears to be remotely controlled activities similar to other bulk generation sources or transmission control points.

Since the dispatch centers already have existing supervisory control and data acquisition (SCADA) ties to the bulk generation and transmission equipment, an effort should be made to determine whether the monitoring and control for the distribution system should be similar to, or different from, that for generation and transmission. Perhaps the existing choices of control and data for low, medium, and high precision and for slow-, medium-, and fast-time response can be found to be acceptable for use with DSGs. If possible, generic means for monitoring and control of DSGs should be sought so that special custom-designed control means are not required for each DSG technology.

5.8.4 Scheduling and control of remote DSG units should be based on the need to make the overall system service, i.e., generation, transmission, and distribution, most effective.

Scheduling of some types of DSG power involves a measure of uncertainty, e.g., whether the sun is shining or if the wind speed is adequate. Operation of the remainder of the system is also subject to some unforeseen changes with time because of load demand or equipment availability. The combination of monitoring and control of the DSGs' power contribution and the monitoring and control of the remainder of the generation, transmission and distribution system should provide the information base on which modifications to DSG generation output and characterization of the remainder of the controllable system can be made.

5.8.5 The characteristics of the DSG technologies determine the electrical nature of the power generated and, therefore, the form and nature of local control required.

The extent to which the DSG scheduling can be performed is also influenced directly by the type of DSG and its energy source.

Table 5.8.5-1 shows the relationship between the type of DSG and the form of electrical energy which is produced. Based on the initial form of electrical energy produced, the actual local control requirements will differ in the fashion indicated.

The type of DSG technology employed also has a definite bearing on the extent to which scheduling is possible. Table 5.8.5-1 indicates that certain technologies such as fuel cells, storage batteries, hydro with storage, and cogeneration can be scheduled in advance. Other DSG technologies, such as wind, and under some circumstances, "run of river" hydro and cogeneration, have little possibility of being scheduled.

5.8.6 Monitoring of DSG should be done for both normal and abnormal operation.

Under normal operation, regular periodic reporting of the DSG power generated and energy available should be provided. Under abnormal conditions at the DSG or in the remainder of the system, it may be necessary to have data reported on a more frequent or alarm basis.

Table 5.8.5-1

RELATIONSHIP BETWEEN TYPE OF DSG AND FORM OF ELECTRICAL ENERGY

Type of DSG	Initial Form of Electrical Energy: ac — Steam Turbine	ac — Mechanical Drive	dc — Inverter	dc — Converter-Inverter	Schedulable or Nonschedulable
Solar Thermal Electric	X[†]				NS
Photovoltaic			X		NS
Wind		X			NS
Fuel Cell			X		S
Storage Battery				X	S
Hydro (with storage)		X			S
Cogeneration	X				S*

*indirectly

NS - Nonschedulable
S - Schedulable

†Although the type of solar thermal electric generation process considered in this study does require a steam turbine, not all solar thermal electric generation means do require a steam turbine.

5.9 ANTICIPATED TRENDS IN DSG USE

In understanding the definite control and monitoring requirements for DSG, it is important to recognize the sequence in time when the various DSG technologies are, or will be, available for use; it is also important to understand the overall amount of generation capacity which may be installed for a particular type of DSG. Table 5.9-1 presents this information. More detail is included in Appendix B. Several issues may be considered from this data.

Present Status has been divided into four different stages of development.

Experimental	Preliminary designs have been built to prove feasibility. Some key experiments have been run but prototype manufacture has not yet been started for major portions of the technology or system.
Preproduction	One or more working prototype systems have been built and are performing in an actual utility environment. Equipment has not been made by regular production methods.
Commercial	Systems are comprised of production equipment and are operating in a utility system.
Mature	The system is in widespread use by utilities and the advantages of large-scale production, installation, and operational experience are being realized.

In introducing DSG control and monitoring systems, it will probably be desirable to start work with one or two DSG technologies first, rather than to work with all of them at once. From the present status column described in Table 5.9-1, it would appear that the mature technology, hydro, and the commercial technology, cogeneration, represent early candidates for initial DSG control and monitoring application efforts. Wind generation might be the next most advanced technology and should be considered for early application.

The anticipated date of commercialization column complements the present status data and shows that work with hydro and cogeneration could be started at once with existing equipment of current design and availability. By year 1990 it is estimated that all of the technologies will be commercially available, and thus it would appear that experimental work on implementing a DSG control and monitoring system is appropriate now.

Total additional DSG generation expressed both in gigawatts (GW=10^6kW) and in number of units represents a significant amount of activity that could take place in the coming 20 years. Of interest in this regard is the fact that hydro generation is limited by the amount of hydro resources available. Thus, despite the maturity of the technology, there will be a limited amount of DSG hydro generation (5 to 10 GW) which will be added.

Table 5.9-1

DSG TECHNOLOGY CURRENT STATUS AND ANTICIPATED USAGE IN YEAR 2000

DSG Technology	Present Status	Anticipated Date of Commercialization	Total Additions Output (GW)	Total Additions Number of Units	Anticipated Installations per year 1990	Anticipated Installations per year 2000
Solar Thermal	Experimental	1990	2	2000 @ 1 MW	10-20	100-400
Photovoltaic	Experimental	1990	2	2000 @ 1 MW	20-50	200-500
Wind	Preproduction	<1990	6	3000 @ 2 MW	50	600
Fuel Cell	Preproduction	<1990	3	600 @ 5 MW	>50	>100
Battery	Experimental	1990	15	3000 @ 5 MW	2-100	200-600
Hydro	Mature	Now	6	1200 @ 5 MW	60	60
Cogeneration	Commercial	Now	30	1500 @ 20 MW	60	150
			64*	13,300 Total Estimate		

*Assumes: (1) 5% of U.S. total generation is dispersed storage and generation, units of average size indicated.

(2) This does not include small DSGs (assumed to be 20 kW average), and if these are 0.5% of the United States total, this amounts to 6 GW and 300,000 units.

Cogeneration appears to be a highly likely source for additional electrical energy production and a significant number of units may be built. As time goes on, and wind and batteries become commercial, significant numbers of units will require added control and monitoring equipment.

The number of fuel cells and batteries that may be added will be influenced by the natural gas supplies available and by the amount of nuclear power generated. With more natural gas, the cost of fuel cell energy required will be lower and more fuel cells may be installed. With less nuclear generation available, the amount of base electrical power will be less and fewer batteries may be installed. However, since the average size assumed for the fuel cells and for the batteries was the same, the total number of units involved should remain unaffected.

It should be noted that these estimates are based on 5% of the year 2000 total generation being in the form of DSGs. These estimates are also based on utility-sized units for generation, i.e., 1 to 20 MW, for which the total additional DSGs could amount to 13,300 units as indicated.

If, in addition, one were to assume that 10% of this additional generation (i.e., 0.5% of the United States total) were made up of smaller sized units, i.e., 20 kW on the average, this would amount to 300,000 units by year 2000. Such a large number of DSGs to be controlled and monitored might result in a different approach to the design requirements for control and monitoring equipment.

The anticipated installations per year for the years 1990 and 2000 indicate that presently commercial and mature DSG generation sources will have a relatively uniform number of installations per year, while the technologies that are experimental will have a considerable increase in numbers from the year 1990 to the year 2000. Although such data are undoubtedly rather "soft," from the viewpoint of the control and monitoring equipment involved, the choice of one DSG technology or another will not have as significant an effect on the control and monitoring equipment required as it will have on some of the DSG generation equipment which will be developed and built.

The estimates in Table 5.9-1 have been based on a more thorough study described in Appendix B and presuppose an overall economic environment for the United States economy that is summarized briefly in the following.

Historically, there has been a close correlation between the long-term level and growth rates of the United States economy and its energy consumption. Electrical energy consumption has increased at a faster rate than total energy consumption, as its industrial, commercial, and residential use expanded. From 1920 to 1977, the average annual growth rates for GNP, total energy, and electrical energy consumption were approximately 3.7, 3.3, and 6.6%, respectively. During this period, the population's average annual growth rate was 1.26%. The sustained growths in GNP, total energy consumption, and electrical energy consumption were achieved during a period of relatively low price energy. This era has apparently ended and major adjustments are in progress.

A sampling of projections regarding population, economy, total energy consumption, and electrical energy consumption reveals that the United States growth rates are expected to decrease from historical values.* On this expectation there appears to be a consensus.

Regarding the degree and timing of the slowing down of these major factors, there are diverse opinions. The diversity of opinions can be accounted for in the differences in assumptions and to some extent on the intentional or unintentional bias of the organization or individuals conducting the studies. Table 5.9-2 shows the range of values for basic economic-energy factors growth rates, both historical and projected. These factors have implications for potential DSG technology growth. "Energy for Electricity" listed in Table 5.9-2 has particular significance since this information predicts that an increasing proportion of the energy to be consumed nationally will be used for electricity production.

Regarding the overall potential for DSGs, the price of various fuels and the proportion of their mix used to generate electricity will be of equal or greater effect than the major economic energy factors in Table 5.9-2. In particular, the price of the fuel which could be displaced by DSGs using solar, wind, or hydro energy will have a direct effect on their economic viability. Although there is quite a spread of estimated future fuel prices as shown on Figure 5.9-1, the consensus is that fuel prices are expected to increase significantly and this indicates increasing possibilities of DSG economic viability in the 1980 to 2000 time period.

The magnitude of total electrical energy and generating capacity between the years 1977 and 2000 is shown in Table 5.9-3. These values predicted for year 2000 are median values. There appears to be a consensus that the proportion of energy consumed in the form of electrical energy is going to increase.

Considering the economic, energy, and electrical industry statistics in Tables 5.9-2 and 5.9-3, it is important to note that even a small percentage of the total generating capacity required by year 2000, if supplied by DSG units, could amount to a large number of DSGs. If the economic viability anticipated is achieved by DSGs, their potential is considerable. With a manufacturing base to support them, the remainder of the 20th and the beginning of the 21st century could see the anticipated annual installation rates listed in Table 5.9-1.

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* Annual Report to Congress, 1978, U.S. Department of Energy, Energy Information Administration DOE/EIA - 01/73/3.

Table 5.9-2

AVERAGE ANNUAL GROWTH RATES, IN PERCENT, FOR MAJOR ECONOMIC FACTORS(1), AND PERCENT OF ENERGY CONSUMED FOR PRODUCING ELECTRICITY

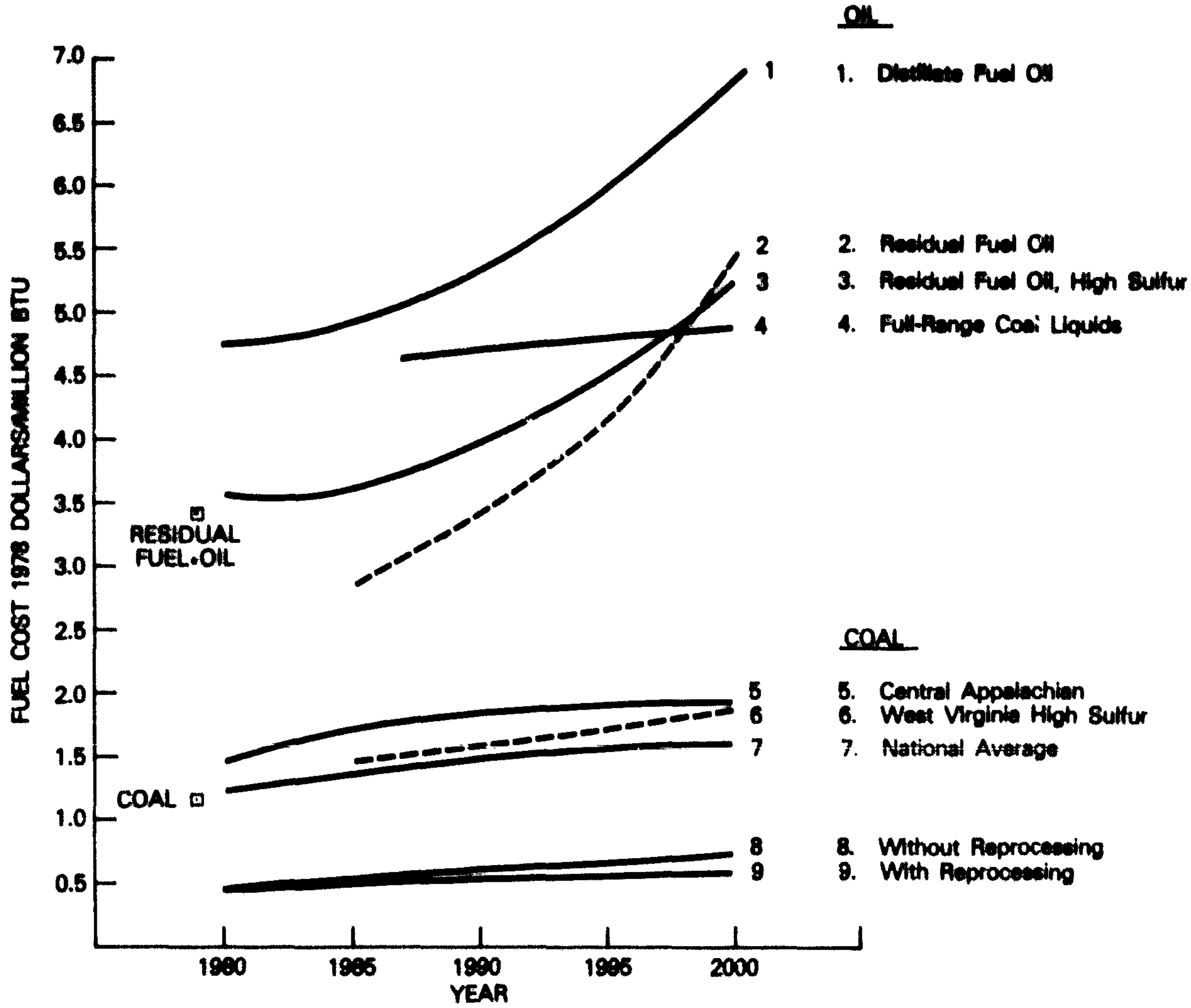
Major Economic Factors	Historical Growth Rates 1920-1977	Projected Growth Rates 1977-2000 (Values Listed Indicate Ranges)		
	Actual	Low End	Median	High End
U.S. Population	1.26		0.8	
Economic (GNP)	3.7	1.5-2.95	2.4-3.3	3-3.75
Total Energy Consumption	3.3	1.0	1.9-3.5	2-4
Electrical Energy Consumption	6.6	2-4	3-5.3	4-6.6
	← (Percentage Values) (2) →			
	1977		2000	
Energy for Electricity:	29	20	35	50

(1) Reports of organizations from which figures were obtained represent a cross section. Organizations included are: U.S. Department of Energy/Energy Information Administration, U.S. Department of Commerce, U.S. Department of Interior, New York State ERDA,* EEI, EPRI, EBASCO, Bankers Trust, and others. Figures were those publicly presented during the general time period of 1977-1978.

(2) Values listed are percentages as defined by the formula:

$$\left[\frac{\text{(Energy Consumed for Producing Electricity)}}{\text{(Total Energy Consumed)}} \times 100\right]$$

*New York State Energy Master Plan and Long-Range Electric and Gas Report, March 1980.



SOURCES

1, 3, 4, 5, 7, 8, 9 EPRI Technical Assessment Guide, EPRI PS-1201-SR, July 1979.
2, 6 DOE/EIA Annual Report to Congress 1978, DOE/EIA-0173/3.
□ DOE/EIA Monthly Energy Review, March 1980, DOE/EIA-0035/03(08), P. 89 (November 79 Data).

Figure 5.9-1. Cost of Fuel Delivered to Electric Utilities

Table 5.9-3

TOTAL ELECTRICAL ENERGY AND CAPACITY FORECASTS
FOR YEAR 2000 AND 1977 ACTUAL

	Year		
	1977*	2000	
		DOE/EIA†	EPRI††
Total U.S. electric utility electrical energy production in billions of kWh (electric utility plus industrial	2124 (2212)	5555§	6100
Average national electrical energy annual growth rate, percent‡			
1920-1977	6.6		
1977-2000		4.7	4.6
Peak load (GW)	396.35		1080
Total generating capacity (GW)	550.0		1300
Load factor, percent	61.4 (11)	67	63
Reserve margin, percent	30.2 (11)	20	20
New generating capacity (GW), required to supply increasing demand and replace retired capacity (by year 2000)			925

*EIA, Statistical History of U.S.

†Annual Report to Congress 1978, U.S. Department of Energy, Energy Information Administration DOE/EIA-0173/3.

††EPRI - Technical Assessment Guide, EPRI PS-1201-SR, Special Report, July 1979.

§Year 2000 value extrapolated from 1995 midrange energy sales projection adjusted by 10% transmission distribuiton loss.

11 EEI Statistical Yearbook for 1977, 18 Year Average = 25%.

‡Growth rate is expected to vary by region with relatively large variations. For example, a 2.1 growth rate is forecast through 1994 by the "New York State Energy Master Plan and Long Range Electric and Gas Report," draft report, August 1979.

Section 6

CONTROL AND MONITORING SYSTEM ARCHITECTURAL AND EQUIPMENT ISSUES FOR DSG INTEGRATION

6.1 INTRODUCTION

Identified in Section 4 were five generic operational and technical problems to consider in defining control and monitoring requirements for integrating dispersed storage and generation (DSG) into the utility distribution system. These included:

- Economics of operation
- Quality of supply
- Security of supply
- Protection of equipment
- Protection of personnel

The control and monitoring equipment necessary to effect the integration of DSGs into the distribution systems must be capable of operating the DSGs and the power systems so that the above operational and technical problems are fully resolved.

A central issue for the implementation of control and monitoring systems is the architecture of the automation system and how it may fit within the control hierarchy of the utilities. The technical considerations in addressing this central issue are summarized in this section. These considerations must take into account:

- The operational characteristics of the DSGs. With distribution system equipment it is expected that DSG units will generally have the following characteristics:

  1. Unattended operation capability
  2. Control and/or monitoring from remote points
  3. Local automatic control, monitoring, and protection with stand-alone operation if possible

  The DSG sizes in the ranges considered in this study, up to 30 MW, may generally be too small to justify attended operation. An operator may be present, but the control, monitoring, and protection equipment will generally be designed for unattended, automatic operation. Control and monitoring from a higher level control center, such as a distribution dispatch center, will vary depending upon the size of DSG units and individual utility practice. For small DSG units there may be little or no control from the higher level control center and only limited indication or data transmitted from the DSG to the control center. The utility may want to know only whether the DSG is ON or OFF and whether it is connected to the utility system. For some small units there will be cases where no communication exists between the DSG units and a utility control center.

Control and monitoring for large DSG units may include control, indication, and data utilizing a supervisory control and data acquisition (SCADA) system and a communication system between the distribution dispatch center and DSG location. Some large DSG units may be controlled directly from the energy management system of the utility. Some DSG units may be included in the automatic generation control (AGC) program of the utility.

Automatically controlled DSG units generally can be classified as partially automatic, fully automatic, and fully automatic remote-controlled. The fully automatic remote-controlled DSG unit, utilizing a distribution SCADA system, may receive only a start/stop signal from the control center. The starting and stopping sequences, including automatic synchronizing to the utility distribution system, would be performed completely automatically by local control and monitoring equipment provided with the DSG unit. Examples of other control commands include raise/lower load and excitation, operator control of breakers and switches at the DSG, etc. Some utilities may also utilize partially automatic remote-control in which an operator at the utility distribution dispatch center maintains control over major steps of the start/stop sequence.

- Distribution automation and control in future distribution systems. With automated distribution systems including automation control and monitoring (DAC) equipment at the distribution substation level, control and monitoring of DSG units may be one of the functions of the DAC equipment. Scheduling of DSG units would most likely be performed at a higher level control center, such as the distribution dispatch center with the DAC equipment utilized for DSG information gathering, and pass through commands or signals from the distribution dispatch center.

- Protective system local to the DSGs and within the distribution power systems. Sufficient protective equipment must be provided with the DSG unit so that it is protected against trouble within the DSG plant, e.g., within the generator, transformer, etc., and also against faults in the distribution system. Integration of DSG with the utility distribution system also imposes additional requirements on the protection and control of the distribution system at both the substation and feeder levels. Most distribution feeders are operated in a radial nature, i.e., sourced from one distribution substation. This is the general application considered in this study. The DSG units which are connected to distribution feeders at points remote from the substation will mean that feeder faults are fed from both the substation and from remote DSG locations. This will impact feeder relaying coordination and fault location techniques. The DSG units at the substation will also impact distribution system design and operation and must be factored into substation and feeder protective relaying and control, circuit breaker ratings, etc.

6.2 CONTROL AND MONITORING ELEMENTS

A control system can be viewed as consisting of five elements:

- Information-processing system
- Decision-making system
- Instrumentation system
- Actuator system
- Communication system

Information processing takes available information, measurements, priorities of human operators, etc., and provides a data base for decision making. Decision making takes the output from the information-processing system and makes explicit choices about what should be done. Instrumentation includes monitoring and other data-gathering devices to provide inputs to the information-processing system. Data are communicated from instrumentation to the information-processing system and from the information processing to the decision-making system by the communication system, especially when these systems are separated spatially from one another. The actuator system takes output from the decision-making system and converts that output into explicit actions. Figure 6.2-1 illustrates how these separate elements may operate together as a simple control system.

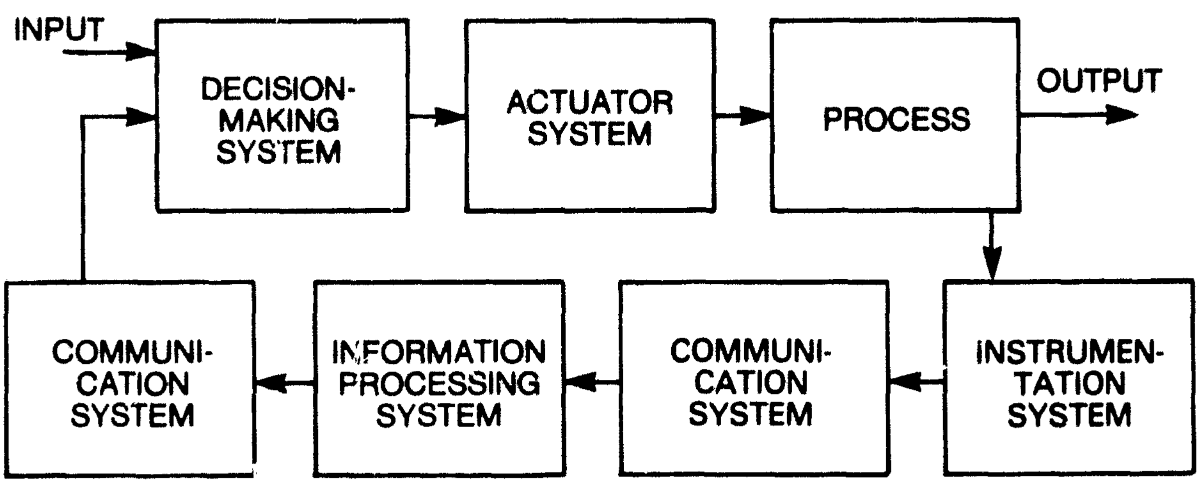


Figure 6.2-1. Simple Control System Representation

6.2.1 INFORMATION-PROCESSING AND DECISION-MAKING COMBINATIONS

Four possible types of information processing-decision making combinations are:

- Local information processing - local decision making
- Local information processing - central decision making
- Central information processing - local decision making
- Central information processing - central decision making

The local information processing and local decision-making combination represent an extreme case where no communication exists between a DSG unit and the distribution dispatch center or the energy management system. Small customer-owned DSGs exemplify such local information processing and local decision making. With local information processing and central decision making, all local information at the DSG site would be passed to a higher control center (DDC or EMS) for decision making. This may not be necessary since many decisions can and should be made locally, e.g., protection, voltage regulation, shutdown in emergency, etc. With central information processing and local decision making, decision making is still done locally but by using a data base developed partly with centralized information, as well as with local measurements. Present automatic generation control is an example of central information processing and local decision making. The central information processing and central decision-making combination represents the extreme case where all information is transferred to one central point and centralized decision making occurs. For larger DSGs the economic scheduling of DSGs from the DDC is an example of this central information-processing and central decision-making set of conditions.

A generalized information-processing and decision-making flow diagram for DSG integration into the overall utility control hierarchy is shown in Figure 6.2.1-1. Some control decisions are shown to be made locally, some centrally.

In the information-processing and decision-making flow diagram, the four major elements of the utility system are shown. These include the bulk system, the distribution system, the customer load, and the DSG units. The location of the local elements of the DSG control and monitoring system would be at the DSG site which is either at the distribution substation or at a remote point on a distribution feeder. Distribution system central information processing and decision making would be at a higher control center, such as distribution dispatch. Bulk system central information processing and decision making would be at the energy management system of the utility. Communication systems are required since the local and central locations are different.

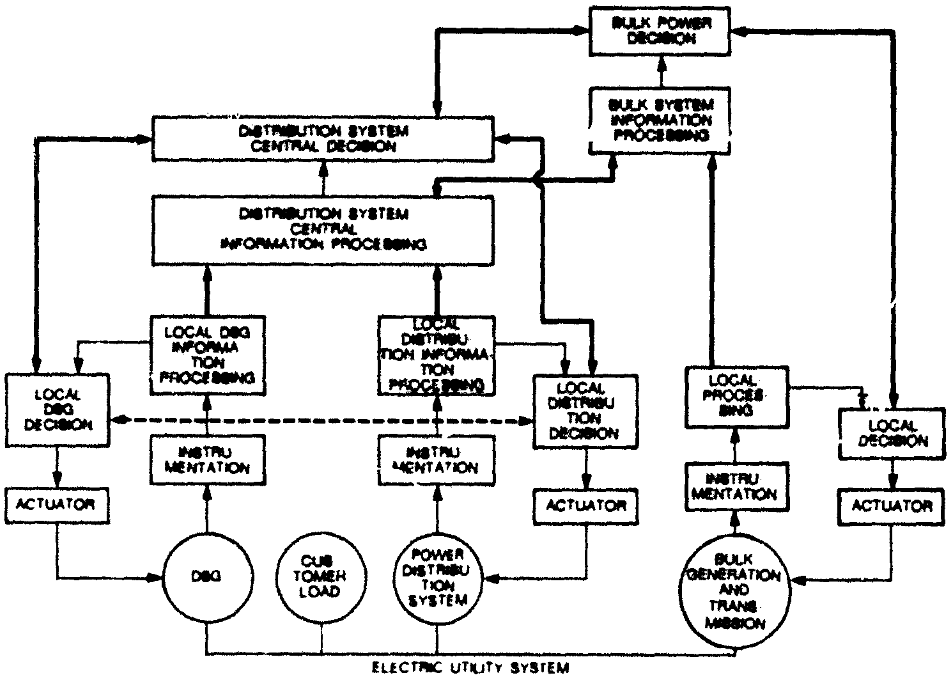


Figure 6.2.1-1. DSG Integration: Information-Processing-Decision-Making Flow Diagram

While DSG is shown as a separate system in Figure 6.2.1-1, there will be some applications where the DSG unit is located on the customer side of the meter. Also worthy of note is the fact that several DSGs may be present where only one is shown.

There is an interaction between the DSG units at the substation or feeder and with other elements of the distribution system. A dashed line is shown between the local decision-making elements of these two systems in the diagram. The flow diagram and this interaction at the local level suggest several approaches for the control and monitoring of DSGs in the electric utility control hierarchy.

Three structural approaches to DSG control and monitoring are discussed in the following sections. The terminology used indicates the nature of the structural approaches that are available to utilities. These terms are -

- Centralized DSG Control and Monitoring - where a DDC primarily controls several DSGs located at different substations and/or feeders.
- Decentralized DSG Control and Monitoring - where a DDC primarily controls several distribution automation functions at each substation of which DSG is only one function.
- Local Control - where the DSG control primarily originates locally and the DSG is only remotely monitored at the DDC.

The centralized approach refers to the monitoring and control of DSGs separately from the other distribution functions. It includes both local decision making at the DSG location and also central decision making at the DDC or the energy management system (EMS) so that the total system control is not truly centralized in the general meaning of the word.

It is pertinent here to mention that truly centralized or decentralized system controls are extreme developments, neither of which is wholly practical. Economic dispatch, at least in its present form, requires some centralization of computation and decision making. On the other hand, most of the distribution system controls (even without the DSG) would present too burdensome a control problem for a central EMS. Elements of centralized and decentralized control will be found in any practical control scheme.

Because of these facts, we are justified here in regarding DSG control as decentralized if the control is exercised from a point in the control hierarchy below the DDC, or centralized if the DSGs are controlled directly by the DDC.

Not all companies have distribution dispatch centers. In this case, the centralized approach results in the DSG control being exercised from the energy management center. If the DSGs are both numerous and small, companies not using a DDC may prefer the decentralized approach in which controllers located at the distribution substation (see next section) assume most of the control.

Whichever method is used, or whether other variations are devised, some local computation and control will almost certainly be used for DSGs large enough to warrant control at all. At the DSG local level are needed the necessary measurement, information processing, and communications to the DDC or EMS. With the centralized approach, communication is direct between the DDC and a number of DSG units, which may be at the substation, feeder, or customer location.

6.3 CENTRALIZED CONTROL AND MONITORING

The centralized control and monitoring approach is illustrated in Figure 6.3-1. For each of the individual DSG units, there will be a number of subsystems and functions for control and monitoring. Control and monitoring requirements for other distribution system functions would be handled separately at the local level with separate communications with the distribution dispatch center. In Figure 6.3-1, instrumentation, communications, actuator, some local information processing, and local decision making for the DSG units are present at each DSG location. For the other distribution functions such as voltage control these control elements are assumed to be located at the substation. Central information processing and central decision making for the DSG and for distribution functions reside at the DDC.

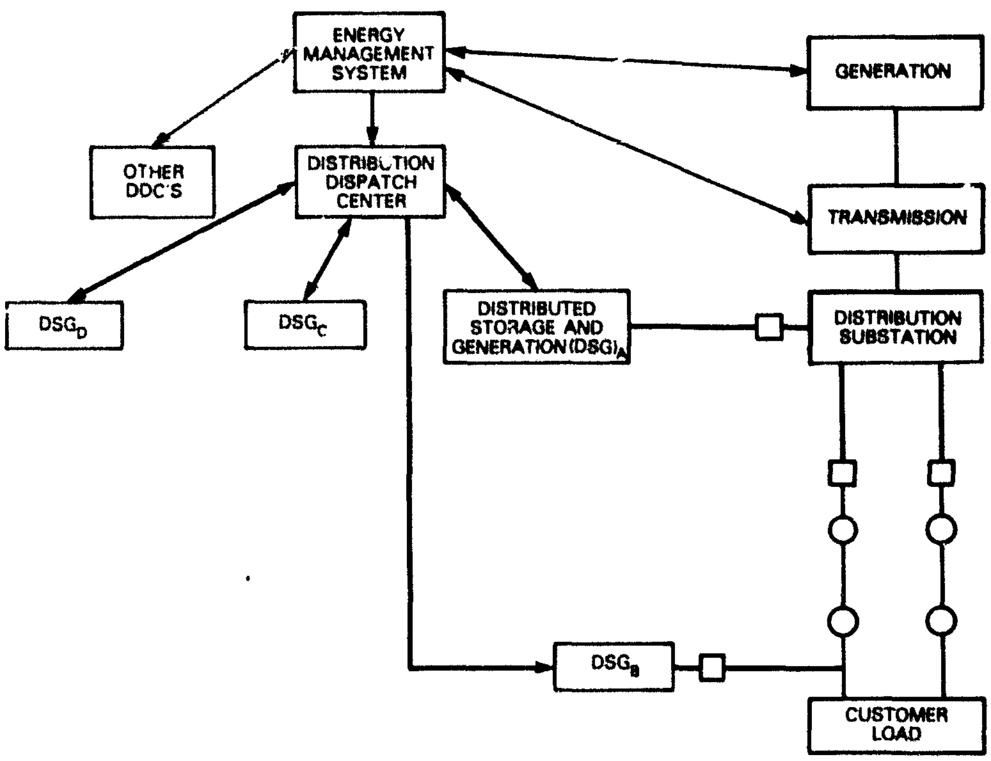


Figure 6.3-1. Centralized Control and Monitoring for DSG Integration

6.4 DECENTRALIZED CONTROL AND MONITORING

The decentralized approach refers to the monitoring and control of both DSGs and other distribution automation and control functions through a control and monitoring system for substations and their feeders. Instrumentation, communications, local information processing, and local decision-making subsystems would be located at a distribution automation control (DAC) system at the substation. The DAC system would communicate with a higher level control center such as the DDC. It could include both substation and feeder automation and encompass functions in the categories of data acquisition and monitoring, control, protection, status and alarm, data logging, and system interface.

The DAC system located at the distribution substation would be responsible for DSG units at both the substation and remote locations on its feeders, as well as the other DAC functions.

The decentralized control and monitoring approach is illustrated in Figure 6.4-1.

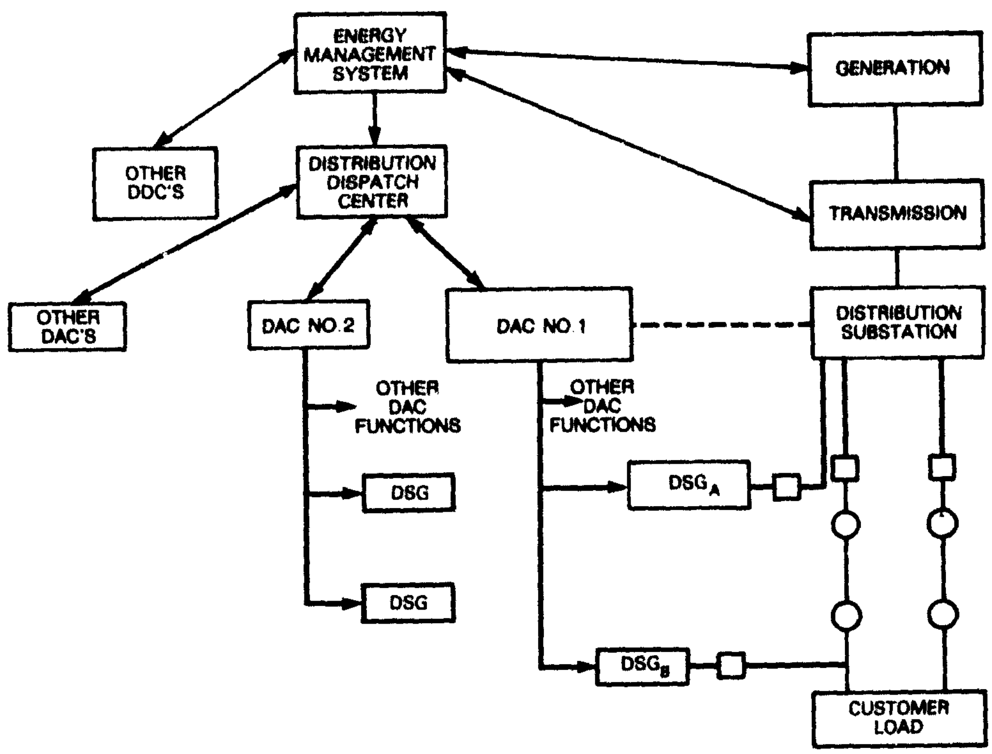


Figure 6.4-1. Decentralized Control and Monitoring for DSG Integration

6.5 LOCAL CONTROL AND REMOTE MONITORING

For some smaller or customer-owned DSG units it may not be legally, economically, or technically feasible to control their operation using either a centralized or decentralized approach. Instead, automatic controls at the DSG site would start up and shut down the DSG unit based entirely on local conditions, e.g., proper wind speed for small wind-driven generators or the customer-owner's need for process power.

Depending on the size of the DSG unit, the only monitored information transmitted back to the control center may be the ON-OFF status of the DSG. With very small units there will probably be some cases where no information is transmitted back to the control center on a continuous basis.

For example, consider an individual residential customer whose average load may amount to 2 kW. A single load element for such a customer may be a range, a water heater, or a resistance heater, any one of which may amount to 4 kW. In order for such a customer to be able to supply his own needs, as well as to provide any appreciable power back to the utility, a 10 kW generation source is a reasonable minimum size for such a small, remote DSG. Although smaller DSG units would pose no particular problem to the utility, it should not be necessary to monitor or control the contribution of each small DSG. Therefore, in this study, a nominal size of 10 kW has been considered the lower limit to small DSGs.

6.6 CONTROL AND MONITORING — DSG SIZE AND QUANTITY

The three approaches which have been described for control and monitoring of DSG units can be related to the size and quantity of the DSG units on the utility distribution system. A generalized matrix is shown in Table 6.6-1 which indicates a possible relationship between the control and monitoring approach and the size and quantity of DSG units on a particular utility system.

Assuming that all are equally accessible, the range of sizes shown for the different DSGs, which amounts to 3000/1, serves to emphasize that some DSGs are more important than others in terms of their need to be monitored and controlled. Furthermore, when one considers that some of the medium and large DSGs and most of the small DSGs, are owned by customers who may not be able or willing to let the utility control their power output, it becomes more apparent that some DSGs may have a different need for remote monitoring and control than others.

Table 6.6-1

POSSIBLE RELATIONSHIP CONTROL AND MONITORING APPROACH - DSG SIZE AND QUANTITY

QUANTITY / SIZE	FEW (UNDER 10)	SEVERAL (10 - 50)	MANY (50 - 1000)
SMALL (0.01 - 0.5MW)	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY	LIMITED REMOTE OR LOCAL CONTROL. ON-OFF INDICATION ONLY
MEDIUM (0.5 - 5MW)	CENTRALIZED CONTROL SOME INDICATION & DATA	CENTRALIZED OR DECENTRALIZED CONTROL SOME INDICATION & DATA	DECENTRALIZED CONTROL SOME INDICATION & DATA
LARGE (5 - 30MW)	CENTRALIZED CONTROL INCREASED INDICATION & DATA	CENTRALIZED CONTROL INCREASED INDICATION & DATA	CENTRALIZED CONTROL INCREASED INDICATION & DATA

From the viewpoint of the operator of the DDC the question which arises is how much time and information is essential for the DDC operator to perform a satisfactory and adequate measure of monitoring and control. In all probability a few small units will represent instances where the DSGs are owned and operated by their customers and the control is principally local and customer-decided. The ON-OFF indication is about all the monitoring that is needed. If the units are medium-sized, there is increased likelihood that they will be owned by a utility and there will be a reason for these to be DDC controlled. Since the units are handling more power, there is a greater need for remote indication and data. For large units, DDC control and increased indication and data are likely to be justified.

In Table 6.6-1 it is assumed that the trend in control and monitoring will be from centralized to decentralized for medium-sized DSG units as the number of units increases on a given utility system. The control and monitoring varies from local control only to control with increased indication and data brought back to the higher level control center as the size of DSG units increases.

6.7 DISTRIBUTION SCADA

With control and monitoring of the DSG from a remote point, the distribution SCADA function is required. This will involve master equipment at the higher level control center and remote terminal unit equipment at the DSG location.

Tables 6.7-1 and 6.7-2 indicate the locations of master and remote terminal equipment with the centralized and decentralized control and monitoring approaches and with the DSG at the distribution substation and connected to a feeder.

The DSG control and monitoring input and output requirements can be tabulated in several ways. One helpful method in picturing the requirements for a higher level control center, such as a DDC, and a remote terminal unit at the DSG location is to identify the inputs and outputs at the DSG remote terminal unit communication interface.

Types of DSG control and monitoring input and output quantities which may be required to be transmitted over the communications system between the control center and the remote terminal unit are shown in Table 6.7-3.

The outputs from the DSG remote terminal unit will be needed at the distribution dispatch level at various periods. For example, status changes, e.g., breaker to switch position, and alarms might be reported at the normal scan cycle of the SCADA function. This could be every few seconds. The update period for values, e.g., generator MW or MVAR, would depend upon the degree of participation in the utility power system automatic generation control (AGC) program. Without AGC participation, an update period for values approximately every 15 minutes or more is probably appropriate. All data values might be obtained automatically once an hour for periodic logging at the control center.

The operator would have the capability at the control center to request status and data values at any time for a selected point or all points at the DSG location. Similarly, the operator at the control center could control the start/stop of the DSG, the open/close of the breakers, the raise/lower power output, the raise/lower voltage/VAR, etc.

6.7.1 DISTRIBUTION DISPATCH CENTER (DDC)

Many utilities have control centers or dispatch centers for controlling their distribution system. The DDC is a manned center and generally serves as the point from which crews are dispatched in the event of trouble on the distribution system and for routine maintenance. Where the utility has a SCADA system for the distribution system, the DDC often is the location of the SCADA master. The DDC may have responsibility for up to 50 or more distribution substations and their feeders.

Table 6.7-1

DSG AT DISTRIBUTION SUBSTATION -
DISTRIBUTION SCADA

DSG Control and Monitoring	Centralized Control and Monitoring	Decentralized Control and Monitoring
SCADA Master Function	DDC*	DDC*
SCADA Remote Function	Remote Terminal Unit at Substation	Combined with DAC Equipment at Substation

For automated distribution systems the DDC would serve as the focal point for a number of distribution automation functions. A representative form of the DDC control and monitoring equipment, including the communications interface to DSG units with both centralized and decentralized control and monitoring, is shown in Figure 6.7-1. Figure 6.7-2 is a representative diagram of possible DDC control equipment. Some users may utilize a DDC redundant CPU approach for greater reliability.

Table 6.7-2

DSG CONNECTED TO DISTRIBUTION FEEDER -
DISTRIBUTION SCADA

DSG Control and Monitoring	Centralized Control and Monitoring	Decentralized Control and Monitoring
SCADA Master	DDC*	• DDC for scheduling • DAC equipment at substation for pass-through commands, indication and data gathering
SCADA Remote Function	Remote Terminal Unit at DSG location on feeder	Remote Terminal Unit at DSG location on feeder

*Some large DSG units may be controlled directly from the utility EMS level.

Table 6.7-3

DSG CONTROL AND MONITORING

Representative Input and Output Quantities To the DSG Remote Terminal Unit from the Control Center	
Inputs	**Outputs**
Control	Status
• Two-Position Control	• Device
• Incremental/Variable Position	• Alarms
Data Requests	Values
• Automatic	
• Operator Demand	

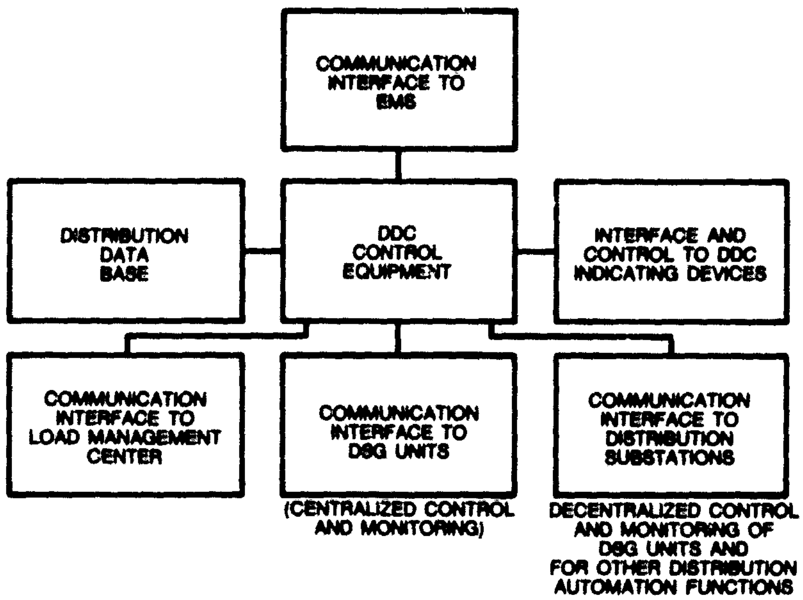


Figure 6.7-1. Representative DDC Control and Monitoring Equipment Configuration Structure

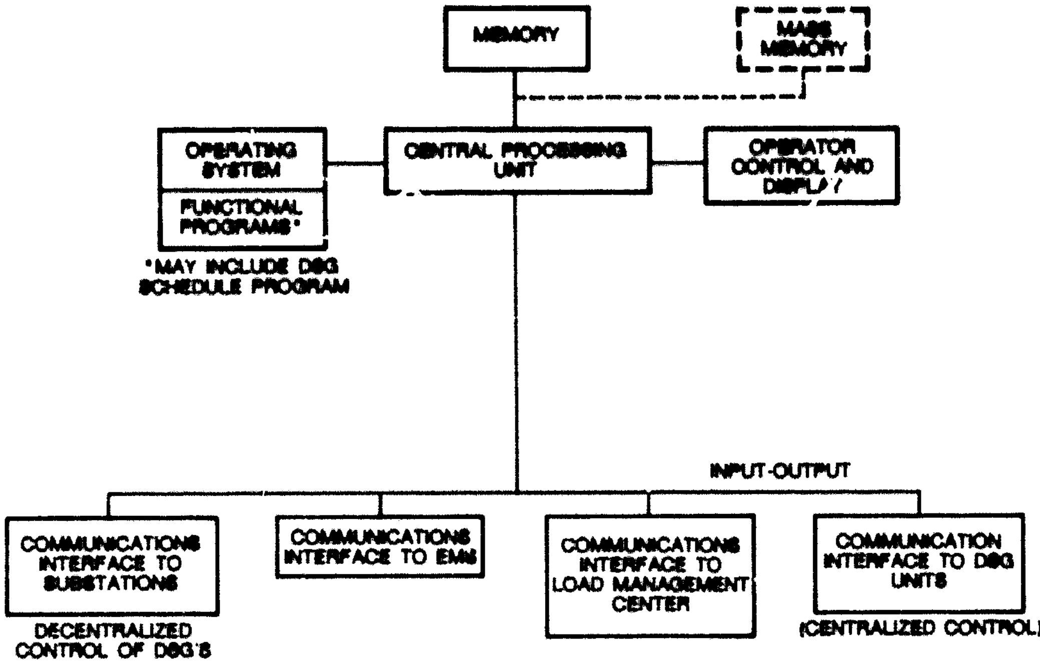


Figure 6.7-2. DDC System Architecture

6.8 COMMUNICATIONS

Communications are required between the utility control center, such as the distribution dispatch center (DDC) or EMS, and the SCADA remote terminal unit (RTU) at the DSG location. Table 6.8-1 shows the major different communication paths which may be utilized for DSG integration on the distribution system.

The amount of control command information to be transmitted from the control center to the DSG location and the data to be returned from the DSG to the control center will vary with the size of the DSG unit, methods of scheduling, and the individual utility practice.

Communications between the DDC and the substation are normally by voice grade circuit. Below the substation distribution, communications systems being evaluated by utilities include the distribution line carrier, radio, and telephone.

The traffic on the communications system for DSGs is determined by the number of control, indication, and data points and the frequency with which information is required. These subjects are addressed in Section 8.4.

Table 6.8-1

POSSIBLE COMMUNICATION
DSG INTEGRATION ON DISTRIBUTION SYSTEM

	EMS	DDC	DAC at Sub-station	RTU at Sub-station	RTU at Feeder	RTU at Customer Metering Point
Centralized Control and Monitoring						
DSG at Distribution Substation		←	—	→		
			or			
(Some Large DSGs)	←	—	—	→		
DSG Connected to Feeder		←	—	—	→	
DSG Internal to Customer Load		←	—	—	—	→
Decentralized Control and Monitoring						
DSG at Distribution Substation		←	→			
		or				
(Some Large DSGs)	←	—	→			
DSG Connected to Feeder		←	—	—	→	
DSG Internal to Customer Load	←	—	—	—	—	→
Local Control and Monitoring						
DSG at Substation		←	—			NOTE: While information flow shown is one way, the scanning system would request data from DSG-RTU
			or			
		←	—	—		
DSG Connected to Feeder		←	←	—	—	
			or			
		←	—	—	—	
DSG Internal to Customer Load		←	←	—	—	—
			or			
		←	—	—	—	—

6.9 REPRESENTATIVE CONTROL AND DATA REQUIREMENTS FOR HYDROELECTRIC GENERATOR UNITS

Table 6.9-1 shows three different examples of representative control, indication, and data information implemented by utilities for hydroelectric generators. The control and monitoring information is tabulated in the general format of Table 6.7-3.

