MASTER

IMPACTS OF DISPERSING STORAGE AND GENERATION IN ELECTRIC DISTRIBUTION SYSTEMS

Final Report

July 1979

Principal Investigators

Fred S. Ma

Leif Isaksen

Ronnie Patton

Work Performed for

U.S. DEPARTMENT OF ENERGY
Assistant Secretary for Energy Technology
Division of Electric Energy Systems
Washington, D.C. 20585

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ABSTRACT

Constraints and uncertainties surrounding fuel availability, siting requirements, financing, licensing delays, and demand forecasts have made it increasingly difficult for utilities to add large-scale capacities and/or interconnections to their supply and delivery systems. Alternative production-delivery-use configurations for future electric energy systems are needed. Small-scale Dispersed Storage and Generation (DSG) connected to the electric distribution systems provide one such alternative. In addition to being generating sources, DSG may also provide benefits to the distribution system by reducing capacity requirements, improving reliability, and lowering losses.

This study offers a consistent, unifying methodology for evaluating the dispersion effect of DSG in distribution systems. The evaluation method and models developed compare the distribution systems expanded with and without DSG, using a consistent set of planning and operating criteria. The effects of DSG outages probabilities, diseconomies of scale, and loss savings are explicitly treated. The method also takes into account the effect on the bulk supply system when DSG is planned and operated for distribution system needs. To obtain the overall DSG impact on a utility system the results derived from this methodology can readily be combined with the impact of the technologies assessed from a bulk supply perspective undertaken in other studies. This assessment methodology would be suitable for use by most utilities since it is based on extant utility planning procedures and data bases, and practical assessment calculations.

Several important findings emerged from the methodology development and application to assessing unconventional firm DSG technologies for two utilities. The distribution capacity and reliability benefits are highly site dependent, with significant benefits achievable in special cases. Potentially higher production cost and DSG capital cost may be incurred, in addition to increased backup generating capacity requirement for energy-limited dispersed storage devices, since operating DSG to realize distribution benefits may depart from supply system economic dispatch principles. The study points to the importance of caution and comprehensive assessment before implementing DSG in the distribution system on a large scale. Further research on extending the methodology and application to address the impact of dispersed intermittent generation is being undertaken.

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EXECUTIVE SUMMARY

INTRODUCTION

Dramatic changes during the past several years have changed the environment in which electric utilities plan for additional generation and transmission capacity. Constraints and uncertainties surrounding fuel availability, siting requirements, financing, licensing delays and demand forecasts have made it increasingly difficult for utilities to add large-scale capacities and/or additional interconnections to their supply and delivery systems. Against this background, a variety of new technologies and planning and control procedures are either under development or being implemented as part of the production-delivery-use configurations for future electric energy systems.

Small-scale Dispersed Storage and Generation (DSG) connected to electric distribution systems is one of these alternatives. Alternate DSG technologies include dispersed supply management devices placed on the utility side of the meter (such as solar energy generation, battery storage and fuel cells) and use management devices placed on the customer side of the meter (such as cogeneration and storage space conditioning). Some of these generation technologies rely on intermittent renewable energy sources while others use fossil fuels in a novel or efficient manner. Storage technologies shift the time of energy consumption. Although the technologies are very different, they all satisfy one or more of the following objectives: (1) conserve capital and energy; (2) shift fuel dependency from scarce to abundant or renewable resources; (3) reduce reserve requirements; and (4) improve reliability of service to essential loads while holding down the cost of service.

In addition to decreasing the need for large central generation capacities at the bulk supply system, decentralized small

EXHIBIT 1

DSG ASSESSMENT METHODOLOGY

* SCOPE OF THIS STUDY

units may offer additional transmission and distribution system benefits by reducing capacity requirements, improving reliability and lowering losses. There are many other complex integration issues associated with introducing DSG into the distribution system, including diseconomies of scale, technological interface, impact on utility procedures, environmental and institutional constraints, as well as financial and rate design problems. To date, studies have primarily focused on the impact of the new technologies on the bulk supply system. This study, conducted by Systems Control, Inc. for the U. S. Department of Energy, Division of Electric Energy Systems (DOE/EES), assesses all the impacts of DSG on distribution systems.

METHODOLOGY

The methodology extends previous studies which evaluated the impact of the new storage and generation technologies on the bulk supply system by comparing the bulk supply system with and without the new technologies. In these studies, the devices are assumed to be planned and operated to satisfy bulk supply system needs by providing sufficient generation at an appropriate level of reliability. However, within the distribution system, in order to provide adequate delivery capacity while maintaining an appropriate quality of service, DSG may be operated in a manner different from supply system economic dispatch principles.

Instead of duplicating the detailed analysis, this methodology focuses on the incremental cost and benefits by comparing the overall power system with DSG to the bulk supply system with the new technologies. This is illustrated in Exhibit 1. The result from applying this methodology can then be integrated with previous study results to obtain a comprehensive assessment of DSG on the entire electric power system.

The methodology includes detailed simulations of distribution systems expansion planning with and without DSG, using a consistent set

EXHIBIT 2
DSG ASSESSMENT PROCEDURE

of planning criteria. In addition, models of alternate DSG operating controls are developed to satisfy distribution and/or bulk supply system needs. The incremental effects on the bulk supply system production costs and capacity requirements are calculated. Detailed planning simulations in the methodology are used to model important distinct distribution system characteristics: least-cost expansion plans are highly site dependent; distribution loads are non-coincident; and planning and operating large numbers of widespread distribution equipment and loads is a complex problem.

Assessment Procedures

The assessment procedures used to evaluate supply-side and customer-side DSG are described separately below. In practice, the same general models and procedures are used to assess both types of devices, but the details of the assessment steps differ. The procedures are illustrated in Exhibit 2.

First, for supply-side DSG, the base case is obtained by reinforcing the distribution system in a conventional manner which does not include DSG. Analysis of conventional options using a set of planning criteria identifies the most acceptable conventional reinforcement plan which satisfies current, voltage, and contingency criteria.

Second, DSG strategies are developed to relieve selected violations of distribution planning criteria for a specific duration. Within a DSG strategy, several options may exist. These options are defined by the size, location, and operating mode of the DSG devices. Each option must meet the same set of planning criteria satisfied by the conventional distribution planning strategy.

Third, the various DSG options developed are simulated to verify that the objectives of the DSG strategies are met. The second and

third steps may be iterated to generate additional feasible options. Since the supply-side devices are operated with distribution objectives in mind, the set of feasible options is called the "with" policy. Two models support Step 3. The DSG Load Model constructs 24-hour daily load curves for each part of the distribution system by synthesizing diversified load curves from the characteristics of individual appliances, equipment, and end uses; and aggregating daily load profiles at points along feeders and at the substation by combining the outputs of the load synthesis. The Load Model represents DSG devices as positive, zero, or negative loads. Negative loads describe generation, and positive loads describe storage charging. The DSG Operations Model simulates the control and hourly operation of DSG devices. Given a DSG option specifying the locations, power capacity, operating objectives, and control procedure, the Operations Model computes the energy generated and/or stored. In addition, the model gives a revised daily load curve for each affected part of the distribution system.

Fourth, the bulk-supply base case is obtained by planning DSG devices in the bulk supply level. The bulk supply DSG device has a power capacity equivalent to the combined capacities of all of the dispersed devices. The bulk supply base case is defined without consideration of the needs of the distribution system and is called the "without" policy. Together with the conventional distribution case, the bulk supply case provides a base case against which the distribution level DSG options will be evaluated. The Equivalent Capacity Model is used to determine the equivalent power capacity available centrally from all dispersed devices. The model accounts for the non-coincidence of the distribution load and the losses in the transmission and distribution systems. For an equivalent power capacity of a storage device, the equivalent energy capacity is estimated. The model calculates the useful energy storage capability which is needed for a system peak day.

Finally, each candidate DSG option is evaluated to calculate the net benefit or cost of dispersing storage and generation devices.

These steps are repeated until all options are evaluated. The option with the highest net benefit is selected for each strategy. In the evaluation, five assessment components are calculated. The sum of these components gives the net benefit (or cost) of dispersing the storage and generation devices. This net benefit is the Dispersion Credit. The five components calculated are:

- The Distribution Capacity Component
- The Reliability Component
- The Dispersal Cost Component
- The Production Cost Component
- The Replacement Component

Each component is defined and discussed below.

The assessment procedures and models for customer-side DSG are similar to those described for DSG. First, a distribution base case is obtained by reinforcing the distribution system without the use of customer-side devices. The second step defines each strategy by the penetration, location and operating mode of the dispersed devices over a number of years. Strategies to operate customer-side devices for bulk supply needs without considering distribution system needs constitute the "without" policy. The "with" strategy consists of operating modes chosen to satisfy the needs of the distribution system. Then, the options are simulated to obtain revised distribution loads, and feasible options are identified. The distribution system is expanded with the revised loads using the same planning criteria as in the base case. The load model and operations model support this step.

Finally, each option is evaluated to obtain the distribution capacity and reliability components. The best option is selected for the "with" strategy. The "with" and "without" strategies are evaluated with respect to the assessment components.

Assessment Components

The outputs of the assessment procedures provide the information and data to compute the five principal assessment components. The cost-benefit components include both distribution system impacts and incremental bulk supply system impacts. Each component is calculated separately for each year over the planning horizon. The sum of the five components is used in a present-worth analysis to compute the net Dispersion Credit. Each of the five components is discussed below.

Distribution Capacity Component. This component is the difference in conventional distribution system costs between the policies where DSG is used and where it is not used. Distribution capacity benefits occur when conventional distribution investments are deferred, cancelled, or required by DSG.

Reliability Components. The reliability component is the value of additional expected service continuity provided by DSG during distribution system outages. The reliability benefits are derated by DSG forced outage rates. The approach is to compute the reduction in expected unserved energy possible with a DSG device, and then assign a value to this reduction reflecting the nature of load served by the device. The DSG devices must be designed to supply only preselected loads before repair crews can restore partial or total service. This component includes the effect of the energy limitation of storage devices on the reliability benefit.

Dispersal Cost Component. The component is the cost difference for DSG equipment between dispersed use and centralized use. The Dispersal Cost Component includes the power capacity, the energy storage capacity, and the communications and control equipment costs. This component captures the effect of diseconomies of scale, capacity effect of loss savings, and load diversity.

Production Cost Component. The use of DSG for distribution objectives causes the total system production costs to be different than when DSG is operated for bulk system objectives only. The Production Cost Component, which includes operating and maintenance costs, is the difference between the production costs of the two types of uses. The Production Cost Component is calculated separately for two kinds of days: (1) days when DSG is operated for distribution needs; this occurs on the days when both distribution and bulk-supply peaks occur, and on the days when only the distribution loads peak; and (2) days when DSG is operated for bulk-supply needs; this occurs on the days when only the bulk-supply system peaks and on the remaining days of the year.

Replacement Capacity Component. A replacement capacity cost is levied against a dispersed storage device on the days of the year when both the distribution and bulk supply systems experience peaks but the dispersed device is operated for distribution needs only. The Replacement Capacity Component occurs because DSG under local control may not provide the full equivalent power capacity for the duration needed by the bulk supply system. An average marginal capacity cost is levied to reflect the need for additional backup capacities.

RESULTS OF CASE STUDY APPLICATIONS

The DSG assessment method and models were applied on case studies on portions of the distribution systems of two U. S. utilities. Characteristics of the utility systems are shown in Exhibit 3. Utility 1 is summer peaking and has a thermally-limited distribution system in an urban area. Utility 2 is winter peaking with pumped storage plants and has a voltage-limited distribution system in a rural area. The areas selected for study were representative of urban and rural distribution systems.

Six DSG technologies were studied: fuel cells, diesel engines, lead-acid batteries, advanced batteries, heat storage and cool

EXHIBIT 3

CHARACTERISTICS OF UTILITIES USED IN CASE STUDIES

CHARACTERISTIC	UTILITY 1	UTILITY 2
SYSTEM-WIDE		
LOCATION	WEST	MIDWEST
PREDOMINANT FUEL	OIL	COAL
ANNUAL LOAD FACTOR (PCT)	60.3	65.5
PEAK PERIOD	SUMMER	WINTER
PEAK PERIOD LOAD FACTOR (PCT)	75.8	77.3
PUMPED STORAGE (PCT)	0	12
DISTRIBUTION SYSTEM AREA STUDIED		
PREDOMINANT LOAD	RESIDENTIAL	RESIDENTIAL
CONFIGURATION	RADIAL	RADIAL
PRIMARY VOLTAGE (KV)	13	13
AREA (SQ. MI.)	13	350
AVERAGE LOAD GROWTH (PERCENT)	4.6	4.5
LOAD DENSITY (KW/SQ.MI.)	4500	40
PREDOMINANT CRITERIA VIOLATION	CURRENT	VOLTAGE

storage. The dispersed devices were placed in various locations in the distribution system, from substation bus to customer service entry. The methodology was illustrated with DSG siting durations from one to three years. The case studies assume that the projected DSG cost and performance are available in 1975, the beginning of the study period. All costs are reported in 1975 dollars. The case studies also use historical and projected bulk supply and distribution system data.

Supply-Side DSG

Exhibit 4 shows the net benefit for the supply-side DSG case studies. The Dispersion Credit is expressed in dollars per kilowatt of installed DSG capacity. The Dispersion Credit can be interpreted as a reduction or increase of DSG device capital cost. Strategies are described by the location and the number of years DSG devices are sited to satisfy distribution system needs.

The Distribution Capacity Component is found to be the dominant benefit component. For the thermally-limited Utility 1, this component increases (becomes more beneficial) as the location of the DSG devices moves from substation to feeder levels because of the feeder capacity savings. For the voltage-limited Utility 2, feeder strategies have smaller benefits because DSG along feeders was unable to relieve voltage regulation problems in the subtransmission system.

The Reliability Component is found to be insignificant when compared to other components. Utility 1 had a more reliable distribution system than Utility 2, yielding lower DSG reliability benefits for Utility 1. Storage devices have smaller reliability benefits than generation devices because of their energy limitation.

The Dispersal Cost Components differ for dispersed storage and generation. For dispersed storage, the longer the device remains at one location the more negative the Dispersal Cost Component becomes (becomes

EXHIBIT 4 UTILITY-SIDE DSG RESULTS

less beneficial). This decrease is largely due to the increasing storage capacity requirement to avoid local equipment overloading. For dispersed generation in feeder strategies, the same phenomenon is also observed because of the diseconomy of scale encountered when smaller devices are placed at feeders. In substation strategies for dispersed generation, however, prolonged service improves the Dispersal Cost Component. For both dispersed storage and generation, moving the location of DSG devices from substation to feeder levels (worsens) causes the Dispersal Cost Component to become more negative. The phenomenon is more pronounced for storage devices because additional storage capacity must be installed due to local diversity among feeders.

The Production Cost Component consists of fuel and maintenance costs, each of which is different for dispersed storage and generation. For dispersed storage the fuel cost sub-component is insignificant when compared to other components. The same amount of energy must be generated for both centralized and dispersed storage. Dispersed generation shows significant savings in fuel costs if the cost of fuel delivered to dispersed locations is the same as for fuel delivered to a central generating station.

The Replacement Capacity Component is significantly negative for dispersed storage. The Replacement Capacity Component can be improved if additional energy storage capacity is provided at significantly higher costs. Dispersed generation can be operated to avoid this penalty by extending its operating hours, thus incurring only production cost increases during days of conflicting objectives. The Replacement Cost Component decreases with increasing installed capacity.

Customer-Side DSG

The Distribution Capacity Component for customer-side thermal storage is highly dependent on penetration and the location of the devices, which in turn depend on the mix of customers on a particular

EXHIBIT 5

EFFECTS OF THERMAL STORAGE ON DISTRIBUTION SYSTEMS

circuit. This is illustrated in Exhibit 5. If the percentage of thermal storage devices is small, to the extent that they replace existing and future electric heating and cooling equipment, they may offer small distribution investment savings. Beyond this saturation, however, additional devices contribute to the off-peak load which may even exceed the daytime peak load. If this occurs, the distribution system investment will be increased, particularly when thermal storage is installed on distribution sections that may already be operating near design limits.

Increased penetration of thermal storage tends to yield diminishing peak load reduction. This result was caused by replacing electric space conditioning load by a higher thermal storage load. This is accompanied by a shift of the time of occurrence of peak loads as penetration increases.

The difference between alternate control strategies tends to be insignificant. Control strategies to satisfy distribution objectives result in slightly lower feeder loadings, while control strategies for bulk-supply objectives have a lower substation loading. The resulting distribution investments under the different control strategies are similar. Both have nearly equal production costs.

CONCLUSIONS

Several important insights into the assessment of DSG impact on distribution systems were gained during methodology development, model building, and case study applications on two utility systems.

Consistent Unifying Methodology. The methodology compares the distribution systems with and without DSG using a consistent set of planning and operating criteria. The method also takes into account the incremental production costs and capacity requirement effects of DSG in the bulk supply system when they are planned and operated for

distribution system needs. In addition the effects of DSG outage rates on reliability, diseconomies of scale and loss savings are explicitly treated.

Conflict of Operating Objectives. To realize distribution capacity and reliability benefits, supply-side DSG may be operated in a manner departing from bulk supply system economic dispatch principles. Potentially higher production costs and DSG capital costs may be incurred, in addition to increased backup bulk supply capacity requirement for energy-limited dispersed storage devices. No significant conflict is evident for various control strategies for customer-side thermal storage.

Importance of Special Sites. The overall cost benefit of DSG technologies are highly site-dependent. The distribution capacity and reliability components are very site-specific, with significant benefits achievable in special locations. Substation placement is generally more favorable than placement along the circuits. Additional distribution investment cost may be needed if thermal storage is concentrated on the distribution sections that may already be operating near design limits.

Effect of Penetration. The overall benefit decreases over time with increasing dispersed utility-side storage, largely due to the increasing penalty of the dispersal cost component: proportionally more dispersed energy storage capacities are required with larger power capacities. Total benefits improve over time with increased penetration for dispersed utility-side generation. Increased penetration of customer-side thermal storage tends to yield diminishing peak load reduction. Higher penetrations of thermal storage may lead to increased distribution system investments due to new peak loads in previously off-peak periods.

Comparison of DSG Technologies. Utility-side dispersed generation tends to attain a greater overall benefit than dispersed

storage. An efficient generator such as a fuel cell, would be very attractive for dispersed use. Utility-side storage is generally more effective in reducing peak loads than customer-side storage because of the greater planning flexibility in locating the devices.

Effect of Degraded Performance. The net cost benefit ratio tends to be very sensitive to degraded performance of utility-side DSG in terms of worsened efficiency, and higher operating and maintenance costs.

Planning and Operational Complexities. The introduction of DSG into the electric distribution system will complicate present planning and operating practices. Present distribution practices relying on established planning guidelines and engineering judgement may prove insufficient because this experience has been accumulated for systems without DSG. Planning and operation of DSG may require close coordination between bulk supply and distribution systems planning.

SUMMARY

Caution and comprehensive assessment are needed before implementing DSG in distribution systems. The distribution system benefits are highly site-dependent, with significant benefits achievable in some special cases. As DSG in a distribution system would also impact the bulk supply system, the methodology offers a consistent, unifying framework for a comprehensive assessment of dispersed storage and generation technologies. This assessment methodology would be suitable for use by most utilities as it is based on extant utility planning procedures and data base, and practical assessment calculations.

1. INTRODUCTION

1.1 DISPERSED STORAGE AND GENERATION (DSG)

Several means are available for altering the real or apparent pattern of electricity use for system objectives [1]. These objectives include:

- Improving the efficiency of the electrical system by conserving energy and capital;
- Shifting fuel dependency from oil and natural gas to more abundant coal, nuclear and renewable resources;
- Reducing reserve requirements for generation, transmission and distribution capacity; and
- Improving reliability of service to essential loads while holding down the cost of electric power to end-use customers.

Two approaches are distinguishable, depending upon the location within the utility system where the loads are modified. Supply management modifies the electric load on the utility side of the electric meter without affecting end-use customers. Pumped hydro storage and the use of interconnections are examples of supply management techniques that have been used successfully by electric utilities for many years. These techniques, implemented primarily upon high voltage transmission systems and large generators, are called centralized supply management procedures.

Use management modifies the electrical load on the customer side of the electric meter. Energy conservation, time-of-day rates and direct control of interruptible loads are examples of use management.

Utilities are seeking additional supply and use management technologies to obtain these benefits. One promising set of technologies is Dispersed Storage and Generation (DSG). DSG refers to the connection of small-scale storage and generation devices to the distribution system. DSG devices typically range from sizes of 1 kW to 10 MW and may

EXHIBIT 1-1

EXAMPLES OF DSG TECHNOLOGIES

DSG TECHNOLOGIES	EXAMPLES
<p>1 SUPPLY-SIDE STORAGE AND GENERATION</p> <ul style="list-style-type: none"> ● ELECTRIC ENERGY STORAGE ● ELECTRIC GENERATION ● INTERMITTENT GENERATION <p>2 CUSTOMER-SIDE STORAGE AND GENERATION</p> <ul style="list-style-type: none"> ● THERMAL STORAGE ● INTERMITTENT GENERATION 	<p>LEAD-ACID AND ADVANCED BATTERIES, FLYWHEELS, CRYOGENIC STORAGE</p> <p>FUEL CELLS, DIESEL ENGINES AND COMBUSTION TURBINES</p> <p>WIND-POWERED AND PHOTOVOLTAIC GENERATION</p> <p>STORAGE-SPACE HEATING, WATER HEATING, AND AIR CONDITIONING</p> <p>WIND-POWERED AND PHOTOVOLTAIC GENERATION</p>

be connected to either side of the meter. DSG may offer most of the benefits of supply and use management alternatives. In addition, if properly planned and operated, DSG may provide benefits to distribution systems by reducing capacity requirements, improving reliability and reducing losses. Examples of DSG technologies include diesel generators, fuel cells, batteries, storage space and water heaters, storage air conditioners, wind electric systems and solar electric systems.

There are two categories of DSG technologies -- Dispersed Supply-Side Storage and Generation (DSSG) and Dispersed Customer-Side Storage and Generation (DCSG). DSSG devices are connected to the distribution side of the meter while DCSG devices are connected to the customer side. This report examines the types of DCSG and DSSG devices shown in Exhibit 1-1.

1.2 NEED FOR ASSESSMENT METHODOLOGY

Each dispersed supply and use management procedure provides different benefits, and each has a different cost. New methods are urgently needed for measuring these differences and for determining the best alternatives for particular situations. These methods would provide an information and data base to guide research and development efforts and to help formulate national energy policies.

At the present time, no comprehensive methodology exists for assessing the impacts of alternative dispersed supply and use management techniques on the production, delivery and use of electric power. A comprehensive methodology should be able to quantify the impacts on generation, transmission and distribution expansion plans, production costs and utility revenue requirements. The methodology should also be able to compare all forms of supply and use management, conventional and intermittent generation (such as wind and solar electric systems), and central and dispersed storage and generation. A comprehensive methodology should be capable of answering questions about the size, location and the type of management technique that is desirable.

The Division of Electric Energy Systems of the U. S. Department of Energy (DOE/EES) is seeking answers to these and other problems related to dispersed supply and use management. As part of this effort DOE/EES is developing analysis techniques to answer questions posed by new technologies. This report describes a methodology which was developed as part of this comprehensive methodology.

This report addresses the dispersion effect of storage and generation in electric distribution systems. Subsequent research programs will address the other aspects of the comprehensive methodology such as central supply management, end-user energy requirements and national energy goals.

Previous studies of new storage and generation technologies generally have not investigated distribution system impacts. Most studies have examined the costs and benefits from the perspective of the bulk supply system. When distribution system impacts were studied, they usually were estimated as a cost or benefit per kilowatt of installation. One study used system-wide and regional cost data to calculate the fraction of a proposed distribution investment that could be eliminated by the introduction of DSG [2].

Storage concepts have been studied by Public Service Electric and Gas Company [2], Energy Utilization Systems, Inc. [3], Sulzberger [4,5], Lewis and Zemkoski [6] and El-Badry [7], and demonstrations of storage batteries are being conducted by the U.S. Department of Energy and the Electric Power Research Institute [8]. Generation concepts have been studied by Lueckel [9] and Fernandes [10].

Dispersed storage in transmission and subtransmission networks has been studied by Lee [11] and the Public Service Electric and Gas Company [12].

1.3 DISPERSION ISSUES AND PROBLEMS

There are many complex issues associated with introducing DSG in the distribution system. These include:

Distribution Investment. Studies show that DSG can reduce distribution investments [2], while others indicate that DSG increases investments [13]. It is not known whether DSG can proportionally reduce investments for each level of the distribution system or whether distribution equipment may require upgrading to accommodate DSG.

Reliability. Dispersed devices may improve service reliability but the improvement may be limited. Devices in one area may not help alleviate outages in other locations, and devices might be unavailable due to energy limitations or forced outages. Even if service reliability is improved, the value of increased reliability is difficult to determine.

Use Conflicts. DSG may benefit both distribution and bulk supply systems, but conflicts between the systems may occur. DSG devices operated for distribution system requirements tend to minimize delivery costs. When operated for bulk supply objectives, DSG devices minimize production costs. Conflicts may cause distribution equipment overloads, increased production costs, or unsatisfied demands due to insufficient stored energy. The means for resolving these conflicts to achieve the best overall operation is unknown.

Delivery Losses. Placement of DSG devices near the end use may reduce losses in the transmission and distribution systems. These losses have an energy and a capacity component, both of which need to be quantified.

Capital and Operating Costs. Small scale, dispersed units may have higher capital and operating and maintenance costs than larger,

central units of the same type. Dispersed units require additional communications, control, relaying and recording equipment. The justification for these costs remains undetermined.

Technological Problems. Existing distribution systems have not been designed to accommodate DSG. Inclusion of DSG devices may require additional equipment for protection, power factor correction, stability and voltage control.

Utility Procedures. Planning and operating procedures and guidelines, developed without consideration of DSG, may be inadequate. When DSG devices are alternatives to conventional technologies, new analysis techniques and additional data may be needed.

Environmental and Institutional Issues. DSG technologies may not face the severe siting problems of central generation. However, the environmental and institutional problems that may arise from dispersed siting are unknown.

Financial and Rate Issues. The placement of DSG devices on the customer side of the meter (DCSG) may require customer investment and ownership. New rate structures will be needed, and new information will be required regarding the effect of total customer costs upon the device penetration and operating pattern.

These complex issues raise several decision problems:

- Placement - Where should DSG devices be placed in the electric distribution system?
- Operation - How should they be operated?
- Penetration - How many should be installed?

Varying the placement, operation and penetration of DSG devices would affect each of the issues above, influencing the total costs and benefits of DSG.

1.4 STUDY OBJECTIVES

This study was sponsored by the Division of Electric Energy Systems of the U.S. Department of Energy (DOE/EES) as an integral part of its Load Management Program to establish:

- Analytical procedures to determine the electric utility impacts of changes in customer loads and to define rate design implications;
- A factual information and data base to evaluate small-scale, decentralized technologies such as those described by Schumacher [14] and Lovins [15] in the context of electric power production, delivery and use; and
- Specific guidelines for R&D planning, addressing the technical and economic issues associated with integrating new technologies into electric power systems.

The objectives of the study are to:

- Develop a general methodology for assessing the dispersion effect of DSG in electric distribution systems. To be general, a methodology must be compatible with the comprehensive methodology as discussed in Section 1.2, capable of evaluating all DSG technologies, and applicable to different electric utility distribution systems;
- Provide generic results on the planning and operation of power systems with DSG, based on case studies; and
- Identify directions for future technology and advanced methods R&D.

1.5 STUDY SCOPE

This study focuses on the dispersion effect of DSG in distribution systems. To help clarify the project scope, consider B and C to be the benefit and cost of DSG used for bulk supply needs, and let ΔB and ΔC be the incremental bulk supply and distribution benefit and cost of DSG used for distribution system needs. This study develops a methodology for finding $\Delta B - \Delta C$. Dispersed storage or generation is cost-justified only when $B + \Delta B > C + \Delta C$. This study does not determine the bulk supply benefit B or cost C.

EXHIBIT 1-2
ONE-LINE REPRESENTATION OF
AN ELECTRIC POWER SYSTEM

The methodology and the associated models were demonstrated in case studies on two electric utilities. One utility is summer peaking and has a thermally- (or current-) limited distribution system in an urban area. The other utility is winter peaking and has a voltage-limited distribution system in a rural area.

Six DSG technologies were utilized in the case studies: lead-acid batteries, advanced batteries, fuel cells, diesel generators, storage air conditioning and storage space heating. DSG devices were situated on the substation bus, primary feeders and end-use entries as seen in Exhibit 1-2. Combinations of the above technologies and placements were evaluated for periods varying from one to several years.

Other customer-side concepts, notably energy conservation and time-of-day pricing, are excluded from the study because they provide neither storage nor generation. However these techniques may encourage customers to adopt customer-side DSG (DCSG) technologies.

Caveats

The study addresses technical and economic questions. Environmental, political, sociological and institutional problems associated with DSG siting, customer preferences, financial constraints and rate structures are beyond the scope of this work and were not explicitly considered. These factors may have an important influence on the practical implementation of DSG.

Care must be taken in using the numerical results. First, the case studies describe only the marginal costs and benefits of using DSG with distribution system objectives; the numerical results do not give the total power system costs and benefits. Second, although the case studies were performed on utility systems carefully selected to be representative, the numerical results may not apply to other utilities and DSG technologies.

Although it is difficult to draw general conclusions from the case studies based on specific utilities, the insights gained from developing, validating and using the methodology identify some generic phenomena that may be applicable to most electric utilities.

1.6 SYNOPSIS

This report is structured into four parts:

PART I: BACKGROUND

- Section 1. Introduction
- Section 2. Overview of Approach
- Section 3. Distribution and DSG Systems Characteristics

PART II: DISPERSED SUPPLY-SIDE STORAGE AND GENERATION

- Section 4. Planning and Operation of DSSG
- Section 5. Evaluation of DSSG
- Section 6. DSSG Case Studies

PART III: DISPERSED CUSTOMER-SIDE STORAGE AND GENERATION

- Section 7. DCSG Methodology
- Section 8. DCSG Case Studies

PART IV: RESULTS AND CONCLUSIONS

- Section 9. Case Study Results
- Section 10. Conclusions

Parts II and III each discuss the methodology, the data used in the case studies and the conduct of the case studies. They also present the numerical results of the case studies. Part IV analyzes the numerical results and presents generic conclusions for both DSSG and DCSG.

The Results and Conclusions (Sections 9 and 10) may be read after the Background (Sections 1, 2 and 3). Readers interested in the mathematical formulation of the simulations will find Sections 4, 5 and 7 useful. Sections 6 and 8 will be helpful to readers interested in the utilities studied and the data used in the case studies.

2. OVERVIEW OF APPROACH

2.1 GENERAL APPROACH

The methodology developed uses a distribution system planning approach to evaluate both DSSG and DCSG. The approach involves the formulation of a policy to plan and operate DSSG and DCSG to satisfy only the bulk-supply needs. A second policy is developed to plan and operate DSSG and DCSG to meet only the distribution system needs. By comparing the two policies, the net value of using DSSG or DCSG to meet the requirements of the distribution system is found. This net value is the Dispersion Credit of DSG.

DSSG and DCSG have different impacts on the planning and operation of distribution systems. For example, DSSG technologies may be a planning alternative to satisfy distribution system needs. In contrast, DCSG technologies change the distribution loads, and distribution planning and operating procedures must be revised to reflect these changes. Distribution planners can plan with DSSG with certainty but must plan for DCSG since the locations, capacities, and perhaps operation of DCSG devices may be beyond the utility's influence and control.

If DSSG are planned and operated for the needs of the bulk supply system the devices (such as batteries or fuel cells) are assumed to be placed in the bulk supply system. The devices are located in the distribution system when the needs of that system are considered. The methodology calculates the costs and benefits associated with each policy and evaluates the effect of dispersing the storage and generation devices at different levels in the distribution systems.

When applied to DCSG, planning and operating from the bulk supply perspective means installing and operating the devices (such as

EXHIBIT 2-1
DSSG ASSESSMENT PROCEDURE

thermal storage units) on the customer side of the meter to achieve bulk supply objectives. Planning and operating with distribution objectives means operating the same devices to satisfy distribution system needs. The DSG methodology calculates the net costs and benefits of fulfilling distribution requirements and gives the impacts on distribution systems.

2.2 ASSESSMENT PROCEDURES

The assessment procedures used to evaluate DSSG and DCSG are described separately below. In practice, the same general models and procedures are used to assess DSSG and DCSG, but the details of the assessment steps differ.

2.2.1 DSSG Evaluation

This section describes the five assessment steps for DSSG. The relationships of these steps and the associated models are shown in Exhibit 2-1. The steps are discussed in detail in Chapter 4.

- Step 1: Conventional Distribution Planning.
A base case is obtained by reinforcing the distribution system in a conventional manner without DSSG. Analysis of conventional options using a set of planning criteria identifies the most acceptable conventional reinforcement plan. The option that is chosen is the plan with the lowest cost which also satisfies current, voltage, and contingency criteria.
- Step 2: Development of DSSG Strategies.
DSSG strategies are developed to relieve selected violations of distribution planning criteria for a specific duration. Within a DSSG strategy, several options may exist. These options are defined by the size, location, and operating mode of the DSSG devices. Each option must meet the same set of planning criteria met by the conventional distribution planning strategy.
- Step 3: Simulation of DSSG Options.
The various DSSG options developed in Step 2 are simulated to verify that the objectives of the DSSG strategies are met. Step 2 may be iterated to generate additional feasible options. Since the DSSG devices are operated with distribution objectives in mind, the set of feasible options is called the "with" policy. Two models support Step 3.

The DSSG Load Model constructs 24-hour daily load curves for each part of the distribution system by performing two functions:

1. Load Synthesis - Diversified load curves are derived from the characteristics of individual appliances, equipment, and end uses.
2. Load Aggregation - Daily load profiles are generated at points along feeders and at the substation by combining the outputs of the load synthesis.

The Load Model represents DSSG devices as positive, zero, or negative loads. Negative loads describe generation, and positive loads describe storage charging.

The DSSG Operations Model simulates the control and hourly operation of DSSG devices. Given a DSSG option specifying the locations, power capacity, operating objectives, and control procedure, the Operations Model computes the energy generated and/or stored. In addition, the model gives a revised daily load curve for each affected part of the distribution system.

- Step 4: Bulk-Supply Case Definition.

The bulk-supply base case is derived by planning DSSG devices in the bulk supply level. The bulk supply DSSG device has a power capacity equivalent to the combined capacities of all of the dispersed devices. The bulk supply base case is defined without consideration of the needs of the distribution system and is called the "without" policy. Together with the conventional distribution case, the bulk supply case provides a base case against which the distribution level DSSG options will be evaluated.

The Equivalent Capacity Model is used in Step 4 to determine the equivalent power capacity available centrally from all dispersed devices. The model accounts for the non-coincidence of the distribution load and the losses in the transmission and distribution systems. For an equivalent power capacity of a storage device, the equivalent energy capacity is estimated. The model calculates the useful energy storage capability which is needed for a system peak day.

- Step 5: Evaluation of DSSG Options.

Each candidate option from Step 3 is evaluated to calculate the net benefit or cost of dispersing storage and generation devices. Step 3 through Step 5 are repeated until all options are evaluated. The option with the highest benefit is selected for each strategy. Five assessment components are calculated during Step 5. The sum of these components gives the net benefit (or cost) of

dispersing the storage and generation devices. This net benefit is the Dispersion Credit. The five components calculated in Step 5 are:

- The Distribution Capacity Component
- The Reliability Component
- The Dispersal Cost Component
- The Production Cost Component
- The Replacement Component

Each component is defined and discussed in Chapter 5.

2.2.2 DCSG Evaluation

This section describes the four assessment steps and the associated models for DCSG. The steps and models for DCSG are similar to those described for DSSG.