The three cases in Table 6.9-1 represent hydroelectric generators in the range of from approximately 1 MVA up to approximately 60 MVA and are for three different user examples. They illustrate a range of inputs and outputs, and from these references representative requirements for communication data and commands were derived and utilized in Section 8.

Table 6.9-1

REFERENCE CONTROL AND MONITORING QUANTITIES - HYDROELECTRIC

Inputs to DSG Remote Terminal Unit from Control Center	A	B	C
Control			
Two-Position Control			
Generator Unit Start/Stop	X	X	X
Generator Unit Circuit Breaker Trip/Close	X	X	X
High-Voltage Circuit Breaker Trip/Close	X		X
Station Service Circuit Breaker Trip/Close	X		
Station Service Transformer Switch Trip/Close		X(3)	
Main Transformer Low-Voltage Disconnect Switch Trip/Close		X(2)	
Main Transformer High-Voltage Disconnect Switch Trip/Close		X(2)	
Sluice Gate Heating On/Off		X	
Transfer Trip Test On/Off		X(2)	
Unit Load Control On/Off	X		
Station Load Control On/Off	X		
Remote-Control Mode Manual/Auto			X
Generator Field Breaker Trip/Close			X
Multiposition Control			
Unit Gate/Governor Four Position			X
Incremental/Variable Position Control			
Unit Voltage VAR Raise/Lower	X	X(2)	X
Unit Gate/Governor Speed/Power Raise/Lower	X	X(2)	X
Unit Gate/Governor Limit Raise/Lower	X	X(2)	
Head Gates Lower		X(2)	X
Sluice Spillway Gate Raise/Lower	X	X	X
Data Requests			
Automatic			
Normal Conditions			
Normal Scan	X	X	X
Periodic Log		X	X
Alarm Conditions	X	X	X
Operator Demand			
Status			
Individual Points	X	X	X
All Points	X	X	X
Value			
Selected Data	X	X	X
All Data	X	X	X

Table 6.9-1

REFERENCE CONTROL AND MONITORING QUANTITIES - HYDROELECTRIC (Cont'd)

Outputs from DSG Remote Terminal Unit to Control Center	A	B	C
Status			
Device (Two-Position)			
Generator Master Control Relay	X	X(2)	
Generator Circuit Breaker	X	X(2)	X
Generator Voltage Regulator Limits		X(2)	
Station Service Transformer Switch		X(3)	
High-Voltage Breaker	X		X
Sluice Gate Heating		X	
Main Transformer Disconnect Switch (LV)		X(2)	
Main Transformer Disconnect Switch (HV)		X(2)	
Headgate Limits		X(2)	
Sluice Gate Limits		X	
Station Service Breaker	X		
Unit Load Control On/Off	X		
Station Load Control On/Off	X		
Unit Running/Stopped	X		
Generator Field Circuit Breaker			X
Status (Device Multiposition)			
Unit Control Mode (3-Position)			X
Unit Gate Position (4-Position)			X
Alarms			
Unit Tripout	X		
Unit Trouble	X		
Breaker Automatic Trip	X		
Generator Overvoltage		Group I: X	
Generator Loss of Field		X	X
Generator Overspeed		X	
Incomplete Start/Stop Sequence		X	
Governor Oil Pressure (Low)		X	
Line Protection		X	
Generator Phase Backup		Group II: X	
Generator Armature Ground		X	
Station Service Transformer Overcurrent		X(2)	
Main Transformer Differential		X(2)	
Main Transformer Phase and Ground Backup		X(2)	
Main Transformer Gas		X(2)	
Generator Split Phase		Group III: X	
Generator Differential		X	
Unit Bearing Over Temperature		X	
13.8 kV Bus Differential		X	
Generator Armature Ground		Group IV: X	
600 V Feeder Protection		X	
Main Transformer(s)			
High Oil Temperature		X(2)	
Hot Spot Temperature		X(2)	
Oil Level		X(2)	
Gas Accumulation		X(2)	
Cooling Failure		X(2)	

Table 6.9-1

REFERENCE CONTROL AND MONITORING QUANTITIES - HYDROELECTRIC (Cont'd)

Alarms (Cont'd)	A	B	C
		Group IV (Cont'd)	
Generator		X(2)	
Bearing Cooling Water		X(2)	
Bearing Oil Level (High or Low)		X(2)	X
Bearing Temperature (High)		X(2)	
Bearing Oil Temperature (High)		X(2)	
Carbon Seal Water Failure		X(2)	
Governor Oil Pressure and Level		X(2)	
Field Ground		X(2)	
Stator Temperature (High)		X(2)	
Field High-Temperature (High)		X(2)	
Creep		X(2)	
Voltage Regulator		X(2)	
Transducer Failure		X	
Carbon Seal Emergency Water		X	
Fire Pumphouse Heating		X	
Service Air Pressure (Low)		X	
Battery Charger Failure		X	
Battery Ground or Undervoltage		X	
Station Service Transfer		X	
Main Sump (High Level)		X	
Deluge System Operated		X	
Deluge System Blocked		X	
CO_2 Discharged		X	
CO_2 Blocked		X	
120/208 V Service Transfer		X	X
Fire		X	X
Station Unauthorized Entry		X	
Loss of Control Bus		X	
DC Head Cover Pumps On		X	
Turbine Greasing Failure		X	
Switchgear Air Pressure		X	
600 V Service Ground		X	
Burnt-Out Thermocouple		X	
Loss of AC to Fire Pumps		X(2)	
Station Service Transformer Low Oil or Surge		X	
Partial Remote Control		X	
On-Demand Telemetering Channel Failure (Frequent)		X	
On-Demand Telemetering Channel Failure (Impulse)		X	
Communications Normal Emergency Power Supply		X(2)	
Automatic Transfer of Supervisory Channel		X(2)	
Failure Main/Standby Supervisory Channel		X(2)	
Failure of Transferred Trip Channel		X	
Loss of DC to Transferred Trip Transmitters			X
Trash Rack Differential			X
Unit Stopped			X
Flashboard Failure			X
General Station Alarm			X
Low Unit Bearing Oil Pressure			X

Table 6.9-1

REFERENCE CONTROL AND MONITORING QUANTITIES - HYDROELECTRIC (Cont'd)

Values	A	B	C
<u>Analog (Variable) Quantities</u>			
Generator (MW)	X		X
High-Voltage System (kV)	X		
Generator Volts (kV)	X	X(2)	X
Generator (MVARS)	X	X(2)	X
Station Service (Amperes)	X	X(3)	
Headwater Level	X	X	X
Tailwater Level	X	X	
Spillway/Sluice Gate Position	X	X	X
Station (MVARS)	X		
Station (MW)	X	X(2)	
System Frequency	X		
Gate/Governor Position		X(2)	X
Generator Field (A)		X(2)	
Gate/Governor Limit Position	X	X(2)	X
13.8 kV Bus Volts		X	
<u>High-Voltage Lines</u>			
MW			X
MVARS			X
kV			X
Pond Water Level			X
Penstock Pressure at Turbine			X
<u>Integrated Quantities</u>			
Generator (MWH)		X(2)	X
Station (MWH)	X		
Unit Water Flow		X(2)	
Generator (MVARH)			X

NOTE: Examples refer to three selected users as below:

Column A. Large hydroelectric plants in the western United States with multi-units, approximately 50 MW each. Reference, <u>Modern Control of Large Hydroelectric Generating Systems</u>; R.H. Bruck, AIEE, Paper 62-1.

Column B. Multi-unit plants with hydroelectric units from 16 to 64 MVA. Numbers in parentheses indicate quantities at a two-unit plant. Reference, <u>Electrical Features of Ontario Hydro's Modern Supervisory-Controlled Hydraulic Generating Stations</u>; J.W. Ellis, AIEE Paper 62-24.

Column B Alarm Categories:
- I Return to service anytime
- II Return to service if required for load
- III Lockout
- IV Sustained fault

Column C. Represents preliminary plans for control and monitoring of unattended hydroelectric plants by Niagara Mohawk Power Corporation (NMPC) in New York State. The NMPC system has 81 hydroelectric stations totalling approximately 660 MW installed capacity

Section 7

MAJOR OPERATING MODES AND STATES

7.1 INTRODUCTION

The installation of dispersed storage and generation on an electric utility distribution system will introduce a new set of operating conditions. For a significant amount of DSG capacity, integration of these new operating conditions into the electric utility framework will probably require remote and automatic control. This may be attributed to three main factors:

- Since DSG unit size is small compared to central station generating units, there could be a large number of units in operation for a significant DSG-installed capacity. This could include many small customer-sized units encouraged by economic incentives. Since it will not be possible to economically justify local operators for individual small DSG units, automatic control will be required.
- For DSGs supplied by intermittent energy sources such as sun, wind, and rivers/streams, and battery or fuel cell peaking-duty DSGs, the number of startup and shutdown operations will be much greater than for baseload plants. This will require automatic operation, especially for intermittent-type DSGs.
- Because of the large number of storage and generation devices which would be dispersed throughout the distribution system and because of frequent unpredictable startup and shutdown, the possibilities of danger to repair and maintenance personnel will greatly increase. Therefore, automatic monitoring and control at the DSG to properly coordinate with abnormal and emergency distribution states, and the monitoring of all DSGs by the utility DDC dispatcher will become very important. The capability to inhibit or block DSG operation or to quickly shutdown and lockout DSGs by remote control can have both efficiency and safety implications.

This section presents a detailed discussion of the DSG operating modes and the states of the DSGs and distribution system. The functional requirements for DSG monitoring and control are strongly influenced by these modes and states.

7.2 DEFINITION OF TERMS

The operation of DSGs as an integral part of the distribution system requires recognition of the DSG condition or "state." In addition, the conditions existing on the bulk power and distribution systems are of major importance for the integrated operation of DSGs within the distribution system. Thus, the state of the distribution or bulk power system can affect the mode of DSG operation. These terms "mode" and "state" are defined in this section to provide a common reference of understanding.

There are interrelationships between DSG operating states and modes, DSG and distribution system states, and DSG modes and distribution states. These interrelationships are described to provide an understanding of the interdependency of and the need for control and monitoring under various conditions. The operator constraints with regard to DSG operation under the various combinations of DSG and distribution states are discussed to provide further understanding of the operating control requirements for the control and monitoring requirements analysis.

A common set of terms is required to discuss and describe interrelationships among DSG, distribution system, and bulk power system operation. A basic differentiation between the terms "mode" and "state" must be made. This report uses the term "mode" to describe the manner in which the DSG plant or unit is being operated. The term "state," as used for DSGs, describes the operational characteristics or conditions of a DSG at a given time. Definitions for the state of the bulk power system are adopted from a published IEEE article,(4) recognizing that they are not universally accepted as standard in the industry. Distribution system state definitions have closely followed the bulk power system state definitions and have adapted them with some elaboration pertinent to distribution system operating conditions.

7.2.1 DSG OPERATING MODES

DSG plants or units may be considered to be in one of three operational modes: ON, OFF, or STANDBY. The definitions of these terms for the purpose of this report are as follows:

- ON - DSG is in an operable condition ("running"), in synchronism or equilibrium with the power system, and electrically connected to it. In this condition the DSG will normally be generating electrical power or absorbing it, as in the case of a storage battery.
- OFF - The DSG is electrically disconnected from the distribution system at the DSG-distribution system interface and is shutdown or inactive, i.e., not "running."
- STANDBY - DSG is in an operable condition, activated ("running") but not electrically connected to the distribution system.

Factors influencing the mode in which the DSG is placed are:

- DSG energy resource
- DSG and power system schedules
- DSG state
- Power system state
- Private owner (customer) decisions

7.2.2 BULK POWER SYSTEM STATES

Power system operating conditions can be described by five operating states: normal, alert, emergency, in extremis, and restorative. The characterization of these five states was developed for the overall power system, but the states have been considered primarily in relation to the bulk system. A brief description of the five operating states follows; states and transitions between the states are shown in Figure 7.2.2-1.

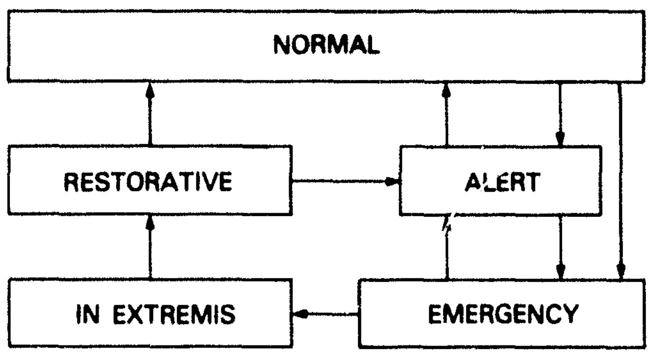


Figure 7.2.2-1. Power System Operating States

In the normal operating state, generation is adequate to meet existing total load demand. No equipment is overloaded and reserve margins for generation and transmission are sufficient to provide an adequate level of security for the stresses which may be imposed on the system.

The alert state is entered if the probability of disturbance increases or if the system security level decreases below a particular level of adequacy. In this state, all constraints such as adequate generation for total load demand are satisfied and no equipment is overloaded. However, existing reserve margins are such that a disturbance could cause overloads or other levels to be exceeded corresponding to physical limitations of equipment. In this state, preventive action can be taken to restore the system to normal.

In the emergency state caused by a severe disturbance taking place before preventive action is taken, the system is still intact but overloads exist or the equipment's physical limitations are exceeded. System security is reduced and emergency control measures are required to restore the system to the alert or the normal state. If action is not taken in time and if the disturbance or a subsequent disturbance is severe, the system begins to (operationally) disintegrate.

While system disintegration (operational) is occurring, the power system is in the in extremis state. Generation and load equalities are not satisfied and major portions of system load are lost. Physical equipment overloads occur and the equipment limitations are exceeded. Emergency control action is necessary in this state to salvage as much of the system as possible from collapse.

In the restorative state, control action is taken to pick up lost load and reconnect the system.

In the discussion of operating states, security is considered an instantaneous, time-varying condition that is a function of the robustness of the system relative to imminent disturbances. Security is determined by the relationship between system reserve margin and the contingent probability of disturbances. Stability is a factor in security and is related to the continuance of parallel, synchronous operation of all operating units.

7.2.3 DISTRIBUTION SYSTEM OPERATING STATES

All five power system operating states apply to the distribution system. In considering the normal, alert, emergency, in extremis, and restorative operating states in the context of the distribution system and DSG integration, the following examples of these states are suggested

DISTRIBUTION SYSTEM OPERATING STATE EXAMPLES
WITH DSG INTEGRATION

- Normal - All customer loads are being served and no overloads exist on distribution substations, feeders, or equipment. Feeders are in their typical configuration. Voltage levels at all points are within specified limits. No equipment limitations are being exceeded. DSG equipment may or may not be in service, depending on scheduling.
- Alert - All customer loads are being served and no element of the distribution system is overloaded. However, "reserve" distribution capacity is reduced in this state, e.g., feeder reconfiguration has occurred with load transfer to a different feeder, leaving less capability to transfer load in the event of

a subsequent disturbance. This state is entered when major distribution system equipment (e.g., substation transformers) is out of service, resulting in increased vulnerability to a subsequent disturbance. In the alert state, no physical equipment limitations are exceeded, but specified alarms may occur indicating limits are being approached. Some examples are transformer LTC at maximum raise or minimum lower tap position, ratio of feeder or transformer actual current to normal rating exceeds specified limit, etc. As indicated, all customer loads are being served. However, load management (load control) may be occurring on direction from the energy management system or distribution dispatch center to achieve a reduction in system load.

- Emergency - In this state, substation or feeder overloads are occurring, or distribution equipment or DSG limitations are being exceeded. This state is also entered when under-frequency conditions are detected or when load shedding is in progress via the energy management system or distribution dispatch center.

  The distribution system is in the emergency state during storm or other conditions with numerous customers out of service due to lines down and/or loss of the distribution system's major transmission facilities.

- In Extremis - Power system (operational) disintegration is occurring. This can be reflected in DSG units operating in island conditions on the distribution system. Communications facilities for control and monitoring of DSG units to control centers may be reduced due to the conditions causing this state.

- Restorative - Control action is taken to pick up customer load which has been lost. Examples include load restoration with cold load pickup following load shedding, service restoration to unfaulted feeder zones on a feeder which has experienced a persistent fault, etc.

7.2.4 DSG STATES

DSG states describe the overall conditions that can exist at the DSG plant. The states represent conditions that are generally analogous to the distribution system states but pertain specifically to the DSG plant (or unit within a multiunit plant). The DSG states are: normal, abnormal, emergency, and inoperative. These states may be described as follows:

- Normal - Refers to the condition existing when all systems, subsystems, and components of the DSG plant or unit are operating within continuous design rating limits. The DSG may be in one of several modes of operation, depending on the DSG and power system conditions and scheduling. These DSG modes are ON, OFF, and STANDBY, as described above. It is pertinent to note that a DSG may be in any one of its modes and be considered in a normal state. For example, it may be ON and producing power, or it may be OFF and awaiting its next scheduled operating period. Another example is that of a DSG that has an intermittent energy supply such as a wind turbine generator. The wind energy source is inherently intermittent, and this is recognized in its design and power system application. Therefore, it is a normal state for the DSG to be in the OFF mode at certain times.

- Abnormal - Refers to the condition existing when the continuous design rating of a major system, subsystem, or component is being exceeded during operation. The condition can be tolerated for a limited time according to predetermined design parameters but may result in shortened life compared to normal operation. Thus, in the abnormal state, the DSG may be operating beyond normal design rating or it may be constrained to less than normal rated output for existing conditions because of reduced capabilities of the DSG system, subsystem, or component.

- Emergency - Describes the situation where continued operation of a DSG plant, unit, system, subsystem, or component will result in imminent failure. It may also be a condition where a major system, subsystem, or component failure has taken place and continued operation of the plant or unit will result in serious damage and danger to personnel. In this state it is imperative that the DSG unit or plant be shut down immediately to limit damage and protect personnel.

- Inoperative - Refers to a DSG unit or plant in the inoperative state that is not available for on-line operation. It is not possible to operate the DSG until the conditions that caused the DSG to be inoperative are restored to normal. The inoperative state may be due to unplanned outages, i.e., failure or scheduled maintenance outages.

7.3 INTERRELATIONSHIPS OF MODES AND STATES

This subsection examines the interrelationships of modes and states.

7.3.1 DSG STATES VERSUS DISTRIBUTION SYSTEM STATES

In general the state of the individual DSG can have only a localized effect on the distribution system. For example, a DSG changing from normal to emergency state would not cause the whole or a major part of the distribution system to change state. Even a DSG fault that was not isolated by the DSG protection system would effect only a limited portion of the distribution system until backup protective devices functioned. The exception would be when a baseload DSG that ordinarily supplied a major percentage of the power on a feeder changed from normal to emergency or inoperative state. In this case, if insufficient capacity exists, a substation transformer or feeder might become overloaded or approach its thermal limits. However, this would be a localized alert or emergency condition on the distribution system.

The opposite can occur when an emergency or in extremis state on the distribution system can cause an abnormal or impending emergency condition for the DSG. An example of this would be an out-of-limit undervoltage condition on the distribution system which could cause greater than rated current and overheating of DSG generators. Thus, the DSGs would be changed from a normal to an abnormal state by an emergency condition on the distribution system. Other distribution system problems which can have the same effect are underfrequency and unbalanced phase voltages.

Thus, distribution system state degradation can cause DSG state degradation, but the opposite is not generally true.

7.3.2 DSG MODES VERSUS DSG STATES

The changing of a DSG mode (i.e., from ON to OFF or OFF to ON) for routine operation does not cause a change in DSG state. The opposite is true when a change of DSG state from normal to emergency can (should) cause the DSG mode to change from ON to OFF.

It is possible, however, for a DSG with a latent or incipient fault to change from normal to emergency state. If in the process of going from OFF to ON a fault takes place, this causes an emergency condition to materialize. This emergency condition, however, would occur only because of a latent condition and would not be basically attributable to a mode change.

7.3.3 DSG MODES VERSUS DISTRIBUTION SYSTEM STATES

This comparison is similar to that between the DSG state and distribution system state. If the distribution system is properly designed, a change in DSG mode should not ordinarily cause a change in distribution state. The opposite, however, is quite likely when a distribution system state change, i.e., from normal to alert to emergency, could impose unacceptable conditions on one or many DSGs; thereby causing their protective systems to operate and change the DSG mode from ON to OFF.

7.4 OPERATIONAL RELATIONSHIPS, MODE CONTROL VERSUS STATES

A DSG will be called upon to transition from OFF to ON and ON to OFF modes for the majority of its normal operational mode changes. These transitions will primarily be dictated by the DSG operating schedule or intermittent energy availability. Certain types of DSGs may have an intermediate mode between OFF and ON called STANDBY. This mode may be required by cogeneration or advanced battery systems to permit stabilization of process preheating and/or energy system balances. This mode may also be used as a "spinning reserve" mode in providing generating margin for the power system.

These operational transitions are represented by Figure 7.4-1. Commands initiated at either the remote-centralized control (i.e., DAC, DDC, or EMC) or the local control to command a DSG to be placed on-line, to be taken off-line, or to be placed on STANDBY, will cause a startup, a shutdown, or a partial transition, as indicated by the arrows in Figure 7.4-1.

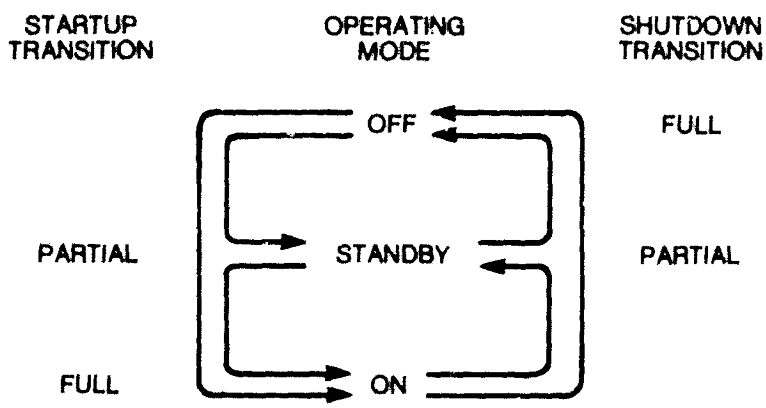


Figure 7.4-1. DSG Modes and Transitions

In the general case for medium and large DSGs, the initiation of mode changes will be possible from either the local DSG controls or remote-centralized control. However, certain types of DSGs, i.e., cogeneration or wind, may for practical reasons preclude absolute remote control. The cogeneration will usually be intermeshed with a heat process that places constraints on electric energy output variations. Since wind turbine generators defy absolute control because of the variable, and intermittent (unpredictable) source, control will be more of a permissive or prohibiting action.

The full range of mode control initiation methods includes:

- Local Mode Control

  A. Manual (LM) - When the operator steps the DSG unit through its sequential startup or shutdown procedures.

  B. Semiautomatic (LS) - When the operator initiates automatic sequencing, usually by a master start or stop command.

  C. Automatic (LA) - When self-contained DSG logic utilizes local sensing or predetermined scheduling to initiate startup or shutdown. This includes protective system action to shutdown for failures.

- Remote Control Center

  A. Manual (RM) - When the control center operator initiates by remote control (i.e., SCADA) the startup/shutdown by either one master start or stop command to the DSG automatic sequencing; or when the operator sequences the DSG in predefined steps for the mode transitions.

  B. Automatic (RA) - When the control center computer in fully automatic control action initiates mode changes.

Consideration of mode control initiation as required for the various combinations of DSG state and distribution system state requires examination for each type of DSG and for the specific energy conversion process within types of DSGs for some cases. Cogeneration will probably be the most restrictive in regard to mode control by a remote control center. Therefore, it tends to provide more exceptions than other types of DSGs to generate control strategies.

Other types of DSGs with intermittent, variable, or periodic energy sources (sun, wind, and run-of-river hydro) will tend to require using the energy as much as possible, whenever it is available, in order to be economically justifiable.

Because there are many types of DSGs with widely different characteristics, generalizations are difficult to make for DSG mode control regarding normal operation. However, as the DSG and/or distribution systems leave the normal state and go to less secure or degraded conditions, the structuring of mode control initiation becomes clearer.

A generalized representation of DSG mode control for DSG and distribution system states is given on Table 7.4-1. This matrix illustrates the need or desirability for local and remote mode control initiation capability for the various combinations of DSG and distribution system states. In reasoning through the coincident conditions of DSG and distribution system states, it is found that it will be desirable to have both local mode control and remote control for most combinations. The exceptions are mainly in the DSG emergency state. In the DSG emergency state the local protection system must initiate immediate action to limit harmful effects. Only in unusual circumstances would a remote control center preempt or serve as backup to local mode control for the DSG emergency state.

Table 7.4-1

MODE CONTROL FOR DSG AND POWER SYSTEM STATES

DSG State	Mode Control Initiation	Power System State: Normal	Alert	Emergency	In Extremis	Restorative
Normal	LM	X	X	X	X	X
	LS	X	X	X	X	X
	LA	X	X	X	X	X
	RM	X	X	X	X	X
	RA	X	X	X	X	X
Abnormal	LM	X	X	X	X	X
	LS	X	X	X	X	X
	LA	X	X	X	X	X
	RM	X	X	X	X	X
	RA	X	X	X	X	X
Emergency	LM	X	X	X	X	X
	LS	X	X	X	X	X
	LA	X	X	X	X	X
	RM					
	RA					

Mode Control Initiation Methods	Symbol
Local DSG Mode Control	
Manual - Operator steps unit through sequences	LM
Semiautomatic - Operator initiates automatic sequences	LS
Automatic - DSG control or protective logic initiation	LA
Remote Control Center	
Manual - Operator initiates automatic sequences	RM
Automatic - Computer initiates automatic sequences	RA

7.5 RELATIONSHIP OF DISTRIBUTION SYSTEM AND DSG STATES TO DSG CONTROL AND MONITORING

Because there are a number of distribution system and DSG states and various combinations of these states that can occur, consideration must be given to DSG control and monitoring to provide the required response to these conditions. It would be desirable to have control logic and the means for the local DSG control to be commanded or operated to the maximum benefit of the power system. As a simple example, the power system may be in the in extremis state, but a DSG with stand-along capability could supply an island within the distribution system that had become isolated from the main power system generation sources. To achieve this, overall monitoring and control coordination would be required.

Although it is not the intent to develop the logic of how the proper DSG mode control commands may be developed for each of the many DSG and utility system states, a brief description of a possible approach to the solution of this problem is presented. Figure 7.5-1 presents a block diagram illustrating an interrelationship of power, protection, and control systems of an electric utility. The right side of Figure 7.5-1 shows the power system elements of generation, transmission, distribution, and DSGs interconnected as a power network with circuit breakers for connecting and disconnecting them. The circuit breakers provide high-speed disconnection capability when it is needed for conditions of over- or undervoltage, overcurrent, and over- or underfrequency. The protection and control functions have inputs from appropriate instrumentation and from the EMS or DDC. The outputs from the protection equipment operate on the power elements causing them to open or close. In a control sense, the protection equipments must be able to determine their own local state and to take appropriate action. This local action tends to be rapid because it is based on locally available information. In addition, the protection and control equipment in Figure 7.5-1 is able to receive inputs from the EMS or DDC. These higher level inputs, which may include load control and restoration functions, provide control logic/decisions based on a more extensive set of data that includes information on the other portions of the electric power system. In an example similar to that given above, based on locally sensed conditions, appropriate immediate local action may be for a DSG to disconnect itself from the distribution network and to go to the OFF mode. Later, upon receipt of signals from the DDC, which are based on information about other portions of the power system, the DSG would proceed to the ON mode through whatever steps were necessary locally based on its present conditions.

The control logic and action that takes into account the broader EMS or DDC information base would take longer than local control, but, in general, speed would not be as critical for these decisions and actions.

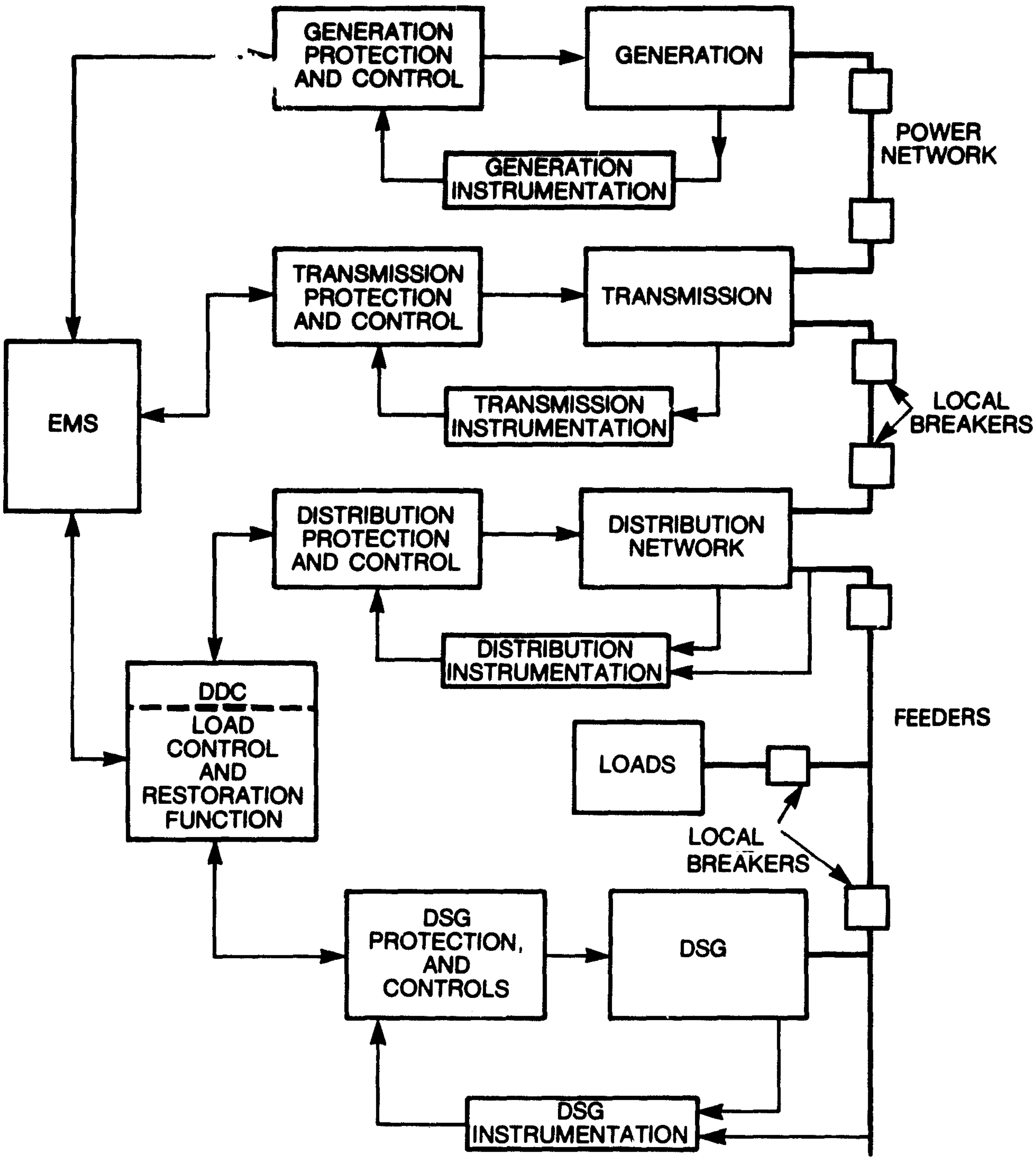


Figure 7.5-1. Electric Utility Power, Protection, and Control Systems

The process of developing the various control actions to be executed by each DSG under the five-power system and five-distribution system states and the three applicable DSG states will require a detailed and comprehensive effort for each DSG. However, in a generic sense, the determination of the DSG operating mode could be represented by a matrix such as that shown in Table 7.5-1. In this table the appropriate mode (or mode transition) for each DSG state is given for each distribution system state. For example, when both the DSG and distribution system are in the normal state, it is permissible to operate the DSG; or, for DSG normal state, the DSG can be operated for any distribution system state if it is beneficial to do so. DSG operation may actually be supportive in nonnormal distribution states provided that sufficient skill and intelligence can be incorporated into the DDC logic and command/control action carried out through the DSG operating mode control. When the distribution system state is normal, but the DSG state is abnormal, the DSG protection supplied with local information should provide the primary basis for determining the DSG mode. For non-normal distribution system states and DSG abnormal states, it may be desirable for the DSG to be in the OFF mode. Thus, each pair of distribution system-DSG state conditions should be analyzed and the proper DSG mode established.

For the DSG in the emergency state, it will be desirable for the DSG to be taken out of service regardless of the distribution system operating state.

Finally, if the DSG is inoperative, the DSG will be OFF regardless of distribution system state.

From consideration and analysis of the matrix conditions of Table 7.5-1, the nature and basic principles can be established for functions such as DSG operating mode control; protection: substation, transformer and feeder; and protection: DSG.

Table 7.5-1

DSG OPERATION FOR VARIOUS DISTRIBUTION SYSTEM AND DSG STAGES

	Distribution System States				
DSG State	Normal	Alert	Emergency	In Extremis	Restorative
Normal	OK to Operate DSG	OK to Operate DSG	May be OK to Operate DSG	Islanding of DSG Possible	May be OK to Operate DSG
Abnormal	Local Conditions within DSG Should Dictate DSG Mode	May Not be Good to Operate DSG	Probably Take DSG Out of Service	Probably Take DSG Out of Service	Probably Take DSG Out of Service
Emergency	Take DSG Out of Service	Take DSG Out of Service	Take DSG Out of Service	Take DSG Out of Service	Take DSG Out of Service
Inoperative	DSG Off	DSG Off	DSG Off	DSG Off	DSG Off

Section 8

DISTRIBUTION DSG SYSTEM FUNCTIONAL REQUIREMENTS

8.1 INTRODUCTION

A distribution DSG system consisting of dispersed storage and generation facilities located throughout the electric utility distribution system, coordinated by a monitoring and control center is a relatively complex system. The functional requirements described in this section provide technical, operational, and performance information required for the integrated distribution DSG system. Six major categories of distribution DSG functional requirements have been identified and used as the means of grouping similar or closely related functions. The six major functional requirement categories are listed in Table 8.1-1. Following this Introduction, the six categories are summarized and illustrations of their relationship to the distribution DSG system equipment and the control system are given.

Particular emphasis is placed on communications data in Section 8.4.5 because of their importance to monitoring and control. This illustration provides an example of how the findings of this study can be used in development and design.

The functional requirements, which are described in this section, provide the basis upon which more detailed designs may be established and upon which functional specifications may be drawn up for specific utilities and DSG technologies.

Table 8.1-1

MAJOR CATEGORIES OF DISTRIBUTION DSG SYSTEM FUNCTIONAL REQUIREMENTS

- Control and monitoring
- Power flow and quality
- Communications and data handling
- Normal, abnormal, and emergency operating states
- Failure and abnormal behavior detection and correction
- Special DSG controls

8.1.1 FUNCTIONAL REQUIREMENT CATEGORIES

Summary descriptions of the six categories of functional requirements are as follows:

- The control and monitoring functions are associated with the distribution dispatch center (DDC) equipment and location, and provide the centralized functions necessary for overall coordination of the DSGs assigned to the DDC. Control and monitoring functions incorporate DDC operator and energy management system (EMS) requirements for distribution DSG operation and control. DDC operator information and control inputs must be accommodated, and information concerning the DSG's operation must be presented to the DDC operator. EMS information relative to overall power system generation scheduling, automatic generation control, volt-VAR dispatch and load management must be input to and incorporated by the DDC into its control strategies and logic operations for the specific DSGs and distribution system operations. The EMS will need feedback information pertaining to aggregate DSG data and characteristics in order to properly represent overall DSG power and energy in scheduling and control strategies.

- The power flow and quality functions are local DSG power-related functions which control power flow, provide appropriate instrumentation, and establish the quality and magnitude of voltage and current wave shapes (including harmonic content). Each of these functions has requirements, related to the specific type of DSG, that must be reconciled with the general requirements of the DDC control, and monitoring function. DSG power control, for example, must consider minimum and maximum power output levels, permissible rate of change, and power reversal characteristics for storage-type DSGs. These requirements involve both distribution system needs and DSG characteristics.

- The communication and data handling functions provide the necessary information transfer and data handling between DDC and DSGs, data transfer interfaces between these equipments and the communication links, and the associated information processing at the DDC. These functions are primarily involved in the transfer of command and control data from the DDC to DSGs and the return of monitoring (normal and alarm) data from the DSGs to the DDC.

  Depending on whether the distribution DSG system uses a centralized or decentralized control structure, the communication and data handling requirements may differ in detail. Using a centralized approach, information transfer takes place directly between DDC and DSGs. With a decentralized arrangement, DSG control and monitoring information shares communication facilities with general distribution automation and control functions. For the decentralized configuration, in addition to the distribution automation and control functions, incremental loading is added to the communication and data handling for DSG requirements.

- The operational requirements associated with DSG normal abnormal, and emergency states relate to local functions at the DSG required for the control of the DSG operating modes, DSG stability and personnel safety. These functions include the logic to determine whether normal, abnormal, or emergency conditions exist and the logic to adjust or change the DSG power production process and associated auxiliary equipment in response to changes in DSG state. The ability of the DSG to remain in step with the power system's fundamental frequency is of utmost importance and, thus, DSG stability is an important requirement. For all states which the DSG may encounter, personnel safety is a primary consideration and requirement. This requires coordination of local DSG and distribution system operation, especially during times of maintenance, outages, and service restoration.

- The failure and abnormal behavior detection and correction functions are primarily associated with protection system equipments of both DSG and the distribution system. There is a mutually dependent requirement that the distribution system be protected from failure and abnormal behavior of DSGs and, conversely, that the DSGs be protected from failure and abnormal conditions in the distribution system. System protection philosophy dictates that protective systems be associated with and located at DSG and distribution equipment facilities. Functional requirements define the protection needs in order to establish decision rules for protective system equipment design. Basically, the protective systems include detection, decision logic, actuation, and power circuit switching equipment.

- The special DSG control functions are associated with the local DSG control equipment. These functions involve controls which cause the DSG unit(s) to respond to remote start and stop commands from the DDC and other special functions. In a general sense, this involves power actuation and control. Therefore, these functions and control equipment make it possible to carry out DSG scheduling directed by the DDC. Since each type of DSG will have different power and energy system configurations, the logic and arrangement of controls for special DSG control functions will be unique for each type of DSG. However, the basic functions of automatic startup and synchronization to the distribution system and automatic shutdown will be a general requirement for most DSGs. There may be some exceptions, however, such as medium and large cogeneration DSGs.

  For the abnormal condition of major outages and isolation ("islanding") of portions of a distribution system, special consideration is required to utilize DSGs to restore partial power to the islands which contain DSGs capable of stand-alone operation.

8.1.2 RELATIONSHIPS OF SYSTEM EQUIPMENT TO FUNCTIONAL REQUIREMENT CATEGORIES

Descriptions of a distribution DSG system with centralized control of DSG units (in Section 6.3 of this report) show an arrangement such as that in Figure 8.1.2-1. Since the monitoring and

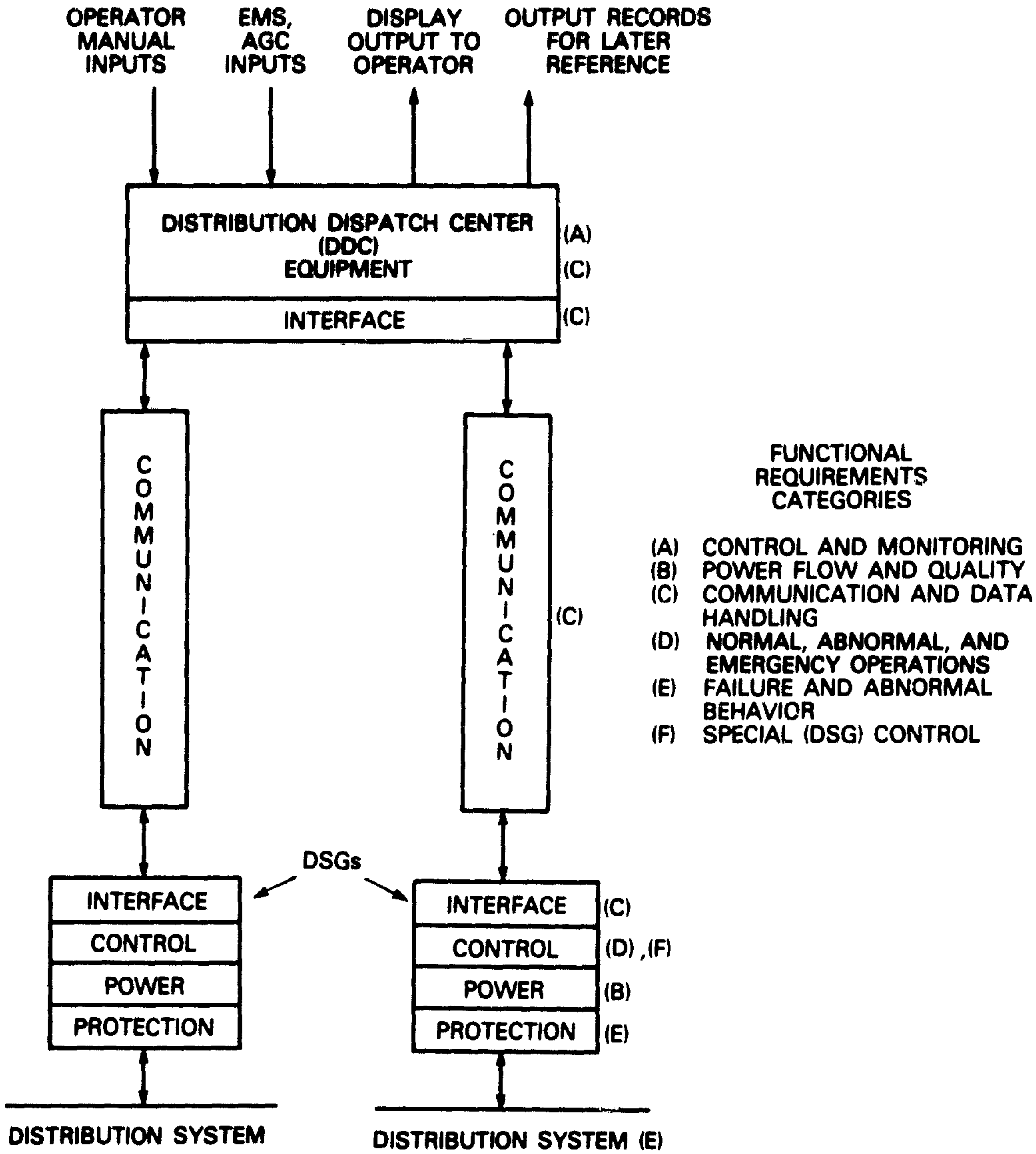


Figure 8.1.2-1. Distribution DSG System Showing Equipment and Functional Requirement Categories

control requirements for the case of centralized control are simpler to describe than those for decentralized control, the centralized structure will be used for illustration. However, the same principles may be applied to both structures of control. The distribution DSG equipment elements are shown on the left of Figure 8.1.2-1. The corresponding six major categories of functional requirements are shown with the equipment elements, listed on the right side.

The intent of this subjective pairing of equipment and functional requirement categories is to provide a more direct understanding of the interrelationships and the associations between them.

The equipment in Figure 8.1.2-1 basically consists of three main groupings. They are Distribution Dispatch Center (DDC), Communication, and DSG equipment:

- The DDC is the centralized equipment for coordination, control, and monitoring of DSGs within the responsibility of the particular DDC.
- The communication equipment provides the means of transmitting control and monitoring information between the DDC and the DSGs and includes interface equipment at both locations.
- The DSG includes local control, power producing, and protection equipment required for the generation and/or storage of electrical energy.

Since the DSGs are situated within the power distribution system, they affect distribution system operations, circuits, equipment control and protection.

It is also important to note that at the DDC, the equipment not only provides automated logic functions, but also serves as the means for the DDC operator to interact with the distribution DSG system and for the DDC to interact with the next higher control level at the energy management system (EMS). DDC-EMS interaction involves DSG power scheduling and control, compatible with the operating goals of the overall power system. Other functions such as load management may also be involved.

The preceding discussions have made a comparison and correlation of distribution DSG equipment and functional requirement categories. The intent was to provide a means of understanding the terms used for the functional requirements categories and their relationship to the major equipments. Table 8.1.2-1 provides a summary of the various functions that are grouped under the six major DSG functional requirements categories.

Table 8.1.2-1

DSG FUNCTIONAL REQUIREMENTS CATEGORIES
AND THEIR ASSOCIATED FUNCTIONS

8.2 A. <u>Control and Monitoring</u>

- 8.2.1 DSG Command and Control
- 8.2.2 Display and Recording
- 8.2.3 DSG Scheduling and Mode Control
- 8.2.4 Distribution Volt/VAR Control
- 8.2.5 Load Control, Including Restoration
- 8.2.6 Automatic Generation Control
- 8.2.7 Security Assessment and Control

8.3 B. <u>Power Flow and Quality</u>

- 8.3.1 DSG Power Control
- 8.3.2 DSG Voltage Control
- 8.3.3 Harmonic Control
- 8.3.4 Instrumentation

8.4 C. <u>Communication and Data Handling Requirements</u>

- 8.4.1 Distribution SCADA
- 8.4.2 Communication
- 8.4.3 Information Processing
- 8.4.4 Revenue Metering

8.5 D. <u>Operational Requirements for Normal, Abnormal, and Emergency States</u>

- 8.5.1 DSG Control
- 8.5.2 DSG Operating Mode Control
- 8.5.3 Personnel Safety
- 8.5.4 DSG Stability

8.6 E. <u>Failure and Abnormal Behavior Detection and Correction</u>

- 8.6.1 Protection: Distribution Substation, Transformer, Feeder
- 8.6.2 Protection: DSG

8.7 F. <u>Special DSG Control Requirements</u>

- 8.7.1 Start Capability
- 8.7.2 Synchronization
- 8.7.3 Stand-alone Capability

8.1.3 CONTROL SYSTEM RELATIONSHIP TO FUNCTIONAL REQUIREMENT CATEGORIES

An alternative method for representing the multilevels of the hierarchical control system that a DDC uses to control one or more DSGs is shown in Figure 8.1.3-1. The DSG power generation process is shown to supply an electric utility distribution network through protection equipment.

It should be noted that each DDC may be controlling and monitoring several DSGs as indicated in Figure 8.1.3-2. Thus, from the DDC point of view, an important feature of the control system is the requirement for multiplexing and time-sharing of the different DSG controls at the DDC. If the number of DSGs controlled by the DDC is expected to be significant, on-line control computer capability is indicated. From the DSG point of view, the local DSG control must be capable of operating semi-independently since it will only be monitored and controlled by the DDC at discrete intervals.

Referring to Figure 8.1.3-1, the DSG power generation process is controlled through special DSG controls which receive feedback from the DSG. In turn, the special DSG controls have, as inputs, signals from the local DSG control which assures that the various auxiliaries are properly sequenced and controlled and that the overall local DSG control is operating in the proper operational control mode. Feedback from the DSG power elements is again employed by local DSG control, and additional feedback from the distribution network may be used. A possibility for local inputs, either manual or automatic, to the local DSG control is also indicated.

Considering the six functional requirements categories, Figure 8.1.3-1 shows the control and monitoring function (A) is associated primarily with the DDC control and monitoring. The power flow and quality function (B) is associated with the DSG power generation process. The communication and data handling function (C) is shown with the communication means for control from DDC to local DSG control and the corresponding return path for monitoring purposes. The information processing portion of the communication and data handling function (C) is located in the DDC control and monitoring area. Functions associated with DSG normal, abnormal and emergency operating states (D) are located at the local DSG control. As such, these functions relate to the communicated inputs from the DDC and the feedback from the DSG power processes and the distribution network. In addition, they supply the necessary DSG operating controls. The failure and abnormal behavior detection and correction functions (E) relate most directly to the protection activities and emphasize equipment protection, although personnel protection should also be a consideration of these functional requirements. Lastly, the special DSG control functions (F) relate to the special DSG control equipment.