- Step 1: Conventional Distribution Planning.
This step is the same for DCSG as for DSSG. A distribution base case is obtained by reinforcing the distribution system without the use of DCSG devices.
- Step 2: Development of DCSG Strategies.
Each DCSG strategy is defined by the penetration, location and operating mode of the dispersed devices over a number of years. Strategies to operate DCSG devices for bulk supply needs without considering distribution system needs constitute the "without" policy. The "with" strategy consists of DCSG options chosen to satisfy the needs of the distribution system.
- Step 3: Simulation of DCSG Options.
Options are simulated to obtain revised distribution loads, and feasible options are identified. The distribution system is expanded with the revised loads using the same planning criteria as in Step 1. Two models support this step. The Load Model has been described under Step 3 for DSSG. The DCSG Operations Model simulates the control and hourly operations of DCSG devices. Its function is similar to DSSG Operations Model.
- Step 4: Evaluation of DCSG Options.
Each option identified in Step 3 is evaluated to obtain the distribution capacity and reliability components which were described previously for DSSG. The best option is selected for the "with" strategy. The "with" and "without" strategies are evaluated with respect to the same assessment components identified for DSSG.

2.3 INTERPRETATION OF RESULTS

Exhibit 2-2 shows how the DSSG results should be interpreted. The quantities used in Exhibit 2-2 are defined below:

- B = Net benefit of DSSG technology to bulk supply system
- C = Net cost of DSSG technology to bulk-supply system
- ΔB = Net benefit of DSSG technology to distribution system
- ΔC = Net cost of DSSG technology to distribution system.

Depending on the relative values of $B - C$ and $\Delta B - \Delta C$, the DSSG should be:

- Exclusively located in the distribution system
- Exclusively located at the bulk supply level
- Apportioned between the distribution system and the bulk supply level, or
- Rejected

This study does not determine $B - C$.

In an analogous manner, Exhibit 2-3 describes how the DCSG results should be interpreted. Depending on the relative values of $\Delta B' - \Delta C'$ and $\Delta B'' - \Delta C''$ as defined in the exhibit, the DCSG should be:

- Operated for distribution needs
- Operated for bulk-supply system needs, or
- Used with caution because of negative distribution impacts.

EXHIBIT 2-2

INTERPRETATION OF RESULTS FOR THE DSSG
METHODOLOGY

EXHIBIT 2-3
INTERPRETATION OF RESULTS FOR THE DCSG
METHODOLOGY

3. DISTRIBUTION AND DSG SYSTEMS CHARACTERISTICS

A number of systems characteristics unique to planning for DSG in distribution systems are important in methodology and model development. These characteristics are also useful in understanding the generic results applicable to a particular DSG technology in a distribution system.

3.1 DISTRIBUTION SYSTEM CHARACTERISTICS

A schematic representation of a distribution system is shown in Exhibit 3-1 which defines important parts of the distribution system. These components include distribution substations with transformers and breakers, primary circuits with laterals, and secondary circuits with distribution transformers and service entries. The system shown is radial, providing a unique path between the substation and the customer service entry. Although distinct from the distribution system, sub-transmission systems are often included in distribution planning because of their close relation.

Distribution systems vary widely due to differences in load, equipment and service area. As shown in Exhibit 3-2 these characteristics determine the delivery system characteristics through the distribution planning process. These three major classes of characteristics are described below.

Load Characteristics

Load Diversity. Not all loads connected to the utility system require service at the same time. There exists a natural diversity between loads which is determined by user requirements. Load diversity is a measure of the differences between load shapes. Mathematically, no

EXHIBIT 3-1

ELECTRIC DISTRIBUTION SYSTEM COMPONENTS

EXHIBIT 3-2

DISTRIBUTION SYSTEM CHARACTERISTICS

EXHIBIT 3-3
LOAD DIVERSITY MEASURES

diversity exists between two load curves $a(i)$ and $b(i)$, $i=1,2,\dots,T$ for all time periods i , if

$$\frac{a(i)}{b(i)} = \frac{a(j)}{b(j)} \quad \text{for all } i, j = 1, 2, \dots, T.$$

Load diversity can also be extended to describe a collection of load curves although these curves generally occur at the same level.

There are three common measures of diversity. Let p_k be the maximum value of load curve ℓ_k , and let P be the maximum of L , the composite of all load curves $k=1,2,\dots,N$. Then

$$\text{Diversity factor} = F_D = \sum_{k=1}^N p_k / P \geq 1$$

$$\text{Coincidence factor} = F_C = 1/F_D \leq 1$$

Contribution factor of ℓ_k with reference to L equals

$$C = \frac{\ell_k(t^*)}{p_k} \leq 1$$

where t^* is the time when curve L reaches its peak. Exhibit 3-3 illustrates these diversity measures.

Coincidence and contribution factors decrease from the substation to the end users. Typically, coincidence factors range from 0.90 to 1.0 for substations and are about 0.5 for residential customers.

Diversity among loads affects distribution planning. DSG operations change this diversity thereby changing the distribution plan.

Diversity between distribution and central system loads complicates the planning and operation of both systems.

Load Uncertainty. There are uncertainties in load growth and fluctuations in the daily use of individual consumers. The further one descends into the distribution system the more the uncertainties of future loads increase. Useful load forecasts for a locality may cover only one or two years. Very little is known about individual hourly load fluctuations. These uncertainties affect both conventional distribution system planning and distribution planning with DSG.

Large Number of Widespread Loads. A large number of widespread distribution loads must be taken into account in planning and operation. The loads usually are small and dispersed throughout the service territory. Typical investor-owned utilities operate hundreds of substations--usually 10 MVA to 50 MVA in size and serve thousands of customers per substation. Consequently, the utility must install and maintain a large amount of equipment. This exposes the system to more frequent service interruption, although fewer customers are affected by distribution failures than by transmission system outages. This increasing probability of service interruption also inhibits the collection and processing of data which is useful and cost justified in distribution planning. Hence, dispersing storage and generation devices can increase operation and maintenance costs as well as communication and control costs.

Nature of Customer Loads. The distribution system serves residential, commercial and small industrial customers but large industrial customers are usually served by subtransmission or even higher voltage bulk-power systems. The composition and shape of the customer loads in different locations determine the nature of the loads throughout the distribution system. The nature of the loads also reflect the value of service continuity to residential and commercial customers.

Equipment Characteristics

Function. Various types of equipment are used in the distribution system. Examples of equipment functions include:

- Carrying current, by means of overhead lines and underground cables.
- Voltage transformation, performed by substation and distribution transformers.
- Voltage regulation, controlled by voltage regulators, boosters and capacitors.
- Protection, accomplished with breakers, sectionalizers, fuses and switches.
- Monitoring and control, by means of customer meters, recording devices and control equipment.

Each piece of equipment that serves the same primary function may have a different capability, reliability, cost, and manufacturer. Equipment is usually selected based on favorable past experience, demonstrated performance, low cost, and the particular distribution needs.

Component Reliability. The components of distribution equipment generally are very reliable when compared to generating machines. Typically, substation and distribution transformers have outage rates on the order of 0.01 occurrences per year [16], as compared with about ten occurrences per year for peaking generation [17]. High component reliability is required since system reliability depends on the individual components. Due to cost considerations and existing high component reliabilities, the distribution delivery system generally has no redundancy in equipment.

Repair and Maintenance. In most circumstances distribution equipment is repaired when defective rather than routinely maintained, because of the high component reliability. The cost of repair increases drastically as the number of equipment faults increases. To restore service the equipment first must be located, and a crew must travel to the location. Switching must be performed to isolate the equipment that has failed, perhaps curtailing service to some customers. Then the

equipment is either repaired or replaced, and switching is reversed to energize the equipment.

Economy of Scale. There is a significant economy of scale in the material cost of distribution equipment. However, its relative importance decreases from the substation to the secondary system. At the secondary or lower portion of the system, the installation and removal costs may become important factors in the choice of equipment size. To illustrate, the installation cost of a 5 MVA substation transformer constitutes only about five percent of the total material cost. On the other hand, the installation cost of a 5 KVA distribution transformer can approach 25 percent of the total material cost. A planner facing the decision to install a small unit now and remove it after a few years, or to install a larger unit for its lifetime, may choose the latter action if the installation and removal cost is very high.

Service Area Characteristics

Topography. The physical environment of a service area is an important factor in the distribution delivery system. The location of customers and the magnitudes of their loads influence the layout of the substations as well as the primary and secondary systems. In high load density city areas, the primary systems are usually looped networks rather than radial systems often found in rural areas. In addition the local topography affects the cost of distribution reinforcement.

Weather Conditions. Weather conditions affect both the performance and design of the delivery system. More frequent outages are expected in areas susceptible to extreme weather conditions such as snow, lightning, and heat storms. Severe weather conditions could account for 40 percent of total outages. Extra planning precautions are required to improve or maintain the level of service continuity. For example, the installation of more protection devices, the modification of loading limits, or the installation of special shielded lines may significantly

reduce outages caused by weather conditions, but each option requires additional planning.

Regulations and Ordinances. Government regulations and ordinances place additional constraints on distribution planning, reducing the number of feasible alternatives. These regulations affect the placement of substations and feeders and in some cases even the type of equipment used. Underground cables are often required in place of less expensive overhead lines. Government regulations and ordinances on environmental emissions are expected to be more stringent for locating dispersed storage and generation near load centers.

Delivery System Characteristics

Reserve Capacity. Reserve capacity exists throughout distribution systems. This capacity provides useful reserves for future load growth, reliability and daily load fluctuations.

In general, reserve capacity increases as one progresses through the system to the end users who benefit from cumulative reserve capacities. Other reserve capacities occur because of tradeoffs between economies of scale in equipment costs and high replacement costs due to labor costs. This reserve capacity characteristic together with load diversity implies that DSG devices placed at lower parts of the distribution system may not give corresponding distribution capacity savings in the short term. DSG devices can also be used as a temporary relief option to reduce excess capacity due to load uncertainties.

Distribution Reliability. Though the individual pieces of equipment are highly reliable, distribution level outages nevertheless comprise about 95 percent of all service interruptions to customers. Only about five percent of the outages are caused by failures in the bulk-supply system. This imbalance is due to the large number of components in the distribution system which are susceptible to adverse natural conditions or human error.

Generally, the cost of improving service continuity is so high that a few infrequent and brief periods of service interruption can be tolerated. Distribution outages, compared to bulk supply failures, are significantly more frequent, are shorter in duration, and affect fewer customers. At the present time, distribution system reliabilities reflect the balance between the value of service continuity to smaller customers and the cost of its improvement.

Distribution Losses. Transmission and distribution systems each lose about four to five percent of the energy they receive. Dispersed generation devices can reduce transmission line losses and reduce distribution losses. Dispersed storage devices have a negligible effect on transmission and distribution losses [10]. To deliver the same amount of energy to end-users, dispersed devices require smaller power and energy capacities than equivalent centralized devices.

Radial Operation. Most distribution systems are operated radially. In this way expensive distribution equipment investments are avoided and the operating and protection complexity is reduced as compared to loop systems. These benefits occur at the expense of service continuity. DSG could be operated to preserve the uni-directional current flow in a radial network, avoiding additional capital investment and planning and operating complexities.

Thermal and Voltage Limitations. Thermally-limited systems require reinforcements to avoid current overloading of equipment. Voltage-limited systems require additional voltage regulating equipment or other reinforcements to maintain voltage levels at customer's entry within proper upper and lower limits. Thermally-limited systems generally serve areas with high load density, and voltage-limited systems are often found in areas with low load density and long primary and secondary lines. Systems can be both thermally and voltage limited. In a thermally-limited system, DSG devices can be used to level the loads about the device location. DSG devices can also increase the voltage level below the device location in a voltage-limited system.

3.2 DISTRIBUTION PLANNING SYSTEM CHARACTERISTICS

Distribution planning is determined by delivery system characteristics. The planning process reflects and integrates information concerning the load, equipment and service area system characteristics. Planning also includes the design of the subtransmission system, the distribution substations, the primary system and the secondary system.

Planning for Peak Load. The load forecast initiates the distribution expansion planning process by defining the planning need. In most cases, the distribution peak load is the most important quantity because its value largely determines the type of distribution system that must be designed. Minimum load projections are occasionally required for systems with excessive voltage differences between peak and minimum load conditions.

Planning Objectives. Beginning with the load forecasts, the distribution planner considers various options to satisfy the future demand. He selects an appropriate service quality and minimizes cost over the planning horizon. Planning is performed under stochastic conditions with uncertainties and data scarcity increasing further down the delivery system.

The quality of customer service is defined by the performance and life span of customer electric facilities and by the frequency and duration of service interruptions. Standard voltage criteria exist to insure proper performance of electrical facilities, but there are no common criteria for service interruption accepted by all utilities.

Minimizing the cost of delivered energy is also a planning objective. The cost of delivering service includes the capital cost of equipment, the distribution energy losses, the cost of maintenance, and the loss of revenue from unserved energy. In distribution planning, only the capital cost and the cost of energy losses usually are con-

sidered because they are the major cost elements and the most likely to be reduced by careful planning.

Planning Criteria. Several procedures are used to achieve planning objectives. Because it is difficult to measure service quality directly, planners have established distribution equipment performance criteria as surrogates to planning objectives.

There are different planning criteria for normal and for emergency operation. A system is in a normal state if all distribution equipment is functioning properly. A system experiences an outage if some distribution equipment has failed to perform properly.

A set of emergency operating criteria--different than those for the normal state--is defined for selected outage states. The states are selected based on high expected costs arising from a high probability of outages or from excessive costs resulting from outages. For these selected outage states, planners select the customer loads which are to be served under the relaxed emergency operating criteria. For example, planning to have all customers receive service under emergency criteria for those outage states with selected single equipment failure is called single contingency planning. For some outage states, selected customer loads are dropped temporarily to protect the system from falling into even more severe outage states.

Two fundamental criteria are used in the normal and emergency states to protect customer and utility equipment: current-loading criteria and voltage criteria.

Current overloading for extended periods overheats the equipment, shortening its life span, or permanently damages the equipment. The life span of all distribution equipment depends on the duration and magnitude of current loading as a percentage of their nameplate capacity. Current loading criteria are established for each type of distribution

equipment, allowing extended operation during normal peak periods without damage. Exhibit 3-4 shows examples of loading limits for various equipment.

Voltage at the customer service entry must be maintained within certain ranges. Both excessively high and low voltages can damage customer electrical facilities and appliances. The voltage at the subtransmission and primary system must be kept within some range which allows for the voltage drop in the secondary system. Exhibit 3-5 lists a sample set of voltage criteria for various parts of the primary and secondary systems.

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

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

Options. Many planning options are possible, but in specific applications to solve local problems, only a very restricted set needs detailed analysis. Many are quickly screened out because of high initial

EXHIBIT 3-4

REPRESENTATIVE CURRENT LOADING
CRITERIA UNDER NORMAL CONDITIONS

DISTRIBUTION EQUIPMENT	CURRENT CRITERIA (PERCENT OF RATED CAPACITY)	
	SUMMER SEASON	WINTER SEASON
SUBSTATION TRANSFORMERS	125	125
SUBSTATION REGULATORS	145	160
RECLOSERS	100	100
AUTO BOOSTERS	135	140
SWITCHES	125	125

EXHIBIT 3-5

REPRESENTATIVE VOLTAGE VARIATION
CRITERIA UNDER NORMAL CONDITIONS

LOCATION	VOLTAGE CRITERIA (PERCENT OF NOMINAL VOLTAGE)	
	MINIMUM	MAXIMUM
HIGH VOLTAGE BUS OF SUBSTATION	92	105
LOW VOLTAGE BUS (AFTER REGULATOR)		
FIRST CUSTOMER SERVICE	102	105
LAST CUSTOMER SERVICE	97	105
CUSTOMER SERVICE ENTRANCE	94	105

cost and/or uncertainty in future benefits beyond the planning horizon. The number of competitive options decreases for operating criteria violations occurring close to the customer. Several different options can relieve violations of distribution planning criteria.

1. Reinforcement and expansion of primary and secondary systems, including addition or replacement of various types and sizes of circuits, voltage regulation equipment (such as distribution transformers, boosters, regulators, and capacitors) and protective devices (such as fuses, switches, and reclosers). New primary or secondary systems may also be added.
2. Reinforcement and expansion of distribution substations, including addition or replacement of various types and sizes of transformers, capacitors, reclosers, and switchgear. New substations may also be added.
3. Reinforcement and expansion of the subtransmission systems, as for Option 1, but for different voltage and current magnitudes.
4. Reinforcement and expansion of the transmission subtransmission substations, as for Option 2, but for different voltage and current magnitudes.
5. Conversion of system voltage classes, converting subtransmissions to transmission configurations, adding new substations, or upgrading distribution voltages.
6. Transfer of load, shifting loads between distribution substation areas by reconfiguring primary and secondary circuits or shifting loads between subtransmission service areas.

Adoption of New Technology. The introduction of new technology as an option in distribution system planning is a long process because of the time required to establish reliable performance to potential users with widely different needs [19]. This caution stems from the substantial costs of repairing, maintaining, and removing a large number of widespread faulty units. This is true for conventional technologies, and it will be true for DSG. The planning and operation of DSG will be subject to the same objectives and criteria used to evaluate conventional technologies.

Planning Horizon. The planning horizon is the number of years various options must be developed and evaluated so that the implementation decision for the first year is optimal. The distribution planning

horizon of five to seven years is much shorter than the generation planning horizon of twenty to thirty years. Factors which affect the planning horizon include:

- the degree of uncertainty,
- the cost of forecasting demand,
- the costs of collecting and processing demand and cost information,
- the cost of finding the optimal expansion plan, and
- the expected benefit of extending the planning period [20].

The distribution planning horizon is short because of:

- uncertainties in predicting area loads,
- the cost of forecasting demand at every part of the system,
- the costs of collecting and processing large amounts of data,
- the planning effort needed to find the optimal expansion plan, and
- the dubious benefit of extending the planning horizon to more than five to seven years.

An exception is the long-range planning for rapid growth areas where the expected benefits of longer planning horizons may be repeated. In these cases, hypothetical service area and load data together with a simple heuristic expansion algorithm substitute for detailed planning under uncertainty. The planning horizon for the secondary system is even shorter, usually less than three years, because of the same reasons given above.

3.3 DSG CHARACTERISTICS

Characteristics Common to Storage and Generation

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

Impact on Generation. Unlike all conventional distribution equipment, a DSG device stores or generates real power. It therefore

affects requirements for bulk supply generation. It may change both the energy and generation capacity. For this reason, DSG devices may be controlled for bulk supply objectives. In addition, if dispersed devices are to satisfy distribution objectives, they may have to be used for a longer duration than for generation objectives. This may increase the production, capital, and operating and maintenance costs.

Economy of Scale in Capital Cost. DSG technologies considered for dispersion characteristically have no significant capital cost economy of scale above 10 MW. However for sizes between 1 kW and 10 MW there can be a substantial economy of scale, depending on the technology.

Operating and Maintenance. There is a diseconomy of scale in operating and maintenance costs for dispersed devices. The unit operating and maintenance cost increases with the number of devices due to the geographical separation of the individual units. The total operating and maintenance cost depends increasingly on the number of units, rather than on the total capacity of individual units.

Communications and Control. DSG technologies require communications and control equipment. For a large number of devices the cost of this equipment depends on the number of units, not on their capacities. Communications and control costs could account for a large part of the total cost as the number of dispersed units increases.

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

Reliability. The reliability of individual dispersed units is expected to be comparable to reliabilities of peaking generators such as gas turbines. These generating devices are expected to have higher

component outage rates than conventional distribution equipment. These rates may vary according to the extent the devices are operated and maintained.

Dispersed Storage

Energy Limitation and Capacity Cost. The amount of energy available from a DSG device to supply the load is limited by its storage capacity. A separate capital cost for the DSG device is associated with the size of the storage capacity. Therefore, providing more energy capability for the same power capacity increases total capital costs.

Energy Payback. Energy stored must be restored during off-peak periods. This operational requirement increases the demand during the payback period. The increased loads could have an effect both on generation and distribution equipment.

Conversion Losses. Some energy is lost in the process of converting electricity into storage. Because of this loss, more energy is required to offset these losses and satisfy the same demand.

Dispersed Electric Generation

Fuel Use. Dispersed electric generation requires fuel. The cost of fuel may be greater when delivered to several dispersed sites than when delivered to a single location. Depending on local conditions and the power system characteristics, the increased fuel cost may offset energy savings obtained by reducing electrical transmission and distribution losses.

Dispersed Solar Generation

Intermittent Supply. Solar thermal and wind-powered generation is intermittent and largely unpredictable. Because such sources may

not be available when needed, the value of their capacity (kW) is smaller. Nevertheless, the energy (kWh) they provide is of significant value in reducing overall production costs. Capacity value may be increased when the intermittent source is used together with storage, but this increases the cost.

3.4 PLACEMENT AND CONTROL TRADEOFFS

DSSG devices can be placed anywhere in the distribution system from the high voltage substation bus down to the customer level. The costs and benefits of each placement and control scheme are different.

Consider, for example, the tradeoffs between placing a DSSG device in the substation and placing it along primary feeders. Feeder placement provides all of the benefits of substation placement, and it also:

- Increases the deferment benefit by postponing the need for feeder reinforcements, and
- Increases the reliability benefit by protecting against distribution failures between the device and the substation.

Feeder placement, however, increases costs. This

- has higher capacity, operating, maintenance control and communication costs because of a large number of smaller capacity units, and
- needs more power capacity and energy capability, which increase production costs, because of increased load diversities.

Evaluation of these and other cost-benefit tradeoffs requires complex models and procedures. There are too many important factors to attempt to use mathematical optimization to find the best plan and operating procedures. Accordingly, this study uses simulation procedures to assess alternative designs and select the one that best satisfies the evaluation criteria. The following chapters describe the models and

procedures developed to simulate the planning and operation of dispersed storage and generation in an electric distribution system.

4. PLANNING AND OPERATION OF DSSG

This chapter describes four of the five steps in the methodology developed for evaluating DSSG (see Section 2.3 and Exhibit 2-1).

- Conventional Distribution Planning
- Development of DSSG Strategies
- Simulation of DSSG Options
- Bulk Supply Base Case Definition

The fifth step, Evaluation of DSSG Options, is the subject of Chapter 5.

The discussion of each step in the methodology focuses on aspects of distribution planning that directly affect or are affected by planning DSSG in distribution systems. Only those topics related to the installation and use of DSSG devices will be found in this and the next chapter.

The sections below describe the function, procedure, and models used in each of the four steps of the methodology. Discussions of the models focus on the use of models as planning tools in each step. Specific structures of the different models are not included since the methodology is completely general. Consequently, the methodology can be applied with any particular set of planning models, allowing electric utilities to use their own models.

4.1 DISTRIBUTION EXPANSION PLANNING: STEP 1

The first step in the methodology is to establish the distribution base case expansion plan without DSSG. This step uses conventional distribution expansion planning. Planning is performed to expand or reinforce the distribution system to provide reliable service at minimum cost. Distribution planning is performed by first establishing the distribution load forecast, then finding specific reinforcement options that satisfy the new load.

4.1.1 Distribution Load Forecasting

The procedure used in distribution load forecasting decreases in sophistication and time horizon with load disaggregation. At the substation, peak load data from recording charts, together with the planners' informed judgement on load growth, provide the basis for load forecasting. Substation forecasts, usually three to seven years into the future, are used to plan distribution substation and transmission expansion and reinforcement.

From the primary system, to the customer level, information on peak loads generally is not available. Except for some special feeders and large customers, no load data is recorded. New loads in distribution service areas are estimated using information on new housing construction and commercial and industrial development. Growth of existing loads sometimes is estimated from the distribution transformer loadings in Transformer Load Management (TLM) procedures. These non-coincident peak loads may be used in planning primary system reinforcements.

The lack of load information is due to the high cost of collecting and processing large amounts of data. The value to the utility of improving load forecasts may not justify the cost of collecting the needed data. Many electric utilities historically have provided excess distribution capacity to assure adequate service, in preference to collecting and forecasting more load data at the secondary system level.

Distribution planners use simple peak load models. Typically, a single uniform growth rate or several different yearly growth rates are applied to all peak loads in a substation area. The growth rate is estimated using extrapolation of past trends and the planners' informed judgement of the area load. Most utilities account for load transfers between substations [21]. Others consider peak load diversities for the first sections of primary feeders [22].

More sophisticated models for projecting substation peak loads are available [23], relating peak load growth to the growth of individual load components. These models have not been widely used by distribution planners. Computerized TLM models to estimate peak loads at distribution transformers are used for some distribution functions [24], but their usefulness in load forecasting to support distribution planning has not been established.

4.1.2 Conventional Distribution Planning

Distribution planning includes designing the subtransmission system, distribution substation, primary systems, and secondary systems. It includes planning for existing service areas and for new service areas.

Although the objectives of distribution planning are the same for all utilities, the procedures and the equipment vary significantly among utilities and sometimes among different parts of the distribution system for the same utility. They differ because load characteristics load conditions, and past standard practices vary.

Present distribution planning is governed by planning criteria, as shown in Exhibit 4-1. Most of the planning time and effort is devoted to planning for normal operation. Beginning with peak load forecasts, distribution equipment characteristics and normal operating criteria, the planner verifies that all criteria for normal operation are satisfied. If they are not satisfied, violations are analyzed and relief options are developed. The cost of each relief option is determined and the least cost one is selected. Once the normal operation criteria are met, the planner considers emergency operations in much the same manner.

Most models are used to evaluate preselected planning options. They do not identify options for the planner. Distribution load flow

EXHIBIT 4-1

CONVENTIONAL DISTRIBUTION PLANNING

models verify current loading and voltage criteria for normal and emergency conditions. Short-circuit analyses are performed separately to determine protection requirements. Results from the distribution planning models, together with the costs of the options considered, form the basis for selecting options for implementation.

Some planning models, however, can identify options. They are classified as general or specific models. General models [25,26] represent the delivery system from subtransmission to the secondary system. System expansion is performed using heuristically-developed options. The objective is to evaluate long-range, global planning options by simulating the decisions of the planners. Thus, the expansion plans do not represent the manner in which the system actually would be planned and operated. These general models require such extensive data collection and processing efforts that they are rarely used in present distribution planning. They are useful, however, in long-range planning for areas with rapid load growth where planners can take advantage of economies of scale in high-cost equipment.

Specific models generate and evaluate a specific class of options, distinguished by the level of the system. For example, models exist which determine substation size and location [27,28], load transfer by feeder reconfiguration [29,30], and secondary system design [31,32]. The models find the best "suboptimal" alternative. Using his own judgement and experience the planner finds the "optimum" solution by combining several alternatives identified by different specific models. The planner may also use more detailed models to help evaluate the combinations and find the "optimal" solution.

Planning of the secondary system is distinct from the planning of the other parts of the distribution system. Secondary system planning involves finding the most economical sizes of distribution transformers and conductors and the appropriate voltage levels for various types of customer loads. In secondary systems, the cost of installation is a much

higher portion of the total cost for the primary system or for substation reinforcement. Therefore, the tradeoffs between installing a small unit (which will need replacement later) and installing a large unit tends to favor the larger unit. Secondary systems are usually sized to allow for future customer load growth.

Transformer Load Management (TLM) models often are used to assist in the planning of existing secondary systems. As new customers are added to the existing system, new lines and transformers are also added. TLM models can aid the planner in selecting among various options, although in fact many decisions are based upon past practices.

In summary, the distribution planner is aided in the planning process by interacting with a set of models. His judgement and experience play an important role in identifying and screening options and in selecting an "optimal" solution.

4.2 DEVELOPMENT OF DSSG STRATEGIES: STEP 2

Defining DSSG strategies is the second step in the methodology developed in this study. The same set of load forecasts, distribution planning criteria, and models used for conventional distribution planning are also used to develop DSSG strategies.

4.2.1 Approach

The general approach to planning with DSSG considers DSSG as a planning option which can help eliminate violations of distribution planning criteria. DSSG is not expected to solve all distribution problems, nor is it expected to be the least cost or optimal solution. A strategy is developed by selectively applying DSSG to relieve specific

distribution violations for a specified duration. In addition, different DSSG options which may constitute a strategy, are specified by:

- DSSG device locations
- DSSG device capacity sizes
- DSSG operating modes

The approach to the development of DSSG strategies uses existing planning models currently used by the utilities. The approach is flexible enough to accommodate more advanced future models. Furthermore the results are credible since utilities apply their own planning procedures and models. The results of this step are:

- Strategies, defined by the occurrence, location, and duration of violations.
- DSSG options within each strategy, defined by locations, sizes, and operating modes of equipment selected to relieve the violations.

Conventional distribution expansion may be the preferred alternative for the base case plan defined in Step 1. Subsequent steps in the methodology will compare the plans developed in Step 1 and Step 2 to determine their relative costs and benefits.

4.2.2 Procedure

First, the specific criteria violations relieved by the base case expansion plan without DSSG are identified. Then, each of the violations is analyzed to determine whether DSSG can provide similar relief. For example, the overloading of substation transformers during an outage of a neighboring substation might be relieved under conventional single contingency planning by an additional transformer. Such an outage also might be relieved by the placement of DSSG devices in the substation. Strategies are defined for relieving selected violations for a designated period. To implement these strategies, options are developed with DSSG devices of various sizes placed at selected locations.

Potential locations for DSSG devices range from the high-voltage bus of the distribution substation to the customer site. No environmental constraints were considered in the study, although suitable factors could be included by the planner for specific applications.

Device capacities are limited by the need to preserve unidirectional current flow. The maximum capacity of a DSSG device at any location is bounded by the sum of all the loads supplied downstream of the device. The sizes of storage devices are further limited by their conversion losses and by the characteristics of the charge/discharge cycle.

Operating modes can meet a range of local and central objectives. The choices of operating modes become separate DSSG options within the strategy. A discussion of different operating modes is presented in the next section.

4.2.2 Models

The same models used in conventional distribution planning can be used to develop feasible DSSG options. DSSG devices are modeled as devices which either decrease or increase the real and reactive loads. In the next step, DSSG options are simulated to evaluate their feasibility.

This approach to evaluating DSSG is consistent with the manner in which planners currently use models to evaluate conventional or new technology options. Long-range planning models are unsuitable, since they ignore many short-range details necessary for evaluating DSSG.

Two new models are needed, however, to help the planner identify feasible options. A new load model containing 24-hour load information and a new model for simulating the operation of DSSG devices are presented below.

4.3 SIMULATION OF DSSG OPTIONS: STEP 3

Simulating the operation of DSSG options in the electric distribution system is the third step in the methodology. Each DSSG option is simulated to determine whether the new technology can relieve constraint violations for the needed duration. The simulation considers selected daily operations over the planning horizon and has the following outputs:

- The modes of operation for the dispersed devices;
- The sizes and schedule of DSSG installations; and
- The revised distribution and system load curves.

Calculation of these outputs is an interactive process. Alternate DSSG options with various device sizes, locations, and operating procedures may be obtained, revised, and simulated. Infeasible options are eliminated in this step.

The two sections below describe two models developed for the simulations: the Load Model and the DSSG Operations Model.

4.3.1 Load Model

Knowledge of distribution peak loads, adequate for conventional planning, is inadequate for planning with DSSG. Planning with DSSG requires 24-hour load data at various levels in the distribution system. DSSG devices modify distribution loads, changing the magnitude of the peak load and its time of occurrence. The Load Model simulates the 24-hour distribution loads. The revised load curves provide time-of-day information for distribution planning and for bulk-supply planning (see Exhibit 4-2). The load model outputs are used in determining the locations, sizes, and modes of operation of DSSG devices.

The Load Model proceeds through three phases. First, the average diversified daily load curves of various customer classes are synthesized, as shown in Exhibit 4-3. The customer classes are defined

EXHIBIT 4-2
USE OF MODELS IN DSSG SIMULATION

EXHIBIT 4-3

LOAD MODEL

EXHIBIT 4-4
NETWORK REPRESENTATION FOR
LOAD MODEL

by type of customer (residential, commercial, industrial), consumption, pattern of use, etc. The data needed for this classification are usually available from previous load surveys.

The pattern of use (or the diversified load curve) of a customer depends upon his mix of appliances and upon his life style. The fundamental distribution load components, such as diversified appliance or customer load curves, are called basic loads in this study.

The second phase of the Load Model involves the calculation of the diversified load for a cluster of customers. The load cluster may describe the combined customer loads, for example, at a distribution transformer. Using information describing the portion of different customer classes within a cluster, the Load Model calculates the resulting load at each individual point, or node, within the distribution network. The nodes are the lowest level of specification in conventional distribution planning models.

The first two phases of the Load Model synthesize customer loads and calculate loads for customer clusters. The third phase of the Load Model aggregates the loads at each node to find the daily loads at different parts of the radially-operated distribution system. The loads for each time of day are added separately so that aggregate time-of-day load data is available at each node.

Load indices useful for planning DSSG are computed. These quantities include diversity measures, the level and time of peak loading, load factors, etc.

A portion of a network description is shown in Exhibit 4-4. Each level corresponds to one of the three phases of the Load Model. In principle, each customer of a utility could be represented by a separate node. It is more practical, however, to associate a multiplier with each node to denote the number of identical nodes aggregated together.

By allowing the loads at designated nodes to change at given annual rates, the Load Model becomes dynamic. The inputs to the Load Model include:

- Diversified basic loads
- Mix of basic loads at each node
- Radial configuration connecting the nodes
- Forecasted load growth rates.

The outputs of the model include:

- Daily load curve at each node
- Planning information such as peak load, time of peak, load factor, and coincidence factor at each node

An electric distribution network is modeled as a set of interconnected nodes. A segment of a radial network can be represented in levels as shown in Exhibit 4-4.

The aggregation process for a radial system as in Exhibit 4-4 proceeds as follows: let the daily load curve for the j^{th} component at the i^{th} level be $\ell_{ij}(t)$. The total load at the j^{th} node of the i^{th} level is obtained by summing over the constituent loads. Thus,

$$\ell_{i,j}(t) = \sum_{k=1}^{J_{ij}} \ell_{i+1,k}(t) \alpha_{i+1,k}$$

where J_{ij} is the number of nodes at level $i+1$ connected to node (k,j) . The multiplicative descriptor, α_{ij} , is used to describe multiple identical loads or to represent the effect of energy losses.

This model is flexible, allowing aggregation of system loads beginning with the characteristics of individual customers and appliances. In many applications, nodes describing several customers may be used as the input data.

The Load Model also calculates many load indices helpful in summarizing load characteristics such as the diversity measures introduced and defined in Section 3.1. These measures help identify parts of the distribution system needing expansion and help plan conventional and new technology additions. The Load Model also computes the following measures at each level:

- The maximum (peak) load P_{ij} at node (i,j) occurring at time t^* :

$$P_{ij} = \max_t \left\{ \ell_{ij}(t) \right\} = \ell_{ij}(t_{ij}^*)$$

where

$$t_{ij}^* = \{t \mid \ell_{ij}(t) = p_{ij}\}$$

- The load factor, ϕ_{ij} , at node (i,j):

$$\phi_{ij} = \frac{\int_0^T \ell_{ij}(t) dt}{P_{ij} T}$$

Load growth is modeled by relating the load in year k to year $k+1$ by:

$$\ell_{ij}^{k+1}(t) = (1+r_{ij})\ell_{ij}^k(t)$$

where r_{ij} is the rate of load growth at node (i,j) from year k to $k+1$.

This formulation of the Load Model was selected because it gives a prediction of the diversified 24-hour load of sufficient detail to accomplish DSSG planning. Yet the Load Model has a very flexible data requirement. Flexibility in the data requirement is essential because of the general lack of detailed, continuous distribution load data. Recent interest and research in load management and distribution automation will improve the quality of customer load data in the future, making more detailed load projections possible.

There are, however, practical limitations to the degree of improvement in the data quality. No matter how detailed the records of past loads are, it is future loads that are of interest. Uncertainties in the forecast are therefore unavoidable. Even if more sophisticated techniques are used to model the random processes, the data collection and processing required to predict individual loads would be substantial and probably unjustified by the modest planning improvement.