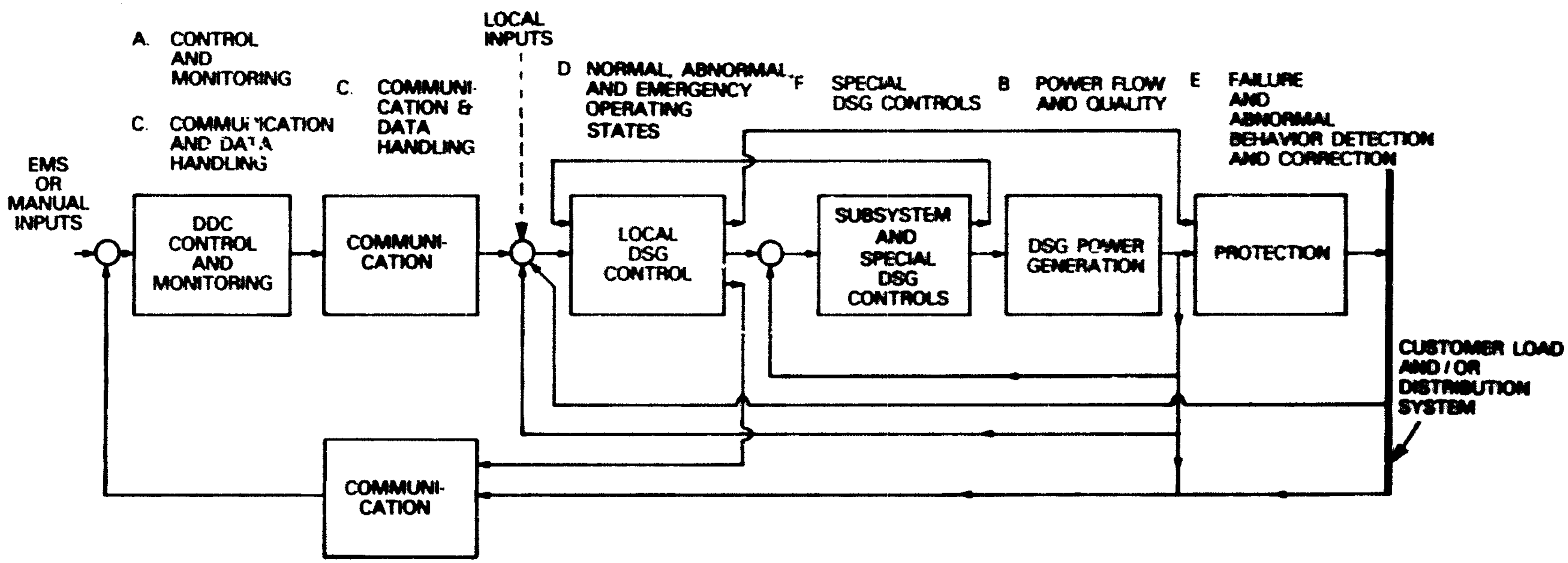


Figure 8.1.3-1. Schematic Representation of Monitoring and Control of DSGs Related to the Functional Requirement Categories

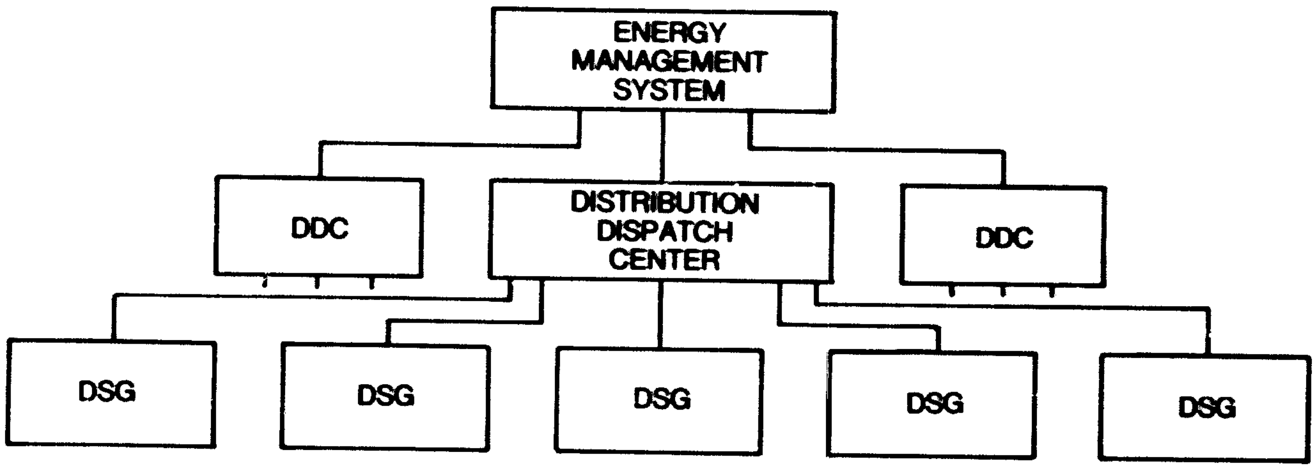


Figure 8.1.3-2. Relationship of One DDC with Multiple DSGs

8.2 CONTROL AND MONITORING REQUIREMENTS

As the number of DSGs connected to a utility distribution system increases, control and monitoring functions will be required at a centralized location such as a distribution dispatch center (DDC). From the control system hierarchies described in Section 6, overall responsibility for the operation of DSGs will be assigned to an operator or dispatcher at a DDC. With the use of a DDC computer system, the dispatcher will monitor and control the DSGs employing automatic, semiautomatic, and manual methods.

The distribution DSG system control and monitoring may be a centralized configuration where the DDC communicates directly with the DSGs, or it may be a decentralized configuration in which distribution automation and control (DAC) is used at the distribution substation level to control and monitor the distribution substation and associated DSGs. With either configuration, principal monitoring and control functions such as command and control, display and recording, and scheduling and mode control are performed at the DDC.

Above the DDC, in the control hierarchy, is the energy management system (EMS). The EMS coordinates the overall power system operation and is principally concerned with the bulk power generation and transmission system. This EMS responsibility includes system-wide generation scheduling, dispatching, and control. With the advent of DSGs in appreciable numbers, the traditional responsibility for all aspects of generation scheduling, dispatching, and control will be partitioned, giving responsibility for controlling and monitoring DSGs to the DDC. Thus, while overall power system generation scheduling, dispatching and control responsibility are retained by the EMS, the EMS will consider all DSG generation within a DDC's responsibility to be one or a few large aggregate generators. (Different types of DSGs may be more accurately represented by one equivalent large generator of each type.) The DDC will therefore deal directly with the individual DSGs, be responsible for optimizing their performance within distribution system constraints, and exercise control and monitoring as appropriate for the type and size of DSG.

There may be some exceptions where the EMS may retain scheduling, dispatch, and control responsibility for large DSGs, or for DSGs in general, until the quantities warrant establishment of an EMS-DDC-DSG control hierarchy.

Functional block diagrams of centralized and decentralized DSG control and monitoring, based on hierarchical relationships described above, are shown in Figures 8.2-1 and 8.2-2 respectively. In these figures, control and monitoring functions are outlined more heavily than related functions. These control and monitoring functions include:

- DSG Command and Control
- Display and Recording
- DSG Scheduling and Mode Control
- Automatic Generation Control - DSG

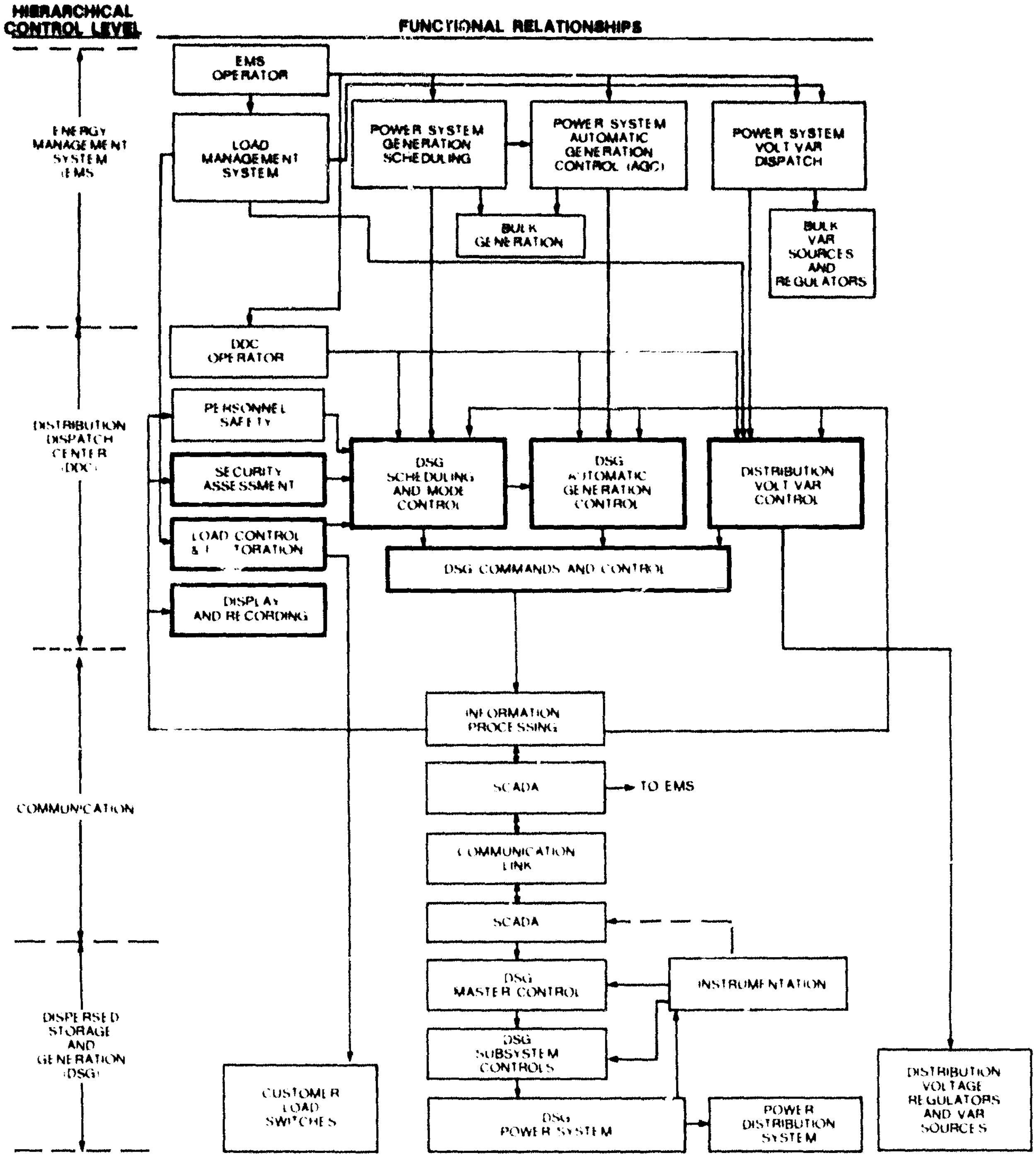


Figure 8.2-1. DSG Control and Monitoring: Functional Block Diagram for Centralized Control

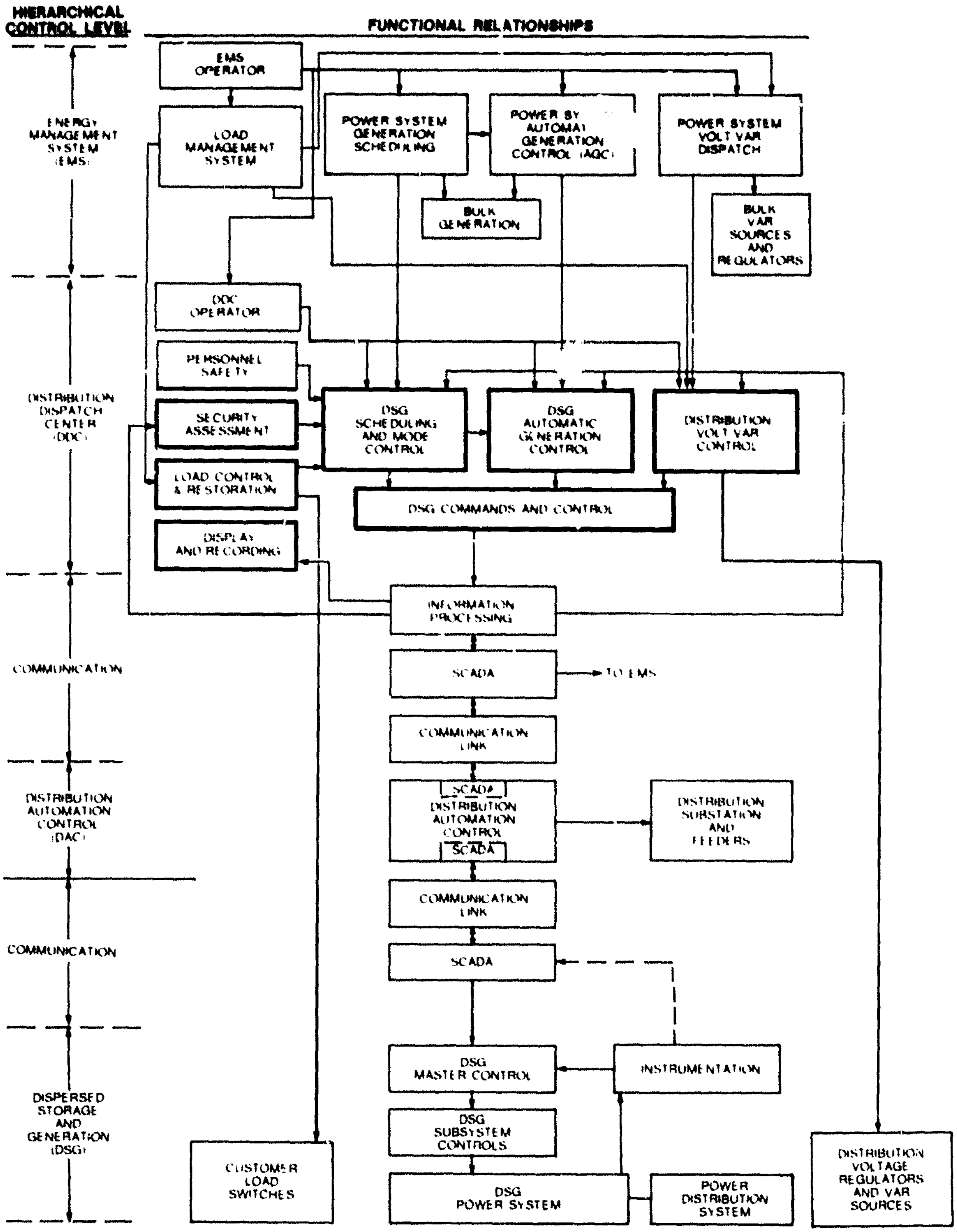


Figure 8.2-2. DSG Control and Monitoring: Functional Block Diagram for Decentralized Control

- Distribution volt-VAR Control
- Load control including restoration
- Security assessment

Figure 8.2-1 and 8.2-2 show general relationships between control and monitor and other functions, and relationships between the EMS, DDC (DAC), and DSG hierarchical control levels.

The primary difference between the centralized DDC-DSG configuration in Figure 8.2-1 and the decentralized DDC-DAC-DSG configuration in Figure 8.2-2 is the interposed DAC equipment and functions in the decentralized case. Basic functions at the DDC and DSG remain the same in both configurations. The DAC provides a control and monitoring concentrating function for DSG information in addition to its primary distribution automation function as described in Section 6 of this report.

A brief description of the functions included in the control and monitoring requirements category provides a basis of understanding for the more detailed functional requirements.

- The DSG command and control function performs a coordinating and interface function for the three major functions which require control actions to be performed at the DSGs. Thus, direct inputs to the command and control function are: DSG scheduling and mode control, DSG automatic generation control, and distribution volt-VAR control. The output of the command and control function is processed and formatted by the information processing function.
- The display and recording function provides nonpermanent and permanent information to the DDC. Nonpermanent displays capable of showing the DDC operators current and trend information of DSG normal, abnormal, or emergency conditions will normally be provided by CRT displays. Some DDCs may also have animated map boards as supplemental information. Preparation of permanent records of operator actions, alarm conditions, and normal periodic logs are also the responsibility of this function. The centralized source of the display and record information is the information processing function. This function is described in the communication and data handling category descriptions in Section 8.4. The outputs are in the form of operator CRT and map board displays and permanent typewritten or magnetic tape records.
- DSG scheduling and mode control involves daily, weekly, and monthly scheduling of DSGs and initiating mode control (on-off-standby) at appropriate times. Daily, weekly, and monthly time periods are associated with unit commitment and maintenance activities. These scheduling activities in turn are affected by DDC distribution

planning, operation and maintenance functions, personnel safety, distribution security assessment, load control including restoration, and EMS power system generation scheduling. Resultant decisions regarding DSG mode control (on-off-standby) are initiated via the DSG command and control function. The mode control may be arranged either to require DDC operator approval or to be carried out automatically.

- DSG automatic generation control (AGC) is a subfunction of the EMS power system AGC function which has the overall responsibility of automatically adjusting the power output levels of electric generators within its control area. The EMS (perhaps excluding some large DSGs) will consider each DDC as having one or a few large "equivalent" generators. These equivalent generators in fact will be comprised of many DSGs. The EMS thus determines total power system control area (AGC) needs and conditions, and performs bulk power system level AGC including equivalent DDC generators. The desired action and pertinent information related to each DDC's (AGC) dispatch and load-frequency control will be transmitted to the DDC(s). There it will be "decomposed," as appropriate, to control the DSGs within the DDC's jurisdiction which are under remote automatic control. Thus the DSG-AGC function may receive direct operator input, DSG scheduling input and EMS-AGC inputs. DSG-AGC output is coordinated and carried out by the DSG command and control function.

- Distribution volt/VAR control is the overall function of voltage and reactive power control within the jurisdiction of a DDC. Included in the means of controlling voltage on the distribution system is the adjustment of voltage and/or volt ampere reactive (VAR) power of DSGs. Volt-VAR control can be used to reduce system power losses, to maintain voltage within an acceptable range, and also to provide a means of load reduction. Thus, inputs to the distribution volt-VAR control are DDC operator, EMS load management system, and EMS power system volt/VAR dispatch. The output control actions for the DSGs would be via the DSG command and control function.

- The load control including restoration function provides the logic, indication and (when fully implemented) the means of switching selected loads at the customer level to reduce overall distribution system load levels, and/or to request DSG power output changes to alleviate local overload conditions. This function can also be called upon to assist in an EMS system-wide load reduction action. Inputs to this function are provided by the DDC operator, EMS load management system, and the security assessment function. Outputs are displays to DDC operator, commands to customer load switches via appropriate distribution automation, communication and control equipment, and requests to the DSG scheduling and automatic generation control functions.

- Distribution security assessment and control determines the relative ability of the distribution system to supply the anticipated loads without exceeding the capabilities of any equipment or circuits. In addition, this function also includes examination of possible contingency situations in order to anticipate overloads which would occur in the event of outages (planned or unplanned). With this security assessment information, preventative actions such as modifying DSG power schedules can be incorporated in DDC operating strategies. Inputs to this function are system equipment and circuit status and loading conditions, load forecasts, and planned maintenance schedules. Outputs would be operator displays/records and inputs to the DSG scheduling and mode control function.

In addition to the individual function requirements that are described in the material that follows, it is important to note that there is a significant definition effort needed to integrate the hardware, the software, and the man-machine interface at the DDC. As an example, the DSG scheduling and mode control function can be illustrated. To be most effective it will be necessary to:

- Acquire, organize and store data
- Perform logic and decision making involving:
  - EMS needs and requirements
  - loads to be served
  - energy potentially available from DSGs
  - economics of DSG energy production
- Provide operator information
- Carry out results of logic decisions

This is only one of the many functions and, in addition to organizing its operation, it must also be coordinated and integrated with the remaining functions. It is recognized that data base and information processing needs will differ from one distribution DSG system to another but there will be common elements present in most DDC-DSG system designs.

Thus, an important continuing effort to define the integration of hardware, software, and man-machine interface should be undertaken. This effort would define, conceptualize, and categorize the possible scenarios and equipment configurations for a distribution system with various forms of DSGs, load control system, and distribution automation, all operating together in a coordinated fashion.

8.2.1 FUNCTIONAL NAME: DSG COMMAND AND CONTROL

Functional Description

The DSG command and control function is performed at the distribution dispatch center level and it coordinates and initiates commands and control actions to DSGs. Thus "system level" functions, requiring command or control action to DSGs, work through the DSG commands and control function. DDC functions are expected to be interposed between EMS functions and DSG command and control actions to permit DDC-level priorities and requirements to be recognized and incorporated.

From the DDC to DSG level, two approaches to DSG control and monitoring have been presented. These are identified as "centralized" and "decentralized" system configurations. In the centralized configuration, the DDC communicates directly with the DSGs. In the decentralized configuration, there is an intermediate control and monitoring level at the distribution substation which is called a distribution automation control (DAC) system. These configurations have been described in Section 6 of this report. Block diagrams of the DSG commands and control function as it interrelated to EMS, DDC, DACs, and DSGs are shown in Figure 8.2-1 for centralized control and Figure 8.2-2 for decentralized control configurations.

In addition to command and control requests initiated by the DDC for automatic response by directly controlled DSGs, other arrangements are also possible. Some DSGs may be customer-owned and of various sizes. Customer-owned DSGs will usually be under the discretionary control of the owner and will be operated primarily for his benefit. However, even though the DSG is directed by local control, it may be desirable for DDC functions, through the DDC command and control function, to inform the local DSG when additional generation is needed by the utility and to indicate the value of energy delivered at that time.

Input or Processed Data

Direct inputs to the DSG commands and control function are:

- DSG scheduling mode control
- DSG automatic generation control
- Distribution volt/VAR control

These three primary input functions are in turn influenced by EMS functions, DDC automatic functions, and DDC operator actions, as shown in the block diagrams of Figures 8.2-1 and 8.2-2.

Output Control and Data

Command and control action requests to DSG units or plants are forwarded through and by the DDC information processing function which organizes all control and data flow to and from other DDC functions and to and from the DSGs. From the information processing function, the command and control action requests are transmitted to the DSGs via the SCADA and communication functions as shown in the block diagram of Figures 8.2-1 and 8.2-2.

Interaction with Other Functions

The interactions with other functions are shown in the block diagram of Figure 8.2-1. Primary interactions take place with:

- DSG scheduling and mode control
- DSG automatic generation control
- Distribution volt/VAR control
- Information processing

Secondary interactions are shown, relative to each of the primary interactions listed above, in Figure 8.2-1.

Special Requirements

There will be a need to coordinate the generation from the many unmanned DSGs located within the distribution system with the load needs of the distribution network. In addition, the needs of the energy management system must be recognized. It is highly important that a proper man-machine interface be provided which combines the command and control function with the display and recording functional needs, as well as those for information processing and personnel safety. The hardware and software to accomplish these interdependent tasks represents new equipments and functions not presently used in most electric utility distribution dispatch centers.

8.2.2 FUNCTIONAL NAME: DISPLAY AND RECORDING

Functional Description

The display and recording function pertains to DDC control center operation and distribution system operation information. The relationship of this function to other functions is shown in Figure 8.2-1.

The DSG information pertinent to the distribution system (control, operation, maintenance, personnel safety and record keeping) will be monitored. Depending on the DSG type, size, SCADA and communication facilities, and degree of automatic control and monitoring, this monitoring function may be either automatic, manual, or a combination of these methods. Generally, it is anticipated that the medium and large DSGs would be provided with automatic monitoring. For these DSG plants, automatic transmission of selected measurements, metering, status, and derived information (i.e., DSG diagnostics) via a communication system is desirable. For small DSGs under DDC control and monitoring, considerably less information is required than for medium or large DSGs. For customer-owned DSGs, especially small ones, the display or recording of monitored data may represent the principal extent of DDC-DSG integration.

At the control center, the information processing function will assimilate the data pertaining to DSGs and store and/or distribute it to the appropriate display, recording and control subfunctions.

For medium and large utilities, with either an appreciable number of DSGs or with large DSG(s), it is anticipated that the DDC will be equipped with a computer directed control system. Associated with this would be CRT displays for DSG data and status.

With a large number of DSGs, automatic monitoring of DSG data for abnormal and emergency conditions will be performed, and automatic displays to operators will be those that are identified as "exceptions." This information may be determined at the DSG and transmitted to the control center, or it may be determined by control center logic which compares DSG and distribution system data and status. Thus the operator is not burdened with large volumes of normal data and status, and he will know that any automatic display presented to him is important. The operator, however, will be provided with the capability to "call up" any stored DSG data which he may require.

Records are kept in various forms. They may be retained in active storage, in background storage or on magnetic tape for longer time storage. This permits ready access and minimal physical space. Printed records are required for a number of operations, for billing, and for company and governmental reporting functions. These "hard copy" records are produced by on-line data loggers (for operating and maintenance personnel) and/or off-line batch process printers (for accounting, billing, and company and governmental operations information reports).

Input or Processed Data

It is noted that many different types of actual and derived data will be provided for display and recording. Depending on the uses to be made of the displays and records, many preformatted inputs will have to be combined with current data to clearly present the desired information from DSG, LDC, and EMS inputs to the DDC operator.

Control Output and Data

- CRT and/or lighted mapboard displays
- Magnetic tape records
- Hard copy:
  - Operator/maintenance logs
  - Financial/energy billing data
  - Company and governmental operations information reports.

Interaction with Other Functions

Display and Recording will interact directly with the following functions:

- Information processing
- DDC operator

Indirectly, the display and recording function interacts with practically all of the other DDC functions.

Special Requirements

These will be dependent on the distribution DSG system, EMS and SCADA hierarchy and hardware, and DSG types and quantities.

A series of specific displays and record formats should be drawn up for presentation of information to and entering of information by the DDC operators. This is especially important for clearly presenting DSG and distribution state conditions and DSG operating modes. Consistent and clear input procedures and formats are also important to make the DDC equipment easy to use. Development of display, record and input formats and procedures, and record storage formats and media should be given consideration.

8.2.3 FUNCTIONAL NAME: DSG SCHEDULING AND MODE CONTROL

Functional Description

The DSG real-power scheduling is the preassignment of the DSG operating condition (mode) and the power output level according to a plan based on a determination of both the power system and DSG conditions, and also the forecasted load. DSG real power scheduling is a subset of the overall power system real power scheduling function. DSG units and/or plants may be scheduled for several different time periods. These periods and their associated purposes are listed in Table 8.2.3-1. The relationship of DSG scheduling to other related functions is shown in Figure 8.1.2-1.

DSG unit and plant real power schedules will be influenced by power system:

- Economics of power/energy production
- Load
- Weather
- Security constraints
- Environmental constraints
- Maintenance schedules (bulk power and distribution systems/equipment)
- Operating state of power system

Table 8.2.3-1

DSG SCHEDULE PERIODS VERSUS PURPOSE

DSG Schedule Period		Purpose of Function
Minutes (1 to 5 minutes)	-	automatic generation control (AGC) on-line economic dispatch and system security
Daily (24 hourly intervals) Weekly (7 days)	-	unit committment for economics, meeting system load and system security
Monthly (30 days) Yearly (52 weeks or 12 months)	-	maintenance scheduling

DSG schedules are also directly influenced by the characteristics of the DSG primary energy source and the availability of the DSG. Short range scheduling assumes the power system will be in a "normal" state. When other states occur, revised schedules are required.

DSG real power scheduling may be performed at the bulk power system (EMS) level, the distribution dispatch level, or assigned to the individual DSG. The lower the level of scheduling responsibility, the more limiting are the input conditions/data included in the scheduling logic. The largest benefits are to be expected when the scheduling responsibility is assigned to the higher levels.

The assignment of the real power scheduling responsibilities among the EMS, DDC and DSGs on a specific utility will be influenced by the generation scheduling philosophy, power system control hierarchy and the number, size and types of DSGs on the distribution system.

DSG scheduling and mode control is a complex function which may be accomplished by a number of philosophical and computational approaches. These vary both in method of determining optimum scheduling and where the computations are executed. It is considered fundamental, however, that the EMS retain overall power system generation scheduling responsibility and that with appreciable numbers of DSGs to be scheduled, the optimizing operations for DSGs be performed at the DDC level or below. Thus, specific performance and cost information for individual DSG scheduling will not be a concern of the EMS. The exception would be DSGs considered large enough or important enough to power system operation to be retained under EMS responsibility. In this case, information may "pass through" the DDC but may not be part of its DDC-DSG optimization responsibility.

The EMS will thus require that each DDC assimilate DSG and distribution system characteristics, energy and scheduling capabilities, load forecasts and DSG status so that "equivalent" DSGs may be derived which represent the aggregate of all DSGs within the DDC responsibility. Bulk generation scheduling at the EMS will thus treat a DDC's equivalent (aggregate) DSG generators as bulk generation.

The responsibility of delegating individual DSG scheduling thus resides with the DDC. From the DDC to DSG, scheduling and control philosophy elected by DSG affects where the final individual DSG schedule is computed. There are two options: first, a centralized approach where the DDC optimizes the individual DSG schedules and transmits this information to the individual DSGs. Second, a decentralized approach where the power level or economic (energy value) information is transmitted to the individual DSGs and they optimize their own output to match the basic conditions determined by the DDC. As stated above, this is a relatively complex matter and is an area which should be considered for further investigations.

<u>Input or Processed Data</u>

Power System Data:

- Economic data (fuel, purchased power costs, operating and maintenance costs)
- Power system conditions (generation and transmission equipment/facilities in or out of service)
- Energy resource availability
- Weather forecasts
- Load forecasts (including intertie power flow agreements)
- Environmental constraints
- Security constraints
- Maintenance schedules (of generation, transmission, and distribution facilities)

DSG Unit/Plant Data:

All items of "Power System Data" listed above, specific to DSG unit/plant, except load forecasts and security constraints.

Controlled Output and Data

If the DSG's energy resource availability and characteristics permit DSG scheduling, preplanned DSG hourly/daily, and weekly/monthly operating schedules will be prepared. If DSG is not "schedulable" on an hourly/daily basis, a set of operating rules and criteria are established for this type of DSG and used in the manual (or automatic) DSG unit/plant control logic. Depending on the degree of power system and DSG automatic control and data processing implemented on a power system, the hourly/daily and weekly/monthly DSG real power schedules may be in the form of printed tabulations and/or stored data at one, two, or all of the following:

- Bulk power system, energy management center
- Distribution dispatch center
- DSG

Thus (DSG Schedule) output data is produced for DDC operators and (if applicable) automatic preprogrammed implementation by DDC and/or DSG control computers.

Printed or stored data is arranged in tabular form and is listed in the appropriate period segments of scheduled power output (or absorption) in MW values. These tabulations are for daily, weekly, monthly, and yearly schedules, as identified in Table 8.2.3-1. The "schedules" or economic dispatch information for the "minutes" period are usually determined by the EMS and DDC Automatic Generation Control logic, and "On-Line" power control commands or information is automatically transmitted to DSGs at the beginning of each economic dispatch period.

Interaction with Other Functions

The function of DSG scheduling and mode control will interact directly with the following functions:

- EMS power system generation scheduling
- DDC operator
- DSG command and control (DDC)
- Personnel safety
- Information processing
- Load control including restoration
- Security assessment and control
- Automatic generation control

Special Requirements

DSG ownership will affect the availability for scheduling DSG real power output. Scheduling of solely (utility) owned DSGs is constrained only by physical, electrical, environmental, security, and economic considerations. Scheduling of jointly owned plants (i.e., utility and private joint-ownership of a cogeneration plant) may be constrained by contractual agreements and plant design.

Scheduling of privately owned DSGs by the utility is not normally to be expected since the scheduling will be done by, and for, the maximum benefit and convenience of the owner. If a privately owned cogeneration plant has or foresees excess power capacity associated with a desirable level of process activity, contractual arrangements will have usually foreseen this possibility and provided the basis for scheduling and selling such surplus to the utility. However, this generally precludes "cost of power" optimization and in the future, on-time control methods similar to economic dispatch functions used for utility owned generation may be developed for privately owned DSGs.

Preliminary analysis of some of the key issues associated with the economic scheduling of many small DSGs located within an electric utility power system which has as its principal power source large centralized units has produced a number of interesting results. A brief summary of the salient points observed are as follows:

- The uncertainties associated with local weather variation patterns (microweather)* on small solar and wind units can be ignored at the EMS level independent of the number of units. For a few units there is little power involved, and for a large number of units the uncertainties tend to average out.

- The effect of global variation in macroweather** patterns on solar and wind units can be important at the EMS level unless the number of units is small or the macroweather cannot be forecast reasonably well at least a few hours ahead.

- Highly accurate scheduling of individual small DSGs does not appear to be required at the EMS level. The amount of power generated by each DSG tends to be small compared with that of the central generating units, and the uncertainties associated with the local variations in weather make accurate scheduling of small DSGs more costly than it is worth.

- In the event that the DSG is customer-owned, the effectiveness of the utility's ability to schedule the DSG will be limited by the nature of the contractual agree-

*Microweather: five minute local weather variations
**Macroweather: passage of overall weather fronts and air masses which should be known at least a few hours in advance

ment between the utility and the customer as well as by the extent of the inherent schedulability of the DSG. When the customer retains the right to schedule its DSG, the DSG will appear to be an uncontrollable negative load and will not be as useful to the utility as if the DSG were utility-scheduled.

- Scheduling research problems could be important if there is a major penetration of solar and/or wind units. However, such scheduling efforts could build on the well-established methodologies and techniques which exist in this field.
- Further efforts are needed to arrive at better defined methods for performing the on-line and off-line scheduling operations.

8.2.4 FUNCTIONAL NAME: DISTRIBUTION VOLT/VAR CONTROL

Functional Description

Generation by DSGs can influence distribution system voltage levels and VAR flow as well as the losses on the utilities bulk power transmission and generation system. Within the framework of distribution volt-VAR control is the functional requirement regarding the proper contribution to be made by the DSG sources to the overall voltage and VAR requirements of the utility system.

Steady-state voltage is controlled on distribution systems in a number of ways. In general, three classes of equipment may be used on a power system to maintain voltage levels. These classes and the types of equipment in each class are as follows:

- Source voltage control
  - generating station bus voltage control
- Voltage ratio control
  - load tap changing transformers
  - induction voltage regulators
  - step voltage regulators
- Kilovar control
  - synchronous condensers
  - switched capacitors

Traditionally, voltage ratio control and kilovar control have been used on distribution systems, and generating station bus voltage control has been associated with the bulk generation-transmission system. Until significant DSG capacity penetration on any particular or general part of a distribution system is reached, voltage ratio control and kilovar control will continue to be the primary means of distribution voltage control. However, certain types of

DSGs inherently or by DSG system design can contribute to voltage control on the distribution system. These relationships are shown on Figure 8.2-1.

At the distribution substation, the substation secondary voltage may be automatically regulated by using transformers equipped with tap changers which operate under load (LTC), by regulators and/or capacitors that maintain the desired voltage level on the substation secondary bus, or by separate regulators for each feeder. Substation LTC transformers or bus regulators may be used when all feeders connected to a transformer have similar load and voltage drop characteristics. Where feeders differ in these characteristics, separate regulators may be used in a substation for each feeder, or supplementary regulation may be provided along the feeder route by means of line voltage regulators or switched shunt capacitors.

Voltage regulating devices are designed to maintain automatically a predetermined level of voltage that usually varies with the load. As the load increases, the regulating devices raise the voltage at the substation to compensate for the increased voltage drop in the distribution feeder. In cases where customers are located long distances from the substation or where voltage drop along the primary feeder circuit is high, additional regulators or capacitors at selected points in the line provide supplementary regulation.

Use is made of shunt capacitors in substations and on primary feeder circuits for the dual purpose of improving power factor and regulating voltage. Many of these installations have sophisticated controls designed to fulfill either or both purposes by automatic switching.

The addition of certain types of DSG units provides another means of controlling voltage or KVAR. If, for example, the DSG is a synchronous machine, then a means exists to use the reactive capability to affect the DSG-distribution system interface voltage and supply or absorb VARs. Induction generators, on the other hand, absorb VARs from the system and do not provide a means of VAR control. Their application (to date) has included wind generators as well as small hydro units. Small, inexpensive dc/ac inverters also have been shown to have poor power factors and require VARs from the power system. These, therefore, would not assist in voltage control.

The DSG volt-VAR scheduling would be done at the DDC level. Some larger DSGs might be scheduled from the EMS, depending on their location in the power system. For example, if a large DSG were located at or near a bulk power substation it would be logical that the EMS would control the voltage/VAR supply of the DSG.

Three distribution system operating states and control priorities can be identified as shown in Table 8.2.4-1. For normal system conditions, the control of voltage may have first priority; control of VARs, second priority; and minimizing losses in the distribution system, the lowest priority. Under an emergency condition, such as loss of a major transmission line or generating plant, the top priority may be to provide system VAR support by means of feeder and substation switched capacitors.

Operational priorities of the volt-VAR control can be determined by weighting factors used in the control algorithm.

Table 8.2.4-1

OPERATING PRIORITIES VERSUS OPERATING STATE

Controlled Quantity	Normal	Operating State** Abnormal	Emergency
Voltage	1	*	*
VARs	2	*	*
Losses	3	*	*

*Operation priority of each controlled quantity to be preset for each operating mode.
**Determined by DDC.

Input or Processed Data

To accomplish voltage control requires the measurement of line voltage. VAR control can require measurement of voltage, current or VARs.

The addition of controllable DSG units would require similar measurements being made for volt-VAR control. In addition, the status and operating mode of the DSG units is required, along with the status of the DSG main breaker.

Depending on the control logic devised, some of the following inputs would be required:

- Indication of operating priority to DDC
- Voltage setpoint and bandwidth of DSGs
- Status of substation and feeder capacitor banks
- Status of DSG dc/ac power conversion capacitor banks
- Status of LTC and voltage regulators
- Time delay for LTC and voltage regulators
- Feeder and substation KVAR limits

Output Control and Data

Aspects of output control relevant to DSG coordination:

- Control of the DSG synchronous generator excitation subsystem to control reactive power (VARs), and voltage
- Control of switched capacitors associated with line commutated dc/ac power conversion DSGs
- Control of voltage and/or reactive power flow of forced commutated inverter equipped dc/ac power conversion DSGs

Interaction with Other Functions

As shown in Figure 8.2-1, the volt-VAR control interacts directly with the following functions:

- DDC operator inputs
- EMS power system volt-VAR dispatch
- EMS load management system
- DSG command and control

The volt-VAR control interacts indirectly with the following functions:

- Distribution SCADA
- Instrumentation
- Load control including restoration

Special Requirements

With a customer-owned DSG, the utility and customer have to coordinate a mutually acceptable owner supervised VAR and voltage schedule, or an agreement permitting the utility to exercise control over the DSG volt-VAR capabilities.

With significant penetration of DSG sources, it will become increasingly desirable to coordinate distribution volt-VAR control with the EMS level bulk power system volt-VAR dispatch function as shown on Figure 8.2-1.

8.2.5 FUNCTIONAL NAME: LOAD CONTROL INCLUDING RESTORATION

Functional Description

In a distribution system directed by a DDC distribution automation system the load control function would provide a means of reducing an area load by disconnecting selected loads or alleviating distribution circuit overload by increasing DSG output. These actions would be in response to the DDC or the EMS monitoring and control requirements.

Load control, used in conjunction with DSGs, serves to reduce peak demands and shift loads from peak periods to off-peak periods. This may also reduce maximum load on a given feeder. Control commands drop specified loads (water heaters, air conditioners, electric space heating, and so forth) for a preset time interval. These commands are generated at the DDC or EMS.

The presence of DSGs on the distribution system offers a means of reducing loading on feeder sections or at the substation. This might be required under overload conditions brought about by equipment failure or circuit reconfiguration.

Another aspect of load control and restoration function involves faulted distribution feeder circuits. After a fault is isolated, service can be restored to nonfaulted sections through automatic switching and resynchronizing of the DSGs, provided that the DSGs are on the nonfaulted section of the feeder. If nonfaulted feeder sections become isolated from the distribution system, but there are DSGs connected to them which can operate under isolated conditions, then service restoration can be accomplished to those sections by synchronizing the available DSGs and coordinating with the load control function as required to balance load and available generating capacity.

It is important that the load control including restoration function be properly coordinated with the personnel safety function. Under conditions of an isolated portion of the distribution system served by the local DSGs, it is important to have an indication of the DSG operating mode or voltage in that area to prevent injury to maintenance personnel.

Power system loads can also be affected by voltage control. This technique has been used, for example, to reduce the total system load when generation shortages exist. Thus, the load control function can interact with the distribution volt-VAR control function.

Input or Processed Data

Input data relevant to DSG coordination:

- Indication of overload on distribution circuits or equipment
- Commands from EMS to initiate load control
- Status availability of DSG and scheduling requirements

Output Control and Data

Output data relevant to DSG coordination:

- Switch control signals to portions of customer's load, e.g., electric water heater or air conditioner

- Adjusting DSG power output to alleviate distribution overloads

Interaction With Other Functions

As shown in Figure 8.2-1 this function directly interacts with the following functions:

- DDC operator
- EMS load management system
- Security assessment
- DSG scheduling and mode control
- Distribution automation system (customer load switching)

This function interacts indirectly with the following functions:

- DSG command and control
- Volt-VAR control
- Distribution SCADA
- Communications
- Instrumentation

Special Requirements

Customer load control requires communication to user loads, interface (auxiliary equipment switches), and load control units. These communication and control means are not normally considered to be part of the distribution DSG system.

The load control function will interact with the EMS load management control center and therefore require coordination and integration.

Special attention and study are needed for operations involving isolated DSGs or portions of distribution systems which have been disconnected from the normal utility power supply source.

8.2.6 FUNCTIONAL NAME: AUTOMATIC GENERATION CONTROL

Functional Description

Automatic generation control (AGC) is any area supplementary control that automatically adjusts the power output levels of electric generators within a control area, which is usually an entire electric utility system. Automatic generation control schemes usually include one or more subsystems (or subfunctions) such as load frequency control, economic dispatch control, environmental dispatch control, security dispatch control, and like functions.

Schedulable types of DSGs that can be scheduled like hydro with storage, batteries, or fuel cells are candidates for participation in AGC. Some intermittent sources, like wind turbines, would not be good choices for AGC.

AGC for an entire power system has traditionally been performed at the EMS level. With the addition of DSGs that may be scheduled and automatically controlled, the overall power system AGC responsibility would remain with the EMS; but AGC for specific DSGs would be assigned to DDCs. This relationship is illustrated in Figure 8.2-1. The impact on the DDC is that it would be required to allocate its assigned AGC requirement among the individual DSGs or pass AGC signals through to some of the large DSGs on behalf of the EMS.

AGC is directly related to DSG scheduling, because economic dispatch is a form of generation scheduling on a short-time basis. This relationship was described in Section 8.2.3 and is shown in Figure 8.2-1.

In addition to using schedulable DSG generation sources to optimize overall power systems generation production costs, DSGs with controllable energy resources may also participate in the power system load-frequency control function. Thus, DSGs may supplement bulk generation in performing power system frequency and intertie regulation.

Input or Processed Data

The DDC receives aggregate DSG power generation requirements from the EMS and power generation economics data where DDC has responsibility for DSG economic dispatch.

MW output values of DSGs are under AGC control, if economic dispatch is performed at DDC for individual DSGs.

Output Control and Data

The output from DDC to DSGs for AGC purposes may be in different forms depending on AGC control philosophies. Examples could be: (1) raise and lower signals, (2) desired power level requirement information, or (3) economic production cost information if DSG economic dispatch logic function is located at DSGs.

Interaction With Other Functions

The AGC function interacts directly with the following functions:

- EMS power system AGC
- DSG command and control
- DDC operator for override control
- DSG scheduling

The AGC function interacts indirectly with the following functions:

- Load control including restoration
- Distribution SCADA
- DSG power control
- Instrumentation

Special Requirements

If high-capacity penetration of nonschedulable DSGs is realized on a power system, the requirement for closer control of existing central (non-DSG) generation units is highly desirable. This may require changes in the centralized generating plants, or fine tuning of boiler controls.

If DSGs are to operate within DDC areas in an "island" configuration, special requirements will be placed on the DDC. The DDC would have the responsibility for maintaining the frequency and voltage levels for these islands within acceptable tolerances. This is a complex problem that needs examination, analysis, and direction. There are major distribution system monitoring, control, communication, and operating considerations if islands of any appreciable size are to be temporarily self-sufficient generation-distribution-load entities.

8.2.7 FUNCTIONAL NAME: SECURITY ASSESSMENT AND CONTROL

Functional Description

The security assessment and control function is a reliability evaluation means of trying to keep the distribution system in a normal state; i.e., all customer and interconnection demands are met, no apparatus or line is overloaded, and the consequences of an unexpected contingency are minimal. If the system departs from the normal state for any reason, the object is to restore it in an acceptable period of time.

The security of the distribution system may be assessed and controlled at the DDC through one or more degrees of automation. Each of these is a more progressively sophisticated level that builds upon the underlying functions. In ascending order of complexity, security assessment and control would consist of:

- Status monitor and display
- Contingency evaluation
- Corrective strategy formulation
- Automatic control

At the first level, the operator receives information on the status of the distribution system and manually makes assessments and decisions and takes necessary control action. In the second step, the computer predicts the effect of contingencies and planned outages and alerts the operator to potential troubles. The operator then analyzes the problem, determines corrective action, and initiates appropriate control. In the third step, the computer formulates corrective strategies. At this step, the DDC would indicate the chosen strategy to the operator, who would, upon acceptance, initiate appropriate control actions. In the final step, the DDC, through the communication network, would execute automatically the formulated strategies.

DSGs can contribute to the overall system security as a source of available generation that may be able to serve the distribution It is important, then, to determine what state each controllable DSG is in, viz, normal, abnormal, emergency, or inoperative. If the power system is in the alert state, a schedulable DSG can be used to reduce potential overloads. For example, if a substation transformer is at its peak load, a DSG on the secondary bus or on one of its feeders can be used to reduce the likelihood of exceeding that limit, provided it can be called upon to produce more power output.

The DSG operating state will have an impact on system security. For example, whether the DSG is in the normal, abnormal, emergency, or inoperative state will determine how much the DSG can contribute to the overall system security. In addition, the DSG operating mode (on, off, standby) is another consideration for distribution system security assessment, because some DSGs will require longer startup times (up to several hours) than others and thus not be immediately available for service. Some types may be brought on line in a matter of minutes.

<u>Input or Processed Data</u>

- Major distribution substation, feeder, and subtransmission
- Power flow information
- Electrical and thermal limits for substations, feeders, and subtransmission lines
- Overload alarms
- Equipment temperature alarms
- Status of DSGs (mode and state)
- Load projections

<u>Output Control and Data</u>

- DDC control to feeder switches and breakers
- Load control
- DSG schedule requirements

Interaction With Other Functions

Security assessment and control, as shown in Figure 8.2-1 directly interacts with the following functions:

- DSG scheduling and mode control
- Information processing
- Load control, including restoration

Security assessment interacts indirectly with:

- DSG command and control
- Display and recording
- Distribution volt/VAR control
- Distribution SCADA
- Instrumentation

Special Requirements

The security assessment and control function in its fully implemented form as described above has not been implemented on an electric utility distribution system. After higher priority DDC control and monitoring functions have been satisfied, development work on this subject will be required.

8.3 POWER FLOW AND QUALITY REQUIREMENTS

The power flow and quality requirements relate to the local DSG functions involved in quantity and quality of the service provided by the DSG. Because power flow and quality may be remotely controlled by the DDC and involves the DSG process, it is important that these functions and processes be mutually understood by DSG, DDC, and distribution system designers and engineers. Included in this power flow and quality category are the following subfunctions:

- DSG power control
- DSG voltage control
- Harmonic control
- Instrumentation

The DSG power control subfunction is concerned with the local control of the magnitude of real power delivered by a DSG to the power distribution system. This may directly or indirectly involve the control of other DSG subsystem controls and auxiliary functions that are required to produce the desired DSG output. The DSG power control will receive information from the DDC or from local DSG operational requirements that will provide the desired power reference signal.

The DSG voltage control is a local DSG function that helps support the distribution system voltage in the immediate area where the DSG is located. It is interrelated with the DSG power control function.

Harmonic control functional requirements of a DSG identify permissable voltage and current wave harmonic content introduced by a DSG and its associated equipment. These harmonics must be limited because they produce unwanted heating in power equipment and/or undesirable electromagnetic interference with communications and electronics equipments. As presently envisioned, harmonic control is one of the design requirements for a DSG and its distribution system application rather than an on-line control function.

Instrumentation is required to measure the actual DSG conditions, performance, and output and to condition the information for local use and transmission to the DDC. Because this instrumentation provides the basic inputs for DDC functions, it is desirable to be able to identify the instrumentation requirements as soon as conveniently possible in the design cycle. Figure 8.3-1 provides a simplified overview and relation of the power flow and quality functions to the DDC-DSG overall control and DSG plant functions.

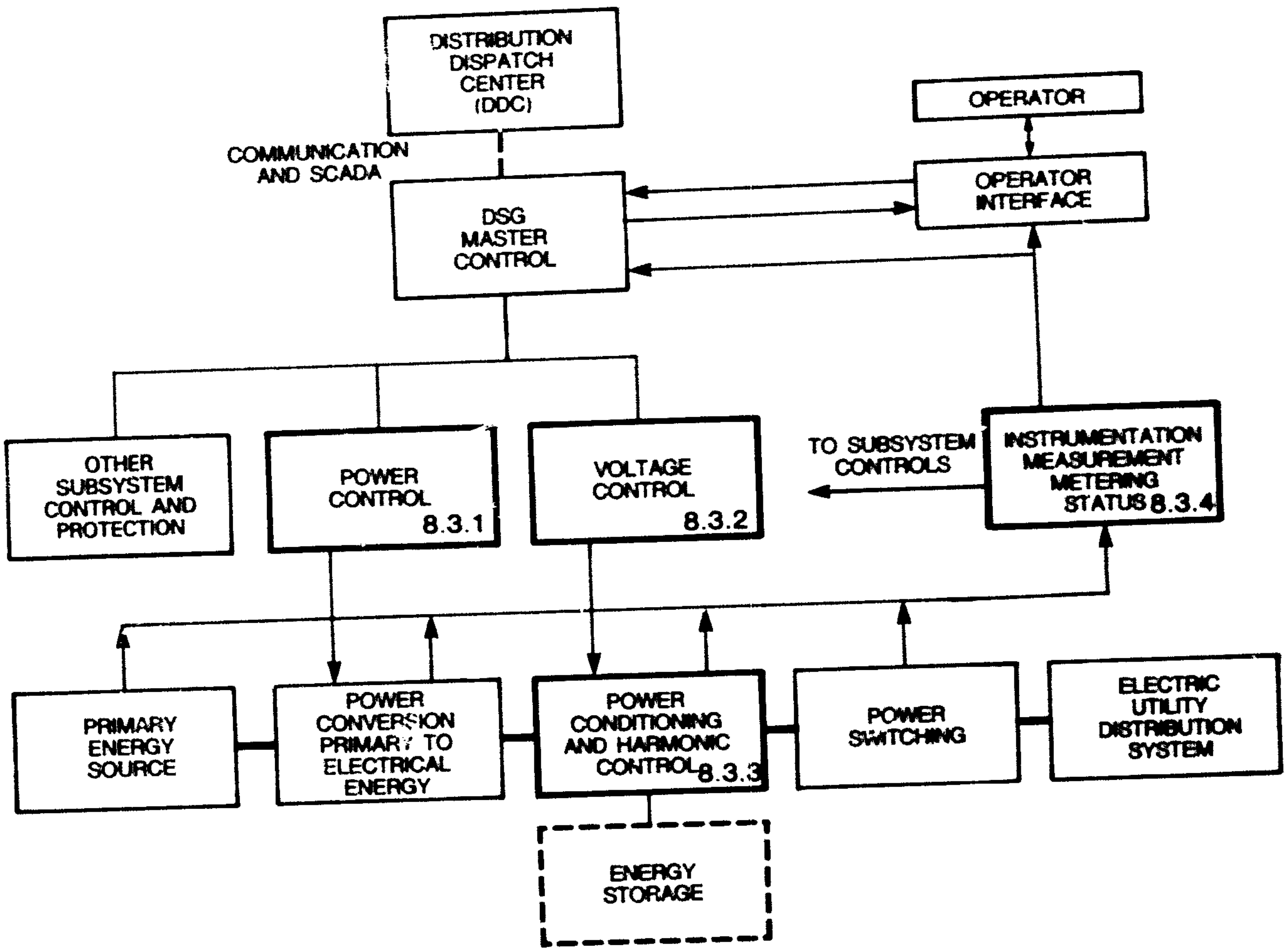


Figure 8.3-1. Power Flow and Quality Functional Relationships

8.3.1 FUNCTIONAL NAME: DSG POWER CONTROL

Functional Description

DSG power control involves local DSG control of the DSG real power (watt) output, while the DSG is connected to the utility power distribution system.* The DSG power output (generating), or absorption (storing), will be controlled or influenced by one or a combination of the following:

- A DDC control center employing DSG scheduling and/or automatic generation control (AGC) functions
- Local DSG plant or unit control decision logic based on
  - DSG state
  - Power system state
  - DSG energy source availability and characteristics
  - Process heat/electricity requirements (for congeneration plant)
- Local operator's decisions
  - Owner's decisions (private party ownership/operation)
  - Utility operator (testing and maintenance)

The hierarchal relationship of these control factors to the major control elements are shown in Figure 8.3-1. Control Center scheduling or AGC decisions and actions take place at the DDC level; the local DSG and owner's decisions and actions take place at the DSG plant or unit level.

The decisions and actions listed above are ultimately carried out by either manual or automatic control action through or by the DSG master control acting on the DSG power control subsystem. The DSG master control/DSG power control can range from simple to complex depending on the type and size of DSG.

Input or Processed Data

Depending on the primary responsibility assignment for, or origin of, DSG power control, the input data could involve:

- DDC direction of DSG power

  A. Automatic generation control (AGC) function, including economic dispatch and possibly load-frequency control requirements. This information is transmitted and received via distribution SCADA, or simplified equivalent, and communication link(s).

*DSG operation, although it is electrically isolated from the power distribution system, is a separate subfunction (stand-alone capability) that is described in the special DSG requirements category.

B. Separately defined and transmitted power schedule, (an alternate to A), for daily/hourly load levels.

- Local DSG power control:
  - A. DSG state
  - B. Power distribution system state
  - C. DSG energy source availability and characteristics
  - D. Preset schedule
  - E. Process heat/electricity requirement
- Local operator's decisions:
  - A. Owner (private)
  - B. Economic factors (cost trade-offs, which may include on-line value of power information from utility
  - C. Process factors (level of operations and schedule)
  - D. Security factors
- Utility operator:
  - A. DSG and distribution systems
  - B. Conditions
  - C. Status

Output Control and Data

The controlled outputs and data for local DSG power control would follow this description:

In the generic sense DSG power control will be provided in the form of signals or data by the DSG master control to the power control subsystem. The form of these signals or data will be dependent upon the specific type of DSG and its control system design. The DSG power control subsystem in turn acts electrically, electromechanically, or electrohydraulically on the DSG power conversion system, subsystems, and auxiliaries.

For DSGs controlled directly by the DDC with on-line closed-loop control (AGC), DSG power output data would be transmitted from the DSG to the control center. If economic dispatch optimization calculations are decentralized and for the specific DSG are performed by the DSG master control logic (with appropriate DDC economic information inputs), different information transfers would be involved than for DDC AGC closed-loop control. In either case, however, DSG characteristics and conditions would be needed by the DDC. Depending on the type and size of DSG, this information could be either simple manual DDC inputs or automatic DSG data outputs.

Interaction with Other Functions

The local DSG power control function interacts directly with the following functions:

- DSG master control
- DSG power conversion
- Instrumentation

The local DSG power control interacts indirectly with the following functions:

- DSG voltage control
- DSG protection
- DSG command and control-distribution SCADA-communication
- DSG scheduling
- Automatic generation control (AGC)
- Load control and restoration

Special Requirements

The implementation will be affected by the bulk and distribution power system control system hierarchy and architecture, real power control responsibility assignment and relationships, type of DSG, size of DSG, and DSG ownership. The interrelationships of these factors can have many variations and conditions. There are control philosphy, institutional, and regulatory aspects that affect DSG power control. This general subject requires further examination and definition, some of which may have to await clarification of regulatory decisions presently being formulated.

8.3.2 FUNCTIONAL NAME: DSG VOLTAGE CONTROL

Functional Description

DSG voltage control is a local DSG function that helps support distribution system voltage in the immediate area where the DSG is located. The voltage reference "signal" may originate at the DDC or locally at the DSG by manual or automatic means. Local DSG terminal voltage and/or distribution system voltage is required feedback for voltage control decisions.

DSGs with synchronous generators, forced (self-) commutated dc/ac inverters, and line-commutated dc/ac inverters equipped with switched capacitors have the ability to assist the DDC Volt/VAR control function described in Section 8.2, Control and Monitoring Requirements.

2-2

The DSG voltage control function is identified on Figure 8.3-1. The type of voltage control subsystem will depend on the type of equipment employed by the DSG power conversion and/or power conditioning equipment.

Synchronous generators are electromechanical rotating machines that have excitation systems to provide generator field current. Voltage control thus involves adjustment of the excitation system reference level for synchronous generators. There are limits to the level of excitation that can be applied to the synchronous generator that are interrelated with the power output level. The excitation affects the reactive volt ampere output or consumption as the generator excitation level is varied from "overexcited" to "underexcited" conditions respectively. The vector total of the real and reactive volt ampere output determines generator (I^2R loss) heating, and thus its output capacity limitation. Excitation systems can incorporate various control logic such as maintaining terminal voltage, reactive volt amperes, or power factor (within machine capability). This function can be used by the DDC Volt/VAR control function to affect distribution system voltage either locally or collectively if a large number of DSGs is installed.

Solid-state (static) dc/ac inverters are of two basic types: forced commutated and line commutated. Forced commutated inverters are usually employed where "stand-alone" capability, that is the ability to operate independently from the main power distribution system, is required. For this capability, voltage control is required that involves the adjustment of the reactive volt ampere output. To provide the capability for producing reactive power, internal capacitance is required in the inverter design. The inverter voltage control thus acts upon the formation of the ac output wave to achieve the desired level of voltage and/or VAR output. Thus, the forced commutated inverter has a relatively continuous control range capability limited by internal capacitance and thermal considerations of the inverter components. It is also important to note that the "raw" output voltage of forced commutated inverters has a "harmonic rich" wave form. This is highly undesirable, and appropriate harmonic filtering is usually required for this type of inverter to be acceptable on a distribution system or to normal distribution types of loads. This harmonic filtering involves the use of capacitors that also supply reactive volt amperes that are similar to shunt capacitor installations.

Line-commutated dc/ac inverters are less complex than forced commutated inverters, differing in that they depend upon the power system to cause commutation action in the inverter. Thus, they do not need the internal capacitance of the forced commutated inverters. However, the line-commutated inverter cannot operate independently from the distribution system (it does not have "stand-alone" capability). Associated with line-commutated inverters are harmonic filters that utilize capacitors that also act as shunt capacitors to supply VARs to the distribution system. The amount of filtering required can vary with the real power output level. Therefore, it may be necessary to switch the filter on or off by "section" if the VAR output exceeds the requirements of the distribution system in which the DSG is located. If additional volt/VAR support is required, switched shunt capacitors would also be utilized. Thus, line-commutated inverters may have volt/VAR control if their harmonic filters and/or shunt capacitors are configured in switchable arrangements. If they are not switchable, the power factor will vary with output, and relatively fixed VAR supply will be provided as long as the DSG is connected to the energized distribution system.

Input or Processed Data

Inputs to voltage regulator/excitation system include:

- Local manual setpoint reference level for DSG terminal voltage regulation.
- Voltage or VAR reference level signals from the DDC supplied to the voltage control subsystem via the DSG master control/information processing function.

Output Control and Data

Signals from the voltage regulator to the excitation, or voltage control circuits, of the DSG regulate DSG terminal voltage and/or VAR output (or consumption).

Data of DSG terminal voltage or distribution system voltage would be required for either local DSG or remote DDC on-line volt/VAR control.

Interaction with Other Functions

The voltage control function directly interacts with the following functions:

- DSG master control
- DSG power control
- DSG startup
- Harmonics (static inverter with switchable filter banks)
- Instrumentation
- Protection: DSG
- Stand-alone function

The voltage control function interacts indirectly with:

- DDC volt-VAR control
- DDC load control including restoration
- Distribution SCADA/communication

Special Requirements

DSGs with voltage control capability offer the possibility of assisting distribution system voltage regulation. To make use of this capability for on-line control (rather than preset or simple timed-voltage schedule) would require voltage measurement and voltage data to be transmitted to the DDC. The value (or worth) of this control must be evaluated with regard to derived benefits to determine whether this control function is justifiable. The size, type, and number of DSGs; distribution system characteristics and needs; and definitive effects would need to be examined in evaluating whether implementation of DDC-DSG voltage control, was justifiable. This will tend to be sensitive to specific conditions and thus some effort to parametrically define the general cases would be desirable for guidance purposes to utility distribution DSG system planners.

8.3.3 FUNCTIONAL NAME: HARMONIC CONTROL

Functional Description

Harmonics on the distribution system are a source of additional heating to power equipment and a source of telephone and electronics interference. Harmonics could also adversely affect the operation of instrumentation and protective relays. Increased voltage regulation is another side effect of excessive harmonics. It is also possible to develop very undesirable resonant voltage conditions, depending upon the circuit configuration and the particular order of harmonics present. Typical sources of harmonics include synchronous generators, static inverters, transformer exciting current, wye-connected loads, arc furnaces, and SCR drives.

A DSG, therefore, is a potential source of harmonics. If the DSG is a synchronous machine, then the harmonic content of the voltage wave may be limited in its inherent design characteristics by purchase specification standards, (ANSI C42 and C50) in terms of:

- The maximum deviation of the voltage waveform from a pure sine wave and
- The weighted average of all harmonics. These requirements are intended to reflect the objectionable effect of inductive coupling at the harmonic frequency with telephone communication.

Where dc/ac inverters are employed, e.g., with battery storage, fuel cells, or photovoltaic generation, every attempt should be made to reduce the objectionable harmonics imposed on the distribution system by the DSG. For the purpose of this study, the control of harmonics will be viewed as a DSG and distribution system design problem and should be resolved prior to the time of writing DSG system specifications. The control of DSG harmonics does not readily yield to corrective measures of control or mitigation taken after the fact.

Input or Processed Data

DSG waveform harmonic content for a set of specific operating conditions must be specified in the DSG procurement specifications.

Output Control and Data

Where "external" harmonic filters are utilized in the DSG system power conditioning subsystem, there may be the need to control the degree of filtering if it adversely affects voltage levels as the power output level varies.

Interaction with Other Functions

Harmonic control can interact directly with the following functions:

- DSG voltage control
- Protection: DSG
- Instrumentation
- Communications

Harmonic control can interact indirectly with the following function:

- Distribution Volt-VAR control

Special Requirements

Where dc/ac inverters are used, reactive power requirements to be supplied from or to the power system should be carefully studied and specified as part of the DSG system. Switched shunt capacitor banks at the DSG location are a possible solution for reactive power supply requirements. The combined capacitance of the harmonic filters and the (power frequency) reactive volt ampere supply shunt capacitors should be coordinated and matched to the distribution volt/VAR control and harmonic control requirements. This sould be done in the design and application engineering phase of DSG definition.

8.3.4 FUNCTIONAL NAME: INSTRUMENTATION

Functional Description

The instrumentation function includes (1) the sensing and conversion of variable electrical and physical quantities to logic level analog or digital equivalents; (2) the production and accumulation (counting and register function) of pulse counts that represent integrated time variable quantities such as electrical energy and volumetric flow; (3) the sensing and presentation of status conditions of binary or multistate devices; and (4) the local presentation or display of this information on discrete devices such as indicating instruments, recorders, register meters, and indicating lights or displays. This set of subfunctions and the coordinated equipment necessary to provide them can be referred to as the DSG instrumentation system. Figure 8.3-1 shows the relationship of the instrumentation system to other DSG functions and equipment in simple block diagram form.

The presentation of the various information, listed above in items (1) through (4), for local use and for transmission to the DDC will be influenced by the type and capability of the DSG master control and information processing/data acquisition equipment. At medium and large DSGs, where the relative expenditure is justifiable, the DSG master control and information processing data acquisition would be performed by computer equipment. This type of equipment could provide an appropriate interface to (or even perform the function of) the SCADA equipment described as the "data terminal equipment" type of function in the communications and data handling functional requirements descriptions. For smaller DSGs with simpler local control and limited or incompatible data acquisition equipment, the instrumentation system would probably have to present its information directly to a separate SCADA remote terminal unit that includes data terminal equipment functions. For these small DSGs, which are under control and monitoring by the DDC, considerably less information will be required by and transmitted to the DDC compared to medium and large DSG systems. This may be as limited as simple ON or OFF mode conditions.

Input or Processed Data

Variable quantities are:

- Electrical
  - A. Volts (kV)
  - B. Watts (MW)
  - C. VARS (MVARS)

- Physical (dependent on type of DSG)

  A. Pressures

  B. Temperatures

  C. Flow

  D. Insolation

  E. Wind velocity

Integrated quantities are:

- MWh
- Input energy (depends on type of DSG/primary energy source)

Status

- Important conditions (specific to type of DSG)
- Alarm conditions (general and specific to type of DSG)

Output Control and Data

Output data same as listed for Input or Processed Data cited above. Basically all of it would be used or stored locally, and only the data pertinent to DDC operations would be transmitted to the DDC.

Interactions with Other Functions

Direct interactions include:

- Distribution SCADA/Communication
- Local DSG display and recording
- DSG startup/shutdown
- DSG stand-alone capability
- DSG power control
- DSG control (includes DSG mode control)
- DSG voltage control
- Revenue metering
- Personnel safety

Indirect interactions include:

- All DDC functions concerned with monitoring and control of the DSG.

Special Requirements

Electrical energy metering will involve special consideration for some types of DSGs, and for ownership other than solely by the utility.

It is noted that ordinary watthour meters will run in reverse if the current flow is reversed, thus producing incorrect readings. Watthour meters can be equipped with detents to prevent reverse operation, however, where bidirectional power flow can take place. Examples of this are: storage-battery types of DSGs, DSGs that require crankup power for starting, DSGs that have auxiliary power requirements that exceed gross DSG output under certain conditions, and customer-owned DSGs with less than peak customer demand capacity. In these cases two meters can be used, one for IN and the other for OUT watthour measurements.

Where the DSG is customer owned and there can be a net IN or net OUT power flow, the revenue metering requirements can become complex. The metering may have to be performed on relatively short demand intervals (i.e., 15 minutes) and the time (hour) of the day may also affect the rates involved for selling or buying power/energy. Separate metering for the customer load and DSG would be helpful but may not always be practical.

Customer revenue metering, therefore, requires consideration of both technical and contractual requirements to provide metering that can perform the required measurements.

8.4 COMMUNICATION AND DATA HANDLING REQUIREMENTS

The communication and data handling functions provide the necessary information transfer and data handling between the DDC and the DSGs, the data transfer interfaces between these equipments and the communication links, and the associated and necessary information processing at the DDC. These functions are primarily involved in the transfer of command and control data from the DDC to DSGs and the return of monitoring (normal and alarm) data from the DSGs to the DDC.

The functional requirements under the category of communication and data handling include the following:

- Distribution supervisory control and data acquisition (SCADA)
- Communication
- Information processing
- Revenue metering

As indicated in Section 6, the Distribution DSG System may use either a centralized or a decentralized control structure depending on the perceived needs of the utility involved. A centralized architecture is a master station located at the distribution dispatch center (DDC) that communicates directly with each DSG remote station. These communication and data-handling functional requirements will be described conceptually in terms of a centralized control structure although the functional requirements are appropriate for either communication structure.

A decentralized control architecture would have the DDC communicating with distribution automation control (DAC) equipments, usually located at or near a substation, which in turn may communicate with one or more DSGs. Communication between the DDC and various DACs would utilize supervisory control and data acquisition (SCADA) equipment or techniques. The considerations involved for the communication and data handling associated with this decentralized architecture are discussed later in this overview.

Communication and data handling functional and physical relationships are shown in Figures 8.4-1 and 8.4-2. Although these figures indicate the telephone means for communication, this has been done in order to simplify the description and is not meant to imply that other means of communication may not be used more effectively. Figure 8.4-1 generically illustrates, in the context of communication network terminology, the communication and data handling system. The terminology DTE and DCE are communication industry standards and are defined as:

- <u>Data terminal equipment (DTE)</u>
  1. The equipment comprising the data source, the data sink, or both

2. The equipment usually comprising the following functional units: control logic, buffer store, and one or more input or output devices or computers. It may also contain error control, synchronization and station identification capability

- Data Communications Equipment (DCE). The equipment that provides the functions required to establish, maintain, and terminate a connection; the signal conversion and coding required for communication between data terminal equipment (DTE) and data circuits. The data communications equipment may or may not be an integral part of a computer (e.g., a modem).

The DCE equipment may or may not be supplied as part of a supervisory control and data acquisition (SCADA) system depending on hardware architecture and/or communication channel requirements. For an understanding of SCADA terms, functions, interfaces, operation, and equipment requirements see Reference 1.

Figure 8.4-2 is a further elaboration showing the use of a telephone company (TELCO) line as a communication circuit and some DDC and DSG input/output functions. Both figures indicate the scope of interest associated with the categories of SCADA, communication, and information processing.*

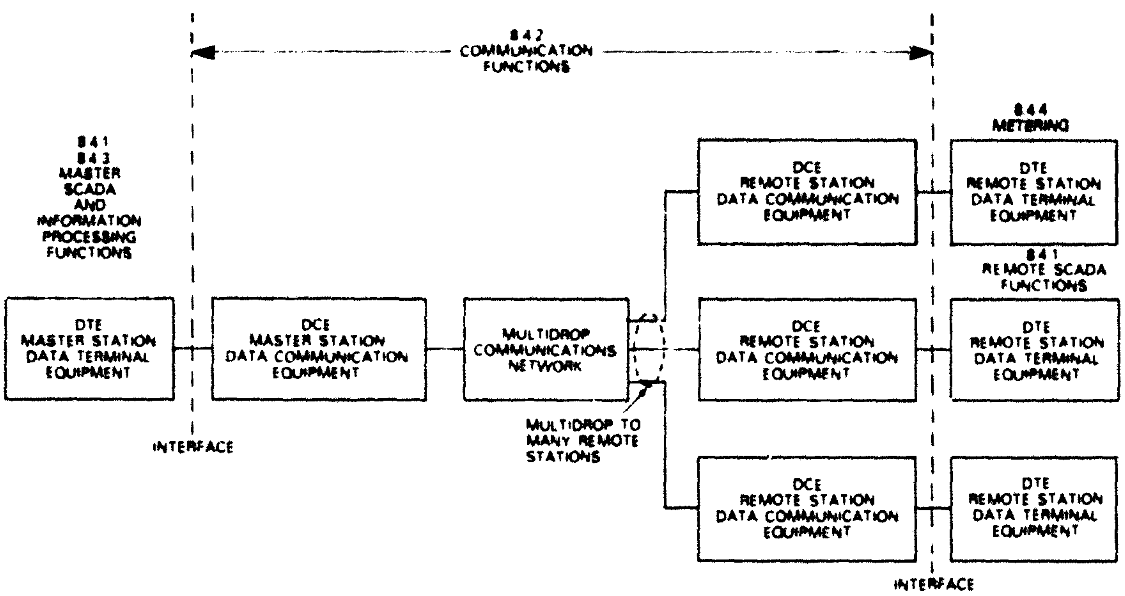


Figure 8.4-1. Generic Data Communication Network

*By definition any information processing involved at the DSG remote sites, whether for DSG control, display, or computation of derived telemetry data, is not included in communication and data handling requirements.

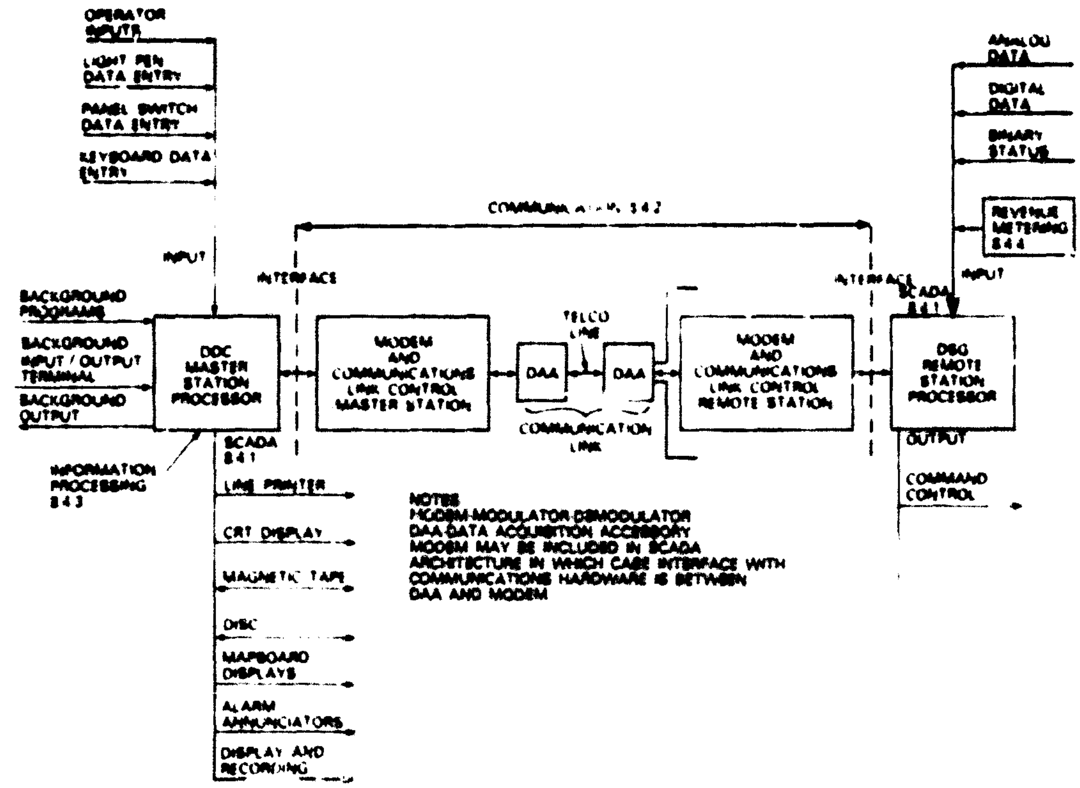


Figure 8.4-2. An Example of Communication Network Details Showing Inputs and Outputs

In general, the category of communication and data handling pertains to the functions of:

- Distribution SCADA. Sampling of digital and analog monitoring data and status conditions at the remote DSG site and the telemetering of this data to the DDC master station site and sending addressed commands from the DDC master station site to the proper addressed remote station DSG site and controlled device at that site.
- Communication. The communication multidrop network and any network protection equipment interconnecting the master and remote stations.
- Information Processing. The data processing equipment, peripherals, and displays located at the DDC master station site.

- Revenue Metering. Metering the integrated value of power consumed and/or produced by a customer of the electric utility and making it available for billing purposes to the utility. Revenue metering may also involve demand metering, time-of-day factors, etc.

COMMUNICATION AND DATA HANDLING CONSIDERATIONS FOR DECENTRALIZED ARCHITECTURE

The preceding overview and the functional descriptions are oriented towards a centralized DSG communication and data handling architecture wherein all DSGs communicate directly with the DDC. A decentralized architecture may be desirable wherein each DSG communicates with its "parent" Distribution Automation Control (DAC), which in turn communicates with the DDC. Each DAC may communicate with none, one, or several DSGs; probably via a point-to-point path (actual DAC-DSG communication depends on available communication media). Communication and data handling functional capability for DDC-DAC communications will be required to accommodate the additional traffic imposed by the added DSG traffic requirements, superimposed on other DAC functions requiring DDC-DAC communications.

The purpose of this discussion is to consider some of the ramifications and impact of a decentralized architecture on the total system communication and data handling environment. As stated above, it will be assumed that the DDC-DAC communications and data handling capabilities will have sufficient capacity to absorb the additional traffic generated by the DSGs as described in 8.4.5. It will also be assumed that the individual DAC processors will nave sufficient I/O capacity to interface with the DSG communication and also reserve memory and processing power to perform communications preprocessing, decentralized DSG monitoring and control, logical operations and message formatting, and transfer to and from the DAC.

Based on the requirements stated in the foregoing assumptions, it appears logical to arrange the DDC-DAC-DSG communications and data handling to utilize the DAC information processor as an intelligent data concentrator to perform the data relay between the DSG and DDC. Several considerations favor this approach:

- Islanding and other fault scenarios could make it desirable for the DAC to exercise rapid and autonomous control of its DSGs.

- It may be desirable that certain data logging be done at the DAC site which otherwise might overburden the DDC-DAC system. Data logging at the DAC might also provide this function for DSGs which do not have any on site data logging capability. In general with the decentralized DAC control, it can be expected that the DDC-DAC communication traffic will be less than if separate DDC-DSG remote station communications were used.

- The DDC-DAC system may have addressing limitations so that it might not be possible to add potentially large numbers of directly addressable DSG remote stations to the network. By using the DAC as a "relay" station, the traffic destined for the DSG can be [illegible] to the DAC processor as data containing the specific DSG address and other information. The DAC processor can then, itself, output appropriately to the DSG. Thus, the DDC-DAC system would not be required to address each DSG individually.
- The DSG alarm/alert conditions could be sensed much more rapidly with appropriate action by the DAC processor, than as part of a centralized DDC-DSG SCADA scan. In such an event, and if necessary, the DAC could interrupt the DDC master station to notify it of an import alarm condition. See Sections 8.4.1 to 8.4.4.

8.4.1 FUNCTIONAL NAME: DISTRIBUTION SCADA

Functional Description

Distribution supervisory control and data acquisition (SCADA) pertains to functions associated with:

1. "Sensing and reading" binary status and analog telemetry data signals, or, if available, their equivalent digital values at the remote DSG site and providing at the DDC master station site corresponding digital output with suitable identification (implied by address/formal or memory address). Note that this latter boundary/interface may be conceptual and physically invisible.*
2. Accepting as input digital command-control and address data from the DDC information processing center, and outputing at the remote DSG site, in accordance with the command, corresponding scaled digital/analog signals or contact closures on their respective addressed terminals with appropriate hold/latch characteristics. Alternatively, and depending on the local DSG processor and control architecture, the equivalent digital information could be transferred to the local processor through proper interfacing.

Note that this function does not include the communication function involving the communication channel and any associated network protection.

*Physical equipment provided by vendors of commercial SCADA systems can vary considerably in terms of the size and architecture of the master station processor. In a minimal sense the associated equipment may be a relatively simple communications preprocessor, or that function might be imbedded in a full-scale computer system that performs information processing and display drive as well. The same comments apply for SCADA remote station equipment.

Involved in this function will be such activities as:

- Multiplexing and scan mode control (master station function)
- Error detection
- Multidrop line control and protocol
- Addressing
- Message formatting, synchronization, and decoding
- A/D conversions as required at the remote DSG site

Input or Processed Data

Input from DSG: Monitored data from the DSG will be binary level voltage signals, binary or multistate contact closures, conditioned analog signals, BCD digital code, pulse/frequency, and contact closure counting. Manual or automatic selection of format mode at the DDC master station will determine which set of data from the DSG is returned to the DDC. In general, for normal mode scan, power-related variables such as voltages, currents, kW, kVAR, and so forth, will be included. Depending on achievable normal scan rates or SCADA system architecture, a separate/dedicated alarm channel priority interrupt may be required.

Input from DDC: Input from the DDC will be in digital form corresponding to control commands and their address, scan mode control manual override, and (if architecture requires) interface communication control/protocol signals. The control commands will include control point, setpoint, and scheduling data. The actual digital input form may be serial or parallel.

Output Control and Data

Output to DSG: Outputs to the DSG will be control point data such as binary level voltage signals and binary contact closures, and setpoint data, digital, or analog signals; all with suitable latching/hold characteristics and properly addressed to desired terminals.

Output to DDC: The digital equivalent of all the data monitored at the remote DSG sites will be output at the DDC information processing interface with suitable addressing and scan mode information. The data formatting will be according to option scan modes that will be selected manually by the DDC operator, or automatically by the DDC information processing, as a function of alarm conditions and other prearranged message scheduling.

Interaction With Other Functions

Control and Monitoring: The "remote control" aspects required for control and monitoring the various number and type of DSGs installed on a given system will largely determine the SCADA I/O performance, capability, and architecture that will influence protocol characteristics, communication interfaces, data rate requirements, and so forth.

Communication: Available and feasible communication link performance characteristics will influence the SCADA and overall system design.

DSG Local Control: Obviously the nature of the DSG technology and its local control implementation will influence the nature of the interface with the SCADA function, and the DSG master control and remote station SCADA functions may both be performed by one hardware-software package.

Information Processing: As was arbitrarily defined previously, the SCADA function will not be considered to include any information processing other than that required for communication control. As such, the interface between the DDC information processing and SCADA functions will depend upon the overall computer architecture (see previous discussions at inputs from and outputs to DDC).

Distribution Automation and Control: In some cases the physical proximity of DSG sites to substations may make it appropriate to consider the combined DAC and DSG remote station requirements.

Special Requirements

Interfaces: Communication interfaces will be required between the SCADA and the communication channel, DSG local control, and DDC information processing.

Expendability: The SCADA system design should be flexible to permit addition of future DSG sites.

Security: SCADA error detection, protocol, and command enabling procedures should give a high degree of security against incorrect data and false command execution.

Modems: Any modems required for encoding/modulation may be considered a part of this function, because communication protocol may intimately involve modem requirements.

8.4.2 FUNCTIONAL NAME: COMMUNICATION

Functional Description

Communication pertains to the base-band communication channel, and any associated network protection, that provides a multidrop* communication link between a master station located at the DDC

*A separate channel per DSG may be applicable for certain individual DSGs where only a few DSGs are involved, or where physical location makes it necessary.

site and the many remote DSG stations. This function will not include any modems in this description.

The communication channel could involve:

- Telephone company (TELCO) or common carrier leased lines or switched network
- Microwave
- Radio
- Carrier current, power line carrier (PLC) or distribution line carrier (DLC)
- Optical fibers

A communication space satellite channel is probably not cost effective.

The communication channel should obviously have high availability (infrequent outages), immunity to interference, and reliability (low rates of error). The minimum acceptable data transmission rate will depend heavily on the number of DSG sites on the multidrop channel and the total traffic. Distribution line carrier (DLC) on feeders will have a much more limited data transmission rate than leased common carrier channels. Half-duplex operation will probably be satisfactory for digital data communications.

A voice grade channel (or subchannel) will be desirable and in some cases necessary.

Depending on achievable scan rates, or SCADA system architecture and protocol, a separate simplex alarm channel (subchannel) may be required to promptly interrupt DDC information processing and pass it an address. Similarly a low-rate acknowledgement channel may be desirable. (These techniques are not normally incorporated in a standard scanning type of SCADA.)

Input or Processed Data

The input, at any port on the multidrop communication, will be base-band signals, i.e., in the frequency range from approximately 300 to 3000 hertz. Internally to and for its own purpose, the base-band signal may be hetrodyned to higher frequency subchannel. The SCADA and its associated modems may utilize various types of modulation such as dibit phase shift keying (DPSK) to more effectively utilize this base band and achieve full duplex operation if required.

Output Control and Data

The output, at any port, will be reasonable facsimile (or shall contain an acceptable facsimile) and any unavoidable noise such that the signal to noise ratio (S/N) is sufficiently high to produce low-bit detection error rates.

Interaction with Other Functions

The communication channel interacts with the modem interface associated with the SCADA.

Special Requirements

No special requirements have been defined.

8.4.3 FUNCTIONAL NAME: [illegible]MATION PROCESSING

Information processing pertains to the information processing located at the DDC* site and associated with:

- Processing, storage (archival, bulk, and random), display (panel, mapboard, annunciators, CRT), of monitored data received from the DSG sites via the SCADA system.
- Background processing, i.e., nonreal time, and control of conventional peripherals such as line printers, keyboard and light pen data entry, CRT displays (monochrome and color graphics), bulk store (tapes, disc, drum), and so forth.
- System training and test.

Depending on the system architecture and scope of the SCADA master station processing, some or all of the information processing function may be incorporated into the SCADA processing equipment or vice versa, i.e., a common processor may be used for both functions.

Input or Processed Data

Input from SCADA: Input from the interface (perhaps only conceptual) with the SCADA function (see Distribution-SCADA; Controlled Output to DDC) will be the digital equivalent of all the data monitored at the remote sites with suitable addressing identification and scan mode information. Depending on whether a separate communication channel is used, an alarm interrupt may also be input.

Input from DDC: Input generated at the DDC will be mostly manual inputs associated with the real-time control/command of the DSG system and conventional nonreal time background processing.

*By definition, for this description, any information processing at the DSG remote site that might involve outputs to or inputs from the SCADA will be considered part of the local DSG control processing and would probably involve DSG master control functions. DSG master control and remote station SCADA functions may be combined into one hardware/software package where economically and functionally warranted.

Other Inputs: Other digital networks may be coupled to the DDC information processing.

Output Control and Data

Output to SCADA: Output to the interface with the SCADA function (see Distribution-SCADA; Input from DDC) will be the digital form corresponding to control commands and their address, scan mode control, and (if architecture requires) interface communication control/protocol signals.

Conventional Output: Output associated with background computations.

Display Recording Drive Outputs: The DDC information processing will drive the various displays and recording devices associated with DSG-monitored data and other system data.

INTERACTION WITH OTHER FUNCTIONS (as described under Inputs and Outputs)

Special Requirements

Redundancy: Depending on the number of DSG sites being controlled and their generating capacity, some degree of redundancy or backup procedures may be advisable.

Command Enable Procedures: A secure procedure is required to prevent accidental execution of unintentional commands.

Archival Data Logging: An integrated management background system may be required to store and retrieve historical operational data.

8.4.4 FUNCTIONAL NAME: REVENUE METERING

Functional Description

Revenue metering is the measurement of power, integrated over a time period, to determine electrical energy consumed by loads or produced by generating equipment. The quantity metered is watthours, often expressed as kilowatthours (kWh). The purpose of revenue metering is to provide a measured basis for buying and selling electrical energy.

Revenue metering is performed by measuring and calculating the product of voltage, current, and the cosine of the phase angle between them so that the (real) power component of total voltamperes is determined and integrated with respect to time.

Electric utilities enter into power/energy contracts with customers who in the past have primarily been energy consumers. Large users often had complex energy contracts that involved charges for capacity, peak demand, and total energy consumed. In some cases in the past, industrial cogeneration facilities have produced more power than they consumed (at certain local plant load conditions), and the excess power/energy was sold to the electric utility. This has not been common practice in the United States, however, because of complex institutional and regulatory constraints. Joint ventures between utilities and industrial concerns have in some cases avoided or reduced the complexities to their mutual advantage.

With the advent of small privately owned DSGs, used for displacing utility supplied energy for local loads, the metering problem may become more complex than when the customer only consumed energy. At times of low consumption and relatively high generation, an excess of power/energy may be generated. Thus there may be either net IN or net OUT power flow at the revenue metering point. In addition to the technical aspects of using watthour meters with detent devices to prevent reverse rotation/registration, and the need for both IN and OUT meters, there are complex contractual matters that must be resolved. These are discussed in Appendix B, Political Factors and Trends. There are federal regulations or rules that are beginning to address this issue. Thus, revenue metering is more a contract matter than a technical problem and will probably involve not only gross energy consumed or produced, but also the time-of-day and the day-of-week during which it was consumed or produced. The value/cost of the energy would depend on these time factors.

Another technical aspect of customer revenue metering that is also in the early stages of development and application is automatic (revenue) meter reading. It is quite possible that automatic meter reading for customers with DSGs could simplify the electromechanical metering equipment complexities, if time-of-day metering rules were to be implemented. In addition, there are implications for sharing the communication overhead costs, if simple DSG monitoring and control could be incorporated.

Input or Processed Data

- Volt and ampere values at the metering point

Output Control and Data

- Register readouts of watthours

Interactions with Other Functions

- Utility billing procedures
- Automatic meter reading (if implemented)

Special Requirements

Special contractual and metering arrangements will be required for customers who own and utilize DSGs that are interconnected to the utility distribution system. Discussions of these issues have been given in the preceding material, and in related material in other sections of this report.

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8.4.5 DSG COMMUNICATIONS DATA HANDLING NEEDS

To provide a more quantitative basis for defining the characteristics and quantity of the data handled by the DSG communication function, it is essential that a detailed analysis be made of the information requirements of each of the DSG monitoring and control functions which have been described and evaluated. It should be realized that depending on the size and character of the DSG type involved, the number of DSGs that are communicated with, and the nature of the communication method from DDC to DSG and back (whether series or parallel communication means are used) the detailed designs will differ. The material that will be considered follows:

- The communication mission
- The communication function information and data timing needs
- The message transactions and format
- The data rate examples for a representative hydro electric DSG

The approach employed considers each DSG separately, so that any practical communications design will have to balance the number and extent of the DSGs to be controlled and the degree to which the sequential or parallel communication between DDC and DSG is used.

8.4.5.1 Communication Mission

As a means for placing the communications requirements in a useful perspective, it is worthwhile to consider the mission performed by the communications function. The functional block diagram of Figure 8.2-1 can be redrawn as in Figure 8.4.5.1-1 to emphasize the nature of the information inputs and outputs to the communication link between the DDC SCADA and the DSG master control. DSG command and control serves as a gathering point of information from several other functional sources located at the DDC, including the DDC operator, and makes data available to information processing.

The SCADA function prepares this and other information at the proper time periods for communication to the various DSGs and other information sources such as the EMS. At the DSGs, information relating to the periodic status of the various major elements of the DSG is prepared for transmittal to the DDC information processing and output to the display and recording and other pertinent functions.

Table 8.4.5.1-1 presents a matrix of the DSG functions associated with the categories for control and monitoring and communications and data handling as a function of the approximate time periods for which the data handling is repeated. These two categories of functions have been shown in this abbreviated version since

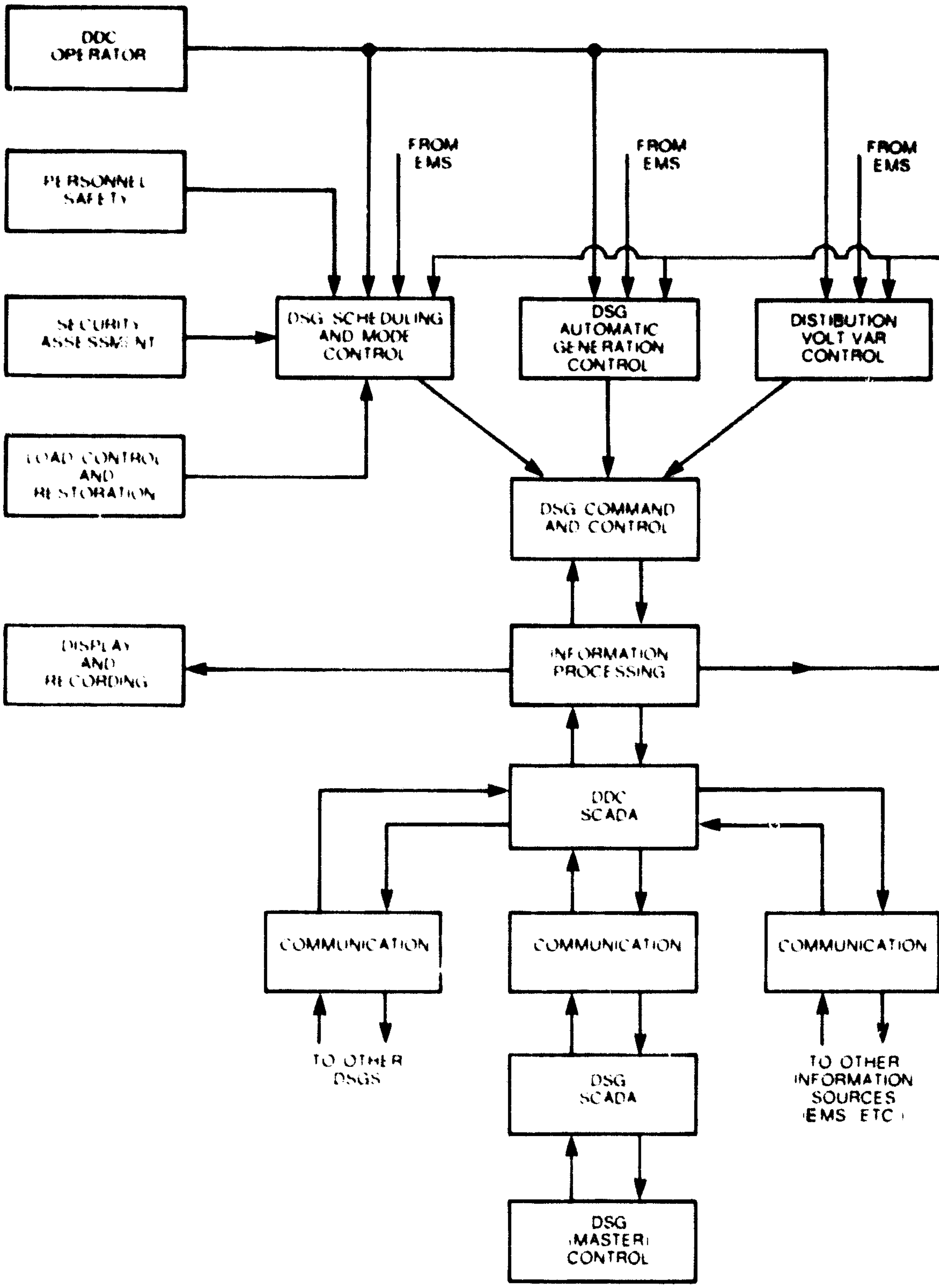

Figure 8.4.5.1-1 Block Diagram Showing Information Inputs and Outputs to Communication Links Between DDC and DSGs

Table 8.4.5.1-1

DDC-DSG VOLUME VERSUS TIME PERIOD, BY FUNCTION; APPROXIMATE TIME PERIODS AT WHICH DATA MUST BE HANDLED; AND QUANTITY (BITS) OF DATA PER DSG FUNCTION

DSG FUNCTION	1 day to 1 month	6 to 24 hours	15 min to 1 hour	5 to 10 min	2 to 10 sec
1. COMMAND AND CONTROL		2516*		820*	246*
2. DISPLAY AND RECORDING					
A. DISPLAYS					
1. Variables Update			276		
2. Single Value		164			
3. Monitor for Control		9840			
4. Alarms	[illegible]				
5. Data by Exception	356				
B. RECORDING					
1. Periodic Log			604		
2. Operator Mode Control		328*			
3. Operator [illegible] Control		492*			
3. DSG SCHEDULING AND MODE CONTROL		712*			
4. DISTRIBUTION [illegible] CONTROL				164*	
5. LOAD CONTROL, INCLUDING RESTART		984*			
6. AUTOMATIC GEN CONTROL					
A. [illegible] and EDC					246*
B. EDC (Alone)				656*	
7. SECURITY ASSESSMENT	324				
8. DISTRIBUTION COMMS					
NORMAL COMM					164
9. REVENUE METERING			164		

*Command and Control is a composite of functions 3,4,5,6,7 plus 2B2 and 2B3. The composite [illegible] cumulative.
[illegible] less frequently if data were stored at DSG. Quantity of data would increase [illegible] proportional to decrease in period.

they represent the predominant functions which require communication between DDC and DSGs. Shown in the boxes are representative values of the number of information bits which may be required to accomplish the function indicated.

In general there are commands and schedules which are of an ON-OFF nature, approximately daily, that are associated with a one to four times-a-day period. Revenue metering also might be done daily or might be done as frequently as a 15-minute to 1-hour basis depending on the wishes of the utility and/or customer. Periodic update of DSG status, including analog data, might take place on approximately an hourly basis corresponding to the 15-minute to 1-hour period. On a five to ten-minute period, power and voltage commands are sent to the DSGs and data are returned. The normal scan for alarms and load frequency control (LFC) information, where required, will be at a faster rate as associated with two to ten second periods. From time to time operator and EMS inputs may have need of a fast response with override (high priority) requirements. On a priority basis these requirements may appear to be a one to two second period input. In order to accomplish all the necessary information handling, the information handling and communication for the many DSGs must take place at bit rates much faster than one per second.