4.3.2 DSSG Operations Model

The Operations Model simulates the generating and charging operations of the DSSG devices in distribution systems according to the strategy specifications. As a minimum requirement, the devices must always be operated to satisfy designated local objectives. The outputs of the model include:

- Operating curves of all devices
- Revised distribution system peak load
- Schedule of dispersed power and energy capacity sizes

The relationship between the Operations Model and other planning and assessment models is illustrated in Exhibit 4-2.

Operating modes of the dispersed devices are chosen to satisfy one of three objectives:

- local objectives only
- bulk supply objectives only
- both local and bulk supply objectives

The choice of the operating policy depends on the type of day. There are central-capacity days, local-capacity days, conflicting days which are both central and local capacity days, and normal days which are neither. The definitions are given below.

Central-capacity days are the days when all the available generating capacities are needed to meet the system load. These are the days when the system load peak may occur. Usually central-capacity days

occur on weekdays in the peak season. Maximum generating capacities would be needed for a certain period during the day.

Local-capacity days are the days when the maximum generating capacity of a dispersed device would be needed to avoid a distribution violation as defined in the strategy. These are the days when the distribution objectives may be violated. The number of local-capacity days depends on the intended use of the dispersed device for local problems.

Central-capacity and local-capacity days may or may not be coincident. In the course of a year, usually there are overlaps which present a conflict of operating objectives for the device. These days are known as the conflicting-capacity days.

Exhibit 4-5 relates the choice of operating modes to the type of days. On normal and central-capacity days, the DSSG device would be operated with purely bulk power objectives. On conflicting days, however, there are two choices:

- The devices may be operated exclusively for relieving the local violations, or
- The devices may be operated to satisfy both bulk supply and distribution needs.

The former may incur a greater bulk supply-related cost, while the latter may incur additional DSSG device-related costs. The net cost benefit of both operating modes is evaluated as different DSSG options using the five assessment components discussed in Section 2.2.

Different communication and control schemes can be used to implement either operating policy. Analysis of the various schemes indicates that a remote communication system can be used to transmit relatively simple codes to the dispersed device. A small number of codes would be required to completely specify all desirable operating modes.

EXHIBIT 4-5

DESG OPERATING MODES

OPERATING MODES	TYPE OF DAY			
	LOCAL- CAPACITY DAYS	CONFLICTING DAYS	CENTRAL- CAPACITY DAYS	NORMAL DAYS
PURELY BULK-SUPPLY OBJECTIVE			X	X
PURELY DISTRIBUTION OBJECTIVE	X	X		
BOTH DISTRIBUTION AND BULK-SUPPLY OBJECTIVE		X		

At each instant, a unique generating or charging level for a dispersed device is defined by a transmitted code and information provided by current or voltage sensing instrumentation at dispersed locations.

In this section, only the operating modes simulated in the case studies are presented. In general, alternate operating modes with different communication and control schemes (at different costs) can be simulated in the model. The operating modes presented here are used in case studies to obtain generic conclusions pertinent to the two operating policies. The operations of intermittent devices such as wind and solar generation are modeled separately.

The DSSG Operations Model includes three types of basic operations:

- Flat Generation, where the generation of the dispersed devices follows the distribution load, if the distribution load rises above a specified level (see Exhibit 4-6). This type of operation is called flat generation because the resulting distribution load is flat during the time of DSSG device operation.

Suppose $g_i^1(t)$ is the flat generation for device i at time t , then:

$$g_i^1(t) = \text{Min}\{x_i, \text{Max}[0, \ell_i(t) - \hat{C}_i]\}$$

where $\hat{C}_i$ is the specified load limit beyond which the DSSG device generates up to capacity x_i . Under flat generation, the dispersed device output is variable, allowing the distribution load to be maintained at the desired level.

- Full Generation, where the generating device is operated at its peak capacity y_i (see Exhibit 4-7).

EXHIBIT 4-6
FLAT GENERATION MODE

EXHIBIT 4-7
FULL GENERATION MODE

EXHIBIT 4-8

STORAGE OFF-PEAK CHARGING MODE

Suppose $g_i^2(t)$ is the full generation operation for device i , then

$$g_i^2(t) = x_i$$

Storage Charging, where a storage device is charged at full capacity, y_i but not exceeding a specified level (see Exhibit 4-8).

$$s_i^1(t) = \text{Min} \left\{ y_i, \text{Max} \left[0, \hat{C}_i - \ell_i(t) \right] \right\}$$

where $s_i^1(t)$ is the storage charging curve for device i .

The operating mode $f(t)$ of a dispersed device is completely defined by a combination of the three basic operations as follows:

$$f(t) = \alpha_i^1(t)g_i^1 + \alpha_i^2(t)g_i^2(t) - \alpha_i^3(t)s_i^1(t)$$

Here $\alpha^1, \alpha^2, \alpha^3$, can be 0 or 1, and only one of the α 's may be non-zero at any given time. That is:

$$\alpha_i^1(t) + \alpha_i^2(t) + \alpha_i^3(t) \leq 1; \alpha_i^j = 0 \text{ or } 1, j=1,2,3$$

By sending a sequence of $\alpha(t)$ codes via remote communication a DSSG device can be made to operate in different modes. The number of basic operating modes can be increased at additional cost. In general, if n basic operations are defined, $n+1$ codes are needed with the additional code turning off all operations.

EXHIBIT 4-9

EXAMPLE OF DSSG OPERATING MODE

These three basic operating modes are used in the case studies. An example of the type of operating modes that can be simulated is illustrated in Exhibit 4-9. Between t_1 and t_2 , $\alpha^1 = 1$; t_2 and t_3 , $\alpha^2 = 1$; t_3 and t_4 , $\alpha^1 = 1$; t_4 and t_5 , $\alpha^1 = \alpha^2 = \alpha^3 = 0$; t_5 and t_6 , $\alpha^3 = 1$; t_6 and t_1 , $\alpha^1 = \alpha^2 = \alpha^3 = 0$.

To facilitate later discussions, the following definitions are provided:

- $g_i(t)$ = Power output of the i^{th} dispersed generator (or discharging storage unit)
 $= \alpha_i^1(t)g_i(t) + \alpha_i^2(t)g_i^2(t)$
- $s_i(t)$ = Power requirement of the i^{th} dispersed storage unit during charging
 $= \alpha_i^3(t)s_i^1(t)$
- $E[g_i(t)]$ = Stored energy delivered by the i^{th} dispersed unit in a day
- ε = Round-trip efficiency of dispersed storage

The simulation of DSSG operations requires that the energy stored equal the energy delivered later during the peak period, correcting for conversion losses. Thus:

$$E[g_i(t)] = \varepsilon E[s_i(t)]$$

Using the operating curves of all devices, the load model finds the revised distribution loads and the equivalent generating capacity at the bulk supply level.

4.4 BULK SUPPLY BASE CASE DEFINITION: STEP 4

The introduction of DSSG in the distribution system affects the planning and operation of the bulk supply system. This fourth step of the methodology is to find the equivalent generating capacity at the bulk supply level. First a base case is established where the equivalent DSSG capacity is centrally located and operated according to bulk supply objectives. The performance is then compared with the case where the DSSG is dispersed and operated with distribution objectives.

4.4.1 Approach

The capacity installed at the bulk supply level is sized to be equivalent to the capacity of all of the dispersed devices. An equivalent power capacity can deliver the same power as all the dispersed devices in a case study. The equivalent energy capacity is the energy storage capacity of a device with the equivalent power capacity that is optimal from the perspective of the bulk supply system. Both the equivalent power and the equivalent energy capacities are used to meet the bulk supply objectives. The equivalent power and energy capacities in general do not equal the sums of the power and energy capacities of the individual devices.

The bulk supply base case should be found by optimally expanding the bulk supply system with the equivalent DSSG capacities specified for a particular level of DSSG device saturation. In the case studies, the reference supply system expansion plan without DSSG was obtained from the utilities. It was assumed that a small penetration of DSSG devices would not affect the supply system expansion. For large penetrations it would be necessary to define a new bulk supply system expansion plan.

In this study, the equivalent energy capacity was found by determining the power and energy usable on a system peak day. This

determination is needed to properly allocate the cost of excessive energy capacities to the distribution system. The bulk supply system is not expected to contribute toward the cost of energy storage which it can not use beneficially.

With these definitions of equivalent capacities, the bulk supply expansion plans of all generation technologies for the centralized and dispersed cases are assumed to be the same. This step in the methodology therefore decouples the assessment of the long-term impact of DSSG from other dispersion effects. Evaluation of the long-term effects of centralized new technologies can be combined with the separate evaluation of the dispersion effect, to give the overall assessment of the new technologies.

4.4.2 Equivalent Capacity Model

The equivalent energy of centralized storage should be found as a part of the optimal generation expansion planning process, using procedures which can consider energy storage. In this study, the Equivalent Capacity Model is used to estimate the equivalent energy without repeating the expansion planning process. This model finds the useful energy storage capability on a system peak day with given power capacities. The objective of the model is to minimize production costs.

Let β_i be the allowance factor to account for the energy losses in the transmission and distribution system up to the location of the device i . Then, the equivalent capacity, X , is defined by:

$$X = \text{Max}_t \left\{ \sum_i [g_i(t) - s_i(t)] \beta_i \right\}$$

To develop the model, some definitions are necessary. Let:

EXHIBIT 4-10

EQUIVALENT CENTRAL STORAGE OPERATING MODE

$L(t)$	=	Load as seen by the bulk supply system
$U_i(.)$	=	A vector of incremental cost curves of central generators and the equivalent central device as functions of power output.
$f_i(t)$	=	$g_i(t) - s_i(t)$, the output of a single DSSG device.
$F(t)$	=	The net load during the operating mode of the equivalent central device.
$G(t)$	=	The load during the generating mode for the equivalent central device.
$S(t)$	=	The load during the charging mode for the equivalent central device.
$H[L(t), U_1(.)]$	=	Production cost of using generators with incremental cost U_1 to meet the load $L(t)$.

Note that:

$$F(t) = G(t) - S(t)$$

This relation is analogous to the similar expression for the individual devices.

Storage devices transfer load as seen by generators from peak to off-peak periods, and energy is lost in the process. Exhibit 4-10 shows an idealized daily system load curve and the effects of the equivalent storage device on the load curve. The heights of the bands shown in the peak and off-peak periods are the equivalent charging and discharging capacities. The area of the band in the peak period is the equivalent energy capacity.

Given the equivalent discharging capacity, the bulk supply planner wants to find the area of the band which minimizes the total production cost of the revised production schedule. Mathematically, the problem is to find:

$$\begin{array}{l} \text{Min} \\ F(t) \end{array} = H[L(t) - F(t), U_1(\cdot)]$$

subject to the constraints:

$$\begin{array}{l} \text{Max} \\ t \end{array} [F(t)] = X$$

$$E[G(t)] = \varepsilon E[S(t)]$$

That is, given an effective power capacity X , what operating policy will give the minimum production cost and satisfy the energy balance equation?

If:

$$F^*(t) = G^*(t) - S^*(t)$$

is the optimal solution, the equivalent energy capacity E is defined as:

$$E = E[G^*(t)]$$

Note that the effective power capacity is defined in terms of the capacities of the individual devices, but that the effective energy capacity is not defined in terms of individual energy capacities. The equivalent energy capacity may be less than, equal to, or greater than, the sum of the individual device energy capacities.

The above observation is significant: it states that perhaps not all shifting of power and energy is necessarily desirable. From the bulk supply perspective, the most desirable production cost effects occur only for particular relationships between energy and power.

5. EVALUATION OF DSSG

This chapter describes the fifth step in the methodology developed for evaluating DSSG options (see Section 2.3 and Exhibit 2-1). The first four steps in the methodology for evaluating DSSG were discussed in Chapter 4. This step of the procedure measures five distinct assessment components.

- Distribution Capacity Component
- Reliability Component
- Dispersal Cost Component
- Production Cost Component
- Replacement Capacity Component

These five components determine the dispersion credit. Each of these assessment components is the subject of the sections below.

Results from the planning procedures of Chapter 4 are used to calculate the five assessment components. Exhibit 5-1 shows the information flow from the planning models to the assessment components.

In each assessment component calculation, there are two types of data: one for the dispersed technology case, the other for the centralized technology case. Differences between the two sets of data determine the assessment component. A positive component value indicates a benefit. A negative value is a cost. The sum of the five assessment components is the net benefit or net cost.

The net benefit (or cost) is the difference in the marginal cost and marginal benefit realized as dispersible devices are placed in the radial distribution system rather than in the bulk supply system. (See Section 2.3, Exhibit 2-2.) This net benefit is also called the dispersion credit. The dispersion credit is not to be confused with the net bulk supply credit (Exhibit 2-3).

EXHIBIT 5-1

ASSESSMENTS MODELS AND PLANNING STEPS

The value of each assessment component is computed as the present worth of annual revenue requirements. All costs and benefits are discounted to the reference year. That is, if the present value discount rate is r , and the benefit flow of the j^{th} component is $B_{1j}, B_{2j}, \dots, B_{nj}$ for n years, the present value of all benefits at the initial year is:

$$PV(B) = \sum_{k=1}^n \left[(1+r)^{-k} \sum_{j=1}^5 B_{kj} \right]$$

5.1 DISTRIBUTION CAPACITY COMPONENT

The distribution capacity component is the difference in distribution reinforcement costs between the cases where DSSG is used and where it is not used. Distribution capacity benefits occur when distribution investments are deferred or cancelled. The capital cost of DSSG technologies is included in the dispersal cost component, Section 5.3, not in the distribution capacity component.

Given an implementation schedule, total capital costs of the distribution system reinforcements are determined and annualized using an annual carrying charge rate. If the capital cost of a piece of equipment is C , the annual carrying charge rate is a , the life of the equipment is L , and the equipment is committed through year k , then Ca is the annual revenue requirement in years $k, k+1, \dots, k+L-1$. Annual maintenance costs usually are included with the annual carrying charge rate. More generally, suppose the distribution equipment expansion costs with and without DSSG are:

$$C_1^1, C_2^1, \dots, C_n^1 \text{ and } C_1^2, C_2^2, \dots, C_n^2$$

respectively, for years 1 to n . The cost in each year may include costs for several different types of equipment, each with different schedules.

Then, the distribution capacity benefits used in present worth calculations are:

$$B_{kl} = C_k^1 - C_k^2, \quad k=1,2,\dots,n$$

If the new expansion schedule is a deferment of the original schedule, the original capital costs are adjusted using an escalation rate. The capital cost of the equipment installed after a deferment of m years is escalated at a rate i , and given as $C_k(1+i)^m$.

5.2 RELIABILITY COMPONENT

The reliability benefit of a DSSG device is due to its generating capacity to satisfy load during distribution systems outages. In this section the reliability component is determined by the value of providing additional service continuity. The reliability component is derived by comparing improvements in distribution reliability between dispersed and centralized devices. The calculation of the reliability component is useful for purposes other than DSSG evaluation. The reliability component calculation for the distribution base case is a means to derive the expansion capacity needed to provide service continuity at a constant reliability.

The dispersed devices can be designed to supply preselected loads during an emergency before the repair crew restores partial or total service. The DSSG device is not expected to satisfy all loads lost in an outage because of insufficient power (or storage capacity) or because power cannot be distributed to the problem location. This requires planning DSSG to meet the preselected loads for a designated number of hours.

A reliability benefit may be obtained but only at some increased instrumentation costs. Instrumentation requirements include

automatic switching to preselected loads and protection schemes in case the fault is associated with one of the loads selected for emergency service.

The approach is to determine the amount of reduction of expected unserved energy $(\Delta EUE)_{ki}$ supplied at a device i in emergency, in year k . It is assumed that the equivalent central devices will have no effect on distribution reliability. This assumption is supported by the fact that 95 percent of all outages occur in distribution systems. The reliability benefit of DSSG is calculated by:

$$B_{k2} = \sum_i (\Delta EUE)_{ki} V_i$$

where V_i is the value of emergency energy service in \$/kWh reflecting the mix of customers supplied by the device i . For simplicity, the subscript k will be left out in subsequent discussions.

The numerical values of V_i for different customers has been reported by many authors [33-36]. Generally, the value varies for 50¢/kWh to \$10/kWh, depending on the nature of the customer.

For dispersed generation, it can be assumed that the fuel supply of the DSSG device is adequate to serve the designated loads for the duration of a distribution outage (with replenishment if necessary). Let τ_i and $\bar{n}_i$ be the average number of customer hours per outage occurrence and the average number of occurrences per year for the area served by device i . These quantities can be estimated from outage records of the area or from outputs of distribution reliability models [37,38]. The data are usually measured in customer minutes and number of occurrences per year. The load to be served in general would be less than or equal to the peak capacity of the DSSG device. If outages in a day occur at random, the average load served can be estimated as $\phi_i p_i$, where ϕ_i is the annual load factor and p_i is the peak of the designated loads. Let the forced outage probability of the device be θ_i .

The reduction in the annual expected unserved energy supplied by generator i is given by:

$$(\Delta EUE)_i = p_i \phi_i \tau_i \bar{n}_i (1 - \theta_i)$$

For dispersed storage, the computation of the reduction of unserved energy is complicated by the storage limitation. The duration of some outages may exceed the time the storage can supply the energy. In addition, the amount of energy stored varies according to the timing of the charge-discharge cycle. In order to evaluate the reduction of unserved energy, four random variables have to be considered: the time the outage occurs, the duration of the outage, the amount of energy in storage, and the level of load during outage. The latter two random variables are usually correlated with the time the outage occurs. The model described below treats the level of load and the energy in storage as deterministic but related by time of day.

From the past outage record, a probability density function $f_i(\tau)$ can be developed for the outage duration, τ , during which the designated loads are supplied by the storage i . The data are usually expressed as frequency and duration of outage occurrence for an area.

We assume that outages are equally likely to occur at any hour of any day. Then the time of occurrence, the random variable t , has a uniform probability distribution. The following terms will be used in the ensuing discussion:

- $\ell_i(t)$ = Designated load to be served by storage i
- $E_i(t)$ = Amount of energy in storage i as a function of time
- $h_i(t)$ = Number of hours that $\ell_i(t)$ can be supplied by the amount of energy stored, $E_i(t)$.