Although the various DSG functions develop the basic information to be handled, the SCADA function is responsible for the proper information coding and the development of the complete message to be communicated and received and how it is to be interpreted. Total data transmitted in a message contain not only the basic information but also other housekeeping and error detection overhead items. Thus there is a message efficiency factor that affects the data rate requirements.

In considering the overall mission requirements of monitoring and control communications, one should include such factors as reliability, error rate, and efficiency, as well as the physical environment.

Factors Affecting Reliability, Error Rate, and Efficiency

In selecting the communication system message transactions and format concept described in this subsection, a number of factors affecting reliability, error rate, and efficiency of channel utilization have been incorporated as part of the information handling process. These factors include:

- Data error detection and correction
- Message identification and ordering
- "Select before operate" control philosophy

Data error detection refers to the area of data transmission errors because of communication media and to hardware errors in the DCE equipment. Data error detection can occur on the frame (single data element) level or on the message level. While it is desirable to have the most practical comprehensive data detection scheme, the protocol should at least provide for message-level error detection.

Such data error detection is accomplished by a variety of methods, but it is suggested that a method at least as effective as cyclic redundancy checking (CRC) be employed. For the illustrations and examples presented, a BCH check code(8) was used.

Data error correction covers the ability of the protocol to ignore erroneous messages and to establish a new message exchange to correct the original error. This process of error correction is known as "retry processing." In retry processing, the sender inquires of the receiver whether the previous message, or groups of messages, were received properly. The receiver then responds with a positive or negative response. A negative response will cause the last message, or the last negative messages, to be retransmitted.

The select-before-operate feature of a protocol ensures a high degree of security in the correctness of a control action. In a select-before-operate scheme the control point must be accessed twice in succession, with intermediate confirmation of point selection and no intervening commands, before the control action is taken. The first message is said to select the device; the second message is the execute message.

In addition to system reliability concerns as referred to above, the hardware and component reliability is a matter that must be given consideration in the communication requirements definition. Since each utility will have its own cost-reliability trade-off criteria, further mention of this selection process will not be made here.

Communication Function Information and Data Timing Needs

As DSG monitoring and control move toward a system definition, a key to its application and implementation will be the definition of the data handling requirements for the purposes of communication, supervisory control and data acquisition, and information processing system design. To obtain a perspective of the impact which the various distribution DSG functions may have on communication and on SCADA and information processing functions, a summary of the period, the allowable time to perform, the amount of information, and the resultant data rate requirement for each originating function have been prepared. Such information has been accumulated on the basis of one DSG. The results are presented in Table 8.4.5.1-2 and each column and row of the table are explained in the set of associated notes.

To construct Table 8.4.5.1-2 with the objective of defining representative data rate requirements for individual distribution

Table 8.4.5.1-2

REPRESENTATIVE DATA RATE REQUIREMENTS FOR INDIVIDUAL DISTRIBUT

Function	Notes	Function Period 1	Allowable Time per Transaction 1A	Message Transaction Types DDC → DSG 2	OUTGOING DATA: Information to DSG Description 3	Information Bits per Period 4	Information Bits per Transaction 4A	Outgoing Information Data Rate (bps) 5	Information to DDC Description 6
A CONTROL AND MONITORING									
1 DSG Command and Control	11	(Composite)							
2 Display and Recording									
(a) Operator Displays									
(1) Stored Data, Periodic Update of Variables	12	1 hour	30 sec	6	Data Request	24	24	0.8	Values of Variables
(2) Current Single Status or Value Upon Request	13	8 hours	5 sec	2	Data Request	24	24	4.8	Status or Value
(3) Continuous Update of a Status or Value During Operator Control	14	8 hours	2 sec	2	Data Request	24 × 30 × 2	24	12	Status or Value
(4) Alarms	15	1 month	2 sec	5	Data By Except Req	24	24	12	Alarms
(5) Data by Exception, Status or Values	16	1 week	5 sec	5	Data By Except Req	24	24	4.8	Status or Values
(b) Recording									
(1) Periodic Log	17	1 hour	5 min	2 & 6	Data Request	24 × 3	24 × 3	0.24	Status, Value & Integr
(2) Revenue Metering	18	15 min	10 min	2	Data Request	24	24	0.04	Integrated Quant. kWh
(3) Operator Action (Mode Control)	19	8 hours	2 sec	3	Mode Control	24 × 2	24 × 2	24	Check Back Acknowl
(4) Operator Action (Raise/Lower Control)	19	8 hours	2 sec	1	Raise Pulse Control	24 × 6	24	12	(none)
(5) Alarm Conditions	20	1 month	2 sec	5	Data By Except Req	24	24	12	Alarms
3 DSG Scheduling and Mode Control	21	24 hours	5 min	4	Schedule	432	432	1.4	Acknowl
4 Distribution Volt/VAR Control	22	10 min	10 sec	2	Voltage Set Point	40	40	4	Acknowl
5 Load Control Including Restoration	23	6 hours	2 sec	1	Raise/Lower Pulses	24 × 12	24	12	None
6 Automatic Generation Control	24								
(a) Load Frequency Control (LFC)		2 sec	12 sec	1	R/L Pulse	24	48	24	None
MW Feedback		2 sec		2	Data Request	24			MW Value
(b) Economic Dispatch Control (EDC)		5 min		1	R/L Pulses	24 × 6			None
MW Feedback		5 min	130 sec	2	Data Request	24	168	5.6	MW Value
7 Security Assessment and Control	25	1 month	10 sec	3	Mode Control	24 × 2	24 × 2	4.8	Check Back Acknowl
B POWER FLOW AND QUALITY									
1 DSG Power Control	26								
2 DSG Voltage Control	26								
3 Harmonics	26								
4 Instrumentation	26								
C COMMUNICATIONS AND DATA HANDLING									
1 Distribution SCADA (Normal Scan)	27	2 sec	2 sec	2	Scan Request	24	24	12	Confirm Normal
2 Communication	28								
3 Information Processing	29								
4 Revenue Metering	30	15 min	10 min	2	Data Request	24	24	0.04	Integ. Quan. kWh
D NORMAL, ABNORMAL, AND EMERGENCY OPERATIONAL REQUIREMENTS									
1 DSG Control	31								
2 DSG Operating Mode Control	31								
3 Personnel Safety	31								
4 DSG Stability	31								
E FAILURE AND ABNORMAL BEHAVIOR DETECTION AND CORRECTION									
1 Protection - Subst., Transf., Feeder	32								
2 Protection - DSG	32								
F SPECIAL DSG CONTROL									
1 Start Capability	33								
2 Synchronization	33								
3 Stand Alone Capability	33								

NOTES: sec = second
min = minute

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Table 8.4.5.1-2

[R]EMENTS FOR INDIVIDUAL DISTRIBUTION DSG FUNCTIONS

OUTGOING DATA				INCOMING DATA				TOTALS		
Information to DSG Description	Information Bits per Period	Information Bits per Transaction	Outgoing Information Data Rate (bps)	Information to DDC Description	Information Bits per Period	Information Bits per Transaction	Incoming Information Data Rate (bps)	Total Bit Content per Period	Total Bit Content per Transaction	Data Rate (bps)
1	4	4A	5	6	7	7A	8	9	9A	10
Data Request	24	24	0.8	Values of Variables	136	136	4.5	276	276	9.2
Data Request	24	24	4.8	Status or Value	24	24	4.8	164	164	12.8
Data Request	24 × 30 × 2	24	12	Status or Value	24 × 30 × 2	24	12	164 × 30 × 2	164	82
Data By Except Req	24	24	12	Alarms	216	216	43.2	356	356	178
Data By Except Req	24	24	4.8	Status or Values	216	216	43.2	356	356	71.2
Data Request	24 × 3	24 × 3	0.24	Status, Value & Integr	184	184	0.6	604	604	2
Data Request	24	24	0.04	Integrated Quant kWh	24	24	0.04	164	164	0.3
Mode Control	24 × 2	24 × 2	24	Check Back Acknowl	24 × 2	24 × 2	24	328	328	164
Raise Pulse Control	24 × 6	24	12	(none)	0	0	0	492	82	41
Data By Except Req	24	24	12	Alarms	216	216	43.2	356	356	71.2
Schedule	432	432	1.4	Acknowl	48	48	0.2	712	712	2.4
Voltage Set Point	40	40	4	Acknowl	40	40	4	164	164	16.4
Raise Lower Pulses	24 × 12	24	12	None	0	0	0	984	82	41
R L Pulse Data Request	24 24	48	24	None MW Value	0 24	24	12	82 164	246	123
R L Pulses Data Request	24 × 6 24	168	5.6	None MW Value	0 24	24	0.8	492 164	656	21.9
Mode Control	24 × 2	24 × 2	4.8	Check Back Acknowl	48	48	4.8	324	324	32.4
Scan Request	24	24	12	Confirm Normal	24	24	12	164	164	82
Data Request	24	24	0.04	Integ Quan kWh	24	24	0.04	164	164	0.3

FOLDOUT FRAME

NOTES

1 The period (inverse of Repetition Rate) for the major functions is based what has been general practice for similar functions in Electric Utility Control systems. These periods may have a range of values. A singular value has been shown to illustrate the relative data rates between functions. Tables 8 4 5 1-3 and 8 4 5 1-4 contain representative values.

1A The Allowable Time per Transaction is an approximation of the reasonable time that can be tolerated to perform a function, i e , control action or data acquisition. In the case of an action such as repetitively scanning a data value to maintain current information, or sending a series of "raise" pulses to a DSG, the allowable time for each discrete transaction has been used since the total period of this activity is variable.
This allowable time per transaction establishes the gross time base used in determining the relative data rates for the various functions.

2 Transaction types are message sequences used between master station terminal and the remote station terminal (DDC and DSG in this case). The transaction types corresponding to the numbers used in Table 8 4 5 1-2 are given in Table 8 4 5 2-1, and message formats assumed are given in Table 8 4 5 2-2.

3 Information from DDC to DSG consists of commands, control, data requests, and data as required by the function involved.

4 Number of outgoing information bits per function period comprising the fundamental information being transmitted from Master to Remote (DDC to DSG) specific to the function being performed. This generally is the content of the applicable Information Field in Table 8 4 5 2-1 and may be contained in one or several message transactions.

4A Information bits per transaction is generally the same as the information bits per period for DDC to DSG messages. However, where repetitive data update or repetitive discrete control actions are involved, the amount of information to be transmitted for each single transaction is used with the allowable time for a transaction for determining the relative outgoing information data rate.

5 The Outgoing Information Data Rate is a relative measure of the rate at which the basic outgoing information would have to be transmitted to achieve the transfer in the allowable time for the transaction. Since neither the requirement for incoming information nor message overhead nor housekeeping bits are recognized, this outgoing information data rate is only relevant for interfunction comparisons. This measure expressed in bits per second is obtained by the following relation

$$\text{Outgoing Information Data Rate (bps)} = \frac{\text{Information Bits per Transaction}}{\text{Allowable Time per Transaction (Seconds)}}$$

6 Information from DSG to DDC will be dependent upon the basic function, the type of transaction, and the message format as shown in Table 8 4 5 2-1 and 8 4 5 2-2 respectively. Such information may be data, a confirmation or check, or an acknowledge message.

7 Number of incoming information bits per function period comprising the fundamental information being transmitted from Remote to Master (DSG to DDC), specific to the function being performed. This generally is the content of the applicable Information Field in Table 8 4 5 2-2 and may be contained in one or more message transactions.

7A Information bits per period is generally the same as information bits per transaction. However, where repetitive data update is involved, the amount of information to be transmitted for each single transaction is used in conjunction with the allowable time per transaction for determining the relative incoming information data rate.

8 The Incoming Information Data Rate is a relative measure of the rate at which the basic incoming information would have to be transmitted to achieve the transfer in the allowable time for the transaction. Since neither the requirement for outgoing information nor message overhead nor housekeeping bits are recognized, this incoming information data rate is only relevant for interfunction comparison. This measure expressed in bits per second is obtained by the following formula

$$\text{Incoming Information Data Rate (bps)} = \frac{\text{Information Bits per Transaction}}{\text{Allowable Time per Transaction (Seconds)}}$$

9 Total Bit Content per Period is the total bit count in the complete sequence of outgoing and incoming message transactions in a given period based on the assumptions made. All message establishment, basic information, and message termination bits are included. There is no consideration or addition for message repetition required by error detection correction techniques.

9A Total Bit Content per Transaction is the total bit count associated with the transaction of outgoing and incoming messages(s) required to complete one control or data acquisition action. In general this is the same total bit count as for the function period. However, where a set of repetitive control or data acquisition activities are involved, the data rate is more meaningfully represented by the amount of data (bits) in one discrete transaction divided by the allowable time for one of these transactions. The total bit content per transaction includes all message establishment, basic information, and message termination data in the complete outgoing and incoming message transaction.

10 Data Rate is the expression represented by

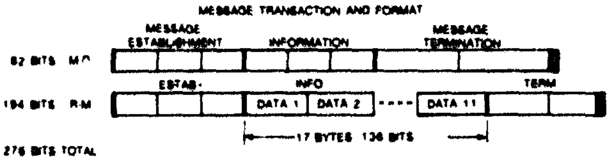
$$\frac{\text{Total Bit Content per Transaction}}{\text{Allowable Time per Transaction (Seconds)}} \text{ expressed in bits per second}$$

There is no allowance for communication channel propagation delay, master or remote terminal turnaround time, or error correction considerations. (A nominal modem "preamble" of one byte (8 bits) has arbitrarily been included at the beginning of each message establishment segment as part of the overhead burden.)
Thus the Data Rate is not a channel bit rate since total turnaround time delay has not been included. The data rate provides a measure of relative data rate requirements for comparison of the various DSG functions.
It is not appropriate to sum various individual DSG function data rates to obtain a "total data rate" figure since the protocol and message format and utilization in many cases permit combining functions to effectively achieve lower apparent data rates than a simple arithmetic sum of individual function data rates.

11 Functions A3, A4, and A6 are the direct inputs to Function A1, DSG Command and Control which requests control action via functions C3 and C1. Indirectly, Functions A5 and A7, DDC Operator and EMS Functions also may initiate control actions which result in inputs to Function A1. The details associated with each of these originating functions are therefore given in the separate functions. Function A1, DSG Command and Control, is the composite of these individual functions. As such, Function A1 depends on which of the functions (A3 through A7) are implemented regarding the composite data rate requirements. Also included are operator-initiated control actions. However, the operator actions usually "pass through" one of the basic direct or indirect initiating functions and are relatively infrequent.

12 Function A2a1, Stored Data Periodic Update of Variables provides storage for DSG data collected via the SCADA function. The DSG data collected serve as the data base for multiple functions including operator displays. Depending on the DSG and DDC functions implemented, the update period of values for various functions may be different and related data are listed under the specific functions. For the subfunction "periodic update of variables" the example used assumes "Report by exception capability whereby local DSG SCADA monitoring of variables is performed," and only values which exceed a predefined bandwidth since the last reading are reported more frequently than the periodic update period. For this example the period for routinely updating variables is one hour. Other data i e , status of discrete devices, integrated values, alarms conditions, and so forth are discussed under other subfunctions, functions, and categories.

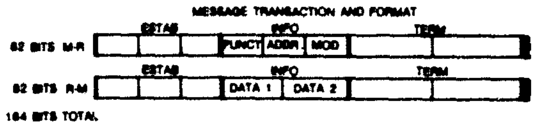
MESSAGE TRANSACTION AND FORMAT



Note Eleven data values are involved for the example DSG and listed in table 8 4 5 3 *rounded off to nearest byte

13 Function A2a2, Current Single Status or Value, Upon Request has several ramifications. The DDC operator may want the status of one or more discrete devices verified or the current value of one or more variables displayed. When the DSG and distribution systems are in a normal state, this function would be required relatively infrequently, perhaps once per 8 hour shift. For monitoring one or two variables or a group of discrete equipment status conditions this subfunction can be accommodated within the SCADA protocol and message format and obtained as part of a normal scan cycle without imposing an extra data transmission burden on the communication system.
However, this subfunction can impose (or contribute to) peak loading, high priority conditions on a communication channel during Alert, Abnormal, Emergency, In Extremis, or Restorative DSG or distribution system states. During these states the operator may wish to monitor several variables in a continuous update data acquisition mode. Combined with alarm reporting and control action, this monitoring and display subfunction would receive top priority.
Example given is for a single request for one or two values (or the seven discrete status points listed in Table 8 4 5 3)

MESSAGE TRANSACTION AND FORMAT



14 Function A2a3, Continuous Update of Status or Value During Operator Control Action, or for Monitoring
DDC operator initiated remote control actions at a DSG are performed relatively infrequently, perhaps once per 8-hour shift, or less often, during normal DSG and distribution system conditions. In conjunction with these DDC operator-initiated remote control actions (or simple continuous monitoring), the status change of a discrete device or the value of a controlled variable would be monitored and displayed for the DDC operator. The status change of a discrete device would be detected and reported (displayed) during

a succeeding "data by exception" and
and at the normal scan rate period for
A typical case would be the display of
action (or simple monitoring) the disp
channel, unless the deadband for a "s
scan cycle) and the data scan mode ma
During an abnormal state at the DSG,
tivity could take place more frequentl
the communication channel data burd

15 Function A2a4, Alarms
DSG alarms conditions, as detected
predefined discrete events or conditi
ticipated to occur frequently, perhap
distribution system states. Alarm con

16 Function A2a5 Data by Exception,
Changes of discrete device status, or
SCADA local monitoring function
Consequently, in the next normal sc
(2), a value exceeding deadband ev
predefined message protocol and for
For the example used in Table 8 4 5.
same for either type of data since a 2
These types of events depend on D
example used

17 Function A2b1 Periodic Log
A periodic log data scan is performe
status of all discrete devices, the val
status condition., eleven values of va

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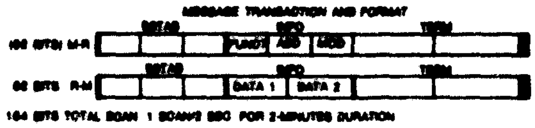
a succeeding "data by exception" and the "data scan" cycles. Similarly a controlled variable would be monitored and updated for operator display as a part of the normal scan and at the normal scan rate period for the duration of the control (or monitoring) action activity until released by the operator.

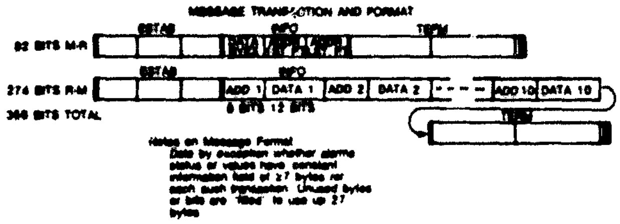
A typical case would be the display of a DSG power output value in conjunction with DDC operator action to change DSG power output level. During operator remote control action (or simple monitoring) the displayed quantity would be updated as part of and at the normal scan period. This would impose no extra data burden on the associated channel, unless the deadband for a "report by exception" limit were exceeded. The update period may be two to ten seconds (according to predefined requirement for normal scan cycle) and the data scan mode may exist for about two minutes once during an 8-hour shift.

During an abnormal state at the DSG, or an Alert, Emergency, In Extremis, or Restorative state on the distribution system, the DDC operator control and/or monitoring activity could take place more frequently than once per 8-hour shift. However, as noted above, the data acquisition portion of the activity for a variable quantity does not add to the communication channel data burden, unless a limit is exceeded.



15 Function A2a4, Alarms

DSG alarms conditions, as detected by the SCADA (normal) scan function would automatically be monitored and displayed to the DDC operator. Alarm conditions are predefined discrete events or conditions which are defined in the Notes to Table 8 4 5 1 3 and consist of 14 discrete points (events). Alarm conditions for a DSG are not anticipated to occur frequently, perhaps once per month under normal conditions. For Abnormal, or Emergency DSG states or Alert, Emergency, In Extremis, or Restorative distribution system states, Alarm conditions at a DSG could occur much more frequently.



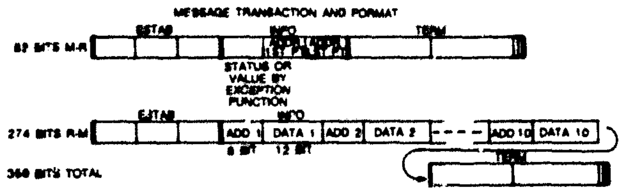
16 Function A2a5 Data by Exception, Status or Values

Changes of discrete device status, or changes of values which exceed a predefined deadband compared to the last acknowledged value, are detected by the DSG master or remote SCADA local monitoring function.

Consequently, in the next normal scan transaction a "flag" is set in the message termination field of the remote to master response which denotes either, (1) a status change, or (2), a value exceeding deadband event has occurred. The master SCADA function then requests data by exception which is transmitted by the Remote terminal according to predefined message protocol and format. The data is then called to the attention of the DDC operator and displayed at his request.

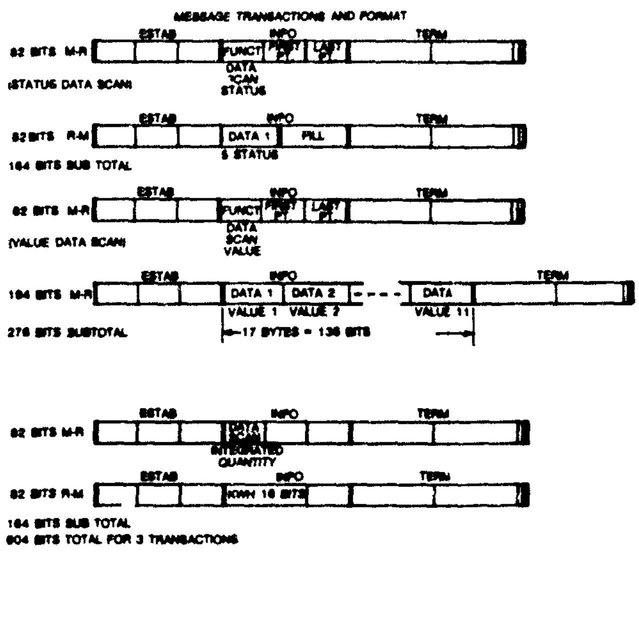
For the example used in Table 8 4 5 1 3 there are seven status conditions and ten values which are locally monitored at the DSG. The message transaction lengths would be the same for either type of data since a 27 byte information field is a fixed length parameter for this type transaction.

These types of events depend on DSG and distribution system characteristics and also on external causes. A frequency of occurrence might be once per week for the hydro example used.



17 Function A2b1 Periodic Log

A periodic log data scan is performed once per hour to provide historic operating records and information from which reports may be prepared. The information collected is the status of all discrete devices, the value of all variables, and integrated quantities. This information, for the hydro DSG example, is given in Table 8 4 5 1 3. It consists of five status conditions, eleven values of variables, and one integrated (kWh) quantity.



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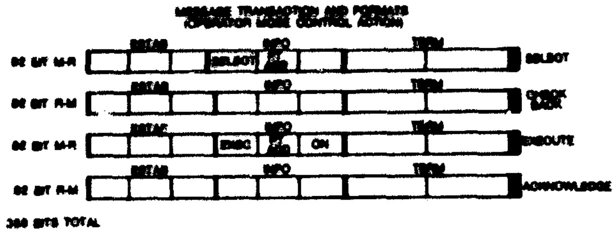
18 Function A2b2 Revenue Metering
This while being classified as a recording function is described in Function C4. Rational, periodicity, and message transaction and format are explained in Function C4.

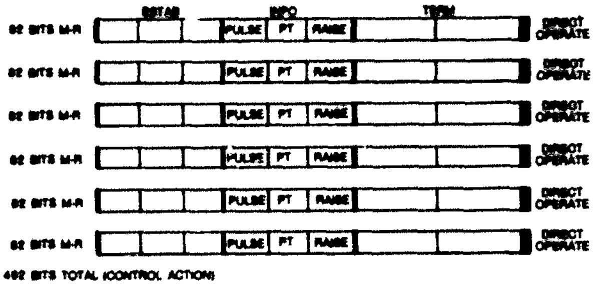
19 Functions A2b3 and A2b4, Operator Action
Operator actions involving control of DSGs would be recorded for historic operating records. Operator control actions would include the following:

- DSG Schedule and Mode Control
- DSG Volt/VAR Control
- DAG Power Level

Operator Data/Information requests are not recorded.
These operator-initiated functions for individual DSGs would be performed relatively infrequently, perhaps once per 8-hour shift on the average for DSG mode (ON/OFF) and DSG power level. One operator control action of each type per 8-hour shift is therefore assumed.

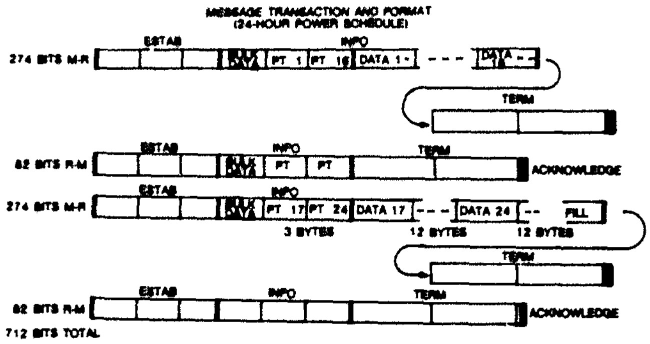


Operator DSG Power Level Adjustment
Raise/lower type control is assumed and six "raise" pulses (of fixed duration) are assumed for this example. Direct operate control, Type I message transaction (Table 8.4.5.2-1), is used followed by Data SCAN Requests to provide operator display of DSG MW output in conjunction with succeeding or interim scan cycles, if the pulses are spaced out in time. (See Note 14, Function A2a3)

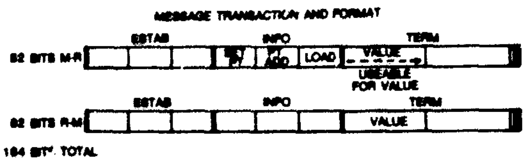


20 Function A2b5, Alarm Conditions
The recording of alarm conditions reported to the DDC as a result of a detected alarm condition during a normal scan cycle (SCADA Function) and the subsequent Alarm Data Scan would be performed as such conditions occurred and would be typed out on hard copy for the operating records, for reporting, and for analysis. The alarm information is the same as that described in subfunction A2a4 and therefore is simply a repetition of the same information.
MESSAGE TRANSACTION AND FORMAT
Refer to Note 15. Data collected for function A2a4 is utilized for the alarm recording function also.

21 Function A3, DSG Scheduling, and Mode Control
The frequency and type of control or command information transactions involved in DDC computer directed DSG scheduling and mode control will depend on the degree of logic capability of the DSG Master Control. "Down loading" of a 24 hour hourly mode and power schedule may be transmitted from DDC to DSG master control where it is stored and used to adjust the DSG Power Control Function, and the DSG Operating Mode Control; or Direct Mode (ON/OFF) Control from the DDC may be employed in conjunction with DSG Power Control actions.
The transactions for the latter method are essentially covered by subfunction descriptions A2b3 and A2b4. A bulk data transfer example is presented to illustrate this type of message transaction.



22 Function A4, Distribution Volt/VAR Control
DSGs may assist in distribution system voltage and VAR dispatching if their excitation systems may be adjusted by DDC remote control. The period for this function may be from ten minutes to one hour. The shorter period of ten minutes has arbitrarily been chosen for data transmission calculations. The information transmitted has been assumed to be either a voltage or VAR setpoint value.



23 Function A5, Load Control Including Restoration
Control of DSG mode (via Function A3) and DSG Power (by direct command or via Function A6) may be used to assist distribution load control and/or EMS load management system functions. Generally the mode (ON/OFF) of the DSGs would be determined by the scheduling function and so the power output level adjustment control is used for this example. Essentially the power may be increased for two daily peak periods per day and correspondingly decreased at the end of these periods. Therefore, four sets of 12 raise/lower pulses are assumed. These control signals are "Direct Operate" transactions and require no acknowledgment or checkback from the DSG Remote Terminal.

24 Function A6 Automatic Generation C[illegible]
Load Frequency Control (LFC)
Economic Dispatch Control (EDC)
When applicable, refer to Tables 8.4[illegible]
employed. The first requires increme[illegible]
to each DSG on LFC or EDC contro[illegible]
The second method for performing [illegible]
algorithm. The latter method is used [illegible]
Raise/lower pulses are sent to the D[illegible]
EDC control action information. E[illegible]
It is noted that the MW feedback o[illegible]
loading

25 Function A7 Security Assessment a[illegible]
This function would be activated r[illegible]
on-line to help alleviate overloads. T[illegible]
Message Transaction and Format
(same as A2b3. Refer to Note 19)

26 Functions B1, 2, 3, 4, Powerflow a[illegible]
This category and its functions invo[illegible]

27 Function C1, Distribution SCADA
The basic SCADA function of mon[illegible]
a normal scan routine. Its period w[illegible]
practical. A two-second period will [illegible]

28 Function C2, Communication
Communication media and channe[illegible]
used

29 Function C3 (DDC) Information P[illegible]
This is an internal DDC function a[illegible]

30 Function C4, Revenue Metering
Revenue metering, involving auton[illegible]
readings as often as once per 15 mi[illegible]

31 Functions D1, D2, D3, D4, Associ[illegible]
Functions D1, D2, and D4 are loca[illegible]
Function D3 personnel safety requ[illegible]
Thus, no additional message trans[illegible]

32 Function E1 and E2, Protection S[illegible]
Basically these are local functions[illegible]
not a DDC-DSG message, it is not[illegible]

33 Function F1, F2, F3, Start Capabi[illegible]
Basically these are local DSG fun[illegible]
tions, DDC control actions from a[illegible]

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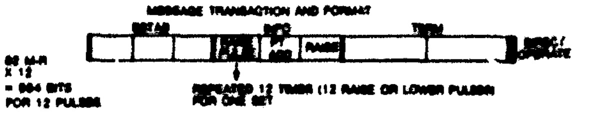
continued

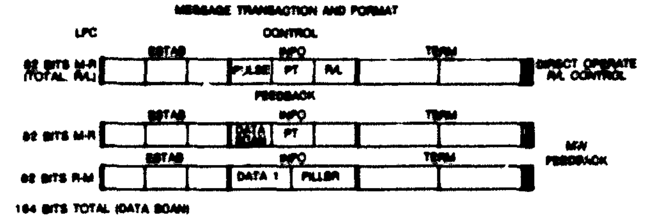
...be explained in Function C4

...following

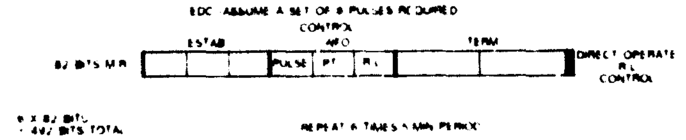
...average for DSG mode (ON, OFF) and

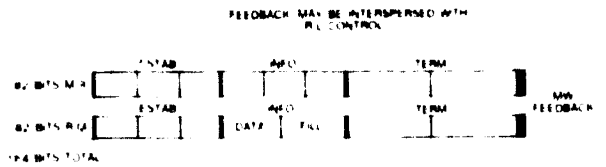


24 Function A6 Automatic Generation Control
Load Frequency Control (LFC)
Economic Dispatch Control (EDC)
When applicable, refer to Tables 8.4.5.1-4 and 8.4.5.1-5, these subfunctions (LFC), (EDC) require control action to adjust the DSG power output. Two basic techniques may be employed. The first requires incremental cost data and closed loop control capability at the DSG Master Control System "lambda" incremental cost composite and transmitted to each DSG on LFC or EDC control. For this method no on-line feedback of DSG MW is required.
The second method for performing LFC and EDC subfunctions is to have the DDC operate as the closed loop controller with MW feedback from DSGs required in the control algorithm. The latter method is used for this example since it is in common use.
Raise/lower pulses are sent to the DSG for both functions. Thus, if both LFC and EDC are implemented, the LFC period (i.e., 2 seconds) and control signals can also include EDC control action information. EDC alone would require a set of pulses/5 min period.
It is noted that the MW feedback can be incorporated in a normal scan SCADA function thereby obviating the need for a separate (additional) scan and associated channel loading.



...message transaction (Table 8.4.5.2.1)
...cycles, if the pulses are spaced out in





...ection) and the subsequent Alarm Data
...for analysis. The alarm information is

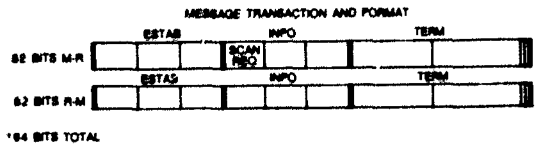
25 Function A7 Security Assessment and Control
This function would be activated relatively infrequently since the distribution system is usually in a normal state. For other than normal states a DSG may be started up and put on line to help alleviate overloads. Thus, a mode control function may be initiated by this security function. This action may be required approximately once a month per DSG.
Message Transaction and Format
(same as A2b3, Refer to Note 19)

...e control will depend on the degree of
...DDC to DSG master control where it is
...al from the DDC may be employed in

26 Functions B1, 2, 3, 4, Powerflow and Quality Category
This category and its functions involved local DSG actions to carry out DDC or local operator control requests. In themselves they require no DDC-DSG communication.

...e is presented to illustrate this type of

27 Function C1, Distribution SCADA (Normal) Scan
The basic SCADA function of monitoring DSGs to determine if there have been any uncommanded status changes, out of band excursions, or alarm conditions is performed by a normal scan routine. Its period will depend on the importance and size of the DSGs and personnel safety considerations. A range of two to ten seconds is usually considered practical. A two second period will be used for this example.

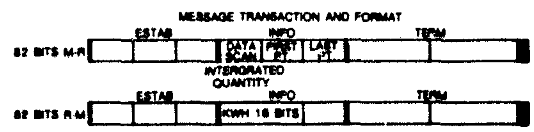


28 Function C2, Communication
Communication media and channels carry DDC-DSG messages. This overall continuity of the communication link is checked by Function C1 and thus no separate messages are used.

29 Function C3 (DDC) Information Processing
This is an internal DDC function and in itself does not utilize DDC-DSG communications messages.

30 Function C4, Revenue Metering
Revenue metering, involving automatic collection of kWh data, may be utilized for customer-owned DSGs. If demand clauses are included for energy usage or production, kWh readings as often as once per 15 minutes may be required and is used for this example. It is noted that for utility-owned DSGs, revenue meeting is not required.

...d. The period for this function may be
...rmation transmitted has been assumed



31 Functions D1, D2, D3, D4, Associated with Normal, Abnormal, and Emergency States Operational Requirements Category.
Functions D1, D2, and D4 are local DSG functions and do not involve DDC-DSG communications for execution.
Function D3 personnel safety requires information transmitted, collected, and stored by other functions (primarily Operator Display and Recording) for its implementations. Thus, no additional message transactions are listed for this function.

32 Function E1 and E2, Protection Substation, Transformer, Feeder and Protection DSG.
Basically these are local functions. For certain fault conditions, however, substation-to-DSG communication (of Transfer Trip Signal) may be required. However, since this is not a DDC-DSG message, it is not known on this chart.

...control and/or EMS load management
...vel adjustment control is used for this
...e periods. Therefore, four sets of 12
...m the DSG Remote Terminal

33 Function F1, F2, F3, Start Capability, Synchronization, and Stand-Alone Capability.
Basically these are local DSG functions that do not require DDC-DSG communications to carry out these functions. However, in the initiation and carrying on of these functions, DDC control actions from among those noted in other categories may be required.

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DSG functions, certain basic assumptions were required. The quantity of information, the timing of its transmission, and the message transactions and format were needed.

Typical information quantities with regard to the status of devices, conditions, and values at a DSG were needed to make sample calculations of data rate. For the examples and results presented in Table 8.4.5.1-2 for one DSG, a set of information was derived from the survey data presented in Section 6, Table 6.9-1, of this report. The derived data is presented in Table 8.4.5.1-3 and is considered typical for medium-to-large hydroelectric DSGs. Other types of DSGs would have somewhat different process-and energy-oriented information, and small DSGs would quite likely have less information exchanged between DDC and DSG. Since Table 6.9-1 and the derived Table 8.4.5.1-3 is equipment-oriented; it was necessary to recast the information presented in Table 8.4.5.1-3 into the DSG function-oriented arrangement of Section 8. To do this, DSG functions which initiate action involving DDC to DSG communication were correlated with the types and quantities information listed in Table 8.4.5.1-3. This work was done on the basis of a single-unit hydroelectric DSG station. Values representing multi-unit station summations were therefore omitted.

Values of the periodicity and allowable time to perform the necessary message transactions(s) to satisfy operator and DDC automatic control and monitoring requirements have been assumed for each distribution DSG function. The assumptions are based on representative values considered typical in electric utility experience and practice for similar functions at the EMS level. Most of the bases for period and allowable time to transact communication messages are contained in the notes of Table 8.4.5.1-3 and the supporting Table 8.4.5.1-4 which concerns automatic generation control function timing requirements. With the examples provided, other numerical values for "Function Period" and Allowable Time per Transaction" in Table 8.4.5.1-2 can readily be substituted and evaluated.

To derive meaningful data rate values, a reasonably efficient and secure message transaction, protocol, and format had to be defined for use in the calculations. Over many years various codes and modes of operation have been developed and have been used to perform remote control, monitoring, and data acquisition in electric utility systems. Recently, activity has begun toward developing a recommended practice for communications between "master" and "remote" stations in conjunction with an existing standard for supervisory station control and data acquisition.[1] Basic message requirements for distribution supervisory control and data acquisition are essentially the same as those which have historically evolved for serving major generation and transmission facilities. Since a reasonable message transaction, protocol, and format have been proposed by a recognized professional body,[8] the material has been adopted for the purpose of developing Table 8.4.5.1-2. Thus message transactions, formatting, and total data content for the distribution DSG functions which require DDC-DSG communications

Table 8.4.5.1-3

DSG MONITOR AND CONTROL INFORMATION FLOW
DSG TYPE: HYDROELECTRIC POWER GENERATION
MEDIUM AND LARGE SIZE STATIONS

	Type Station		Control and Monitoring Message Types						
INPUTS TO DSG REMOTE TERMINAL UNIT FROM CONTROL CENTER:	Single Unit	Multi Unit	F	G	H	I	J		K
							D	V	
● Control									
Two-Position Control:									
Generator Unit, Start/Stop	X	X					X		
Generator Unit Circuit Breaker, Open/Close	X	X					X		
High Voltage Circuit Breaker(s), Open/Close		X					X		
Incremental/Variable Position Control:									
Unit Gate/Governor Speed/Power, Raise/Lower	X	X						X	
Unit Gate/Governor Limit, Raise/Lower	X	X						X	
Unit Voltage/VAR, Raise/Lower	X	X						X	
Head Gates, Raise/Lower	X	X						X	
Sluice/Spillway Gate, Raise/Lower	X	X						X	
● Data Requests									
Automatic:									
Normal Conditions									
Normal Scan	X	X	X						
Periodic Update	X	X							X
Periodic Log	X	X			X				
Alarm Conditions or Status Change				X					
Operator Demand:									
Status									
Individual Points	X	X				X			
All Points	X	X				X			
Values									
Selected Data	X	X				X			
All Data	X	X				X			
OUTPUTS FROM DSG REMOTE TERMINAL UNIT TO CONTROL CENTER									
● Status									
Change of Any Status Point			X						
Device (Two-Position)									
Generator Master Control Relay	X	X		X	X	X			
Generator Circuit Breaker	X	X		X	X	X			
High Voltage Circuit Breaker(s)		X		X	X	X			
Start Sequence in Progress	X	X		X					
Start Sequence Complete	X	X		X					
Unit Running/Stopped	X	X		X	X	X			
Local/Remote Control Switch	X	X		X	X	X			
● Alarms									
Change of Any Alarm Point			X						
Unit Tripout	X	X		X					
Unit Trouble	X	X		X					
Generator Over Voltage	X	X		X					
Incomplete Start/Stop Sequence	X	X		X					
Governor Oil Pressure, Low	X	X		X					
Unit Bearing Oil Pressure, Low	X	X		X					
Unit Bearing Temperature, High	X	X		X					
Main Transformer Oil Temperature, High	X	X		X					
Battery Ground or Under Voltage	X	X		X					
Fire	X	X		X					
Station Unauthorized Entry	X	X		X					
Station Auxiliary Power Failure	X	X		X					
Trash Rack Differential (Press. or Level)	X	X		X					
General Station Alarm	X	X		X					

Table 8.4.5.1-3 (Cont'd)

DSG MONITOR AND CONTROL INFORMATION FLOW
DSG TYPE: HYDROELECTRIC POWER GENERATION
MEDIUM AND LARGE SIZE STATIONS

OUTPUTS FROM DSG REMOTE TERMINAL UNIT TO CONTROL CENTER (Cont'd)	Type Station		Control and Monitoring Message Types						
	Single Unit	Multi Unit	F	G	H	I	J		K
							D	V	
● Values									
Variable Quantities (Analog Measurements)									
Generator, MW	X	X			X	X			X
Generator Reactive Volt Amperes, MVAR	X	X			X	X			X
Generator Voltage, kV	X	X			X	X			X
Station Power, MW		X			X	X			X
Station Reactive Volt Amperes, MVAR		X			X	X			X
High Voltage System, kV	X	X			X	X			X
System Frequency, Hz	X	X			X	X			
Unit Gate Governor Position	X	X			X	X			X
Unit Gate Governor Limit	X	X			X	X			
Head Gate Position	X	X			X	X			
Headwater Level	X	X			X	X			X
Tailwater Level	X	X			X	X			X
Spillway Sluice Gate Position	X	X			X	X			
Integrated Quantities									
Generator Energy, MWh	X	X			X				
Station Energy, MWh		X			X				

LEGEND AND NOTES

Control and Monitoring Message Types Description and Update Period:

F Normal scan cycle, 2-to-10 second period. Assumes a "Report by Exception" type scanning system where station is only interrogated for status changes or alarms.

G Status Change and Alarm Report. Reported upon occurrence, as detected by normal scan, F. Infrequent period, i.e. 1 Month for Alarms, 1 set 8 hour shift for status changes.

H Periodic Log Scan. Reported on 1 hour period.

I Selected point(s) are either device status points or specific variable quantity point(s) selected for observation by Control Center Operator either for passive monitoring or monitoring in conjunction with control of a selected variable, 2-to-10 second period.

J Control of a Mode (Sub Column D - Discrete) or a Variable (Sub Column V - Variable).

K Periodic update of variable quantities. The update period for each variable will depend upon the degree of DSG participation in power system AGC real power (watt) and reactive power (VAR) dispatch, and or Load-Frequency Control. To some degree the update period will depend on the DSG Master Control or Remote Terminal Unit logic capabilities whereby local monitoring for values within a specified acceptable band would alleviate reporting unless the band was exceeded. Typical update period values are given in Table 8.4.1-3.

Table 8.4.5.1-4

PERIODIC UPDATE OF VARIABLES VERSUS DEGREE OF AUTOMATIC GENERATION CONTROL AND LOCAL MONITORING/LIMIT CHECKING

		Update Period			
		With AGC		Without AGC	
		Economic Dispatch Control (EDC)			
Monitored Quantity	Load Freq Control (LFC)	Watt Disp.	Var Disp.	Monitored: Local	Monitored: Central
Generator MW	2-10 s	5 m		60 min	15 min
Station MW	2-10 s	5 m			
Generator MVAR			10 m		
Station MVAR			10 m		
Generator kV					
Station kV					
Headwater Level					
Tailwater Level					
Unit Gate/Gov. Position					

Notes: s = seconds
m = minutes
AGC - Automatic Generation Control

in Table 8.4.5.1-2 are based on References 1 and 8. Each DSG function that requires DDC-DSG communication uses a specific message transaction, format, and content. This information is explained for each function in the corresponding set of notes for Table 8.4.5.1-2, Table 8.4.5.1-5 and Table 8.4.5.1-6 on a general basis.

It is important to note that while the complete set of functions defined in Section 8 have been listed on Table 8.4.5.1-2, many DSGs will not have all of these functions implemented. Therefore, Table 8.4.5.1-2 should not be used as a guide for defining "typical DSG" communication, SCADA, and information processing requirements. Furthermore, since Table 8.4.5.1-2 is function-oriented, Table 8.4.5.1-2 does not inherently contain data rate information pertaining to data rate requirements for combinations of several or many functions. For example, two functions may be accomplished by one message transaction. Table 8.4.5.1-2 does provide an indication of the magnitude of data rates which may be anticipated for serving a medium or large DSG. Channel data rate requirements will depend on the number, size, and types of DSGs served by the specific channel, as well as the functions performed for each DSG.

8.4.5.2 Message Transactions and Format

To provide the basis for defining message lengths and number and order of messages required to perform the various individual distribution DSG functions, a set of message transactions and message formats for Master-Remote communications is required. For the purpose of developing the information and data rates of Table 8.4.5.1-2 it was considered reasonable to use material developed by IEEE for Master-Remote communications[8] and the associated ANSI/IEEE standard, "Definition, Specification, and Analysis of Manual Automatic, and Supervision Station Control and Data Acquisition."[10] Thus direct extractions from these sources have been used to describe the basic message transactions presented in Table 8.4.5.2-1 and the message format presented in Table 8.4.5.2-2 with notes also extracted from Reference 8. Slight simplifications, expansions, and condensations were made where it was considered appropriate for the purposes of the illustrative material in this report. For more detailed information, the referenced sources should be consulted.

Table 8.4.5.2-1, Master Station-Remote Terminal Unit (RTU) Transactions presents six basic types of message transactions. The initiation of message traffic always originates at the Master Station (in this study this is equivalent to the DDC location). The "communication discipline" imposed for message transactions between Master and Remote terminals has been assumed to be as follows.

8.4.5.3 Communication Operation

All communication between a Master Station and a Remote Station will operate in the half duplex mode, defined as follows:

- A Remote Station will transmit data on a channel only in response to receipt on that channel of a valid Master Station message that requests such transmission.
- The Master Station will transmit data on a channel only when no Remote Station is transmitting data on that channel.
- The Master Station will manage the use of each channel on a priority basis. The highest priority traffic will be transmitted before lower priority traffic with the exception that a multipart, low-priority message will not be interrupted by a higher priority message.
- The Master Station will be capable of managing traffic simultaneously on more than one communications channel.

The "Type Numbers" listed in Table 8.4.5.2-1 are those referenced in Table 8.4.5.1-2 regarding the message types(s) transaction used to accomplish a special function. The explanation of the Message Establishment, Information, and Message Termination segments are given in Table 8.4.5.2-2 with its accompanying notes.

Table 8.4.5.2-2, Communication Message Formats and the accompanying notes have been extracted from Reference 8 and only minor

Table 8.4.5.2-1

MASTER STATION/REMOTE TERMINAL UNIT
(RTU) TRANSACTIONS (8)

TRANSACTION DESCRIPTION		M&R MESSAGE COMPOSITION	
NO	TRANSACTION TYPE	MASTER TO REMOTE	REMOTE TO MASTER
1	RTU COMMAND DIRECT OPERATE	E I T 3	NO RESPONSE REQUIRED
2	RTU COMMAND OR CONTROL (IE SETPOINT VALUE EXTERNAL DEVICE CONTROL OR DATA REQUEST)	E I T 3	E I T 3
3	RTU SELECT BEFORE OPERATE CONTROL ACTION (TWO CONSECUTIVE TRANSACTIONS)	SELECT E I T 3 EXECUTE E I T 3	CHECKBACK E I T 3 ACKNOWLEDGE E I T 3
4	BATCH DATA TRANSFER (MASTER TO REMOTE)	E I T 27	E I T 3
5	RTU DATA REQUEST (MORE THAN 3 BYTES OF INFORMATION UP TO 27 BYTES VARIABLE)	E I T 3	E I T 3 - 27
6	RTU BATCH DATA REQUEST (IE REQUEST FOR REPORT BY EXCEPTION INFORMATION)	E I T 3	E I T 27

NOTES

E MESSAGE ESTABLISHMENT SEGMENT
I INFORMATION SEGMENT MAY BE 3, 3 TO 27 OR 27 BYTES (8 BITS/BYTE) AS INDICATED ABOVE FOR SPECIFIC MESSAGE TRANSACTIONS
T MESSAGE TERMINATION SEGMENT
THESE SEGMENTS ARE FURTHER DEFINED IN TABLE 8.4.5.2.2 COMMUNICATION MESSAGE FORMATS

Table 8.4.5.2-2

COMMUNICATION MESSAGE FORMAT

Message Format Summary

The following diagrams and notes summarize the message format definitions:

1. **Basic Message Structure**

MESSAGE ESTABLISHMENT	INFORMATION	MESSAGE TERMINATION

2. **Message Establishment Field**

FILL	PREAMBLE	SYNC	RTU ADDRESS	INFO
	8.0 MS MIN*	8 BITS	8 BITS	

MODEM TRANSMITTER KEYED ON

*NOTE: For simplification of illustrative examples this was arbitrarily assumed to be 1 byte (8 bits) for all message establishment segments

3. Information Field

(M-R) ADDRESS	FUNCTION	POINT ADDRESS	DATA 1	DATA 2	TERMN
	8 BITS	8 BITS	8 BITS	0-24 BYTES	

(R-M) ADDRESS	A	B	C	DATA 3	TERMN
	8 BITS	8 BITS	8 BITS	0-24 BYTES	

NOTES: Byte A is either FUNCTION or RTU DATA Byte 1.
Byte B is either POINT ADDRESS or RTU DATA Byte 2.
Byte C is either DATA 1 or RTU DATA Byte 3.
DATA 2 is allowed only in dedicated channels.
DATA 3 is the remainder of the requested data.

Message Termination Field

INFO	STATUS/COMMAND	(255,239) BCH CODE	END	FILL
	16 BITS	16 BITS	2 BITS	

MODEM TRANSMITTER KEYED OFF

NOTES FOR TABLE 8.4.5.2-2

NOTES

COMMUNICATION MESSAGE FORMAT

All communication message transmissions will comprise three basic fields, respectively "Message Establishment," "Information," and "Message Termination." The Message Establishment and Message Termination fields will be of fixed length and the Information Field of variable length up to a defined maximum length. Protocol control procedures will ensure that each receiving terminal is preset to accommodate length, of the transmitted Information Field for the next message to be received.

1 MESSAGE ESTABLISHMENT FIELD

This field will consist in general of three subfields, respectively "Preamble," "Sync," and "RTU Address." The Sync subfield will consist of eight bits, which will be used by the receiving terminal to establish message, as distinct from bit, synchronization. The RTU address subfield will also consist of eight binary bits, with address value zero not used. Each RTU will respond to a unique address value in the range of 1 through 254_{10} and will accept address value 255_{10} as a "broadcast" command address to which no response will be transmitted.

2 MESSAGE INFORMATION FIELD

The Information Field will consist of a variable number, in the range 3 to 27, of eight-bit bytes. Master Station messages will normally use the minimum length Information Field, the content of which uniquely defines the Information Field length of the corresponding RTU response message, if any. This explicit control of RTU message lengths will be made use of by the Master Station terminal control logic to preset the Master Station receiver accordingly.

2.1 Variable Length Master Station Information Fields

Where variable length Master Station to RTU message Information Fields are required, special procedures and arrangements will be used including message length control procedure.

2.2 Master Station Message Information Field Usage

The first three bytes of all Master Station message Information fields shall be assigned as follows:

Byte 1 Function Code: Function type to be performed by the RTU

Byte 2 Point Address: Device number, within the specified Function type, to be activated

Byte 3 Modifier: Significance depends on the associated Function Code

Additional bytes in the termination segment may be used as required, under the control of the first three bytes, for transmission of data to the RTU.

2.3 RTU Message Information Field Usage

RTU responses to Master Station messages will (1) nominally copy the received message (e.g., 3 bytes) for protocol control and RTU command messages, (2) result from a RTU checkback action (e.g., 3 bytes), or (3) contain from 3 to 24 bytes of requested data.

3 MESSAGE TERMINATION FIELD

This field will consist of three subfields, a 16 bit security code, and a 2-bit message-end code. The status-command field is used in both Master-to-Remote and Remote-to-Master communication messages. This field is used to influence processes that are internal to the receiving terminal by communicating status and/or commands from the transmitting terminal. The security code used will be the (255,239) Bose Chadhuri, BCH, code. The message-end code will consist of two bits at logic "1" level, after which the transmitting terminal modem carrier may be keyed off.

3.1 Status-Command Field-Remote to Master

This field is 16 bits in length and is used to communicate information from the remote terminal to the master station in every remote-to-master transmission. The contents of this field can indicate that a data snapshot request should be used by the master to obtain information not specifically reported in the status-command field. For the Remote-to-Master message flow this field will be used to communicate the following types of information:

- a RTU Restart Flag
- b Hardware Failure Flag
- c Communications Error Flag
- d Status Report by Exception Flag
- e Analog Report by Exception Flag
- f Sequence of Events Data Flag
- h Accumulator Freeze Flag
- j Batch Data Message Flag
- k Fault Data Flag
- l to p Unassigned Bits

3.2 Status-Command Field Master to Remote

This field is 16 bits in length and is used to communicate commands from the Master Station to each specific RTU in Master Station to each specific RTU in Master-to-Remote transmissions. The contents of this field shall be used to command each RTU as defined in this paragraph.

- a Reset RTU Restart Flag
- b Reset Hardware Failure Flag
- c Reset Communications Error Flag
- d Clear Status Report by Exception
- e Clear Analog Report by Exception
- f Clear Sequence of Events
- g Reset Analog Freeze Flag
- h Reset Accumulator Freeze Flag
- i Reset Buffer Overflow Flag
- j Batch Data Message Flag
- k Clear Fault Data
- l Clear Status with Memory
- m to p Unassigned Bits

modifications simplifying assumptions and condensations were made. For additional details of bit, segment, or message utilization, Reference 8 should be consulted. The message format presented in Table 8.4.5.2-2 and accompanying notes has been used in developing the data volume quantities of Table 8.4.5.1-2.

8.4.5.4 Data Rate Examples for a Representative Hydroelectric DSG

For a given DSG, a number of the functions listed in Table 8.4.5.1-2 involving DDC-DSG communications may be performed in the process of monitoring and control. Since hydro is a mature technology and one of the most flexible, it has been chosen to illustrate six functional examples and the communication data rates associated with each function. Scheduling and automatic generation control have been included in the example functions for hydro DSG. Other types of DSGs have varying capabilities and constraints regarding participation in these functions. Table 8.4.5.4-1 presents information for all seven types of DSGs that are examined in this study.

Six examples of data rate calculations for typical functions contained in Table 8.4.5.1-2 are given in this description, along with figures showing specific message transaction, format, and content. By this mechanism an understanding can be gained of how the material in Table 8.4.5.1-2 was developed. Also, the relationship of message information content versus total data (information plus overhead) can be perceived.

Whereas Table 8.4.5.1-2 "data rates" did not include any significant time delay considerations (other than that noted in Table 8.4.5.2-2 in the message establishment segment), the examples presented here have included in a gross way a factor for total turnaround time delay. An arbitrary value of 200 milliseconds (0.2 sec) has been used for illustrative purposes. Other values could be used and would be influenced by communication media, mode of transmission, and communication channel circuit configuration. For simplification purposes half (100 ms) of the 200 ms time delay (TD) in the examples was assigned to Master-to-Remote transmissions and half to the Remote-to-Master transmissions.

As for Table 8.4.5.1-2, the number of status, alarms, or values is based on the information presented in Table 8.4.5.1-3. The gross time values used to calculate data rate are those listed in Table 8.4.5.1-2 in the "Allowable Time per Transaction" column.

A summary of the results from the six examples is given in Table 8.4.5.4-1, "Summary of Data Rate Requirements for Six Individual DDC-DSG Functions."

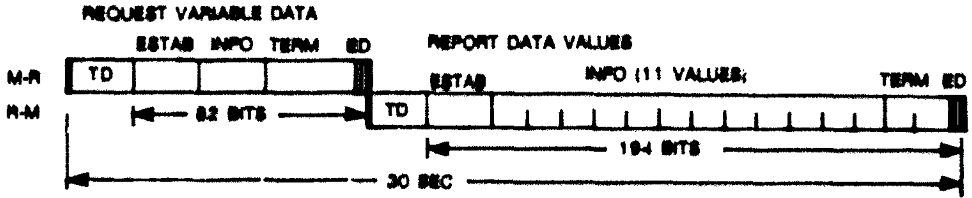
DATA RATE EXAMPLES FOR A REPRESENTATIVE HYDROELECTRIC DSG

EXAMPLE 1

PERIODIC UPDATE OF VARIABLES

To update the DDC data base, values of eleven DSG variables are periodically requested by and reported to the DDC. The assumed time to carry out this transaction is 30 seconds. Message Transaction Type 6.

MESSAGE TRANSACTION SEQUENCE



ASSUME TIME DELAY (TD) = 0.1 SEC

$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{82 + 194}{30 - .2\ (\text{TD})} = \frac{276}{29.8}$$

DATA RATE = 9.3 BITS PER SECOND

M = MASTER
R = REMOTE
ESTB = MESSAGE ESTABLISHMENT 3 BYTES
INFO = INFORMATION FIELD (3 TO 27 BYTES)
TERM = MESSAGE TERMINATION 4 BYTES
ED = END OF MESSAGE (2 BITS)
TD = TIME DELAY 100 MS (0.1 SECONDS)
TYPES OF MESSAGE TRANSACTION ARE ILLUSTRATED IN TABLE 8.4.5.2-1

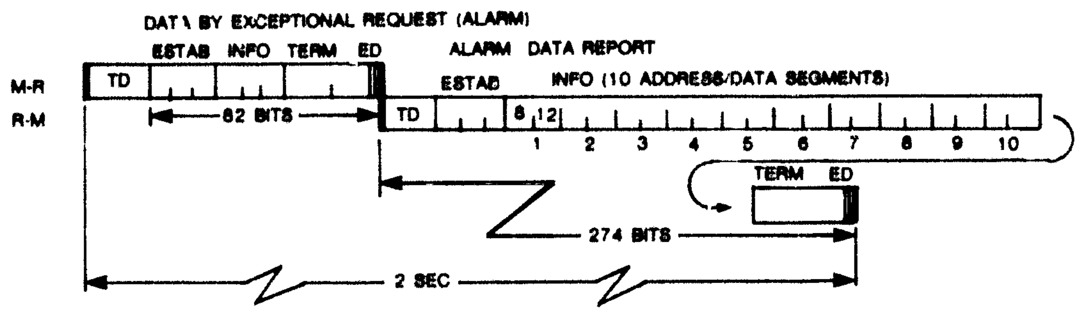
EXAMPLE 2

ALARM REPORTING

The alarm reporting sequence follows a SCADA (Normal) Scan that contains an alarm condition that exists at the DSG. Status of all alarm indication points is transmitted.

Message transaction consists of a request for "report by exception" of alarm data and a response by remote identifying data and status in groups of 12 points per data address and in this example 14 alarm points are reported (see Note 1). Assumed time for complete transaction is 2 seconds. Message Transaction Type 5.

MESSAGE TRANSACTION SEQUENCE



ASSUME TIME DELAY (TD) = 0 1 SEC

$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{82 + 274}{2\text{-}2\ (\text{TD})} = \frac{356}{1\ 8}$$

DATA RATE = 197 BITS PER SECOND

Note 1
While Only 14 Alarm Points are Reported, the Mar .age Format-Protocol Implemented Defines a Report by Exception Response From the Remote as a Constant 27-Byte Information Segment Containing Capability for 10 Addresses (120 Points) Thus, a Cons‹ºrable Penalty Exists When Few Points are Required

EXAMPLE 3

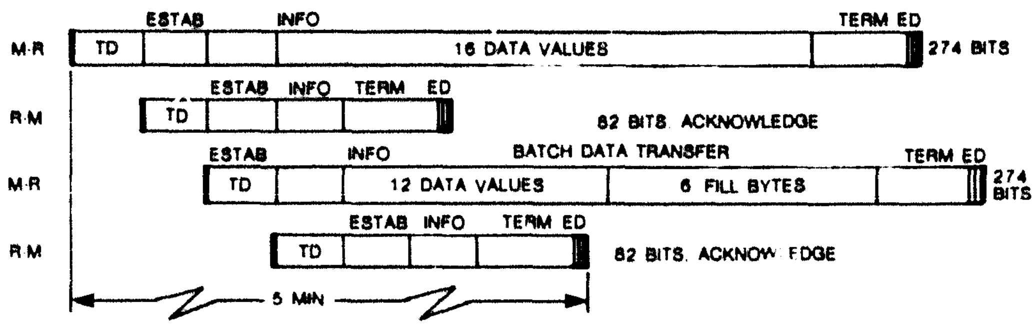
SCHEDULING AND MODE CONTROL

One method of scheduling would be to transmit to the remote DSG master control 24-hour power output values, once per day. This could be done by a batch data transfer from DDC Master to DSG Remote.

Message transaction consists of the previous ED (end) bits setting the remote to receive, in the next Master-Remote message, a "Batch Data Transfer," Message Transaction Type 4. Assumed time for this transaction is 5 minutes.

MESSAGE TRANSACTION SEQUENCE

BATCH DATA TRANSFER



ASSUME TIME DELAY (TD) = 0.1 SEC

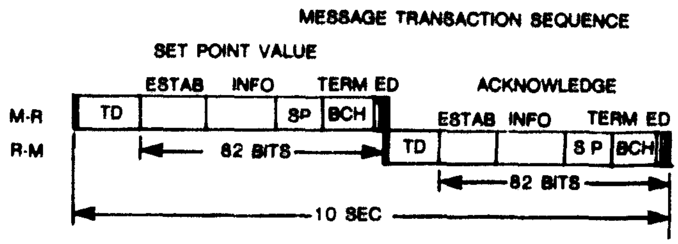
$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{274 + 82 + 274 + 82 \text{ BITS}}{5 \times 60 - 4 \text{ (TD) SEC}}$$

$$\text{DATA RATE} = \frac{712}{300 - 0.4} = 2.4 \text{ BITS PER SECOND}$$

EXAMPLE 4

DISTRIBUTION VOLT/VAR CONTROL

DSGs with voltage control adjustment capability may be used to assist in distribution system volt/VAR control. Periodic adjustment of a voltage reference set point at the DSG by transmitting this set point value periodically is one method of implementing this function. The assumed time to carry out this transaction is 10 seconds. Message Transaction Type 2.



ASSUME TIME DELAY (TD) = 0 1 SEC

$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{82 + 82}{10 - 2\ (\text{T D})} = \frac{164}{9.8}$$

DATA RATE 16 7 BITS PER SEC

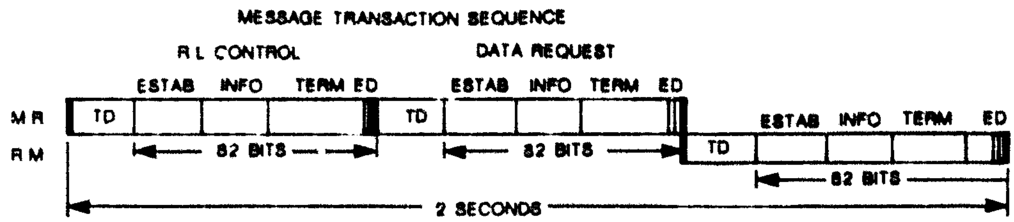
Note Set Point Values Uses 16 Bits of Message Termination Segment (Omitting Request and Report of Change Conditions in This Transaction)

EXAMPLE 5

AUTOMATIC GENERATION CONTROL

Load Frequency Control can also include Economic Dispatch Control information in same data transmissions.

Message transactions consist of sending one raise or lower pulse "direct operate" control signal (if no change required, no R/L pulse control signal is sent) and analog data (DSG MW output) request, and the remotes' data response. Assumed time for complete transaction is 2 seconds. Message transaction types 1 and 2.



ASSUME: TIME DELAY (TD) = 0.1 SEC

$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{82 \text{ BITS} + 82 \text{ BITS} + 82 \text{ BITS}}{2 \text{ SEC} - 3 \times \text{TD}}$$

$$\text{DATA RATE} = \frac{246}{2 - .3} = 145 \text{ BITS PER SECOND}$$

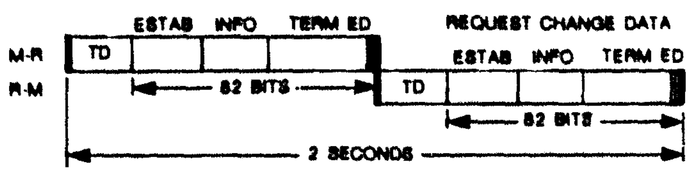
EXAMPLE 6

SCADA (NORMAL) SCAN

Scanning of remote DSG for detection and reporting of any alarm, change of status, or out-of-limit value.

Message transaction consists of a change of condition scan request and a response reporting on "no change, or change of conditions." Assumed time for complete transaction is 2 seconds. Message Transaction Type 2.

MESSAGE TRANSACTION SEQUENCE



ASSUME TIME DELAY (TD) = 0.1 SEC

$$\text{DATA RATE} = \frac{\text{TOTAL BITS}}{\text{NET TIME}} = \frac{82 \text{ BITS} + 82 \text{ BITS}}{2 - 2\,(\text{TD})} = \frac{164}{2 - 0.2}$$

DATA RATE = 91 BITS PER SECOND

Table 8.4.5.4-1

APPLICATION OF DSG TYPES FOR SCHEDULING AND AUTOMATIC GENERATION CONTROL

DSG TYPE	SUITABILITY FOR UNIT COMMITMENT SCHEDULING (DAY AND/OR WEEK WHEN UNIT WILL BE ON OR OFF)			SUITABILITY FOR AUTOMATIC GENERATION CONTROL: LOAD-FREQUENCY CONTROL (LFC)			SUITABILITY FOR AUTOMATIC GENERATION CONTROL: ECONOMIC DISPATCH CONTROL (EDC)		
	YES	NO	LIMITED	YES	NO	LIMITED	YES	NO	LIMITED
Solar Thermal Electric			X Conditional on Weather		X*	X**			X***
Photovoltaic			X Conditional on Weather		X*	X**			X***
Wind			X Conditional on Weather		X*			X	
Fuel Cell	X			X			X		
Storage Battery	X			X			X		
Hydroelectric - with Storage	X			X			X		
Hydroelectric - without Storage			X Conditional on Water Flow	X					X
Cogeneration			X Conditional on Process, Plant Schedule and Power Energy Contract		X				X

NOTES:

*Solar thermal, photovoltaic, or wind generation impose additional regulating duty on other units performing LFC because of fluctuating output due to variable input. Varying generation will appear as apparent "load fluctuations" on system (degrades system regulation performance).

**During steady input conditions (clear, sunshine days) these units would be capable of performing LFC duty, but implementation will be dependent on cost/benefit effectiveness.

***During steady input conditions (clear, sunshine days) these units would be capable of participating in EDC duty. However, for reasonable payback period, maximum available energy production is expected to be an operational requirement.

Table 8.4.5.4-2

SUMMARY OF DATA RATE REQUIREMENTS
FOR SIX INDIVIDUAL DDC-DSG FUNCTIONS

Function	Function Period	Allowable Transaction Time, s	Data Rate (bps)
Periodic Update of Variables	1 Hour	30	9.3
Alarm Reporting	1 Month	2	197
Scheduling and Mode Control	1 Day	300	2.4
Distribution Volt/VAR Control	10 Minutes	10	16.7
Automatic Generation Control, Load-Frequency Control Sub-function	2 Seconds	2	145
SCADA (Normal) Scan	2 Seconds	2	91

8.4.5.5 Communications to Small DSG Sites

When the utility system is populated by small DSGs, the control and monitoring and communication requirements change character from those of a system with medium-to-large units. For small DSG units the utility may wish to apply only permissive and prohibitive signals to the local DSG control system. If these simple enable-disable types of controls are used, they probably will not be sent more than a few times a day. In addition, for a small DSG, there are probably only a few status, alarm, or values that the utility may want to monitor.

For small DSGs, the communications and data handling requirements must be tempered by actual needs for utility distribution system operation and personnel safety as compared to equipment costs.

8.4.5.6 DDC Information Processing

The direction and coordination of certain communication system on-line operations related to DSG control and monitoring is the responsibility of the DDC computer. The number of parallel data channels required by the DDC computer is a function of the communication channel capabilities, number of DSGs in the system, their locations, and the amount of control and data per DSG. In order to see the effect of communication load on the DDC computer, we can assume that the communications processor on the DDC computer is 30% efficient and that the data rate of the communication processor is 50 K bytes per second. At 1200 bps for communication channel data rate, these numbers translate into a capability to accommodate about 150 data channels. If each data channel handles an average of 10 medium-to-large DSG sites, then the DDC can handle about 1,500 DSG sites.

Assuming the above to be correct, one can conclude that the data channel requirements of the communications processor is not a communication system constraint. The system limitation arises when the DDC computer must place the data gathered by the communications processor into a data base.

A reasonably designed data base on a minicomputer can be expected to perform about 250 data base accesses per minute. For a periodic scan, the DDC might be updating about 30 data items per medium-to-large scale DSG every 15 minutes. The amount of time spent per DSG would be about 20 seconds; the DDC, therefore, could store the data for about 75 medium-to-large scale DSG sites. This is a worst-case assumption because it has been assumed that each data item requires a complete data base search and access cycle, when in reality this is not the case.

The DDC data base would be used to provide input to system control and monitoring programs and to act as a data source for the operator functions. It is possible that when all of the DDC functions are enumerated (for this and other power system functions), that a computer larger than the current minicomputer may be needed. However, for the case of just DSG control and monitoring, the current minicomputer is likely to be quite satisfactory.

8.5 OPERATIONAL REQUIREMENTS FOR DSG NORMAL, ABNORMAL, AND EMERGENCY STATES

Operation of DSGs when they are in the normal, abnormal, or emergency states (which includes all possible DSG conditions), will either directly or indirectly involve all major functional categories and their functions. However, since the other five major functional categories deal with functions of primary concern to them, this category (Section 8.5) will be confined to local DSG control, performance, and operating procedures. These operating functions are:

- DSG control
- DSG operating mode control
- Personnel safety
- DSG stability

The relationships of these functions are shown in Figure 8.5-1. The DSG control function is at a higher, more comprehensive level than the DSG operating mode control which, in effect, is a subfunction of the DSG control.

The DSG control function involves the overall local supervision and direction of control activities of the DSG. DSG control can range from very simple to very complex. The degree of complexity depends on the type of DSG, its system size, and its complexity. The ownership (utility, private, or joint ownership) will also influence the operating philosophy and requirements for local and remote control and monitoring. Considering that the DSG size may range from 10 kW to 30,000 kW, and that the owner-influenced operating philosophy and criteria can vary widely, the DSG control function scope can cover a wide range of requirements. Basically, however, the DSG control function may accept inputs from local operator/maintenance personnel, DDC, and local DSG/distribution system conditions. By recognizing the priorities of these inputs, the DSG control function coordinates the required DSG control action and its initiation. In this respect, the DSG control function may be considered as a local "DSG master control." The actual form of hardware implementation, scope, and complexity will vary with DSG size, type, and ownership and could range from simple electromechanical relay logic to a minicomputer-directed DSG control system.

The DSG operating mode control function is required to recognize local conditions of both DSG and distribution system interface, to accept "DSG control" input commands, and to carry out mode control action. The basic DSG operating modes are ON, OFF, and STANDBY. Transition between OFF and ON, and ON and OFF are

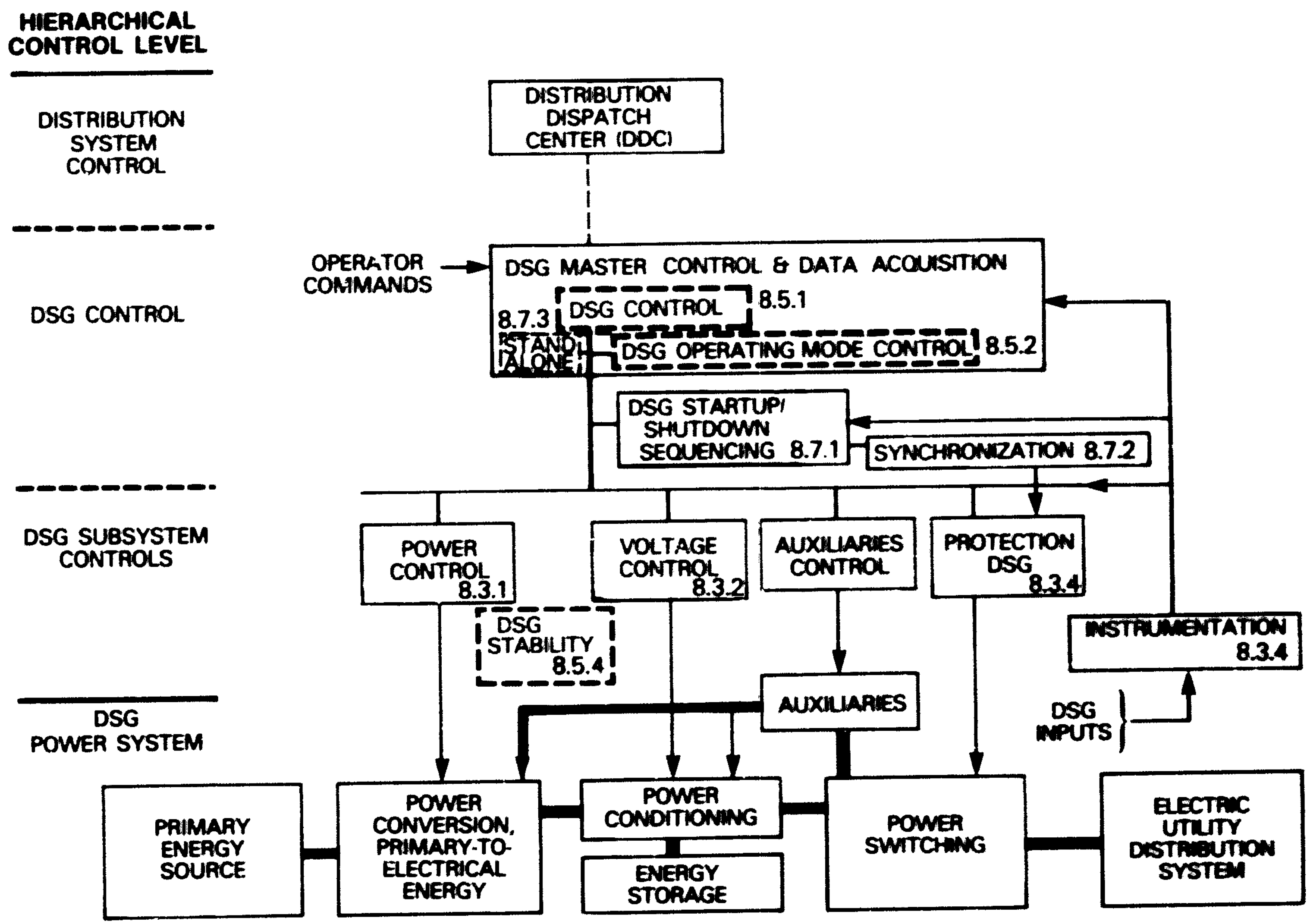


Figure 8.5-1. DSG Functional Control Block Diagram

called startup and shutdown respectively. Descriptions of DSG and distribution system states and DSG operating modes were presented in Section 7.

Under some emergency conditions other functions such as DSG protection may take direct action (i.e., opening the main circuit breaker for a short circuit condition), which preempts all other functions and initiates a DSG emergency shutdown mode change via the DSG control function. In these situations, the DSG control function described above recognizes the condition, initiates a request for the mode change, then subsequently reorganizes the DSG in preparation for the next event or mode control request.

Once a local or remote operator or automatic logic decision is made to initiate a change in DSG operating mode, the DSG operating mode control function initiates action by other subfunctions such as the startup function.

Personnel safety is a vital operating consideration for both system operators and maintenance/repair crews. DSG control, assurance of its operating mode, and positive confirmation of the actual physical/electrical condition is required for personnel safety. To minimize the time required for service restoration, remote control and indication of DSG mode is desirable as opposed to sending crews to perform local control required for personnel safety. However, certain OSHA regulatory requirements must be considered, and additional equipment and controls may therefore be required.

DSG stability is an operational condition which is dependent upon design parameters and characteristics of the DSG system, the relative impedance of the DSG to power system connection, the proximity of other DSGs, and DSG controls. Thus, consideration of these factors in the DSG design and distribution system application engineering stages is required.

Functional requirements for each of the subfunctions are given in the following descriptions.

8.5.1 FUNCTIONAL NAME: DSG CONTROL

Functional Description

DSG control is the local control function which coordinates requests for action, reconciles them with local DSG conditions, and initiates proper action. Other local control and protection functions may in turn take directions from the DSG control function and carry on these functions semi-independently. Thus, the DSG control is the outer local control loop shown on Figure 8.1.3-1. The DSG control relationship to other local functions is shown in Figure 8.5-1. In this diagram, the relative importance of DSG control in the local control hierarchy is shown to be at the top level. Figure 8.5-1 also illustrates the dependency of the DSG control function upon inputs. There may be DDC, local operator, and local information inputs of various kinds. The local information will basically consist of DSG and distribution system state information and DSG system, subsystems, protection, and control information.

While Figure 8.5-1 shows the functions and functional relationships generically, the intention is not to imply complexity of hardware or software/logic requirements. The degree of hardware/software complexity must be balanced from an economic and practical standpoint with type, size, and ownership requirements of the DSG as criteria. From a hardware/software standpoint, the DSG control for a customer-owned 10 kW wind energy conversion DSG may be a single electromechanical master control relay with push-button, remote-control permissive contact, and local emergency shutdown/lockout contact inputs. At the other extreme, the DSG control function for a 10 MW solar thermal electric DSG plant could be software imbedded in a DSG master control and data acquisition minicomputer system. This minicomputer could also be performing complex system and subsystem control functions as well as data acquisition, display, operator interface, and SCADA functions.

In its supervisory and directory function, the main purpose of the DSG control function is to assimilate all pertinent inputs and to initiate appropriate control action. Major subfunctions which the DSG control function initiates and/or modifies are: DSG operating mode control, power control, voltage control, other subsystem controls, and blocking of main DSG switching via protective and synchronizing functions.

Input or Processed Data

Direct inputs to the DSG control function may involve the following:

- Local operator commands and control requests
- DDC command and control requests
  - DDC operator
  - DSG scheduling and mode control
  - DSG automatic generation control
  - Distribution volt/VAR control
  - Personnel safety
  - Security assessment
  - Load control
- Local inputs from:
  - Protection
  - Instrumentation
  - Subsystem control feedback

(Refer to Figure 8.5-1)

Output Control and Data

DSG control function outputs are provided to:

- DSG operating mode control (function)
- Blocking control of main DSG/distribution system interface switching via DSG protection function
- Blocking of synchronizing function
- Power control
- Voltage control

Interaction with Other Functions

Primarily the interactions with other functions are comprised of the inputs and outputs listed above. Basically, the DSG control is the highest control logic level at the DSG, and it interacts by responding to inputs and, as possible, initiates local control action to carry out local, and/or remote operator command and control requests, and DDC automatic command and control requests.

Special Requirements

Each type of DSG will have different detailed requirements for the implementation of the DSG control function since this function is closely related and integrated with subsystem controls and the DSG master control and data acquisition hardware and software. The DSG control complexity is also a variable related to DSG size and the proportion of costs which are economically justifiable. Ownership (utility, private, or joint ownership) will affect the form of control inputs and the relative priorities and weighting of input requests and information. These special DSG control requirements should be defined as part of DSG master control and data acquisition hardware and software specifications. Some conceptual and preliminary design effort on this function appears to be desirable.

8.5.2 FUNCTIONAL NAME: DSG OPERATING MODE CONTROL

Functional Description

The DSG operating mode control function acts in response to a mode change request from the DSG control function. In carrying out a mode change (i.e., from OFF to ON condition), the DSG operating mode control function monitors local DSG system and subsystem conditions, initializes control settings, and directs mode changes. In effecting mode changes, predefined sequencing logic for the startup and shutdown transitions between operating modes is employed. These logic sequencing functions are, in essence, functions of the DSG operating mode control. Start capability is described in Section 8.7.1. The DSG operating mode control and, more generally, the DSG control have detailed local relationships which are specific to each type of DSG. In Appendix A of this report, a description of system control is included for each selected DSG technology. In a generic sense, the relationship of the DSG operating mode control to the overall DSG control hierarchy is shown in Figures 8.2-1 and 8.5-1.

The following discussion illustrates the interrelationships involved in DSG operating mode control with other DSG functions. DSG modes are DSG operating/distribution conditions, which are identified as ON, OFF, and STANDBY.

These modes are defined as follows:

- ON - The DSG is in operating condition, "running," and electrically connected to the distribution system. In this condition, the DSG will normally be generating electrical power, or will be absorbing it as in the case of a storage battery.
- OFF - The DSG is electrically disconnected from the distribution system at the DSG-distribution system interface, and it is shut down or, inactive, not "running."
- STANDBY - The DSG is in an operable condition, activated, "running," but not electrically connected to the distribution system.

DSG mode changes carried out by the DSG operating mode control function involve transitions from OFF to ON, and ON to OFF, called startup and shutdown. Since these mode transitions involve complex and critical local DSG control, instrumentation and equipment interactions, the DDC will not be involved in the startup/shutdown sequencing logic. At most, the DDC may direct a semi-automatic startup where startup is performed in a few major steps. Special functional requirements related to startup mode transition and coordination with the distribution system are described in Section 8.7.1 of this report.

The determination of the DSG operating mode is influenced by a number of factors which include:

- DSG state
- Distribution system state
- DSG schedule
- DSG energy resource
- Private owner decision

The DSG and distribution system states have a direct effect on the DSG mode and, in other than normal states, the need for DSG mode control can be urgent. Possible DSG and distribution systems states are:

- DSG states:
  - Normal
  - Abnormal
  - Emergency
  - Inoperable
- Distribution system states:
  - Normal
  - Alert
  - Emergency
  - In-Extremis
  - Restorative

While both DSGs and the power system are expected to be in the "normal" state for nearly 100% of the time, it is the other states which require extensive planning and design provisions for safe operation. There are a large number of combinations for conditions affecting DSG operating modes and the interaction with power system operations and these relationships between DSG modes. DSG states, and distribution system states are described in Section 7 of this report.

The factors involving DSG schedule, DSG energy resource and private owner decisions regarding DSG operation are discussed in Section 8.2.3, "DSG Scheduling and Mode Control," of this report. It is noted that the private ownership arrangement adds another dimension (degree of complexity) to the determination of operating mode selection since another set of judgment and decision criteria are involved.

Control decisions regarding the DSG operating modes may originate at either the DDC or local DSG level. In bulk power/transmission "emergency" or "in-extremis" states, the EMS may originate gross DSG mode change requests as discussed in Section 8.2. Under normal DSG and distribution system states, mode control logic or information related to unattended schedulable DSGs will originate in the DDC scheduling and mode control function (described in Section 8.2). For intermittent energy resources (i.e., wind and solar without storage), a DDC permissive type control command may be employed. This, in effect, would give or deny permission for the local DSG control to go on-line, subject to local energy resource availability or other conditions. Small privately owned DSGs may not be subject to DDC scheduling and mode control and have only local owner, manual DSG control. Thus, a wide range of DSG control initiation conditions may be encountered, and control responsibility assignment will be dependent on factors such as:

- DSG conditions
- Distribution system conditions

- DSG ownership
- DSG size and type
- DSG location (remoteness)
- DSG interrelationships with other DSGs or system elements

Input or Processed Data

- DSG control function (initiates request for mode change
- DSG system, subsystem, and control information
- DSG - distribution system interface information
- Distribution system conditions

Output Control and Data

- Commands/signals to DSG startup/shutdown subfunctions
- Data concerning normal and abnormal mode change sequencing

Interaction with Other Functions

The DSG operating mode control function interacts directly with the following functions:

- DSG control
- Instrumentation
- Protection: DSG
- Local DSG subsystem controls
- Start capability
- Stand-Alone capability

Indirectly, the DSG operating mode control interacts with the following functions (via the local DSG control function):

- Local DSG operator
- DDC (DSG command and control)
- DSG scheduling and mode control
- Load control including restoration
- Personnel safety
- Security assessment and control

Special Requirements

Regarding the general topic of DSG mode control, coordination of DSG and distribution system operating conditions and contractual/operational relationships for DSG private ownership are required. The degree of coordination required is related to control responsibility factors and to the quantity of DSGs installed on the distribution system. Personnel safety is also a primary concern, requiring careful attention to both mode control authorization and implementation. Coordination of DSG and distribution system operation can be a relatively complex matter when a significant number of DSGs of various types and sizes are installed on a distribution system. Further study is warranted to examine DSG mode control for high DSG capacity penetration on electric utility distribution systems.

8.5.3 FUNCTIONAL NAME: PERSONNEL SAFETY

Functional Description

Personnel safety is everyone's concern. For the operating and maintenance crews, it is a physical concern, and the final implementation of safety rests with them. However, the overall direction and coordination of work and safety is the responsibility of the DDC. Personnel safety is represented in Figure 8.2-1 as a DDC function.

A principal concern with DSG is for the safety of both utility and customer personnel. It is necessary that the presence of DSG systems on utility systems not result in any hazard to personnel during the various modes of operation or states of the DSG and distribution system.

From an information standpoint the personnel safety function is related to the distribution SCADA system which collects data, indicates to the DDC whether the DSGs in a given area are operating and indicates the status of switches or circuit breakers at each DSG location. Supplied with critical DSG and distribution system information, the DDC operator in charge can perform tagging and identification of circuits and equipment on which crews are working and can direct work and repair crews in a safe manner. To comply with certain regulatory requirements (OSHA), additional equipment such as grounding switches may have to be added to distribution DSG systems.

Input or Processed Data

Relative input data:

- Switch and circuit breaker position status
- Operator input (tagged status on feeder breakers and switches and those at DSG location)
- DSG operating mode indication to DDC and local DSG: ON, OFF, or STANDBY

Output Control and Data

Relevan output data:

- On/Off command to DSG
- Tagged status indication to DDC, or DAC
- Inhibit command for DSG synchronizing depending on connection to distribution system
- Tagged switch location

Interaction with Other Functions

Functional interaction:

- Display and recording
- Protection: substation, transformer, feeder
- Communication
- Information processing
- DSG operating mode control
- DSG command and control
- Distribution SCADA
- Protection: DSG
- Start capability

Special Requirements

Positive visible grounding of equipment with a possible generating source may be required, and this safety requirement needs further investigation and definition.

Reclosing out-of-phase is a potential hazard to equipment and personnel. Means of avoiding this potential hazard should be provided.

Personnel safety practices and operating procedures will have to be completely reviewed with the introduction of DSGs on the distribution system. DSGs will introduce a source of backfeed to circuits disconnected at the substation and traditional "radial circuit" operating and personnel safety practices will have to be revised.

8.5.4 FUNCTIONAL NAME: DSG STABILITY

Functional Description

When an induction or synchronous machine is operating in a steady-state condition, there is equilibrium between the power input and output. System disturbances cause oscillations of power flow which must be critically damped to maintain DSG system stability. Problems of power system stability resolve into the question of whether the electrical system is capable of holding two or more machines in synchronism (or at rated speed for induction generators) and without undue oscillation so that this balance is maintained. Transient stability conditions are generally studied by simulating models of the machines and the power system before, during, and following system disturbances, (e.g., due to fault clearing or load control). Steady-state stability conditions may also be studied to determine power transfer capability of the system.

From steady-state, dynamic, and transient stability studies, it is possible to determine a range of DSG and distribution system characteristics that may be used as design parameters for successful DSG stability performance.

Input or Processed Data

For DSG stability analysis (not on-line control), input data is required. Typical required information consists of DSG and distribution system characteristic impedances, DSG inertias, DSG power conversion system characteristics, distribution system circuit configurations, and load characteristics.

Output Control and Data

There is no on-line DSG stability control other than that designed into the DSG excitation system during the DSG and distribution system design and application engineering stages. Excitation control assisting in synchronous generator dynamic stability limits tends to be a complex control function and might not be economically justifiable except for larger DSGs.

Interaction with Other Functions

In the event of DSG instability, action is required to disconnect the DSG from the distribution system. This involves:

- Protection: DSG
- Protection: substation, transformer, feeder

Special Requirements

A unique problem associated with wind turbine generators, compared to other types of DSGs, is the rapidly fluctuating nature of the input torque due to wind gusting. This can produce instability as well as voltage fluctuations and should be considered for the specific site and DSG system design involved.

8.6 FAILURE AND ABNORMAL BEHAVIOR DETECTION AND CORRECTION REQUIREMENTS

Failure and abnormal behavior can occur within the DSG system or in the distribution system, and these conditions in one can cause adverse effects in the other. Failure and unusual conditions can be associated with DSG abnormal and emergency states and the distribution emergency state.* These conditions or states are associated with equipment, component or circuit overloads, incipient faults, or actual faults or failures. While abnormal states, such as overloads, may be tolerable for a short time, they usually must be corrected or isolated to prevent harmful effects. Failures, of any degree, require immediate isolation to prevent extensive damage, cascading effects, or personal injury to workers. Prompt detection and appropriate (i.e., selective) isolation of equipment, subsystems, a complete DSG system, or parts of distribution systems are usually involved in corrective action. Protective systems used to perform these functions include detection devices and/or logic functions, such as those provided by protective relaying, and power switching devices, i.e., fuses, reclosers, switches and circuit breakers, safely isolating the abnormal or failed elements.

The function of "protection: substation; transformer and feeder" in electric utility systems with centralized generation facilities has mainly been concerned with unidirectional current flow. Load and fault currents both originate from bulk generation transmission "power sources" and flow toward the distribution system loads. With the addition of DSGs to the distribution system at the distribution substation level and below, bidirectional current flow may occur. In the past unidirectional current flow permitted relatively simple time-current coordination for fault detection and circuit/equipment protective devices. With the addition of DSGs the traditional distribution system substation, transformer, and feeder protection schemes may have to be revised to accommodate DSGs at this level. Therefore, more complex protection schemes similar to those used on the bulk generation/transmission system may have to be used.

Where multiple generation sources and transmission system interconnections cause bidirectional current flows, "zone" protection schemes are in common use. A set of protective equipment is designed and assigned to protect a specific equipment or circuit segment. The zones of protection are usually overlapped with time coordination, if possible, and if warranted, both local and adjacent backup protection is provided to assure prompt fault isolation and minimization of the extent of the outage.

The "protection of DSGs" is primarily an onsite responsibility with the objective of equipment and personal protection of personnel and the prevention of undue disturbances to the distribution

*Section 7, "Major Operating Modes and States" system. Within the DSG system protective equipment is usually assigned to guard specific equipment or circuits and, therefore, a minimum of equipment or DSG system is deactivated for fault conditions. Internal DSG system protection and controls are inherently incorporated in the DSG system and subsystem design and are specific to the type of power conversion and power conditioning systems. The degree and complexity of the internal DSG protection systems will be related to the size and complexity of the DSG. The cost of DSG protection must maintain a reasonable balance with the cost of the DSG.

The DSG protective systems will detect internal DSG faults and isolate them from the distribution system to prevent unnecessary distribution system outages from the operation of backup protection on the distribution system. Conversely, to protect the DSG from prolonged distribution system faults or sustained abnormal conditions, backup protection should be incorporated in the DSG protection system to protect it for these conditions.

For the integration of DSGs into the distribution system the primary concern will be with the DSG distribution system interface. This will require coordination of both DSG and distribution system protection systems and the functional overlapping of these two basic protective systems. Conceptually, this is illustrated in Figure 8.6-1.

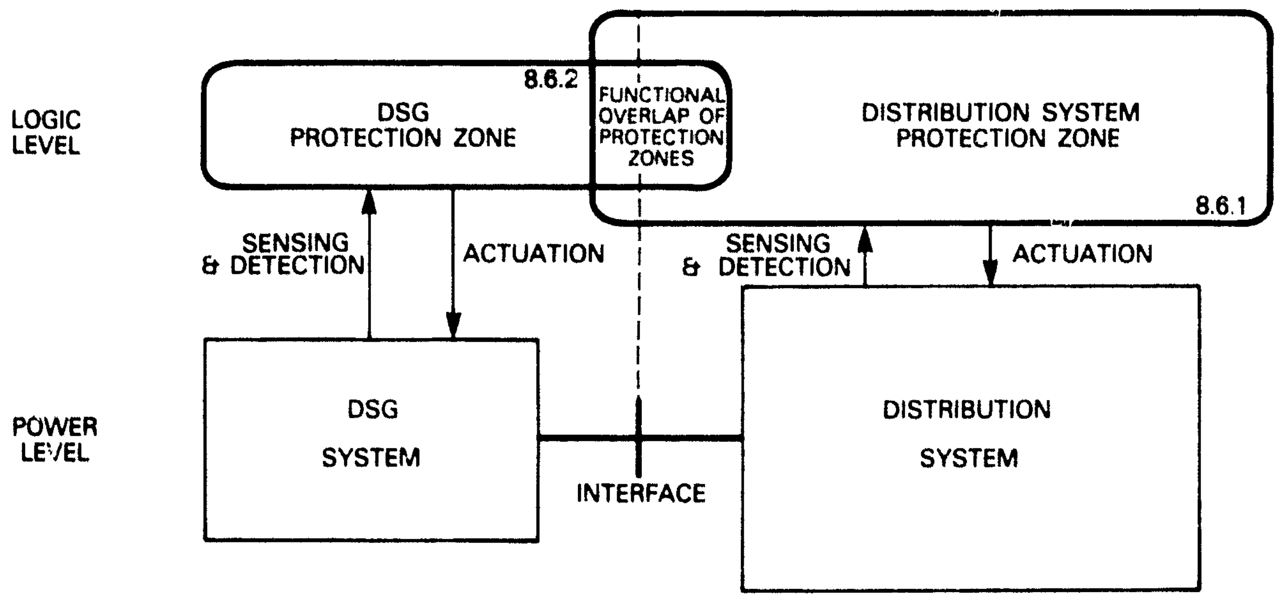


Figure 8.6-1. Coordination of DSG and Distribution Protection Functions

8.6.1 FUNCTIONAL NAME: "PROTECTION: DISTRIBUTION SUBSTATION, TRANSFORMER, AND FEEDER"

Functional Description

Distribution substations contain switching equipment to isolate a faulted circuit or transformer automatically from the remainder of the system. From the substation distribution circuits radiate to serve the surrounding area.

The principal components of a distribution substation are high- and medium-voltage switching equipment and transformers. High-voltage switches, circuit breakers, protective systems, and associated controls are necessary for system operation, the detection of abnormalities, and the rapid isolation of faulted segments of the system.

In general, the substation circuit breaker will open within a fraction of a second in the event of disabling trouble on a feeder and immediately reclose. If the trouble was of a transient nature, such as a lightning flashover, all service would be restored, and the only effect to customers served by this feeder would be a momentary interruption of less than a second. In the event the trouble on a lateral circuit is not transient, the fuse or sectionalizing device would isolate the faulty lateral from the main feeder.

In the event that disabling damage occurs to the main feeder the entire area served by the feeder will be without service until the faulty section is isolated. Service may be restored to the remaining sections by switching to alternate sources if available. If alternate sources are not available beyond the point of trouble, service cannot be restored in the faulty section, and beyond, until repairs can be made.

In general, the present substation, transformer, and feeder protection is based on a radial system with the equivalent source(s) of generation at the primary of the distribution substation transformer. The addition of DSGs to the distribution system, at the distribution substation level or below, requires their removal for faults involving their particular associated substation, transformer, or feeder. In the event of an unsuccessful reclosing, the resynchronizing of the DSG would have to take place after successful fault isolation. This assumes that the DSG is on the unfaulted section.

Overload protection is normally provided for the substation transformer by temperature relays. Feeder circuit breakers offer limited feeder overload protection with tripping at 200 to 300% of full load being a typical practice. The addition of DSGs able to be scheduled can relieve feeder and substation overloads through scheduling from the DDC to increase DSG output.

Input or Processed Data

Input or processed data can aid protection in the following ways:

- Indication of the successful reclosing of the feeder breaker
- Indication of the completion of fault isolation
- Operator limits on allowable feeder section and transformer current and voltage magnitudes
- Feeder, transformer, and feeder section loads - each 30-60 minute interval.