Note that $h_i(t)$ can be derived from the equation:

$$E_i(t) = \int_0^{h_i(t)} \ell_i(x) dx$$

The amount of energy in storage $E_i(t)$ is available as output from the DSSG Operations Model.

The amount of reduction in expected unserved energy per outage at any time of day t is:

$$(1-\theta_i) \left[\int_0^{h_i(t)} \int_t^{t+\tau} \ell_i(x) dx f_i(\tau) d\tau + \int_{h_i(t)}^{\infty} \int_t^{t+h_i(t)} \ell_i(x) dx f_i(\tau) d\tau \right]$$

The first term is the reduction when the storage device has enough stored energy to completely supply the load; i.e., $h_i(t) \geq \tau$, where τ is the outage duration. The second term describes the case where the stored energy is not adequate; i.e., $h_i(t) < \tau$.

The total amount of reduction in expected unserved energy supplied by storage i is given by:

$$\Delta(\text{EUE})_i = (1-\theta_i) \frac{1}{24} \bar{n}_i \int_0^{24} \left[\int_0^{h_i(t)} \int_t^{t+\tau} \ell_i(x) dx f_i(\tau) d\tau + \int_{h_i(t)}^{\infty} \int_t^{t+h_i(t)} \ell_i(x) dx f_i(\tau) d\tau \right] dt$$

EXHIBIT 5-2
RELIABILITY COMPONENT

It can be easily shown that if the storage device has an infinite amount of energy stored (i.e., $h_i(t) = \infty$), the above expression for the reduction of unserved energy is exactly the same as that for dispersed generators.

Exhibit 5-2 illustrates the procedures in computing the reliability component.

5.3 DISPERSAL COST COMPONENT

The dispersal cost component is the capital cost difference for DSSG equipment between dispersed use and centralized use. It is the incremental cost of dispersing technologies rather than locating them centrally. The dispersal cost accounts for diseconomies of scale in DSSG equipment and the cost for communications and control equipment. The dispersal cost is calculated differently for dispersed generators and for dispersed storage.

The dispersal component for dispersed generation, B_3 , is calculated by:

$$B_3 = a_1 q_1(X)X - a_1 \sum_i q_1(x_i)x_i$$

where a_i is the annual carrying charge; q_1 is the unit capital cost in \$/Kw as a function of device capacity; X is the central equivalent capacity; and x_i is the power capacity of individual devices. The capital costs of dc/ac inverters are included in q_1 .

The dispersal cost component for dispersed storage is calculated similarly to the cost for generation except an additional term is included for the cost of storage capacity. The dispersal component is:

$$B_3 = a_1[q_1(X)X + q_2(X,E)E] + a_2q_3(X)X - a_1 \sum_i [q_1(x_i)x_i + q_2(x_i,E_i)E_i] - a_2 \sum_i q_3(x_i)x_i$$

where E , E_i are the central equivalent and dispersed energy capacities and q_2 is the unit energy capacity cost, in \$/kWh, as a function of power and energy capacities. The form of q_2 can be represented as:

$$q_2(X,E) = q(X)m \left(\frac{E}{X}\right)$$

where q is the unit energy capacity cost dependent on the size of the power rating, and m is a multiplier dependent on the number of hours the storage can generate at maximum power.

Dispersal of DSSG devices incurs additional costs for communication and control. These are calculated as:

$$a_2q_3(X)X - a_2 \sum_i q_3(x_i)x_i$$

where a_2 is the annual carrying charge for communication and control equipment including operating and maintenance costs, and q_3 is the unit capital cost depending on the device capacity.

5.4 PRODUCTION COST COMPONENT

The use of DSSG for distribution benefits causes the total generation production cost to differ from that of the equivalent central device with bulk supply objectives. The production component measures the difference between the costs of the two types of operations.

The production cost benefit is calculated separately for two kinds of days in a year (see definitions in Section 4.3.2, DSSG Operations Model).

- Days when DSSG devices are operated for distribution benefits. This is the sum of K_1 conflicting-capacity days and K_2 local-capacity days.
- Days when DSSG devices are operated with bulk supply objectives. This is the sum of K_3 central-capacity days and K_4 normal days.

The production cost component includes the cost of fuel consumed and operating and maintenance costs. Not included are reductions in losses due to leveled load, which was estimated to be insignificant for storage when compared to the magnitude of the production cost component [10].

The unit operating and maintenance cost of a dispersed device is expected to be higher than that of centralized devices. It requires more effort to monitor, locate, and travel to the device. Therefore, the unit operating and maintenance cost (\$/kWh) depends on the size of the power capacity of DSSG devices.

The production component on K_1 and K_2 type of days B_2^1 is calculated by:

$$B_4^1 = \sum_{k=1}^{K_1+K_2} B_{k4}^1$$

- B_4^1 = Bulk power production cost with equivalent central capacity under central control
- Combined production cost of the dispersed devices
 - Bulk power production cost to supply load modified by the dispersed devices

Using the notations of Section 4.4 this relation for a single day is expressed as:

$$B_4^1 = H[L(t), U_1(\cdot)] - \sum_i H[f_i(t), u_i(\cdot)] - H[L(t) - \sum_i f_i(t) \beta_i, U_0(\cdot)]$$

where $u_i(\cdot)$ represents the incremental production cost of the dispersed device i reflecting the cost of fuel delivered to a dispersed location. Terms $U_1(\cdot)$ and $U_0(\cdot)$ are the vectors of incremental bulk power production cost curves with and without the equivalent central device respectively. Operating and maintenance costs are included in U_0 , U_1 , and u_i .

For storage devices the first term in the equation is replaced by $H[L(t) - F(t), U_1(\cdot)]$. In the second term $f_i(t)$ is replaced by $g_i(t)$ to include only the generating mode. The term $u_i(\cdot)$ includes only operating and maintenance costs, not fuel costs.

The total annual production cost component on days when DSSG devices are operated with bulk supply objectives is given by:

$$B_4^2 = \sum_{k=1}^{K_3 \cdot K_4} B_{k4}^2$$

where B_{k4}^2 is the production component on a single day.

This quantity is calculated for the DSSG devices under central control with bulk supply objectives. The DSSG devices are operated individually at an incremental production cost of u_i/β_i , which accounts for losses. Operated in this manner, the DSSG unit is treated as a conventional generator in the dispatching of units.

For dispersed generation, B_4^2 , for a given day can be estimated as:

$$B_4^2 = H[L(t), U_1(\cdot)] - H[L(t), U_2(\cdot)]$$

where U_2 is the vector of incremental cost curves of the bulk power generators and those of the dispersed devices u_i/β_i .

For storages, $L(t)$ is replaced by $L(t) - F(t)$ in both terms, and the incremental cost of the storage devices includes only operating and maintenance costs.

The total annual production component is given by:

$$B_4 = B_4^1 + B_4^2$$

These components for each year are used in the present worth analysis.

5.5 REPLACEMENT CAPACITY COMPONENT

A replacement capacity cost is levied against dispersed devices on conflicting capacity days if they are operated with only distribution objectives. This cost is the capacity penalty against DSSG for not providing the full capacity for the time needed by the bulk power system. Exhibit 5-3 illustrates the replacement capacity cost phenomenon, showing the differences between the operating curves of the central and combined dispersed devices as seen by the bulk supply system between peak periods t_1 to t_2 .

Mathematically, using the previous notations and letting q (\$/kWh) be the average unit central capacity cost, the replacement capacity cost is calculated as:

EXHIBIT 5-3

GENERATION OUTPUTS FROM EQUIVALENT CENTRAL AND COMBINED
DISPERSED DEVICES.

$$B_5 = K_1 \int_{t_1}^{t_2} \left[\sum_i f_i(t) \beta_i - F(t) \right] q \, dt$$

This expression places a cost on the difference between the operating curve of the equivalent device and the sum of the operations of the individual dispersed devices.

The unit capacity cost, q , represents the cost of acquiring generating capacity during the system peak period. It can be the cost of capacity transactions between utilities, or it may be the capacity cost of peaking units prorated by the annual hours of use. For the latter case, if C is the total capital cost of a peaking unit, a the annualization factor, and b the number of hours the unit is used in a year, the $q = Ca/b$.

6. DSSG CASE STUDIES

The DSSG assessment methodology and models described in Chapters 4 and 5 were demonstrated with case studies on portions of the distribution system of two U.S. utilities. Utility 1 is summer peaking with a thermally-limited distribution system in an urban area. Utility 2 is winter peaking with a voltage-limited system in a rural area. This chapter presents the performance and cost data of the four DSSG technologies studied (lead acid batteries, advanced batteries, fuel cells, and diesel engines), the case descriptions, and results.

The case studies assume that the projected cost and performance characteristics of the DSSG technologies are known in 1975, the beginning of the study period. All costs are reported in 1975 dollars. The case studies also use past and projected utility data.

The use of historical data in case studies has several advantages. First, it significantly reduces the number of assumptions and load projections for the distribution system since these are available as historical data. Second, the data indicates immediately the weak parts of the system since records of past expansion projects specify the reasons for reinforcement. Third, historic data reflects the experience of distribution planners who are most familiar with the system. Previous experience is particularly important for distribution planning, as discussed in Section 3.2.

There are potential difficulties with the use of historical data for DSG technological assessment purposes. The Distribution Capacity Component depends on the total investment due to conventional planning without DSSG. There may have been a unilateral management decision regarding the selection of a reinforcement plan which was independent of any stated planning criteria. For instance, short-term budget constraints may favor expansion projects having a small initial

EXHIBIT 6-1

DSSG EQUIPMENT CAPITAL COSTS*

COMPONENT	(10 MW, 4 HOUR DEVICE)		FUEL CELL	DIESEL
	LEAD-ACID BATTERY	ADVANCED BATTERY		
ENERGY-RELATED (\$/KW FOR 4-HOUR)				
MODULE	148 (140-260)**	104 (120-200)	----	----
BALANCE OF PLANT	112 (100-180)	48 (32-80)	----	----
COST	260 (240-440)	152 (112-240)	----	----
POWER-RELATED (\$/KW)				
MODULE	---	---	190 (140-300)	225
CONVERTER	60 (60-80)	60 (60-80)	60 (60-80)	---
COST	60 (60-80)	60 (60-80)	250 (210-380)	225
TOTAL (\$/KW)	320 (300-520)	212 (172-320)	250 (210-380)	225

* NOMINAL (10 MW DEVICE) VALUES TO BE USED TO DERIVE UNIT COSTS FOR SPECIFIC CONFIGURATIONS

** PARENTHESES DENOTE RANGE OF VALUES

investment cost over other projects having a greater initial cost but smaller future costs. The historical conventional distribution plan should therefore be checked to verify that it is the least cost alternative. If not, an alternative least cost expansion plan should be determined.

6.1 DSSG TECHNOLOGY DATA

Data describing the DSSG technologies selected for the case studies generally reflect the probable performance and cost due to successful future research and development of new DSSG technologies. Generally, the data fall on the optimistic side of a spectrum of projections given by different sources. This section discusses practical implementation aspects not included in the models.

6.1.1 DSSG Equipment Costs

Dispersible technologies of 10 MW and less are considered in the case studies. Such technologies usually have relatively insignificant economies of scale above 10 MW. However, between 1 kw and 10 MW significant economies of scale often exist. The maximum practical sizes of DSSG devices are about 10 MW at substations, 1 MW at primary feeders, and 10 kW for residential applications.

As described in Section 5.3, a storage technology has both power and storage capacity cost components. The range of capital costs of the various components of 10 MW lead-acid and advanced batteries are listed in Exhibit 6-1. The unit costs of the battery module and the balance of plant, \$/kWh, are the costs of installing sufficient storage capacity to generate for one hour at the rated power capacity. The exhibit also shows nominal values within the range of values. The overall cost of lead-acid batteries is 50% greater than that of advanced batteries. Note that over 80% of the capital costs are energy capacity related. The paragraphs below explain the calculations embodied in Exhibit 6-1.

EXHIBIT 6-2

ECONOMIES OF SCALE:
BATTERY COMPONENTS

EXHIBIT 6-3

ECONOMY OF SCALE:
STORAGE CAPACITY ADJUSTMENT FACTOR*

*BASED ON A NOMINAL 4-HOUR STORAGE CAPACITY. FOR EXAMPLE,
THE UNIT COST OF AN 8-HOUR BATTERY IS .84 OF THAT OF THE
4-HOUR BATTERY.

EXHIBIT 6-4
CAPITAL COSTS:
LEAD-ACID BATTERY

Exhibits 6-1, 6-2, and 6-3 are closely related. They contain information useful for calculating the costs of three battery components -- the module itself, the inverter, and the balance of plant -- for a range of energy and storage capacities.

The economies of scale for a 4-hour lead-acid battery, as a function of rated power capacity, are illustrated in Exhibit 6-2. The ordinate is a scaling factor used in subsequent calculations.

Adjustments in the costs of the battery module and the balance of plant are required for storage batteries with different energy capacities. Exhibit 6-3 gives the multipliers used to adjust the nominal 4-hour lead-acid batteries to find the capital costs for different storage capacities. For example, to compute the unit capital cost of a 1 MW, 8-hour lead-acid battery, the unit converter/inverter cost is found by first multiplying \$60/kW (from Exhibit 6-1) by 1.83 (from Exhibit 6-2), to get \$110/kW. The unit balance of plant cost is computed by multiplying $8 \times \$28$ (from Exhibit 6-1) by 1.79 (from Exhibit 6-2) and 0.84 (from Exhibit 6-3), to get \$337/kW. The unit battery module cost is \$249/kW. The total capital cost of a 1 MW 8-hour lead-acid battery is \$695/kW. The same calculations are repeated for lead-acid batteries of different sizes to derive the capital cost curves in Exhibit 6-4 and Exhibit 6-5.

The above lead-acid battery cost data were supplied by DOE [39], and the nominal advanced battery cost is based on those used by EPRI for planning assessment [40]. No economy of scale data or storage capacity multipliers are available for advanced batteries. In case studies, they are assumed to be the same as those of lead-acid batteries.

Ranges of capital costs of a 10 MW fuel cell and diesel engine are included in Exhibit 6-1 along with the nominal values used in the case studies. The data is from United Technologies, Inc. [41]. Fuel cell costs include stacks, reformer, and inverter. The economy of scale data for fuel cells and diesel engines, obtained from manufacturers [42], [43], are illustrated in Exhibit 6-6.

EXHIBIT 6-5

CAPITAL COSTS:
ADVANCED BATTERY

EXHIBIT 6-6
CAPITAL COSTS:
FUEL CELL AND DIESEL

EXHIBIT 6-7
ECONOMIES OF SCALE:
OPERATING AND MAINTENANCE COSTS

Operating and maintenance (O&M) cost estimates for the new technologies vary greatly because actual operating data is not available. Estimates of O&M costs for nominal 10 MW lead-acid batteries vary from 0.3 mills/kWh to 2.7 mills/kWh [2], [40]. The O&M costs for fuel cells and diesel engines are taken to be 3 mills/kWh and 4 mills/kWh, respectively. These O&M cost data are based on a 10 MW plant located in a bulk power generating station.

There are no data pertaining to the economy of scale of O&M costs for DSSG technologies. Because of their geographically dispersed locations, DSSG devices are expected to have significant O&M economies of scale. Based on O&M costs of transformers, it is estimated that the unit O&M costs for a 10 kVA distribution transformer is approximately ten times that of a 10 MVA substation transformer [44]. The case studies assume that O&M costs are inversely proportional to the logarithm of the power capacities. Exhibit 6-7 illustrates the multipliers used to estimate O&M costs of various DSSG device sizes based on the nominal 10 MW plant.

Annual carrying charges of 17.9% are applied to storage batteries and 14.0% to fuel cells and diesel engines. The annual charges depend on various assumptions about plant life, salvage value, method of depreciation, debt-to-equity ratio, return rates on equity and debts, and tax rates [45]. In the case studies all the annual charges are based on those of the Public Service Electric and Gas Co. [2], assuring consistent assumptions on technology-independent parameters.

The above performance and cost data are used to calculate the Dispersal Cost and Production Cost Components described in Sections 5.3 and 5.4.

EXHIBIT 6-8

DSSG PERFORMANCE DATA

CHARACTERISTICS	LEAD-ACID BATTERY	ADVANCED BATTERY	FUEL CELL	DIESEL
EFFICIENCY (%)	75	75	-	-
HEAT RATE (BTU/KWH)	-	-	8700	14000
OPERATION & MAINTENANCE COST (MILLS/KWH)	2.7	2.7	3.0	4.0
SCHEDULED MAINTENANCE (WEEKS/YEAR)	2	2	2	2
OUTAGE RATE (%)	3	3	4	4

* AVERAGE VALUE OVER THE RANGE OF SIZES STUDIED

** HEAT RATE IS HIGHER THAN FULL LOAD PERFORMANCE DUE TO START/STOP
AND PART LOAD OPERATIONS

6.1.2 Technological Characteristics and Data

The performance data of the DSSG technologies used in the case studies are included in Exhibit 6-8. Advanced batteries are projected to have a slightly better round-trip conversion efficiency than lead-acid batteries. Round-trip efficiency of lead acid batteries ranges from 65% to 75% as the storage size increases from 1 hour to 15 hours. In the case studies, both battery technologies are assumed to be 75% efficient, independent of the size. The heat rates of fuel cells and diesel engines are taken to be 8,700 BTU/kWh and 14,000 BTU/kWh, respectively.

Several previous studies have found that no technological barriers exist to interfacing batteries and fuel cells with distribution systems [46-50]. Adequate and proven converter/inverter devices either exist or are under research and development. Conclusions from these studies indicate that the two conversion technologies under R&D -- force commutated and line commutated converters -- would not contribute to existing voltage regulation problems. Circuit breakers would not need upgrading for increased short-circuit duty and would not cause transient stability problems.

Technological requirements and costs for remote control of DSSG devices also have been investigated. First, it suffices to transmit a small number of control codes (signals) to each DSSG device in order to execute functions to satisfy bulk supply and distribution system requirements. Control of DSSG devices can be achieved using uni-directional communication to transmit control codes from a dispatch center to the device. Control codes include signals to initiate and terminate operations to satisfy changing local needs.