Output Control and Data

Output control and data contribute to protection in these areas:

- DSG main circuit breaker (for utility-owned DSG)*
- Alarm overload on feeders, sections, and substation transformers

Interaction with Other Functions

The interaction of protective operations with other functions includes:

- Feeder fault isolation and service restoration
- Communication
- Information processing
- DSG operating mode control
- DSG scheduling
- Instrumentation

Special Requirements

Once a feeder has been disconnected from the distribution substation, additional protection is required to prevent the feeder circuit breaker from reclosing out-of-phase with a DSG located on that feeder if it is operating in an isolated condition. A possible solution would be to disconnect the appropriate DSG(s) for substation, transformer and feeder faults, (i.e., go to standby

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*See "Special Requirements"

mode) and only permit resynchronizing of the DSG to the distribution system after the feeder breaker has sucessfully reclosed. An override for permitting resynchronizing might be available from the DDC if no danger to the safety of personnel is involved.

The momentary and interrupting ratings of interrupting and sectionalizing devices might have to be increased, depending on the size and number of DSGs and where they are located on the distribution system.

For customer-owned DSG the utility might have the option of controlling the DSG breaker or the customer's main breaker. From the standpoint of providing distribution protection, the control of either breaker will provide the same function. However, the availability of either breaker for tagging by utility line crew personnel may limit the selection.

8.6.2 FUNCTIONAL NAME: "PROTECTION: DSG"

Functional Description

The DSG protection generically consists of sensing conditions, detecting abnormalities or failures, and initiating action to: isolate the source of trouble, protect equipment from damage, and protect personnel. In the broadest sense, protection of a DSG plant or unit would include protection of all electrical and mechanical operating systems and equipment. However, in regard to power conversion, power conditioning and auxiliary systems and equipment, subsystem protection and controls normally will have appropriate protection functions included in their design scope, and specific protection devices for individual equipments are usually included for abnormal or failure conditions as indicated by temperature, pressure, and electrical values.

Therefore, the DSG Protection function, associated with DSG-distribution system integration, will be primarily concerned with the DSG distribution system electrical interface and equipment immediately associated with this interface. The DSG utility interface can have various configurations from simple to complex. The DSG protection function is shown on Figure 8.5.1-1.

There are two major categories of DSG protection which may be described as "initiating" and "blocking" actions. These two categories can be identified by what they do and the conditions which are associated with them. They are as follows:

- Initiating actions isolate faults or remove equipment from service. Conditions for which automatic protective action (initiation) is required are:
  - Short circuits
  - Overvoltage - steady state and transient
  - Undervoltage
  - Underfrequency

- Blocking actions prohibit or prevent the act of DSG - Utility electrical connection. Conditions, causes, or reasons for imposing blocking action are:
  - The DSG and the utility not in synchronism
  - The DSG and the utility not in proper condition for synchronizing
  - Fault conditions on the distribution system
  - Personnel working on the distribution system

The major hazard involving electrical equipment is a "short circuit," which is usually caused by an insulation failure. It is necessary to interrupt the flow of current to such a failure in the shortest practical time, and if possible remove only the faulty portion of the system without removing service to other parts of the system. For a DSG which consists solely of one generating source, a short circuit in the DSG utility interface or in one of the main DSG equipments will result in the disconnection and shutdown of the DSG. However, a multi-unit DSG plant or a cogeneration plant with redundancy in the DSG utility interface configuration may be able to continue operation following a fault, and successful fault isolation. In addition to short circuit faults, there are other conditions which can cause damage or shortened equipment life if they are allowed to persist. These are conditions of overvoltage, undervoltage, and underfrequency. The DSG protection system senses, detects, and interrupts/isolates appropriate equipment for the DSG or the DSG distribution system interface faults and abnormal conditions. For distribution system faults and abnormal conditions which are not promptly removed, time-delay backup protection may be required in the DSG protection system to protect the DSG. Briefly, the protective system is described as follows:

- Sensing and detection of fault or out-of-limits conditions are done by protective relays or fuses. These are commonly called circuit protective devices. The actual disconnection of faulty system equipment or elements is done by circuit breakers or fuses. The over-all arrangement of protective relays and fuses is commonly referred to as a "protective system." An overall "picture" of the protective system and the main electrical system elements connected by circuit breakers or fuses is usually prepared and is called a one line diagram. Instrumentation and metering devices are often shown on this one line diagram.

In regard to blocking the following description is given:

- Blocking is the act of prohibiting control action to connect the DSG electrically to the distribution system. The blocking function involves either local sensing of unacceptable conditions or a control center derived decision to order "blocking" of the DSG distribution system connection. The sense in which the term blocking is used in this latter description would normally apply to a DSG which was in a standby mode or in transition from off to on (startup). Blocking could also include the prohibiting of startup initiation.

In synchronizing the DSG with the utility system, blocking is a subfunction of the synchronizing sequence whereby the connection of the DSG to the utility is prevented when voltage difference, electrical phase angle, rate of change of frequency or frequency is not within acceptable limits. Synchronization is described in Section 8.7.2.

With the distribution system operation DSG blocking is initiated when distribution system conditions are aggravated or the personal safety of personnel compromised or threatened by the connection of the DSG to the distribution system. Examples are: (1) a fault condition on the distribution circuit to which the DSG is normally connected; (2) personnel working to restore a faulted distribution system circuit or equipment which is energized by the connection of the DSG to the distribution system.

Input or Processed Data

"Protection: DDS" functions as follows with input or processed data:

- Locally sensed voltage, current, and frequency values
- Locally sensed or detected fault and abnormal conditions on the distribution system
- Control center blocking orders (command)

Control Output and Data

Another protective function is to regulate output and data in the following ways:

- Control action to cause circuit breakers and/or switches to cperate
- Control action to prevent DSG-utility connection (blocking action)
- Data identifying fault detection protective system operation (local DSG and DDC).

Interaction with Other Functions

Other "Protection: DSG" interactions are with the following:

- Safety of personnel
- DSG command and control
- DSG operating mode control
- Distribution SCADA
- Communication
- Information processing
- Protection: substation, transformer, feeder
- Start capability
- Synchronization
- Load control including restoration

Special Requirements

There may be special requirements associated with particular or unusual DSG utility interface configurations. Revised distribution protection schemes may be needed for integration of DSGs to accommodate bidirectional load and fault current flows. Conventional unidirectional distribution system protection schemes may not be able properly to protect equipment, circuits, and personnel when DSGs are added to conventional distribution system configurations.

8.7 SPECIAL DSG CONTROL REQUIREMENTS

Special requirements are local DSG control and monitoring functions that are required for incorporation and integration of DSGs into a utility power distribution system. These special functions are:

- Start capability
- Synchronization
- Stand-alone capability

These functions involve actions that relate to the DSG's ability to operate as an attended or unattended, manual, semiautomatic, or automatic unit or plant. The special functions interact and interface with other functional categories, involving functions such as:

- DSG power control
- Instrumentation
- Distribution SCADA
- DSG operating mode control
- Personnel safety
- Protection: DSG
- Protection: substation, transformer, feeder

The relationships of the special DSG control functions to each other and to other monitoring and control functions at the DSG are shown in Figure 8.7-1.

Start capability involves local DSG automation for accomplishing the transition from OFF to STANDBY, and from OFF to ON modes. The complete startup procedure for the DSG is included in the start capability function and includes startup of major power conversion, power conditioning, energy storage, auxiliary, and ancillary systems necessary to bring the DSG to the ON mode. The degree of start capability automation can be affected by the type of DSG, its ownership, and size. Start capability may be manual, semiautomatic, or fully automatic.

Synchronization is a necessary part of the transition to the ON mode. Synchronization is required for synchronous machines and static inverters, and for unattended DSGs synchronization will be performed automatically as the final step in the transition from OFF to ON and from STANDBY to ON modes. In addition to synchronization being performed automatically, it may also be performed by a local operator if appropriate controls and instrumentation are available. Synchronization requires that the frequency of the DSG ac voltage and the frequency of the distribution system be essentially the same and that the relative phase angle between them be within a few electrical degrees. When these

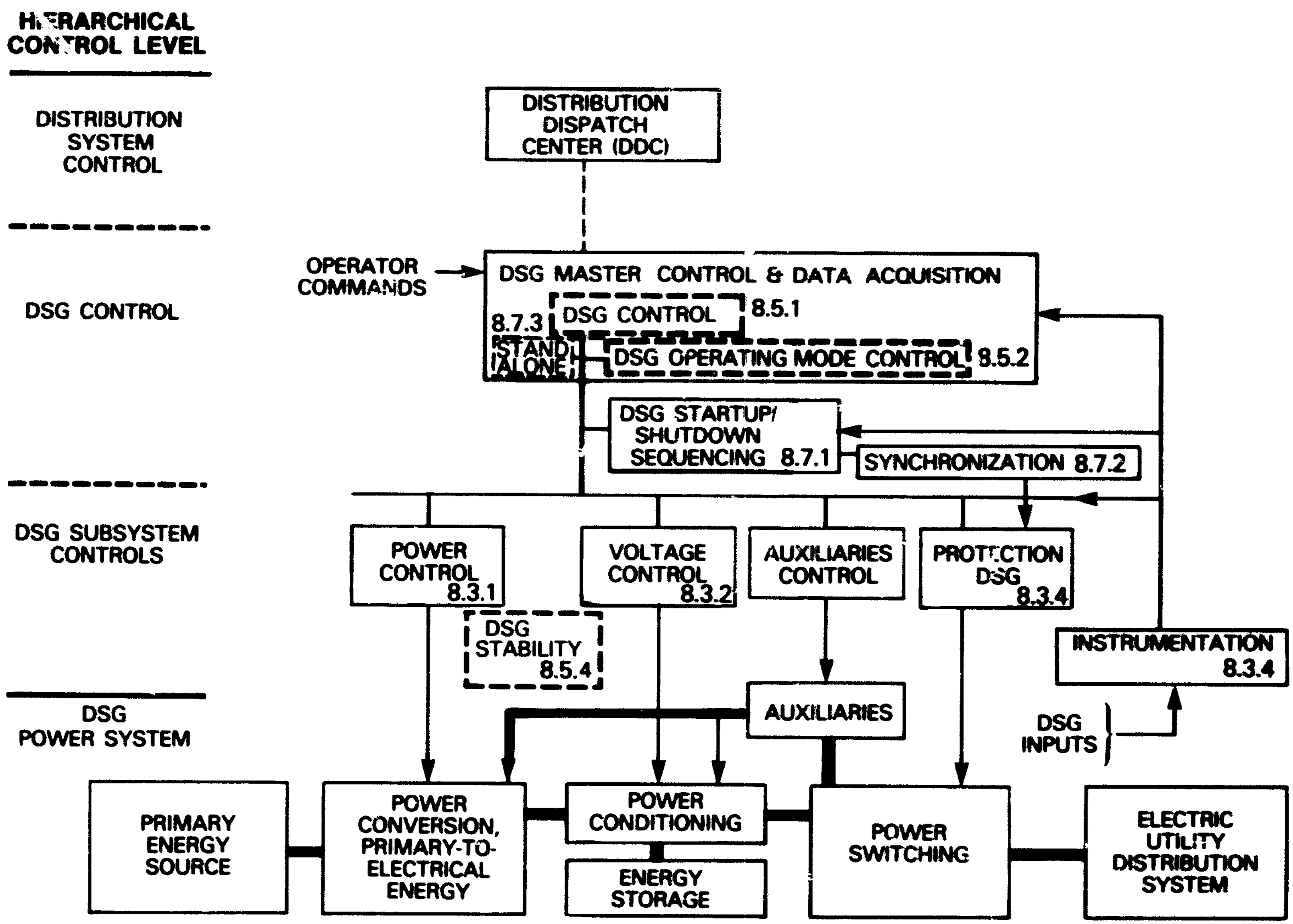


Figure 8.7-1. DSG Functional Control Block Diagram

conditions are met, the main circuit breaker (or switch) is closed, thereby connecting the DSG to the distribution system.

The stand-alone function involves the operation of one or more DSGs that supply a portion of the distribution system that is not connected to the major generating sources of the power system. This configuration is also referred to as an "island." This requires coordination of related functions of power, load, voltage, and frequency control. The primary concern is that synchronous DSGs that are isolated from the utility distribution system be of sufficient capacity to provide the connected load and to maintain inter-DSG stability. For a single DSG-load combination the situation is relatively straightforward. As the number of interconnected DSGs, loads, and electrical interconnections in an "island" increases, the problem can become very complex. In addition DSGs may tend to be relatively low-inertia-constant sources, and this will tend to result in poorer inter-DSG stability under isolated conditions. Stand-alone capability for a group of DSGs would probably require some form of load control and automatic generation control (AGC) from a centralized source such as the DDC.

8.7.1 FUNCTIONAL NAME: START CAPABILITY

Functional Description

Start capability refers to the ability of the DSG to be started manually, semiautomatically, or automatically. This then determines whether an operator is required for this function.

The start capability involves the preconditioning and startup of all necessary major, ancillary, and auxiliary systems necessary to bring the DSG from the OFF to the ON mode.

As foreseen for medium- to large-sized DSGs solely owned by the utility and at the commercial stage of development, the DSGs will be capable of unattended, automatic operation. Thus, automatic startup would be required for these DSGs. The exception would probably be a cogeneration type of DSG that, because of its dual purpose, tends to be relatively complex in equipment and operational coordination of both electricity and heat production. This will be generally true of privately owned cogeneration facilities and jointly owned (utility-private company) DSGs that involve industrial processes. For cogeneration involving the production of electricity and space heating (commercial or domestic), it may be possible to automate this type of cogeneration DSG, depending on the type of primary energy.

Starting involves all of the safe and orderly steps required to make the transition from the OFF mode to the ON mode (as described in the operating modes function description).

In general, startup is a relatively complex set of sequential operations with appropriate checks, involving DSG unit or plant auxiliaries and the major power conversion, power conditioning, and power switching equipment. The relative complexity will vary with the type of DSG and increasing order of complexity would progress from a hydro to solar thermal electric to cogeneration DSG.

For automatic or semiautomatic startup, the sequencing and checking operations would be performed by the startup control function:

This function can be accomplished by separate logic and actuator equipment or may be incorporated as an integral part of the DSG master control. Thus the hardware/software can take many forms. The startup function is initiated by the DSG operating mode control, which makes prestartup checks and coordinates local DSG distribution system conditions. Once initiated, the startup sequence proceeds to its normal conclusion of electrically connecting the DSG to the distribution system.

Input or Processed Data

This category includes all pertinent DSG parameters such as:

- DSG operating mode control signal
- Primary energy source status and measurements
- Power conversion system status
- Unit/Plant auxiliary status and measurements
- Power conditioning system status and measurements
- Energy storage system status and measurements (if applicable)
- Power switching equipment status

Output Control and Data

The startup control will transmit appropriate control signals plus the DSG subsystem's controls and DSG auxiliary system controls to perform the necessary operations in the correct sequence.

The startup function will provide startup status progress to the DSG master control and data acquisition function and in turn this information is presented to the SCADA and communication interface for transmission of this information to the DDC. This information will provide status of a normal startup progression or an aborted startup with appropriate diagnostic information in the latter case.

Interaction With Other Functions

The startup function will interface with the following functions:

- Directly
  - A. DSG Operating Mode Control
  - B. DSG Command and Control
  - C. Protection
  - D. Synchronization
- Indirectly:
  - A. DSG Scheduling
  - B. Load Control Including Restoration
  - C. Distribution SCADA
  - D. Communications
  - E. Information Processing (DDC)
  - F. Personnel Safety

Special Requirements

Each type of DSG will have specific startup functional requirements as related to the primary energy source, power conversion, power conditioning, ancillary, and auxiliary systems. These requirements are inherently part of the DSG power and control systems design and mainly require interface definition with DSG operational mode control function and equipment.

8.7.2 FUNCTIONAL NAME: SYNCHRONIZATION

Functional Description

The synchronization function involves matching of the DSG frequency and voltage phase angle to that of the distribution power system and connecting the DSG to the distribution system. This is normally done by automatic synchronizing logic/equipment. However, local-manual synchronizing may also be provided. The DSG is connected to the distribution system via the DSG-utility power switch-interface. The synchronizing function is normally a subfunction of the startup function and interrelates to other subsystem control functions, particularly the "speed/frequency" control subsystem. The specific related subsystem controls involved are dependent on the type of DSG, i.e., rotating equipment or static inverter. Automatic synchronizing control actions are directed by local control elements. Control of synchronization in a "remote-manual" control sense from a remote control center is not practical. Certain types of DSG will utilize induction types of generators, and these do not require exact synchronization prior to electrical connection of the DSG to the power system. Also, some types of DSGs may require a motor action ("crankup") type of startup that involves connecting the DSG generator to the power system as a motor for start up of the generator to approximately synchronous speed. These are considered special cases.

Input or Processed Data

All inputs originate locally for this local DSG automatic control function. The major functional relationships are with the startup and the DSG operating mode control function. Local inputs to the synchronizing function are:

- DSG protection:
  - A. Permissive conditions
- Voltage:
  - A. DSG
  - B. Distribution system
- Frequency:
  - A. DSG
  - B. Distribution system
- Power switching equipment:
  - A. Main circuit breaker status

Controlled Outputs

Outputs are both control and status data. They are:

- Control signals to speed/frequency control subsystem (increase or decrease speed/frequency)
- Status of frequency match/mismatch (Hi-Lo)
- Value of relative frequency mismatch, data, and/or display
- Control signal to close main circuit breaker

Interaction With Other Functions

Interaction of the synchronizing (sub)function is primarily with the local Startup and DSG operating mode control functions. Local DSG protection function provides permissive condition.

Special Requirements

Special requirements will involve specific synchronizing interface arrangements for the different types of DSGs as required by their power conversion and power conditioning control subsystems.

8.7.3 FUNCTIONAL NAME: STAND-ALONE CAPABILITY

Functional Description

Stand alone capability is the ability of a DSG (or an interconnected group of DSGs) to operate and serve associated electrical loads on an isolated part of the distribution system. In this in extremis distribution system state there is no connection to the main power system generating sources. This stand-alone capability has several basic requirements and/or implications. The most fundamental requirement is that the DSG electric power conversion/conditioning equipment be self-excited, or self-commutated, thereby being capable of producing a 60 Hertz voltage output. This implies synchronous or permanent magnet generators and self-commutated inverters. Some types of DSG power conversion/power conditioning equipment will not be capable of this stand-alone operation by their very nature. Examples are induction types of generators and line-commutated inverters.

In addition to being self-excited or self-commutated, stand-alone capability requires that the connected electrical load will not exceed the power output capability of the DSGs. This is easily determined if it is a single site, directly connected, known load associated with the DSG. Expansion of the configuration to accommodate multiple loads with one or more DSGs introduces complication. The basic requirement of electrical load not exceeding DSG capacity still applies but may require automatic or manual load management to ensure this condition. For example, a feeder with a DSG could conceivably serve several or many residences, but there would be a limit to the connected load, and the limit would probably have to consider that all load diversity could be absent.

There is another degree of "stand-alone" operation, and that could include a whole "island" of a distribution system that is isolated from the remainder of the main distribution system. This becomes even more complex and would probably require supplementary automatic generation control and load control capability at the DDC for such an "island."

There may be a fundamental problem with multiple DSGs in an island configuration. This problem is one of DSG/island stability. Maintaining synchronism between DSGs with relatively high internal impedance and low inertia and connected by relatively high distribution system impedance circuits presents potential problems.

Stand-alone DSGs serving a local load would probably have a wider voltage and frequency variation than would be noted with the normal state of interconnection with the main distribution system. These are secondary matters in comparison to those mentioned above; however, they would need to be recognized and appropriate control provision made to keep these quantities within acceptable limits.

Input or Processed Data

- Command to start up and connect to a distribution system that has zero voltage and frequency signals. (The normal condition DSG protection/synchronizing would consider this a no-go condition)
- Bypass of blocking function
- Load management action to limit applied load

- Voltage and frequency subsystem control adjustments as required for stand-alone operation

Output Control and Data

- Control action
- Status and measured variables associated with stand-alone operation to be transmitted to DDC

Interaction With Other Functions

Stand-alone operation would involve interaction with one or more of the following functions:

- Directly:
  - A. DSG command and control
  - B. Volt/VAR control
  - C. Load control including restoration
  - D. Automatic generation control
  - E. DSG power control
  - F. DSG operating mode control
  - G. Distribution stability
  - H. Protection: substation, transformer, feeder
  - I. Protection: DSG
  - J. Synchronization
  - K. Start capability/startup control
- Indirectly:
  - A. Distribution SCADA
  - B. Communication
  - C. Metering
  - D. Personnel safety
  - E. DSG scheduling and mode control

Special Requirements

This whole function has special requirements as outlined above. Study of individual applications is required to obtain satisfactory operation and warrants further investigation.

Section 9

NIAGARA MOHAWK POWER CORPORATION (NMPC) DISTRIBUTION SYSTEM COMPOSITE

9.1 INTRODUCTION

In order to explore the implications of the control and monitoring functional requirements for DSGs which are integrated into a utility distribution system, a representative distribution system composite has been employed. For various operating scenarios the impact on several types of DSGs and their monitoring and control requirements has been examined.

The composite chosen to examine DSG control and monitoring was derived from a distribution system composite representing the Niagara Mohawk Power Corporation in the vicinity of Syracuse, New York. The DSGs introduced were selected on an assumed basis rather than from any actual system planning effort. This use of scenarios has been helpful in highlighting and clarifying a number of the functional requirements for DSG monitoring and control.

The Niagara Mohawk Power Corporation (NMPC) system includes a service area of approximately 24,000 square miles in the state of New York. Approximately 1,300,000 customers are served from three divisions: the Western, Central, and Eastern Divisions. The service area includes a broad range of urban, suburban, and rural areas. Among the principal metropolitan districts served are Buffalo-Niagara Falls, Syracuse, Utica-Rome, and the Albany-Schenectady-Troy area. The NMPC system load has experienced a swing away from higher load factor industrial customers to a preponderance of residential and commercial loads. In spite of this trend, NMPC's annual load factor has remained consistently stable at approximately 68%. Actual peak load figures for 1977 were 4878 MW summer and 5284 MW winter. In addition to generating power from nuclear, oil, and coal, NMPC uses hydroelectric generation and purchased electric power to meet its system needs.

NMPC has for many years used hydroelectric power as a valuable source of energy. Presently NMPC has approximately 80 small hydroelectric plants with a total 666 MW capacity. By 1990 NMPC plans to add 16 new hydroelectric generating plants with almost 200 MW of added capacity. Many of these units can be considered as dispersed sources of generation. NMPC also has an interest in other DSG sources and has been considering fuel cells and storage batteries as possible additions to its system.

Transmission voltages used by NMPC include 345 kV, 230 kV, and 115 kV. Several lines are also designed for 765 kV but are operated at 345 kV. NMPC uses several distribution voltages, including 4.16 kV, 4.8 kV, 6.9 kV, and 13.2 kV. The 13.2 kV system is the highest distribution voltage planned by NMPC, and it is the 13.2 kV standardized voltage class that is experiencing the most load growth on the NMPC system.

Recognizing the potential advantages of automated distribution systems, NMPC has initiated several projects to evaluate the feasibility and has estimated benefits and costs of distributon automation. In 1977, an agreement was reached between NMPC and GE to make a joint assessment of distribution automation functions and alternative conceptual control structures based on specific consideration of a small portion of the NMPC distribution system. For the distribution automation/control study it was decided that attention would be focused on a small composite 13.2 kV distribution system and would include rural, urban, and suburban feeders.

This composite 13.2 kV distribution system is shown in Figure 9.1-1 and includes approximately 200 square miles in the Syracuse, New York area, serving 40,000 customers. Within this composite 13.2 kV distribution system, an area was selected which focused on three specific substations in the Syracuse area which are sourced from the Niagara Mohawk 115 kV transmission system. These substations (Bridgeport, Fly Road, and Pine Grove) serve approximately 10,000 customers. From these substations, feeders could be selected illustrating rural, urban, and suburban loads. The composite 13.2 kV distribution system includes several distribution substations with approximately nine feeders having ties to feeders from the three principal substations in the assessment (Bridgeport, Fly Road, and Pine Grove). This provides interactions pertaining to the scenarios studied.

The NMPC distribution system composite provides an illustrative example for consideration of conceptual integration of DSG units on the distribution system in developing the functional requirements for DSG control and monitoring.

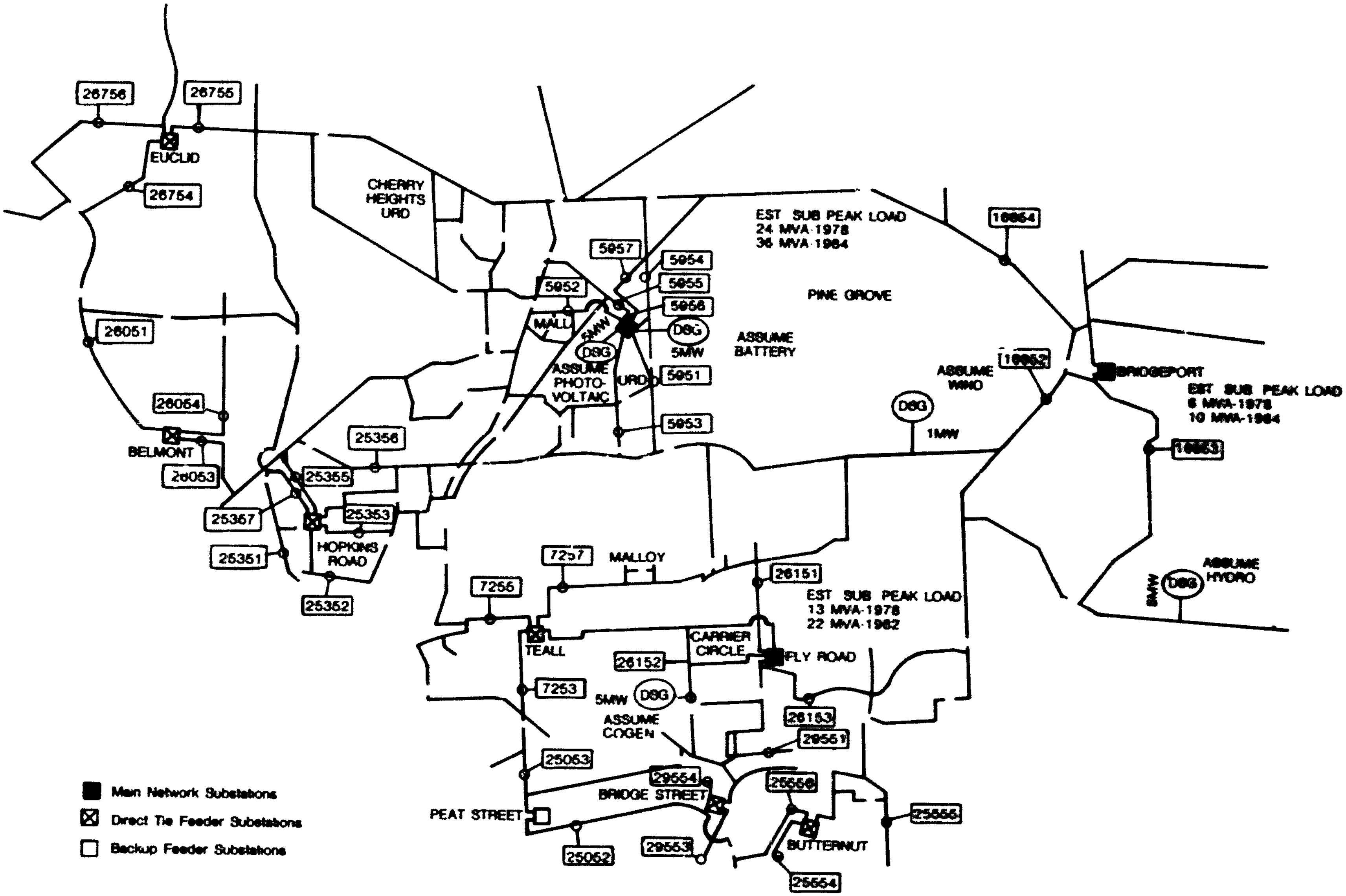


Figure 9.1-1. Illustrative DSG Locations and Types-Conceptual Design Only

9.2 CONCEPTUAL DSG INTEGRATION ON THE NMPC COMPOSITE 13.2 kV DISTRIBUTION SYSTEM

The feeder and substation configuration shown in Figure 9.1-1 is the NMPC preliminary estimated configuration for 1984 study conditions and is for the estimated nonautomated composite 13.2 kV distribution system. For study purposes, five DSG units are shown in the composite. Four are assumed to be rated 5 MW and the wind DSG is assumed to be rated 1 MW. In the composite, the assumed DSG locations and types are listed in Table 9.2-1.

Table 9.2-1

CONCEPTUAL DSG INTEGRATION ON NMPC COMPOSITE 13.2 kV DISTRIBUTION SYSTEM

Location	Type DSG*	Size (Rating)
Pine Grove Substation (Suburban)	Battery	5 MW
	Photo Voltaic	5 MW
Bridgeport Feeder 16853 (Rural)**	Hydro	5 MW
Bridgeport Feeder 16852 (Rural)**	Wind	1 MW
Fly Road Feeder 26152 (Urban)	Co-Generation	5 MW

NOTES:
*NMPC does not plan to implement DSG units at these locations. They are for illustrative DSG study purposes only.
**For the nonautomated case (Figure 9.1-1), the hydro DSG is assumed to be on Bridgeport feeder 16853. In the automated Case (Figure 9.4-1), Bridgeport feeder 16853 is not required (deleted), and its loads and the hydro DSG are assigned to Bridgeport feeder 16852 which consists of two sections.

In the composite 13.2 kV distribution system, the Pine Grove Substation is expected to have the largest load growth during the 1978-1984 period. Based on this, two DSG units were assumed to be located at the Pine Grove Substation. One was assumed to be a storage battery and the other a photo voltaic type DSG. Both are dc energy types. Conversion equipment would be required to provide ac output for connection to the 13.2 kV ac substation. It is probable that a hydro DSG unit would be located in a rural area, and Bridgeport feeder 16853 was assumed for this DSG location. A wind generator DSG unit is also assumed on another Bridgeport rural feeder, 16852. It is likely that a cogeneration DSG unit would be located in an urban area; Fly Road feeder 26152 is assumed for this DSG.

9.3 NMPC COMPOSITE 13.2 kV DISTRIBUTION SYSTEM LOAD GROWTH SUMMARY

The estimated peak load for each of the feeders of the Bridgeport, Fly Road, and Pine Grove substations for 1978 and 1984 critical season conditions was determined by NMPC and is shown in Table 9.3-1. Estimated critical season peak load for each of these substations was assumed by GE by adding the feeder peak loads and multiplying by 0.95 to estimate the effect of feeder load diversity.

For the composite 13.2 kV distribution system, changes in load were estimated for all the feeders for the years 1978, 1980, 1982 and 1984. The changes in load during these years result from normal load growth, load transfers and conversions, and spot load additions. However, in Table 9.3-1 only the 1978 and 1984 estimated data for Bridgeport, Fly Road, and Pine Grove are shown.

Substation transformer ratings for the Bridgeport, Fly Road, and Pine Grove substations are shown in Table 9.3-2.

The Fly Road and Pine Grove substations are each fed by two 115 kV independent transmission lines with a normally open tie breaker on the high voltage side. Bridgeport substation is served by a single 115 kV transmission line.

Normal design criteria (station getaway limited) for the feeders is that feeder current is not to exceed 400 amperes under normal conditions and 500 amperes during emergency conditions. Certain sections of individual feeders may have lower ampere limits. For example, feeder "getaways" (short connections in ducts at the substation) may result in higher or lower normal and/or emergency ampere limits. In terms of establishing cable ratings, when one cable in a duct is carrying its emergency rating, for an extended period of time all other cables in the same duct must be at or below normal feeder getaway ampere rating.

For the composite, the voltage criteria is that the primary feeder voltage, in secondary (120 volt base) terms, is not to exceed 126 V or be below 118.5 V under normal conditions. The 118.5 V excludes voltage drops on the laterals, distribution transformers, and secondaries. Voltage is not to be less than 114 V during emergency conditions.

Table 9.3-1

NIAGARA MOHAWK POWER CORPORATION
ESTIMATED LOAD GROWTH SUMMARY
BRIDGEPORT, FLY ROAD, AND PINE GROVE

Substation/Feeder	Peak Load - MVA (Critical Season)*	
Nonautomated System	1978	1984
Bridgeport		
16852	3.13	3.77**
16853	----	3.04**
16854	3.22	4.05
Total	6.35	10.86
Est. Sub. Load	6	10
Fly Road		
26151	5.0	7.64
26152	1.76	7.61
26153	7.02	8.07
Total	13.78	23.32
Est. Sub. Load	13	22
Pine Grove		
5951	4.46	4.05
5952	7.52	7.55
5953	2.97	5.83
5954	5.67	6.04
5955	4.46	5.30
5956	----	5.81
5957	----	4.09
Total	25.08	38.67
Est. Sub. Load	24	37

Source: Niagara Mohawk/General Electric Joint Assessment of Distribution Automation

NOTES:
*Critical season for some feeder peak loads is summer; for others it is winter. It is the season with the highest seasonal normal configuration peak load.
**16853 and 16852 loads are added for the automated case, since 16853 does not exist in the automated case.

Table 9.3-2

SUBSTATION TRANSFORMER RATINGS
BRIDGEPORT, FLY ROAD, AND PINE GROVE SUBSTATIONS

Substation	Transformer Type	Transformer Rating
Bridgeport	OA	8.4 MVA, 65 °C
Fly Road	OA/FA/FA	22.39 MVA, 65 °C
Pine Grove		
Bank #1*	OA/FA/FA	20 MVA, 55 °C
Bank #2	OA/FA/FA	33.6 MVA, 65 °C

*NOTE: Study assumed this transformer to be replaced with 18/24/30 MVA unit in 1983 or 1984 for non-automated system, and removed for automated system.

9.4 AUTOMATED COMPOSITE

The composite 13.2 kV distribution system is shown in Figure 9.4-1 with the addition of distribution automation control (DAC) equipment at the three distribution substations of interest: Bridgeport, Fly Road, and Pine Grove. Each of these DAC equipments would have two-way communication with the distribution dispatch center (DDC) which has overall responsibility for that area of the distribution system. Distribution automation control is more fully described in Section 6.2 of this report.

A distribution communication system would be utilized to communicate among the DAC equipments at the substation level and pole-mounted remote terminal units (RTU) located at automated sectionalizing switches, switched capacitor banks, etc. at remote control and monitoring points on the feeders. A number of distribution communication systems are being evaluated by electric utilities. Representative of communication means being considered are distribution line carrier, radio, and telephone.

Similarly, for control and monitoring of DSG units located on the distribution feeders, communications would be required between the DSG unit and either DAC equipment at the substation, the DDC, or the EMS level of the utility. The five assumed DSG units are shown on the automated composite in Figure 9.4-1. These are the same DSG units and locations listed in Table 9.2-1, the non-automated composite.

Only those automated sectionalizing points in the immediate vicinity of the DSG units on the feeders are shown in Figure 9.4-1. The automated sectionalizing points for automated feeder sectionalizing and feeder load management would be under direction of the DAC for the substation serving as the source for the respective feeders.

In choosing the sectionalizing points and tie points proposed for automated sectionalizing on the feeders, the following criteria were used:

- Deferment of construction projects
  - Feeder getaways
  - Substation transformer changeouts
- Service restoration to industrial loads
- Service restoration to commercial loads

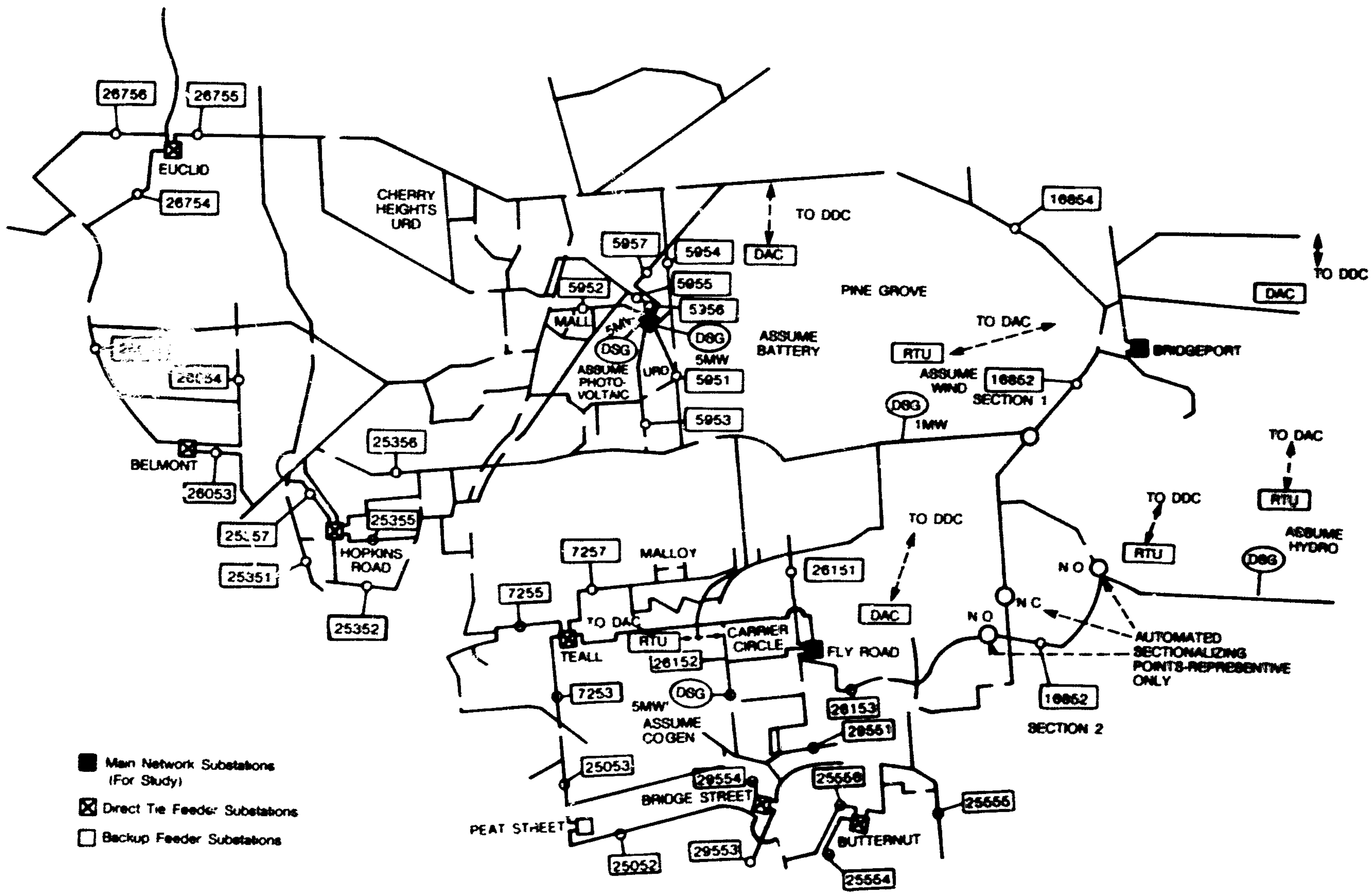


Figure 9.4-1. Illustrative Niagara Mohawk Composite with the Addition of DAC

9.5 CENTRALIZED VERSUS DECENTRALIZED CONTROL OF DSG UNITS

In Figure 9.1-1 and 9.4-1, DSG units have been assumed at Pine Grove substation, on Bridgeport feeders 16852, 16853 (16852A), and on Fly Road feeder 26152. In Sections 6.2 and 6.3 of this report, centralized and decentralized control and/or monitoring for DSG units are described. In the centralized control and monitoring of the DSG units, the distribution dispatch center (DDC) would communicate directly with each DSG unit. This is illustrated in Figure 9.5-1 below. Some larger DSG units may be controlled directly from the EMS level.

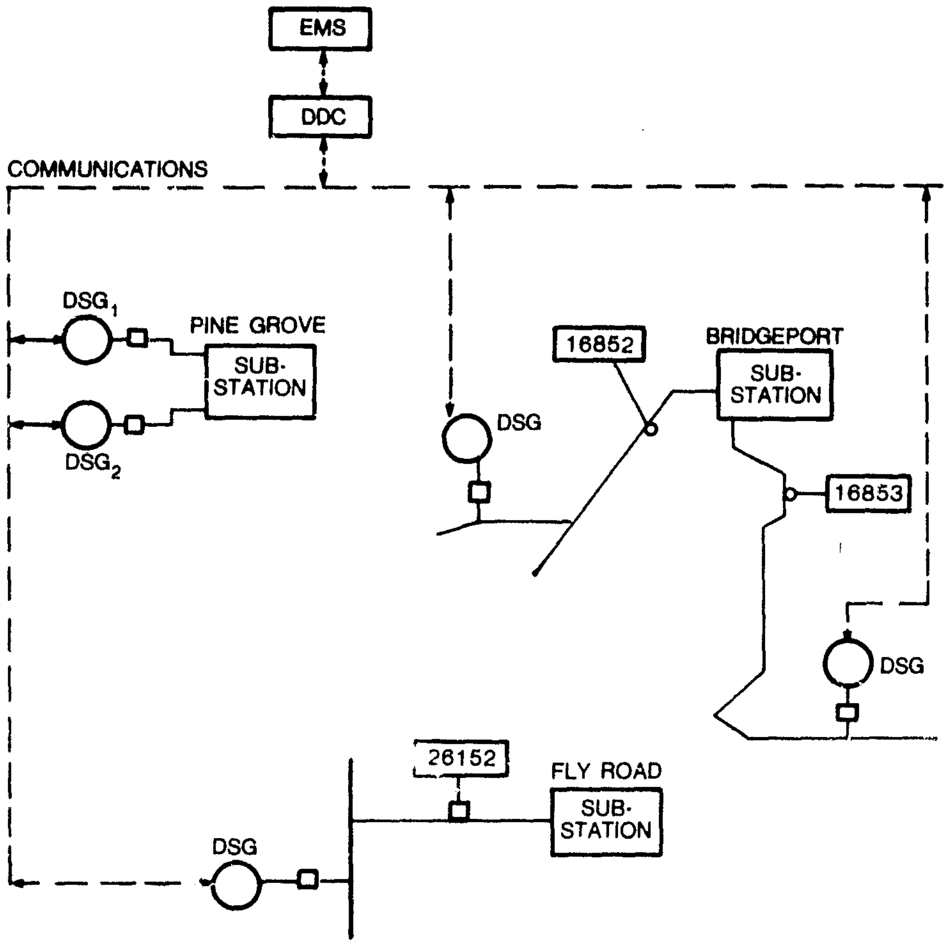


Figure 9.5-1. Centralized Control and Monitoring of DSG Units

With decentralized control and monitoring of the DSG units, the DSG control and monitoring function will be one of many functions performed by the DAC units at the substation. This type of control is shown in Figure 9.5-2.

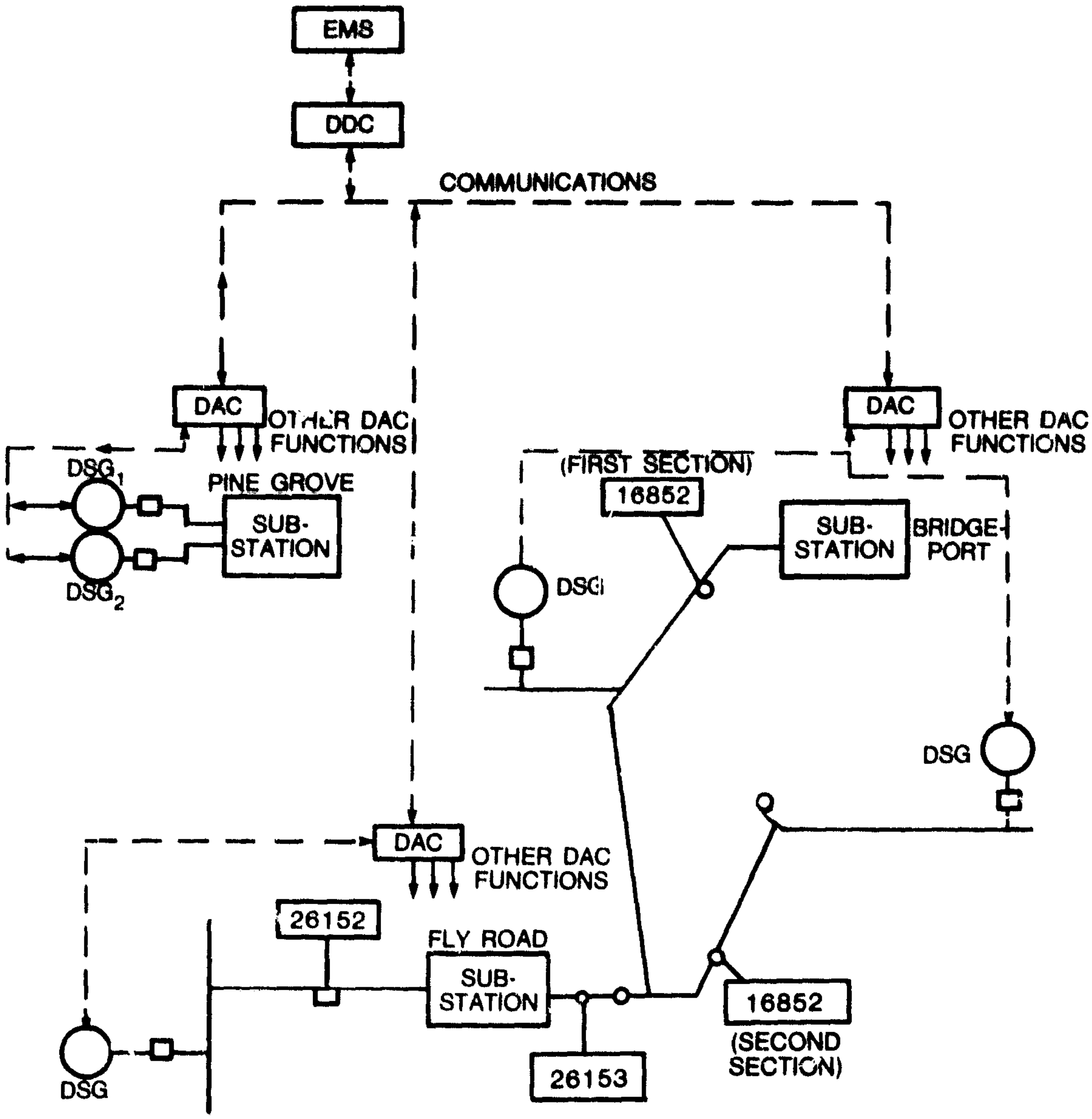


Figure 9.5-2. Decentralized Control and Monitoring of DSG Units

For small customer owned DSG units, the control may be based entirely on local conditions without any remote control signal to start-stop, or to raise-lower output. In this case (assuming communications to the DSG are provided), the only information monitored at a higher level control center may be ON-OFF status of the DSG unit.

9.6 OPERATING SCENARIO WITH CONCEPTUAL DSG INTEGRATION

Using the composite 13.2 kV distribution system, it is possible to envision a number of representative scenarios involving the operation of DSG units integrated with the distribution system. Several examples of these, used as aids in developing and checking the functional requirements for control and monitoring of DSG units, are described below.

Scenario 1. Startup DSG Units

Assume that the distribution system composite, shown in Figures 9.1-1 and 9.4-1, is in the normal operating state and that the schedulable DSG units (hydro, cogeneration, and battery) must be started up. Assume both a centralized (Figure 9.5-1) and a decentralized (Figure 9.5-2) control and monitoring system for control and communications. The hydro generator DSG and the cogeneration DSG will continue in normal operation for the scheduled period. The storage battery DSG supplies power to the distribution system for several hours and is then placed in a stand-by mode for a few additional hours before it is connected for recharging. The battery DSG is later put in a standby condition, and it will then be ready for the ON mode to supply power. Non-schedulable DSG units (wind generator and photovoltaic) may be permitted to start up, as the energy resources are available.

Scenario 2. Transient Fault Followed by Successful Reclose

Referring to Figure 9.1-1, the 13.2 kV non-automated composite is in the normal operating state. Distribution system load is peak load for the 1984 winter case and all DSG units are operating at rated output. A transient fault occurs on Bridgeport feeder 16853 between the substation and hydro unit. Assume a feeder breaker automatic reclosing sequence of 15, 30, and 90 seconds with the 30 second reclose successful. The hydro unit must be disconnected from the feeder circuit when the fault occurs. It can be restarted, resynchronized, and reconnected after the successful reclose.

Scenario 3. Persistent Fault, Unsuccessful Reclose

Assume the automated 13.2 kV composite shown in Figure 9.4-1 with all DSG units operating and system in the normal operating state. A persistent fault occurs in the section of Bridgeport feeder 16852, between the substation and the automated sectionalizing point connecting the DSG hydro. Reclosing of the feeder breaker goes through its sequence and locks out after tripping after the 90 second reclose. The feeder fault isolation and service restoration function must locate the persistent fault and isolate the faulted section. Assume (a) the tie to Fly Road feeder 26153 is not available for switching, and (b) the tie is available for switching. The hydro and wind DSG units must be disconnected from the feeder circuit during the reclosing sequence. The hydro DSG must be restarted, resynchronized, and reconnected to the unfaulted section of feeder 16852, after the fault has been isolated. The wind DSG cannot be reconnected since it is associated with the faulted section of feeder BR16852 and is locked out. Assuming the load on the second section of 16852 is 1 MW the power output of the DSG hydro unit in case (a) must match this load. In case (b), the full 5 MW output can be utilized with the tie closed to the Fly Road feeder 26153, assuming the tie can carry the surplus power from the hyrdo DSG.

The fault must be located properly as being on the first feeder section of feeder 16852 even though it is fed initially from the substation, and also from the wind and hydro DSG units.

Scenario 4. Operation with Distribution System in Emergency State

Assume the automated composite in Figure 9.4-1 with all DSG units operating and with distribution system in the alert state, due primarily to the Pine Grove 20 MVA transformer bank being out of service. Assume that the 30 MVA transformer at Pine Grove has been in service but is now forced out of service. A backup mobile transformer can be connected; however, it will be several hours before the mobile transformer arrives. Load conditions are 1984 peak with 33 MVA load in the Pine Grove area. The adjacent substation transformers are operating at their emergency ratings; both Pine Grove 5 MW DSG units are operating at their rating; and the remainder of the Pine load is supplied by ties to feeders from other substations. Assume now that the photovoltaic DSG unit at Pine Grove must be shut down and that no further load transfer capability from other substations is available. The remaining DSG, feeder ties, and adjacent substation transformers will be overloaded unless load is shed. This is accomplished by rotating the feeders on outage for 20 minutes each (Feeders 5951 through 5957) until the system peak is passed with intermittent overloads during this period. The distribution system is in the emergency state until the mobile transformer is connected and then enters the restorative state.

9.7 COMPOSITE APPROACH

While the composite 13.2 kV distribution system described in this section was developed during the course of another study, it has been described in this section to provide an illustration of conceptual DSG integration on the utility distribution system. By postulating the operating scenarios given in Section 9.6, the composite serves as an aid in better understanding the control and monitoring functional requirements for DSG integration.

As examples, the sequences associated with scenarios one through four of Section 9.6 are listed in Tables 9.7-1 through 9.7-4 respectively.

Table 9.7-1

SCENARIO 1. STARTUP OF DSG UNITS

(Reference Figures: 9.1-1 and 9.5-1
9.4-1 and 9.5-2)

Step 1.	Check DSG scheduling and mode control to determine which DSG units are needed and for what time periods.
Step 2.	Use Display to determine status of each DSG and distribution system for outages and personnel safety.
Step 3.	Check at DDC for protection status of substation, transformers, and feeders.
Step 4.	Command startup for schedulable DSG units which are available (example: hydro, cogeneration,* and battery) at proper time distribution SCADA and communication are employed to transmit command from DDC to DSG units. Send permissive signals to unschedulable DSGs which have intermittant energy resource supply.
Step 5.	DSG control will receive startup command and initiate checking action at each DSG to be started.
Step 6.	DSG protection will be checked.
Step 7.	DSG operating mode control logic will be initiated at each DSG to be started.
Step 8.	DSG power controls will be initialized prior to starting.
Step 9.	Startup and then synchronizing will be initiated and carried through to completion.
Step 10.	Verification will be received by the DDC operator that each DSG is connected to the system as this occurs.
Step 11.	Monitored values of DSG outputs, e.g., MW, MVAR, voltage, status are received at DDC.

*Cogeneration may not be completely schedulable in the usual sense.

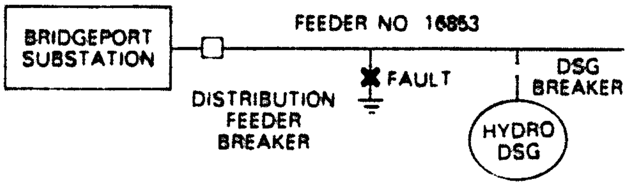
Notes:

1. The startup sequence noted above would be repeated for other schedulable DSGs according to the appropriate startup schedules.
2. The wind or photovoltaic DSGs are sent permissive commands allowing them to startup according to the availability of local energy resources.
3. For high temperature batteries, it is necessary that they be maintained at elevated temperatures, and it is not practical for them to be shut down in the usual sense. Special DSG controls and operating mode controls are used to keep high temperature batteries in their proper operating condition.
4. Development of a set of operational steps of activities for startup, such as indicated above, must be performed for each type of DSG and for each utility to be sure that all necessary activities are properly accounted for. This scenario approach enables the system designer to draw up a plan of action which engineering and operational personnel can use for discussion and evaluation to integrate DSGs into the distribution system.

Table 9.7-2

SCENARIO 2. TRANSIENT FAULT FOLLOWED BY SUCCESSFUL RECLOSE

(Reference Figures: 9.1-1 and 9.5-1)



Step 1. Fault occurs on Bridgeport Feeder 16853 ' [illegible] n substation and hydro DSG.

Step 2. Distribution feeder breaker opens.

Step 3. Hydro DSG protection detects fault conditions and trips hydro unit off line by opening DSG main circuit breaker.

Step 4. Emergency shutdown initiated by DSG protection function at hydro.

- A-1. Emergency shutdown control (special DSG control) at hydro is initiated to slow down the hydro generator, (and transition it safely to the OFF mode).
- A-2. Local DSG control at hydro alerted that hydro shutdown has been initiated.
- A-3. Personnel safety display indicates at hydro that hydro unit has been tripped off; a signal is initiated to inform DDC of trip by DSG control via SCADA and communication.
- A-4. Turbine speed control governor, DSG power control, acts to close flow valves to minimize generator overspeeding, and slow unit down as part of emergency shutdown sequence.

Step 5. Distribution protection initiates feeder reclosing sequence.

Step 6. Fault clears and voltage is restored to distribution feeder No. 16853 (via Bridgeport distribution substation) by means of feeder breaker reclosing.

Step 7. DDC display shows trip of the unit; the DDC operator must then command a restart of hydro to get DSG control at hydro to initiate a restart.

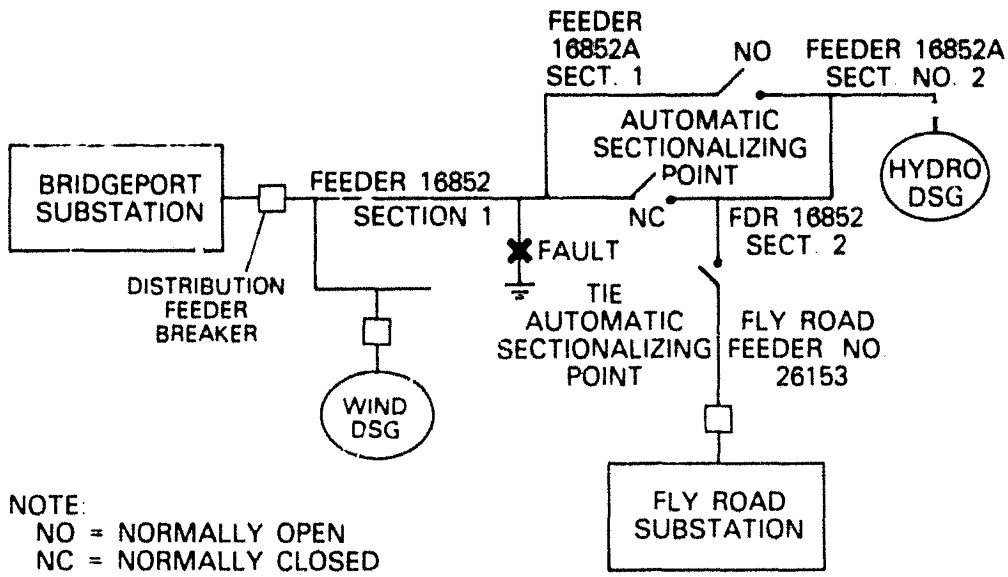
Step 8. The restart signal from DDC to hydro DSG control enables DSG operating mode control logic to bring hydro unit to standby (or ON) mode.

Step 9. Hydro plant DSG control (master control) restores power schedule to normal value as established by and from DDC.

Table 9.7-3

SCENARIO 3. PERSISTENT TRANSIENT FAULT
WITH UNSUCCESSFUL RECLOSE
(with Distribution Automation Control Equipment)

(Reference Figures: 9.4-1 and 9.5-2)



The initiation of scenario 3 is similar to scenario 2 with a fault postulated on the first section of feeder 16852. The sequence is identical until Step 6 when the fault persists and the feeder breaker BP16852 trips the final time and is locked out (open). The BP16852 automatic sectionalizing point opens on the faulted feeder on command from the DAC equipment, isolating the fault.

Under case a, the tie automatic sectionalizing point to Fly Road Feeder No. 26153 is unable to close so that only the hydro DSG is available to supply the load (island) of the unfaulted section of 16852. Since the wind DSG is associated with the faulted section of feeder 16852, it must remain OFF. The hydro DSG power control may require a signal from the DSG operating mode control to change its power control to an alternative method such as isocronous ("flat frequency") control.

Steps 1-5 are like those for Scenario 2, with the wind DSG unit also tripping off in Step 3.

Step 6. Feeder breaker 16852 is locked out, and auto sectionalizing point is opened, isolating the fault on the first section of feeder BP16852.

Step 7. The hydro unit is isolated in the OFF mode and must be restarted, connected to feeder 16852A, section 2, and must pickup load. There is no other generation available to supply the load on section 2 of the BP16852 feeder, (1 MW load assumed).

Table 9.7-3 (Cont'd)

SCENARIO 3. PERSISTENT TRANSIENT FAULT
WITH UNSUCCESSFUL RECLOSE
(with Distribution Automation Control Equipment)

(Reference Figures: 9.4-1 and 9.5-2)

Step 8.	DDC display shows trip of unit and indicates that it is isolated. The operator at DDG must command DSG control at hydro to restart under "island" conditions.
Step 9.	Restart signal from DDC to hydro enables DSG control and DSG mode control logic to bring hydro unit up to standby (or ON) mode. Note: The system frequency on the de-energized, unfaulted, feeder 16852, section 2 will be zero, and there will be zero voltage. This requires the DSG control to modify the automatic synchronizing permissive circuits to carry out closing of DSG main breaker on to a dead line.
Step 10.	DSG operating mode control acting in response to information from DSG control must select a special "stand alone" capability method of operation. Under this control condition, the hydro unit must match its power output to the load requirements to maintain frequency control by itself. The power supplied through the DSG power function control should be just enough to keep the system "island" frequency at 60 Hz. Under case b the tie auto sectionalizing point is able to close, on command from the DAC equipment connecting the second (unfaulted) section of BP16852 to Fly Road feeder 26153 which, in conjunction with the restarted hydro, serves this second section of feeder load. This situation is very much the same for the hydro DSG as in scenario 2: see steps 6-9 of scenario 2, where the source voltage restored in this case corresponds to the tie to feeder FR26153. This new feeder source appears to the DSG like the feeder of the previous scenario 2. However both feeder FR26153 and DSG protection logic may have to be adjusted to reflect new circuit parameters. It is assumed that the tie to feeder FP26153 is capable of carrying the 4 MW surplus power from the hydro DSG, (5 MW DSG output - 1 MW load on BR16852, section 2 feeder).

Table 9.7-4

SCENARIO 4. OPERATION WITH DISTRIBUTION SYSTEM IN EMERGENCY STATE

(Reference Figures: 9.4-1 and 9.5-2)

Pine Grove is in an alert state and the 30 MVA transformer bank in the automated case is loaded to maximum capacity at the time of peak load. When the 30 MVA transformer is disconnected due to a forced outage, the whole composite goes into an emergency state. With the additional forced outage of the photovoltaic DSG, the situation is made worse. At Pine Grove substation, the remaining storage battery DSG is called upon for maximum power output, and feeder units are required to use load shedding by rotating the feeders on outage for 20 minutes each, until the system peak is passed. Intermittent overloading is experienced during this period.

Load shedding is done as a part of distribution automation and control. DSG control is not normally involved in that aspect of the control operation. However, the storage battery might be called upon to use its energy at a higher than normal rate for a couple of hours during the peak loading period.

Step 1. Under alert or emergency conditions, the DDC operator would interrogate the DSG scheduling subfunction, note that the photovoltaic DSG is out and that more power from the storage battery is desired.

Step 2. A revised storage battery schedule could be determined and displayed to the operator at the DDC.

Step 3. If agreeable to the operator, the revised schedule could be forwarded to the storage battery DSG.

Thus, during alert or emergency conditions, DSGs may be called upon to operate in an abnormal state, supplying more power than their nominal ratings. The capability to do this depends on the DSG type and the specific capabilities built into the DSG design. Being aware of the nature of the emergency and being able to reschedule DSGs for more than their nominal rated output can help alleviate distribution emergency conditions.

Section 10

COST-AND-BENEFIT ANALYSIS

10.1 INTRODUCTION

Although the major interest of this study is focused on the technical aspects of the monitoring and control requirements of the distribution DSG system, the cost and benefit implications of the various DSG alternatives were also investigated. The benefits of DSG may accrue in the generation and transmission portions of the utility system, while the costs tend to be centered in the distribution portion of the utility system; so it is important that the costs and benefits of the whole system can be analyzed and judged.

Alternative methods exist for supplying some of the energy needs of the customers of an electric utility system.[10] Several DSG technologies are potentially available to supplement the basic generation needs. However not all DSGs are available at all times of day or night nor is the cost per installed kW or per kWh delivered the same for each. In addition, there are alternative means for accomplishing the task of monitoring and control of the DSGs and these means may have different costs and benefits. It is desirable to be able to evaluate the relative costs and benefits of different DSGs. Conventional means exist for evaluating economic cost and benefits for such electric utility equipments, and the methods described in this report are meant to represent appropriate extensions of present methods.

The costs being considered cover the total costs for DSG including the associated equipment, land, interest charges, construction, installation, and services, and the subsequent operation and maintenance costs. Costs for the DSG equipment and services to provide dispersed storage and generation, for the added remote monitoring and control equipment and installation, and for the added operating and maintenance costs associated with the dispersed storage and generation are included.

The benefits being considered should include reduced costs for equipment, installation, services, or operations and maintenance that might have been planned or required but, by virtue of DSGs, are no longer needed. Benefits also take into account the savings corresponding to reduced losses or reduced expenditures for energy. Benefits may be realized from reduced generation, transmission, or distribution costs. The benefit may be a one-time sum stemming from the deferment of a particular investment or it may be annual savings generated by the reduction or elimination of energy purchases that would be required each year.

Appendix D, "Cost Benefit Considerations for Providing Dispersed Storage and Generation to Electric Utilities," covers the general and quantitative elements of costs and benefits pertaining to DSGs. This section covers some other aspects of DSG applications. Included are:

- The influence of DSG equipment cost and availability, i.e., total initial costs and amount of time availability;
- The nature of other cost issues, such as the monitoring and control costs as compared with the DSG equipment costs and the cost of DSG equipment when it is owned by the utility or when it is owned by the customer;
- The nature of the benefits that may be realized at the generation, transmission, and the distribution levels in the electric utility system;
- A few numerical examples of cost and/or benefits for illustrative comparisons.

10.2 CHARACTERISTICS OF DSG TECHNOLOGIES

In performing cost analyses associated with different DSG technologies there are a number of characteristics that are of significance. These include the following:

- DSG Cost per kW of installed capacity
- Cost of other elements that are necessary but are not included in cost given for installed capacity
- Availability of DSG in per-unit time and in terms of time of day and days of year
- Nominal rating of DSG unit

Table 10.2-1 shows some representative values that have been assumed as being typical for the seven types of DSGs indicated. The numbers shown are estimated values that have been selected for illustrative purposes to indicate the range of costs that may be associated with the DSGs that have been listed. Table 10.2-1 is not intended to provide a basis for making specific selections for particular DSGs but rather to illustrate the fact that there are a number of different characteristics and that the specific values of these characteristics may vary widely from DSG to DSG.

Table 10.2-1

ASSUMED REPRESENTATIVE VALUES FOR
DSG COST/kW, AVAILABILITY, AND NOMINAL SIZE
FOR VARIOUS DSG TECHNOLOGIES

DSG Technology	DSG Cost $/kW (1978 $)	Other Major Elements Required (but not included in COST)	Time Availability in Per-Unit of Time	Nominal Rating in MW
Solar Thermal Electric	1300		0.30	1-10
Photovoltaic	3500-5000	Converter	0.30	0.1-5
Wind	1000		0.30	0.1-5
Fuel Cell	350	Converter	0.85	2-25
Storage Battery	350-450	Converter	0.30	2-20
Hydro	500-1000	Dam	0.50	1-25
Cogeneration	800	(Process)	0.3-0.80	1-20

As has been noted in Appendix B, "The State of the Art, Trends, and Potential Growth of Selected DSG Technologies," the development status of the DSGs being considered varies widely. Thus, the initial cost range shown in Table 10.2-1 is more than 10 to 1. However, with continued development, DSG cost in $/kW will in all probability be reduced. However, there will doubtless continue to be significant differences in DSG equipment costs due to the characteristics of the DSGs involved.

The need for other major items of equipment such as dc-ac converters for technologies that produce direct-current electricity initially, or for dams not already present that are required by hydrogeneration involve significant items of additional cost that must be included in a cost analysis.

The time availability of certain DSGs, such as solar thermal electric, photovoltaic, or wind and others will be limited by the physical nature of the phenomenon involved. In most cases there will not be a significant increase in the availability assumed; although, unscheduled outages or unusual weather conditions may reduce the availability.

Concerning the nominal rating in megawatts indicated, the upper range of ratings listed might be attractive to utilities to install DSGs for their own use. For individual customers who may have much smaller energy needs and who may wish to purchase their own DSG, the units involved may be considerably smaller than those of Table 10.2-1. However, in those cases involving customer DSGs much of the monitoring and control requirements will probably be the primary responsibility of the customer and not the utility. Where the customer owns the DSG, the costs to the utility will be negotiated with the customer and not be directly related to the DSG cost in $/kW shown in Table 10.2-1.

10.3 DISTRIBUTION DSG SYSTEM COST COMPONENTS

Cost components can be grouped into three major categories: equipment costs; installation costs; and operations and maintenance costs, which include the energy costs. The equipment and installation costs are essentially one-time, fixed costs that, by means of an annual fixed charge rate (FCR), can be converted into an annual cost. The operating and maintenance costs are annual charges and are used in that fashion. Another factor that must be considered as affecting the system cost is the time availability of the equipment, because low time availability may require additional capital equipment to meet the essential system needs.

The cost components noted above must be applied to each of the equipment elements that make up the distribution DSG system. Because there can be extensive communication and control costs, including the equipment at the DDC site, associated with the integration of the DSG into the utility network, it is important to recognize and include all the equipment items associated with the distribution DSG system.

The equipment costs cover the supplier costs of the equipment that is the essential DSG system as well as the supplier costs of such other distribution DSG system items as:

1. The communication link with the distribution dispatch center (DDC) if this is utility owned.
2. The interface and control equipment that is located at the DDC that enables the distribution dispatcher to interact with the remote DSG.
3. The interface and control equipment that is located at the DSG that interfaces the communication link and the DSG local control equipment.
4. The system DSG power protection interface equipment that enables the DSG power equipment to operate compatibly with the utility distribution network.

The essential DSG system should include not only the electrical generation means and its local control, but also the balance of plant as well as any necessary associated expenses (for example, the cost of the land and dam for a new hydro DSG system).

The installation costs are another one-time cost and should include not only the hardware installation cost but the software installation costs as well.

Operation and maintenance costs include not only personnel costs and consumable materials for operation and maintenance, but also the energy costs or losses associated with the distribution DSG system. With increasing energy costs, the operation and maintenance cost category could represent a significant portion of the total cost over the life of the plant.

If storage or backup equipment is required for the DSG and included as an added element to the overall system, then its own equipment, installation, and operation and maintenance costs will have to be taken into account.

10.4 SYSTEM BENEFIT COMPONENTS

In considering the overall benefits of the distribution DSG system, it is convenient to group the benefits to the utility into four major components:

- Investment-related savings
- Interruption-related savings
- Customer-related savings
- Operation and maintenance savings

Investment-related savings are the result of deferring previously planned major incremental expenditures for such items as new substations, new transformers, new feeders, or new generation and transmission facilities. With the higher cost of equipment and mortgage money, investment-related savings can represent a significant element of the benefits.

Interruption-related savings refer to the fact that with dispersed storage and generation, failures at the central stations and on the major transmission lines can be relieved in part through the use of the dispersed storage and generation capacity.

Customer-related savings are benefits that accrue from few customer outages, less expense for customer complaints, and so forth.

Operation and maintenance benefits refer to manpower, material, and energy cost savings that may result from use of renewable resources in contrast to the purchase of fossil fuels. Unattended operation of DSG as contrasted with use of manned sites would represent another operation and maintenance benefit.

In evaluating the distribution DSG system benefits, it is essential that the effects on the overall electric utility system be considered.

An electric utility system is traditionally described in terms of its generation, transmission, and distribution power characteristics as is indicated schematically in Figure 10.4-1. The generation, transmission, and distribution structure that is shown as a single line in this figure is generally, in fact, a plurality of generation sources and transmission lines. The generation sources are interconnected to variously sized loads, either directly through large transmission ties or indirectly through a distribution network.

The addition of dispersed storage and generation will in general require the use of an energy management system as shown in Figure 10.4-1 to obtain the maximum benefit from a distribution DSG system. In considering costs and benefits it is important to be aware of the various characteristics of the electric utility

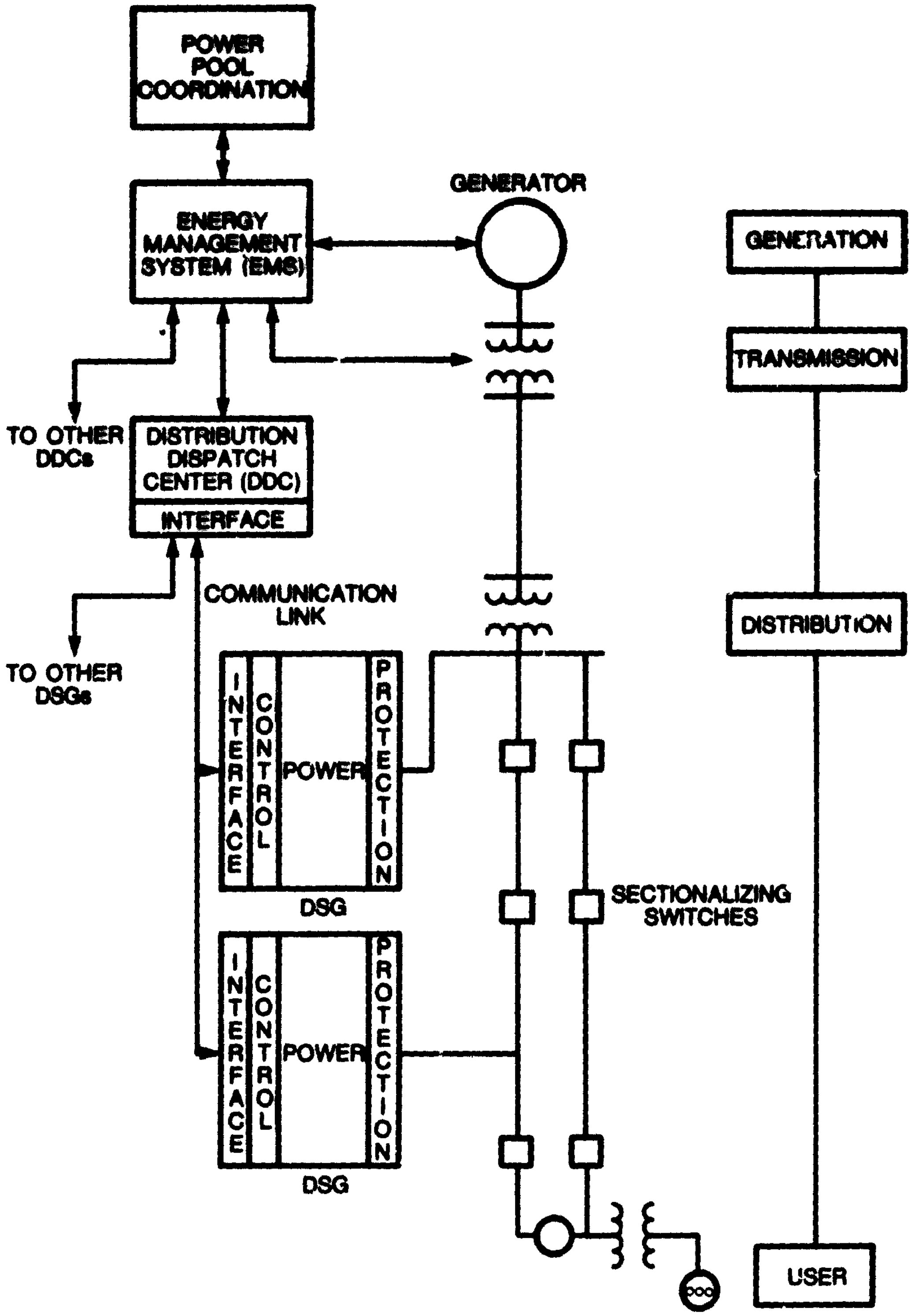


Figure 10.4-1. Electric Utility System Showing Power System and DSG with Associated DSG Equipment

system that are of importance as they relate to the costs and benefits with and without dispersed storage and generation.

For example, the generation shown in Figure 10.4-1 by a single block actually consists of several sources of generation, placed at different geographical locations, with different sized generating units with different fuel types as well as equipment of different thermal efficiencies and therefore different costs. It is important to note that these multiple sources of generation may have different standby and startup costs and therefore operating decisions are made depending on each particular generator's characteristics. These generators may have different operating costs at different amounts of loading for the generator. For example, some units may have certain inefficiencies in valving when they are operated at one load level as contrasted with considerably different efficiencies when operated at neighboring load levels. Furthermore, an incremental amount of load that is supplied at a certain time of day may result in a considerably different cost than at a different time because of the generation source used. Thus, it is important to know the characteristics of the several sources of generation involved.

With regard to transmission, there may be different amounts of losses in transmission depending on the relative location of the source of power generation and the location of the load. This may result in a significant change in the cost of the energy. Thus the transmission characteristics can have a significant effect on the cost of the energy supplied to a load in a particular part of a given utility network.

The distribution characteristics may also have quite a marked influence on the cost of supplying a given load. By use of communication and control it is possible for the energy management system and the distribution dispatch center to schedule more economically the generation that takes place at the local distribution level. Hence it is quite important that the characteristics of the electric utility system, for which dispersed storage and generation is being considered, be understood in detail as far as performance, cost, and availability are concerned.

10.5 INFLUENCE OF SIZE OF DSG UNITS ON COST AND BENEFITS

The advent of dispersed storage and generation has opened the possibility of using small generators located at the customer's site and of selling power generated by the customer to the utility. In order to differentiate among the cost and benefit conditions that are present for the various size, quantity, and ownership of DSGs, consider Table 10.5-1.

Table 10.5-1

COMPARISON OF COST AND BENEFIT FOR DIFFERENT DSG SIZES AND BENEFITS

DSG Characteristics	Few (under 10)	Several (10-50)	Many (50-1000)
Small (0.01-0.5 MW)	• Customer Pays DSG Equipment Costs and for Basic Energy • Utility Pays for DDC, Communication and Interface Equipment Costs • Utility Pays Customer for kWh Supplied by Customer to Utility • Utility May Benefit on Generator, Transmission, Distribution Losses, and Equipment Costs • Customer Has a Reliability Benefit Factor		• Similar to Case of a Few Small DSGs • Utility DDC and Communication Costs Can Be Spread over a Larger Number of Units • Utility Has a Reliability Penalty
Medium 5-5 MW)	(The Cases of Medium-Sized Units, Rather Than Small or Large, and of Several Units, Rather Than Few or Many, Tend To Be Intermediate Rather Than the Extremes Shown)		
Large (5-30 MW)	• Utility Pays DSG Equipment Cost • Utility Pays Primary DSG Energy Costs • Utility Pays for DDC, Communication, and Interface Equipment Costs and Maintenance • Utility May Benefit on Generation, Transmission, Distribution Losses, and Equipment Costs • Customer Has a Reliability Benefit		• Similar to Case of a Few Large DSGs • Utility DDC and Communication Costs Can Be Spread over a Larger Number of Units • Added Communication and Data Processing May Be Required

Although the range of DSG sizes can be from small to large and the number of units on a utility distribution system go from few to many, the cases for a few small units and a few large units will be considered first. The small units are assumed to be customer owned and the DSG equipment costs are not a direct concern of the utility except as they may affect the cost for energy that the customer will want the utility to pay. However, the DDC, communication, and interface equipment will have to be compatible with the remainder of the utility equipment. These will be utility expenses that will have to be paid for by the customer on the basis of relatively few kWh per year. In addition, the utility will have to pay the customer for the energy supplied to the utility. This will probably be rather a small amount because the units are small to begin with. Reduced losses may occur and these may benefit the utility. Because the utility may be able to get along with a somewhat smaller amount of generation and transmission capacity if the utility buys some electrical energy from the customers, there may be investment benefits or penalties that are realized by the utility. The customer has a second source of power and can benefit from improved reliability.

Large units are likely to be owned and operated by the utility. Again, the utility would pay the DDC, communication, and interface equipment costs, but this time it would be on the basis of a much larger number of kWh per year so that the per-unit cost could be much lower. The generation, transmission, and distribution losses could be reduced and investment benefits realized. Again, the customer would benefit from a reliability improvement.

As the number of DSG units increases significantly, the same general ownership and cost relationships would tend to hold, but there would doubtless be some size effects. Because not much control and monitoring data were needed for the small-sized units, with more units DDC and communication equipment could perhaps be used more effectively. On the other hand, there might be more data desired on the larger units, and the DDC and communications equipment might tend to be overloaded. This case of the larger units is probably something that can be managed, because with larger units there will still be fewer units than there are with the small-sized units. Further, with more large units it will be less important if one is not operating well or at all than if there were only a few large units.

A similar line of reasoning may be applied to the case of medium-sized units and several units. The results should be intermediate and bracketed by the cases that have already been considered.

Critical areas that appear to be developing in the use of small DSGs are (1) the relatively high cost of DSG equipment to the customer with a small DSG and therefore the need for the customer to receive a high rate for the energy purchased by the utility; and (2) the relatively high cost of DDC and communication equipment to the utility, which the utility must charge to the customer versus the small amount of energy that the utility is able to purchase. By holding down the amount of control and monitoring of small customer-owned DSGs, the utility may be able to minimize the customer costs caused by this situation.

In view of the interest that has been expressed for using small residential DSGs, it is worthwhile to consider some of the more significant issues involved in such generation sources as photovoltaic and wind that could be used for supplying electric power to the utility. Some of these issues include:

- How much power may be generated per DSG and therefore how much benefit might result from this source of energy?
- Are the communication needs expressed in terms of costs per DSG?
- How much central control and monitoring is needed at the DDC?
- What is the potential cost associated with these needs?

Photovoltaic and wind generators are being developed in the 6 to 10 peak kW range for residential use. On the other hand, the average single-family dwelling residential load is considered to amount to 2 kW. Thus for the single-family dwelling there may be times when there is a surplus of 4 to 8 kW per DSG available to be fed back into the utility. Assuming a capacity factor (or availability) of 0.3 and a selling price of \$0.05/kWh, this amount could be -

8 kW x 0.3 x 8760 hrs/yr = 21,000 kWh/yr

21,000 kWh x \$0.05/kWh = \$1,050 yr   income/DSG

For a DSG equipment cost including the installation of \$1,000/kW and a fixed cost rate (FCR) of 0.20 per year, the annual cost for a 10 kW unit in terms of utility thinking would be -

\$1,000/kW x 10 kW x 0.20 = \$2,000/yr/DSG

In Appendix D, the total costs for the communication needs of a single DSG such as might be required for a 5 MW utility installation were considered to be \$3,000/yr per DSG. For the power generated per year with a 0.5 availability factor, this cost amounted to less than \$0.002/kWh and did not represent an unreasonable cost burden. However, for a 10 kW DSG associated with a single-family dwelling such is not the case and alternative communication means should be sought.

The communication needs for controlling electricity to a single-family dwelling have been considered must extensively in recent times in connection with the load management of remotely controllable major appliances such as water heaters, air conditioning, and electric heating. Equipment costs of the order of 100 to 150 dollars per house have been estimated for the communication needs that might be required for such ON-OFF remote load control. These cost figures are based on large numbers of customers (thousands, perhaps) being supplied from a remote central control. In the event that a comparable number of DSGs located at the customers' houses would require relatively simple data transfer, it might be possible for communication costs comparable to those for load management to be realized. Furthermore, if such load management communication means to the residential customer already existed, the incremental equipment costs per DSG installation might fall to the \$10 to \$20 per DSG range.

Referring again to Appendix D, the total costs for equipment, installation, and operating and maintenance for DDC monitoring and control amounted to \$8,200/yr/DSG. This amount was based on 20 DSGs per DDC. Expressed in terms of the 5 MW utility DSG power generation capacity, this cost for DDC monitoring and control was considered acceptable.

For 10 kW single-family residential units this monitoring and control cost is far beyond what can be afforded and represents performance beyond what may be required. Using 1000 or more single-family DSGs, considerable reduced annual costs per DSG, in the order of $164/DSG, could be obtained. It would appear that to accomplish this result there would have to be a considerably different structuring and use for the DDC for monitoring and control of small DSGs than has been listed in many of the functions described in Section 8. Efforts should be made to integrate in an appropriate fashion the differing needs for monitoring and control of small, medium, and large DSGs.

10.6 ILLUSTRATIVE COMPARISONS OF COSTS AND BENEFITS

In order to provide an illustrative comparison of costs and benefits for some representative cases of DSG technology alternatives, the following cases have been considered using representative data developed in Appendix D. Although the data have been related to those cases described for the NMPC composite, this information is intended to be representative of a type of situation rather than being strictly applicable to the NMPC composite.

Case 1. Four 5 MW fuel cells at separate locations.

Case 2. Four 5 MW hydrogenerators at separate locations.

Case 3. Four 20 kW customer-owned DSGs at separate locations supplying power to the utility distribution network.

CASE I. FOUR LARGE 5 MW FUEL CELLS AT SEPARATE LOCATIONS

Fuel cells are used in this instance because of the low equipment cost per kW of 350 $/kW. Although fuel charges will be associated with the fuel cells, these costs are less or comparable to the utility generation costs at the same times.

For the fuel cells, the following average annual cost components are incurred:

Fixed-Charge Cost/yr	= 0.028 $/kWh
Energy Cost/yr	= 0.030
O&M Cost/yr	= 0.005
DSG (Fuel Cell) Total Cost	= 0.063 $/kWh

For the DDG, communications, and protection equipment for the four DSG sites, the following annual costs are incurred:

DDC Control and Monitoring Equipment	= $32,800/yr
DDC – DSG Communication Equipment	= $12,000/yr
DSG Power Protection Equipment	= $41,000/yr
	$85,800/yr

With these DDC, communication, and protection equipment charges, the average annual cost amounts to

$$\frac{\$85,800}{20,000 \text{ kW} \times 0.4 \times 8760 \text{ hr}} = 0.001 \text{ \$/kWh}$$

Thus the fuel cell DSG total average cost is

0.064 $/kWh

CASE 2. FOUR 5 MW HYDROGENERATORS AT SEPARATE LOCATIONS

Hydrogeneration is used in this case because the energy cost for water is assumed to be zero although the equipment cost amounts to $1,000/kW which includes the cost of installation.

For the four hydrogenerators, the following cost components are incurred:

Fixed-Charge Cost/yr	= 0.046 $/kWh
Energy Cost/yr	= 0.000
Operation and Maintenance Cost/yr	= 0.002
DSG, Communication, and Protection Cost/yr	= 0.001
Total Hydro Average Cost	= 0.049 $/kWh

As noted in Section 6.6 of Appendix D, there are available in New York State certain hydrogeneration sites where lower equipment costs, such as those in the range of $500/kW, with a 25% cost for installation cleanup, are obtainable. Under conditions such as these even more favorable cost figures for hydrogeneration than that noted above result. The total cost, including the monitoring and control equipment and operations, would amount to $0.031/KWh. Thus it is necessary to consider each DSG installation on its own merits and to take into account the particular benefits associated with that installation and energy source.

CASE 3. FOUR 20 KW WIND OR PHOTOVOLTAIC GENERATORS AT SEPARATE CUSTOMER LOCATIONS

The full rating of these equipments will be considered to be available to the utility only 20% of the time.

Because the equipment is owned by the customer, there are no fixed charges to the utility. However, the utility would be responsible for the DDC control and monitoring equipment as well as the DDC-to-DSG communication equipment. Presumably the cost of the DSG protection equipment would be charged to the customer rather than to the utility. Thus, the following charges would be incurred by the utility:

DDC Control and Monitoring Equipment	= $32,800/yr
DDC-to-DSG Communication Equipment	= 12,000
Total DDC Control and Communication Charges	= $44,800/yr

Over a one-year usage period, with the above-noted control and communication charges, the annual average cost would be

$$\frac{\$44,800/\text{yr}}{4 \times 20\ \text{kW} \times 0.2 \times 8760} = 0.319\ \$/\text{kWh}$$

The energy cost that the utility would have to pay would be additional and might amount to 0.060 $/kWh.

Thus, despite the fact that there might be no cost to the utility for the DSG equipment, the utility would still have a total cost of $0.379/kWh because of the large DDC monitoring and control charges.

From the above, a reduced charge for DDC and communication costs would have to be obtained before the utility would be able to justify getting from the customer the relatively small amount of energy involved. Obviously, a simpler DDC and communication means appears to be called for and can be made available.

Recent rulings of the Federal Energy Regulatory Commission relative to the Regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 with regard to Small Power Production and Cogeneration will, it is hoped, be of help in bringing about workable solutions to situations of the sort that have been illustrated above.

10.7 OBSERVATIONS

- The costs and benefits for monitoring and control of DSGs must be considered with respect to the whole system including generation and transmission and not on the basis of distribution alone.
- The equipment costs in terms of $/kW for different DSG technologies vary over a range of more than 10 to 1 and are generally higher than present means for central power generation. This is especially the case considering the low time availability of the primary energy source for certain DSG technologies.
- The relationships between the control and monitoring equipment and performance and the total system benefits are not readily identifiable or directly quantifiable on a general basis. To establish the relationships it is necessary to have an intimate knowledge of the specific overall electric utility system and its generation, transmission, and distribution characteristics.
- For larger DSGs, i.e., greater than 5 MW, the cost of a rather complete DDC monitoring and control means seems to be a rather small portion (less than 3%) of the total DSG and control costs.
- For smaller DSGs, i.e., less than 0.1 MW and customer owned, a much simpler monitoring and control means seems to be required on a cost-and-benefit basis.
- Cost-and-benefit analysis should be considered in the distribution DSG system design as it affects control and monitoring. However, the nature of the cost-and-benefit analysis done on this project is not such as to be the basis for an economic justification for the purchase of a DSG. Future energy prices will doubtless be higher, and, under those circumstances, the economic attractiveness of DSGs will be enhanced.
- Since there are many causes for uncertainty in the parameters and quantities that are used in the cost-and-benefit calculations, it is desirable that simple, approximate methods for evaluation be used initially to identify those DSG technologies that are more likely to be used and the control and monitoring means associated with them. Once the more economically attractive DSG alternatives have been identified, more exact and detailed cost-and-benefit calculations should be employed.

Section 11

CONCLUSIONS

In some of the previous sections a number of detailed observations have been presented that contain conclusions pertinent to that particular section. The reader is referred to those sections for those additional conclusions to the more general conclusions listed below.

1. The results of the DSG Monitoring and Control Requirement Definition Study indicate that there are no fundamental technical obstacles to prevent the connection of dispersed storage and generation to the distribution system although much work remains to be accomplished.

2. A communication system of considerable sophistication is required to integrate the distribution dispatch center (DDC) into the many possible DSGs of differing sizes, energy characteristics, and types of owners. When the possible use of extensive distribution automation and control, and load management is included, the system means for integrating the power and the control means of the distribution system including DSGs become increasingly complex.

3. The seven different DSGs studied appear to be capable of operation from a common control interface at the distribution dispatch center. However, a certain measure of customizing at the DSGs is required to accommodate the different DSGs to the DDC interface. A significant amount of advanced engineering applications work remains to be done to accomplish the desired engineering results for such integrated systems.

4. The functional requirements for DSG integration indicate the importance of –

   - Increased communication. In addition to providing the means for information flow, it is necessary to keep track of much data from many sources.
   - Utility control hierarchy. The organization of the monitoring and control structure to place proper emphasis on the power and control functions in an economical fashion.
   - Personnel safety. Utility operating personnel are required from time to time to work on the distribution system. With an increasing number of DSGs on the distribution system, a greater effort is needed to ensure that there will be no degradation in the level of personnel safety.

   To achieve these requirements with hardware of low cost implies the standardization of –

   - System architecture and interfaces
   - Communication protocols

- Operator interface
- DSG protective interface
- DSG control interface

5. The selected DSGs that were studied varied in the detail of their local controls and in their input control requirements. In terms of their outputs, however, these DSGs have a relatively small number of different characteristics, such as —

- Alternating current or direct current in terms of primary energy output
- Schedulable or nonschedulable in their energy availability

DSG size can have an important influence on the extent of central controllability required by the utility:

- Small DSGs do not have to have the power closely controlled and may be considered as a variable negative load
- Larger units warrant greater control of their power and may be considered as an alternative to central generation

Some DSGs that are owned by the customer may be of such a nature that the customer is unable or unwilling to let the utility control his power generation. For other customer-owned DSGs, arrangements may be made for the utility to obtain control of the scheduling of such units.

6. The 3000/1 size span of DSGs being considered, from 10 kW to 30 MW, is so great that appropriate monitoring and control means for the larger units may not be suitable for the smaller ones. For larger DSGs, i.e., greater than 5 MW, the cost of a rather complete DDC monitoring and control means seems to be a rather small portion (less than 3%) of the total DSG and control costs. For smaller DSGs, i.e., less than 0.1 MW and customer-owned, a much simpler, less expensive, monitoring and control means may be all that can be justified economically.

7. Several possible states, i.e., normal, emergency, and so forth, exist for a DSG as well as for its associated distribution system. A major effort is required to establish the control logic for the selection of the proper control mode for a DSG at each time period. Coordination of the DSG and of the distribution protection means must be developed and implemented.

8. The six major functional requirements categories listed below provide a useful frame of reference for partitioning and describing the DSG monitoring and control requirements. These requirements are helpful in establishing a useful hierarchy of control and in relating the DSGs to existing and planned distribution systems. As such, such requirements can serve as a base

for future work on monitoring and control and can provide a means for more ready exchange of information among utilities, suppliers, customers, and others in integrated DSG distribution systems.

A. Control and monitoring requirements. These requirements are associated with the way the DDC operator and/or EMS interact at the distribution dispatch center level to provide information about and to be able to command and control remotely those DSGs on the system. This function represents the overall, top-level control of the DSGs.

B. Power flow and quality requirements. These requirements relate primarily to the power characteristics of the DSG and as such serve to define what is physically possible from the DSG or what is essential from the point of view of the distribution network. This function pertains to the characteristics and control of the power generation or power storage process or equipment.

C. Communication and data handling requirements. These requirements pertain to the necessary information transfer and data handling between the DDC and DSGs, the data transfer interfaces between these equipments and the communication links, and the associated and necessary information processing at the DDC. These functions are primarily involved in the transfer of command and control data from the DDC to the DSGs and the return of monitoring (normal and alarm) data from the DSGs to the DDC.

D. DSG normal, abnormal, and emergency states. These operational requirements relate to local control of a DSG at its own site. Each DSG requires controls to start it up, to operate it under all of its operating states, to maintain it to standby, to shut it down, and to have the ability to decide which condition or state should be ordered.

   The requirements for these operational controls and the integration of these controls with commands from, and monitoring to, other portions of the distribution DSG system, are included in the requirements of this category.

E. Failure and abnormal behavior detection and correction requirements. These requirements are associated with the DSG protection equipment and indicate what action is required of the protection equipment under the many possible DSG or distribution network states. This function takes place at the DSG site and represents very fast action to protect the DSG power and other equipment from damage to itself or other equipment.

F. Special DSG control requirements. These requirements are related to equipment at the DSG site and pertain to special controls such as those for startup, standby, and shutdown for each DSG technology. These controls tend to pertain to the carrying out of subordinate but essential functions that are actuated or initiated by other functional categories.

9. A large growth in the availability and in the use of the dispersed storage and generation is highly probable during the period from 1990 to 2000. Using conservative projections for electrical power demand for the year 2000 and assuming that, as an example, 5% of this power is supplied by DSGs, one can estimate that,

13,000 DSG units 1 MW and larger, and

300,000 DSG units 10 kW and larger, may be required.

New and improved DSG equipments using lower cost energy sources are being designed and built, and the cost of nonrenewable energy for conventional generation means continues to rise making dispersed renewable generation more attractive.

10. The recent Federal Energy Regulatory Commission rulings under PURPA Section 210 mandate the purchase by utilities of cogeneration and power production from small facilities, i.e., under 30 MW, at price rates equal to what it would cost the purchasing utility to generate the energy itself. This ruling is intended to encourage the use of DSGs.

Continued emphasis on establishing a more definitive set of conditions of agreement, both technical and financial, between utilities and customers in regard to DSG operation is required. Control of the connection between the utility and the customer-owned DSG must be under utility control to ensure personnel safety.

11. The costs and benefits for monitoring and control of DSGs must be considered with respect to the whole system including generation and transmission and must not be determined on the basis of distribution alone. Likewise, scheduling and control of remote DSG units should be based on the need to make the overall system service, i.e., generation, transmission, and distribution, most effective.

Section 12

RECOMMENDATIONS

The conclusions in Section 11 have indicated that there will be a large growth during the 1980-2000 period in the use of DSGs in connection with electric utility systems. It is important that the research and development for such systems be started now on the critical tasks noted below and that are required for the success of DSG integration. The time for this effort is now, before the DSGs are commercially available on a large scale, and while development demonstrations of integrated distribution DSG systems can be used to gain valuable operating experience.

The present study program should be extended to accomplish the following tasks:

1. Scheduling/Dispatching Methods for DSGs

   Define, develop, and demonstrate effective scheduling and dispatching control of specific DSGs with near-term potential.

2. Standard Dispatching Operator Interface for Various DSG Technologies

   Define, develop, and assess a standard monitoring and control interface for utility operators to remotely control various DSGs. Particular emphasis should be given to developing means for the use of common hardware and software elements for the integration of different DSGs.

3. Design Guidelines for the Integrated Operation of DSGs, Load Controls, and Distribution Automation Using Real-Time Distribution Control and Communication Equipment

   Define and categorize the conceptual framework for the operation of future utility distribution systems that contain DSGs, load control devices, and distribution automation and control systems.

4. Preparation of a Preliminary Specification for a Utility-Integrated Distribution DSG System Design

   This specification for hardware and software should incorporate the recommendations from the preceding three tasks into the basis for a system design that will carry out the DDC control and monitoring and the communication and data processing functions for DSG integration into a combined DSG load control and distribution automation control system.

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