Various communication technologies are considered for implementation: radio, ripple, carrier and telephone systems. Their costs and performance limitations are summarized in Exhibit 6-9. All systems require a controller/encoder. A pre-programmed, desk-top controller

EXHIBIT 6-9

CAPITAL COST AND PERFORMANCE CHARACTERISTICS: COMMUNICATIONS AND CONTROL EQUIPMENT

COST/PERFORMANCE	RADIO	RIPPLE	CARRIER	TELEPHONE
FIXED COST				
ENCODER AND CONTROLLER	\$6000 to \$200,000	\$6000 to \$200,000	\$6000 to \$200,000	\$6000 to \$200,000
TRANSMITTER	\$5000-	-----	-----	-----
INJECTION	-----	\$1000/connected MW	\$10,000/substation	-----
WIRE CENTER EQUIPMENT	-----	-----	-----	\$2400 plus \$1300/y
VARIABLE COST (WITH NUMBER OF FUNCTIONS)				
EXTRA CONTROL FUNCTIONS	\$65	\$65	\$80	\$65 + \$50/year
ADDITIONAL RECEIVERS	\$15-20	\$15-20	\$15-20	\$15-20
LIMITATIONS	<ul style="list-style-type: none"> • 25 mi. radius • affected by terrain • 2 sec. control time per command 	<ul style="list-style-type: none"> • 25 mi. long circuits • affected by distribution circuit configuration • 10 sec. control time 	<ul style="list-style-type: none"> • 10 mi. long circuits • affected by circuit configuration • requires separate communications to each substation • 1-10 sec. control time 	<ul style="list-style-type: none"> • 100 locations per wire center • second party involved • 1 sec. control time

without error checking and control scheme modification features costs about \$6000. More complex controllers using dual minicomputers cost up to \$200,000. Such controllers can operate many DSSG devices for an entire electric utility.

The fixed cost for ripple-signal injection shown in Exhibit 6-9 depends on the total electric load on the line, not on the capacity of the DSSG devices. Typically, about one kilowatt of injected signal is required for every megawatt of load.

The wire center equipment cost for telephone systems reflects current rates charged by telephone utilities for dedicated, leased, data-quality phone lines. These costs include initial costs for labor, equipment, design and engineering, the yearly lease, carrying charges, insurance, taxes, and interest.

The variable costs include receiver and relay costs. The number of receivers depends on the number of dispersed devices while the number of relays, n , is related to the number of functions required m , where $2^n = m$. For the case studies, four functions are needed for the basic operations described in Section 4.3. Two relays are needed, one of which is included in the receiver.

Exhibit 6-10 illustrates typical communication and control costs as a function of the number of DSSG devices for each of the four systems described in Exhibit 6-9. The calculations assumed: (1) the least expensive controller/encoder is used; (2) for reliability reasons, each control system requires one transmitter for every 5000 receivers; (3) a 75 MW connected load exists for ripple control; (4) the carrier system is implemented for one substation; (5) annual charges for telephone equipment are calculated at a 14% capital recovery rate; and (6) one receiver and one relay are used with each DSSG device.

EXHIBIT 6-10

CAPITAL COSTS:
COMMUNICATIONS AND CONTROL EQUIPMENT

Some conclusions can be drawn. Radio appears to be the least expensive communication alternative for DSSG control, although for some geographic locations, such as mountainous areas, it is not applicable. The cost of each alternative depends on the number of devices or control points, rather than on the power capacity, as illustrated by Exhibit 6-10. There is an initial fixed cost so that a small number of devices (about 10 units) of any technology is cost-effective only if the power capacity controlled is greater than 1 MW. For example, telephone and ripple would be very competitive with radio control. As the number of controlled devices increases, the average unit communication and control cost approaches the cost of receivers and relays, about \$85 per device, assuming the controls outlined in Section 4.3. Because communications and control costs are determined by the number of DSSG devices, expensive and sophisticated control schemes may not be practical if a large number of relatively small capacity DSSG devices are used. The case studies use radio costs, as shown in Exhibit 6-10.

6.2 THERMALLY LIMITED DISTRIBUTION SYSTEM: CASE DESCRIPTION

The case description for Utility 1 is organized into three sections. The first section describes the general characteristics of the utility, including the generation system, to provide a background for understanding the case study results. The second section describes the conventional distribution expansion planning without DSSG, the first assessment step. Finally, the third section describes distribution planning with DSSG, the second through fourth assessment steps.

6.2.1 Utility Description

Utility 1 is a large utility in the western part of the United States, providing service to a population of 7.7 million people over 50,000 square miles. The utility owns and operates generation, transmission, and distribution facilities. Energy consumption in 1975 was 26% residential, 32% commercial, and 36% industrial; 16.4% of the residential customers have central air conditioning.

EXHIBIT 6-11
YEARLY SYSTEM PEAK DEMAND

In 1975 the system peak demand of 10,193 MW occurred during September. The summer peak load grew at an average annual rate of 4.6% from 1975 to 1979, as shown in Exhibit 6-11. The seasonal variation of the monthly peak load in 1975 is illustrated in Exhibit 6-12. The annual load factor is 60.3%. Exhibit 6-13 shows the daily load curve on the system peak day in September of 1975. The daily load factor was 75.8%. Based on the daily load data for 1975 the system peak occurs between 1 pm and 5 pm.

Utility 1 had a total generating capability of 12,468 MW in 1975 and 1976. Exhibit 6-14 shows the generation mix. Oil-fired generation provided 59% of the energy. An additional 17% came from coal-fired units, 17% from gas-fired units, and 6% from nuclear units.

Average prices for fuel consumed in 1975 is tabulated in Exhibit 6-15. The cost of light distillate is lower than that of residual fuel, due to prior distillate contracts.

The above generation system data, together with individual plant heat rates, average rates, and maintenance requirements are used in computing the Production Cost Component described in Section 5.4.

The incremental generating capacity cost, which represents the cost of acquiring generating capacity during system peak period, is taken to be \$100/kW with an associated annual carrying charge of 14.0%. This approximates the gas turbine capital costs used by PSE&G [2]. These data, together with the system peak period load data, are used to compute the Capacity Cost Component described in Section 5.5.

6.2.2 Conventional Expansion Planning

The case studies considered the conventional distribution planning of a 13 square-mile area serviced by a large substation with a load of 58 MW in 1975 and a load density of 4.5 MW/square mile. This

EXHIBIT 6-12
MONTHLY PEAK DEMAND

EXHIBIT 6-13

PEAK DAY DEMAND CURVE
UTILITY 1

EXHIBIT 6-14

GENERATION MIX:
UTILITY 1*

SIZE (MW)	NUMBER OF UNITS	CAPACITY (MW)	PERCENT OF TOTAL CAPACITY
FOSSIL			
0- 99	12 (0, 12)**	718 (0, 718)	6 (0, 6)
100-199	8 (0, 8)	1314 (0, 1314)	11 (0, 11)
200-299	6 (0, 6)	1300 (0, 1300)	10 (0, 10)
300-399	8 (2, 6)	2718 (768, 1950)	22 (6, 16)
400-499	6 (2, 4)	2805 (885, 1920)	22 (7, 15)
500+	2 (0, 2)	1500 (0, 1500)	12 (0, 12)
SUBTOTAL	42 (4, 38)	10355(1653, 8702)	83(13, 70)
NUCLEAR	1	344	3
HYDRO	36	1173	9
GAS TURBINE	11	555	5
TOTAL	90	12427	100

*FOR 1975. A 572 MW COMBINED CYCLE PLANT WAS INSTALLED IN 1977, DURING THE PERIOD COVERED IN THE STUDY.

**NUMBERS IN PARENTHESES (A, B) SHOW SPLIT BETWEEN COAL-FIRED (A) AND OIL-FIRED (B) UNITS. UTILITY 1 IS PREDOMINATELY OIL-FIRED.

EXHIBIT 6-15

AVERAGE FUEL COSTS (1975)

FUEL TYPE	COST (¢/MBTU)	
	UTILITY 1	UTILITY 2
COAL	29	96
RESIDUE	267	223
LIGHT DISTILLATES	197	209
NATURAL GAS	85	126
NUCLEAR	17	37

EXHIBIT 6-16

ONE-LINE DIAGRAM OF SUBSTATION:
UTILITY 1

distribution area was selected because of the availability of existing 24-hour load data on the primary feeders and at the substation. The substation serves 15,000 customers with an 80% residential load in an urban area. The area also has some small industrial and commercial loads and a large shopping mall.

Two substation transformers step the 66 kV supply down to 12 kV, as illustrated by the one-line diagram in Exhibit 6-16. Sub-transmission transformers in the same substation convert the 220 kV supply to 66 kV. The primary circuits were constructed as a network with loops but operated radially with normally-open ties to adjacent primary circuits.

Load growth averaged seven percent a year from 1975 to 1976 and was expected to slow down to five percent after 1977. Exhibit 6-17 gives the load mix in each circuit. Exhibit 6-18 shows the shape of the load on selected feeders. Exhibit 6-19 shows the diversified load shapes of residential, commercial, and industrial customers and of the total system load. The substation peak load occurs in the same summer season as that of the total system load.

The conventional distribution system planning was primarily concerned with thermal overloading of transformers and getaways, the first circuit sections leaving the substation. The getaways have been gradually converted from overhead conductors (653 ASCR) to underground cables (1000 KCMIL-CLP) since 1972 because of local ordinances, cutting their thermal capacity in half.

The distribution planners used single-contingency criteria to identify the reinforcements for substation transformers and getaway circuits; thermal loading limits must be satisfied during normal and outage conditions of the largest transformer or of any getaway circuit. Typical normal and emergency thermal limits are illustrated in Exhibit 6-20. The emergency thermal limit of an underground cable is usually

EXHIBIT 6-17

PEAK-LOAD COMPOSITION:
UTILITY 1

FEEDER NUMBER	PEAK DEMAND (KW)	AVERAGE ANNUAL GROWTH RATE (%)	CUSTOMER TYPE (%)		
			RESIDENTIAL	COMMERCIAL	INDUSTRIAL
1	6496	6.1	50	40	10
2	6276	7.1	90	10	0
3	8416	9.0	90	10	0
4	8951	7.4	85	15	0
5	9184	7.5	80	0	20
6	7756	6.1	0	10	90
7	7375	3.6	5	5	90
8	4112	7.0	80	0	20
9	3248	7.0	0	100	0

EXHIBIT 6-18

DIVERSIFIED CUSTOMER LOADS
UTILITY 1

EXHIBIT 6-19

SYSTEM AND DISTRIBUTION LOAD SHAPES
UTILITY 1

EXHIBIT 6-20

TYPICAL DISTRIBUTION
EQUIPMENT THERMAL LIMITS

DISTRIBUTION EQUIPMENT	NORMAL CRITERIA	EMERGENCY CRITERIA
SUBSTATION TRANSFORMER (MVA)	14	20
PRIMARY CIRCUITS (AMPERES)		
336 ACSR	530	590
653 ACSR	820	920
1000 MCM CLP	450	450
500 PILC COPPER	278	278

EXHIBIT 6-21

FINANCIAL PARAMETERS FOR
CAPITAL EQUIPMENT

CAPITAL EQUIPMENT	LIFETIME (YEARS)	ANNUALIZED FACTOR (%)	RATE OF ESCALATION (%)	DISCOUNT RATE (%)
PRIMARY CIRCUIT .	25	15.5	6.0	10
OVERHEAD SUBTRANS- MISSION CIRCUIT	25	15.5	6.0	10
SECONDARY CIRCUIT	25	15.5	6.0	10
DISTRIBUTION TRANS- FORMER	25	15.5	6.0	10
SUBSTATION	25	15.8	6.0	10
STORAGE BATTERY	10	17.9	6.0	10
FUEL CELL/DIESEL	25	14.04	6.0	10

higher than that of normal operation. Voltage is allowed to vary between 11.4 kV to 12.0 kV. During emergencies the minimum voltage allowed is 11.7 kV.

In the case studies, the list of distribution violations and associated reinforcement plans were screened, and representative situations where DSSG could possibly relieve the violations were selected. No attempt was made to pick special situations that would make DSSG especially attractive. Three reinforcement plans were good candidates: (1) in 1975, the capacity of the substation transformer was increased from 42 MVA to 63.5 MVA at a cost of \$232,900 to relieve normal loading limit violations; (2) also in 1975, a new 3400 foot getaway underground (1000 KLM CLP) cable was added at a cost of \$163,000 to avoid overloading the getaways during an outage of one getaway; and (3) in 1977, a 1000-foot underground copper conductor (500 KCMIL PILC) getaway was upgraded with an underground aluminum cable (1000 KCM CLP), increasing the getaway capability from 278 amperes to 450 amperes at a cost of \$29,600, in order to avoid thermal overloading of the existing getaway if one of the getaways failed. Exhibit 6-21 tabulates the data used in deriving the annual carrying charges for conventional distribution and DSSG capital costs.

The SCI distribution planning model ACORN[®] [29] was used to verify the designated relief of violations by the proposed reinforcement plans. The three-phase primary distribution circuits were represented with 115 nodes and 165 branches, with more detailed representation of loads in the six residential feeders. Exhibit 6-22 shows the distribution system represented. The commercial and industrial feeders are not connected with the residential feeders except at the substation switchgear, and no reinforcements of these non-residential feeders were anticipated in the coming years. With the assistance of the area planning and operating distribution engineers, peak loads and the customer mix at the nodes representing 50 to 150 customers were estimated. The resulting substation load constructed from the diversified customer loads approximated the actual substation load.

EXHIBIT 6-22

PRIMARY DISTRIBUTION SYSTEM:
UTILITY 1

The results from the ACORN model showed that the reinforcement plans did satisfy the planning criteria and that they were the least cost alternative.

6.2.3 Planning With DSSG

The previous section discussed conventional planning without DSSG. This section discusses distribution planning when DSSG is available as a planning option. Strategies within a case study with DSSG use DSSG to defer or eliminate the need for conventional distribution investments. The plan with DSSG must satisfy the same criteria as the conventional plan without DSSG.

As described in Section 4.2, strategies are defined by targeted distribution planning criteria violations and duration of relief as follows:

- Substation strategies to relieve normal thermal overloading of substation transformers for one, two, and three years.
- Feeder strategies to relieve both thermal overloading of substation transformers and that of underground getaways in single contingencies for one, two, and three years.

Options implementing these strategies were simulated and evaluated with DSSG devices of various sizes, locations, and operating modes. The options yielding the highest Dispersion Credit for each strategy are tabulated in Exhibit 6-23 for lead-acid and advanced batteries and in Exhibit 6-24 for fuel cells and diesel engines. The hours in both exhibits are the equivalent hours the devices generate on a conflicting day at the installed power capacity. The paragraphs below describe how the possible options were defined.

The relief requirements of the substation transformer define the DSSG capacities needed. Determining the substation options is simpler than the feeder options since there are more alternative feeder strategies. The single-contingency planning criteria limits the minimum

EXHIBIT 6-23

DISPERSED STORAGE CASE DESCRIPTION:

UTILITY 1

CASES	ONE YEAR		TWO YEARS		THREE YEARS	
	CAPACITY (KW)	DURATION* (HR)	CAPACITY (KW)	DURATION (HR)	CAPACITY (KW)	DURATION (HR)
SUBSTATION STRATEGY						
SUBSTATION	4583	4.54	8518	6.31	13512	7.48
EQUIVALENT CENTRAL CAPACITY	4744	4.38	8818	6.09	13196	7.23
FEEDER STRATEGY						
SUBSTATION	783	1.43	1704	2.95	3648	6.49
FEEDER 1	813	5.69	1319	6.90	1728	7.50
FEEDER 2	747	4.82	1250	6.19	1626	6.87
FEEDER 3	1002	5.05	1650	6.30	2123	6.96
FEEDER 4	1252	4.93	1968	6.14	2501	6.76
FEEDER 5	1471	5.11	2215	6.25	2813	6.92
EQUIVALENT CENTRAL CAPACITY	4761	5.90	8818	6.60	13196	7.31

*FIGURES DENOTE THE EQUIVALENT HOURS OF GENERATION AT THE INSTALLED CAPACITY.

EXHIBIT 6-24

DISPERSED GENERATION CASE DESCRIPTION:
UTILITY 1

CASES	ONE YEAR		TWO YEARS		THREE YEARS	
	CAPACITY (KW)	DURATION* (HR)	CAPACITY (KW)	DURATION (HR)	CAPACITY (KW)	DURATION (HR)
SUBSTATION STRATEGY						
SUBSTATION	4583	5.94	8518	7.12	12747	8.06
EQUIVALENT CENTRAL CAPACITY	4744	5.74	8818	6.88	13196	7.79
FEEDER STRATEGY						
SUBSTATION	334	8.50	861	9.00	2817	12.03
FEEDER 1	742	8.50	1271	9.18	1643	12.00
FEEDER 2	727	8.50	1250	9.07	1626	12.00
FEEDER 3	768	8.50	1650	9.10	2123	12.00
FEEDER 4	1005	8.50	1738	9.11	2259	12.00
FEEDER 5	1007	8.50	1748	9.14	2279	12.00
EQUIVALENT CENTRAL CAPACITY	4744	8.21	8818	8.80	13196	11.60

*FIGURES DENOTE THE EQUIVALENT HOURS OF GENERATION AT THE INSTALLED CAPACITY.

EXHIBIT 6-25

SUBSTATION STORAGE OPERATING MODE
UTILITY 1

capacity sited on each feeder, while the single outage contingency of DSSG devices limits the maximum capacities on each feeder. Locating the DSSG devices further along each feeder decreases dispersion credits. The best feeder options placed the DSSG devices at the end of the getaways.

In this thermally-limited system the years of relief provided by dispersed storage devices are technically limited. The off-peak charging is constrained by the shape of the local load served by a storage device. It is desirable to avoid thermal overloading during off-peak periods which would otherwise require distribution reinforcement. Dispersed generators, however, are not similarly limited since charging imposes no constraint. However, they can be economically limited because dispersed generators generally have higher operating and fuel costs than base-load generators.

As shown in Exhibit 6-23 and Exhibit 6-24, the power capacity of dispersed devices must be increased drastically to extend the duration of relief. Although the annual load growth is only several percent, the power capacities are almost doubled. In addition, operating hours of all dispersed devices are increased as greater peak load shaving begins to require generation of more energy.

Different operating modes were simulated to find the mode maximizing the Dispersion Credit. The best operating modes differ for storage and generating devices. All dispersed storage strategies defined in Exhibit 6-23 use flat generation throughout the conflicting day as illustrated in Exhibit 6-25 because it gives the highest Dispersion Credit. Substation strategies for dispersed generation use a mix of flat and full generation as in Exhibit 6-26. For feeder placement of dispersed generation, full generation during the hours of system and distribution peaks, as in Exhibit 6-27, yields the highest dispersion credit. The charging operation of the storage strategies is determined according to bulk supply economic dispatch, constrained by the local limit and charging capacity.

EXHIBIT 6-26

SUBSTATION GENERATOR OPERATING MODE
UTILITY 1

EXHIBIT 6-27

FEEDER GENERATOR OPERATING MODE
UTILITY 1

EXHIBIT 6-28

OUTAGE DURATION PROBABILITY DISTRIBUTION FUNCTION*
UTILITY 1

*DENOTES THE PROBABILITY AN OUTAGE DURATION WOULDN'T BE EXCEEDED

In planning with DSSG, the least-cost conventional distribution expansion plans are identical to those implemented in the historical conventional expansion without DSSG, except deferred for a few years. This deferment happened because the distribution problems are generally local with limited feasible relief options. This deferment phenomenon could accelerate the assessment procedure, giving a lower estimate of the Distribution Capacity Component. In general, other new planning options with lower overall cost may be found.

6.2.4 Assessment Data

The service area studied had an impressively reliable customer service record of 16 minutes per year interrupted customer, as compared to 33 minutes per year for all interrupted customers. The delivery system has a good switching capability enabling quick service restoration to most affected customers. The service outage records indicated that 95% of the interrupted customers had their service restored in less than 30 minutes. From the outage data a probability distribution function for the outage duration was developed. It is shown in Exhibit 6-28.

A value of unserved energy of \$1.17/kWh [51] was used in the cases. This value is significantly higher than the cost of electrical energy to all customer groups which varies from 2.7¢/kWh to 3.2¢/kWh as reported in Electrical World, 1975 [52]. The range of estimates on the cost of power outage in the United States is illustrated in Exhibit 6-29. The two estimates of U.S. average costs [51,53] were derived by averaging either gross national product and/or regional wages over the total energy consumed. The cost data of power outages for industrial and commercial customers [54,55] were determined through surveys.

The loss allowance factor for the transmission and sub-transmission systems, defined in Section 4.4, averages 3.4% of the energy generated. The distribution system accounted for 3.6%, of which the distribution planning models showed approximately 2% is lost in the primary system and 1.6% in the secondary distribution system.

EXHIBIT 6-29

COST OF SERVICE INTERRUPTION

	POWER COST (\$/KW)	ENERGY COST (\$/KWH)	SOURCE
U.S. AVERAGE	-	.60	TELSON (53)
	-	1.17	SHIPLEY (52)
INDUSTRIAL AVERAGE			IEEE (54)
POWER < 1 MW	4.59	8.11	
POWER > 1 MW	1.05	.94	
ALL	1.89	2.68	
COMMERCIAL		7.21	IEEE (55)

The number of conflicting days was studied using the bulk supply and substation peak load data. This number depends on the percentage of local reduction desired, as shown in Exhibit 6-30. It shows that for Utility 1 only a small number of conflicting days would be encountered for a reduction of 5% to 15% of the peak load.

The cost of fuel delivered to the dispersed locations was maintained at the same level as that delivered to central generating stations. The additional delivery cost depends on the accessibility of the dispersed devices and the location of the fuel supplies. Subsequently, the sensitivity of results to fuel delivery cost was analyzed. The round-trip efficiency of dispersed storage devices was assumed to be uniform with size. The sensitivity of assessment results to degraded efficiency was also analyzed.

6.2.5 Case Study Results

The results for the technologies studied are tabulated in Exhibit 6-31 through Exhibit 6-34. Interpretation and analysis of the assessment results are provided in Section 9.1.

6.3 VOLTAGE-LIMITED DISTRIBUTION SYSTEM: CASE DESCRIPTION

This case description follows the same structure as that of the thermally-limited system. First, it describes the general characteristics of Utility 2. Then conventional expansion planning without DSSG and with DSSG are considered.

6.3.1 Utility Description

Utility 2, in the eastern part of the United States, provides electric service to 3.3 million people over 28,000 square miles. The utility owns and operates generation, transmission, and distribution facilities. Of the total energy sales to ultimate customers in 1975, 32%

EXHIBIT 6-30

CONFLICTING CAPACITY DAYS

EXHIBIT 6-31

DISPERSION CREDIT:
LEAD-ACID BATTERY
UTILITY 1

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	13.2	9.5	7.5	22.9	16.6	13.5
RELIABILITY	0.7	0.8	0.9	0.9	0.9	1.0
DISPERSAL COST	12.0	3.0	-68.4	-159.8	-190.9	-269.2
PRODUCTION COST	0.0	-0.3	-2.6	-33.2	-12.3	-9.0
REPLACEMENT CAPACITY	-13.3	-13.9	-4.1	-9.3	-11.9	-3.6
TOTAL	12.6	-0.9	-66.6	-178.5	-197.6	-267.3

EXHIBIT 6-32

DISPERSION CREDIT:

ADVANCED BATTERY

UTILITY 1

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	13.2	9.5	7.5	22.9	16.6	13.5
RELIABILITY	0.7	0.8	0.9	0.9	0.9	1.0
DISPERSAL CCST	8.1	2.7	-41.8	-109.1	-123.9	-168.9
PRODUCTION COST	0.0	-0.3	-2.6	-33.2	-12.3	-9.0
REPLACEMENT CAPACITY	-13.3	-13.9	-4.1	-9.3	-11.9	-3.6
TOTAL	8.7	-1.2	-40.1	-127.8	-130.6	-167.0

EXHIBIT 6-33

DISPERSION CREDIT:

FUEL CELLS

UTILITY 1

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	16.8	12.2	9.6	29.3	21.2	17.2
RELIABILITY	1.8	1.9	2.0	2.3	2.3	2.3
DISPERSAL COST	8.4	7.7	8.5	-21.2	-28.9	-33.0
PRODUCTION COST	33.2	39.9	45.6	-334.5	-119.9	-40.3
REPLACEMENT CAPACITY	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	60.2	61.7	65.7	-324.1	-125.3	-53.8

EXHIBIT 6-34

DISPERSION CREDIT:

DIESELS

UTILITY 1

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	16.8	12.2	9.6	29.3	21.2	17.2
RELIABILITY	1.8	1.9	2.0	2.3	2.3	2.3
DISPERSAL COST	7.5	7.8	8.1	10.4	9.0	8.7
PRODUCTION COST	29.1	32.4	40.3	-270.1	-97.1	-30.2
REPLACEMENT CAPACITY	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	55.2	54.3	60.0	-228.2	-64.6	-2.0

were residential, 23% commercial, and 45% industrial. In 1975, 3.6% of the residential customers had electric space heating.

Total system peak demand in 1975 was 4,204 MW occurring during December. The peak load grew at an average annual rate of 4.5% from 1975 to 1979 (see Exhibit 6-11). Exhibit 6-12 shows the seasonal variation of the monthly peak load in 1975. The annual load factor is 66.5%. Exhibit 6-35 illustrates a daily load curve on the system peak day in winter for the same year. The daily load factor is 77.3%. The utility has two sharp daily load peaks.

Utility 2 had a total generating capability of 5,742 MW in 1975 and 1976. The generation mix for 1975 is illustrated in Exhibit 6-36. The utility is predominantly coal-fired. Of the total energy generated in 1975, 67% was generated from coal-fired units, 15% from oil-fired units, and 13% from nuclear units. The utility also owns a 636 MW (34% of 1872 MW) pumped storage plant. The apparent system load after pumped storage operation is shown in Exhibit 6-35. Peaks occurred from 8 am to 10:30 am and 5 pm to 8 pm.

Average prices of fuel consumed in 1975 range from 96¢/MBTU for coal, 223¢/MBTU for residue fuel oil, to 37¢/MBTU for nuclear fuel (see Exhibit 6-15). Due to prior contractual arrangement, the average price of light distillate is less than that of residue fuel. The above supply system data are used in computing the Production Cost and Capacity Cost Components described in Sections 5.4 and 5.5.

6.3.2 Conventional Expansion Planning

The distribution system selected for case studies covers an area of 350 square miles, is serviced by four substations with a total load of 14 MW in 1975, and has a load density of 40 kW per square mile. This distribution area was chosen because it had an expansion history since 1975 and a 13 kV primary distribution system (the same voltage

EXHIBIT 6-35

PEAK DAY DEMAND CURVE
UTILITY 2

LOAD FACTOR: 77% WITHOUT PUMPED STORAGE
84% WITH PUMPED STORAGE

EXHIBIT 6-36

GENERATION MIX:
UTILITY 2

SIZE (MW)	NO. OF UNITS	CAPACITY (MW)	% OF TOTAL CAPACITY
FOSSIL			
0- 99	20 (3, 17)**	815 (198, 617)	15 (4, 11)
100-199	7 (7, 0)	949 (949, 0)	17 (17, 0)
200-299	3 (3, 0)	795 (795, 0)	14 (14, 0)
300-399	1 (1, 0)	385 (385, 0)	7 (7, 0)
400-499	0 (0, 0)	0 (0, 0)	0 (0, 0)
500-	1 (0, 1)	605 (0, 605)	11 (0, 11)
SUBTOTAL	32(14, 18)	3549(2327,1222)	64 (42, 22)
NUCLEAR	2	887	16
GAS TURBINE	13	320	6
HYDRO	13	131	2
PUMPED STORAGE	6	636	12
TOTAL	66	5523	100

*FOR 1975. A 663 MW OF OIL-FIRED GENERATION WAS ADDED IN 1977 DURING THE TIME INTERVAL STUDIED.

**NUMBERS IN PARENTHESES (A, B) SHOW SPLIT BETWEEN COAL-FIRED (A) AND OIL-FIRED (B) UNITS. UTILITY 2 IS PREDOMINATELY COAL-FIRED.

EXHIBIT 6-37

ONE-LINE DIAGRAM OF SUBTRANSMISSION SYSTEM:
UTILITY 2

level as that of Utility 1). The system serves 3,500 customers in a rural area with mostly (71%) residential loads and other loads for recreation (including a large ski resort), schools, and small manufacturers.

The four distribution substations are connected by a 46 kV radial subtransmission system (see Exhibit 6-37). The three-phase primary circuits within each substation area are radial with no switching capability to transfer load to other feeders in case of equipment outage. Portions of the primary system are 4 kV while some are single-phased. The subtransmission lines are mostly aluminum (No. 2 ACSR) and copper (No. 2) overhead with the primary distribution lines up of smaller copper lines.

The load characteristics of each substation in 1975 are shown in Exhibit 6-38. After 1975 peak load grew at an average annual rate of 7% - 9% except for substation 3 which had a smaller average growth rate of 4.2%. All substation loads are winter peaking, except substation 3. The loads in substation 3 peaked in summer, reflecting the summer resort character of the area. Exhibit 6-38 also shows the mix of customers in the area serviced by each substation based on estimates by the area distribution engineers. The characteristics of the five classes of customer loads are described in Exhibit 6-39. Diversified load curves for four residential classes of customers and a typical load curve for small industrial customers are illustrated in Exhibit 6-40. Load shapes of the total system load of each substation are illustrated in Exhibit 6-41.

The main thrust of conventional distribution planning is to maintain voltages within proper ranges for the subtransmission and primary system in view of the low load density and long radial circuits. The voltage criteria are listed in Exhibit 3-6. For the 46 kV nominal voltage subtransmission system, the planning criteria requires the voltages be kept within 105% and 92% of nominal voltage. For the primary system, the nominal voltage is 12.5 kV, and maximum and minimum voltages are 105% and 97%. Other criteria considered in planning include short

EXHIBIT 6-38

PEAK-LOAD COMPOSITION:
UTILITY 2

SUBSTATION NUMBER	PEAK DEMAND (KW)	AVG. ANNUAL GROWTH RATE (%)	CUSTOMER TYPE (%)				
			RESIDENTIAL TYPE				COMMERCIAL AND INDUSTRIAL
			1	2	3	4	
1	3939	8.9	9	27	6	5	53
2	3628	8.7	6	45	6	18	25
3	2858	4.2	4	50	19	10	17
4	3132	7.7	8	46	15	10	21

EXHIBIT 6-39

CUSTOMER LOAD CHARACTERISTICS
UTILITY 2

CUSTOMER CLASS	MAX DIVERSIFIED DEMAND (KW)	NON-COINCIDENT PEAK DEMAND (KW)	LOAD FACTOR %
RESIDENTIAL 1	1.55	3.62	58
RESIDENTIAL 2	2.58	7.73	59
RESIDENTIAL 3	6.42	11.97	63
RESIDENTIAL 4	2.05	5.36	43
COMMERCIAL & SMALL INDUSTRIAL	287.36	341.5	65

EXHIBIT 6-40

DIVERSIFIED CUSTOMER LOADS

UTILITY 2

EXHIBIT 6-41

BULK SUPPLY AND DISTRIBUTION LOAD SHAPES
UTILITY 2

circuit duty and thermal loading capacity for this area, but they were usually not the primary reasons for reinforcement. Subtransmission lines were loaded only up to 40% and distribution lines rarely reached 30% of maximum capacity. Violation of the voltage criteria during the normal-state operation was the overriding concern of the area distribution planners.

Distribution system expansion since 1975 included a two-year project to replace a 33-mile (No. 4 ACSR) section of a primary feeder from substation 1 by higher capacity lower impedance (336 ACSR) lines, primarily to improve the voltage regulation of the primary feeders, at a total cost of \$50,000. For the radial subtransmission system a new line (336 ACSR) was constructed in 1976 to relieve voltage criteria violations at substation 2 and substation 4 (see Exhibit 6-37). The second project cost was \$714,000.

Two Systems Control, Inc. distribution planning models, ACORN [29] and a model developed by R. Podmore [56], were used to verify the improvements made by the proposed expansion plans given the load conditions. The primary system modeled by ACORN has 185 branches. The results verified that the planning criteria are met, and that the project undertaken was the least expensive. The results also indicated no further violations of the voltage criteria on the primary system before 1981. The subtransmission system was represented as a radial network with nine branches by the second model, which has a more detailed load flow subprogram. The relief provided by the proposed subtransmission expansion plan was verified.

Distribution planning with DSSG as a planning option was used to look for alternatives satisfying the same expansion plan. The general methodology described in Section 4.2 was used.

6.3.3 Planning With DSSG

Strategies to relieve the distribution criteria violations were developed. As described in Section 4.2, strategies are defined by relieving specific planning violations and the duration of relief, as follows:

- Substation strategies to relieve the normal voltage regulation problem of the subtransmission system by planning DSSG on the high voltage side of the substations for one, two, and three years.
- Feeder strategies, to relieve the normal voltage regulation problem of substation 1 by placing DSSG along the primary distribution system for one, two, and three years.

As in the case studies for Utility 1, various options to implement these strategies were simulated and evaluated with DSSG devices of various sizes, locations, and operating modes. The options giving the highest Dispersion Credit are tabulated in Exhibit 6-42 for dispersed lead-acid and advanced batteries, fuel cells, and diesel engines. The determination of possible options is discussed below.

Several options were simulated to implement the substation strategies, including a placement of DSSG at both substations 2 and 4, both substations 1 and 3, and all four substations. Placement of DSSG in substations 2 and 4 at the end of the subtransmission system yielded the best results. DSSG located at substations 1 and 3 required a larger capacity to decrease the same voltage drop at the end of the subtransmission lines. Allocating DSSG among four substations incurred a larger negative Dispersal Cost Component because of the economy of scale in DSSG capital cost.

Several options were also considered for the feeder strategies, including placement of a DSSG device at a single location near a large recreational load and siting several DSSG devices in different locations close to the end of the primary feeders. Placement at a single location has a higher net Dispersion Credit, as many small

EXHIBIT 6-42

DSSG CASE DESCRIPTION:
UTILITY 2

CASES	ONE YEAR		TWO YEARS		THREE YEARS	
	CAPACITY (KW)	DURATION* (HR)	CAPACITY (KW)	DURATION (HR)	CAPACITY (KW)	DURATION (HR)
SUBSTATION STRATEGY						
SUBSTATION 2	1579	7.54	3076	8.62	3650	8.74
SUBSTATION 4	1234	6.68	1724	7.47	2032	7.61
EQUIVALENT CENTRAL CAPACITY	3015	6.68	5154	7.64	6090	7.77
FEEDER STRATEGY						
FEEDER 1	276	5.35	651	7.85	1295	8.82
EQUIVALENT CENTRAL CAPACITY	304	4.86	717	6.59	1426	7.31

*FIGURES DENOTE THE EQUIVALENT HOURS OF GENERATION AT THE INSTALLED CAPACITY

DSSG units incur a significant negative Dispersal Cost Component due to the diseconomy of scale in capital cost.

In this voltage-limited system, generally there were no technical limitations to the duration of placement for both storage and generation. The system did not have a thermal-limitation problem. The off-peak charging of storage is therefore not technically-limited by the shape of the local load served by the dispersed devices. Further, during this off-peak period, loads through the system drop, so that increased apparent load due to charging did not cause a voltage drop problem in this period.

Alternate operating modes were simulated to seek the one maximizing the dispersion credit. The best operating modes tested for dispersed storage for both the substation and feeder strategies are illustrated in Exhibit 6-43. Flat generation was enforced when the distribution system experienced voltage regulation problems.

It was found, as in the case of Utility 1, the least-cost conventional distribution expansions are the same ones implemented in the historical expansion without DSSG, except deferred by a few years.

The following section outlines some assessment data used in the computation that are different from those used in case studies of Utility 1.

6.3.4 Assessment Data

The distribution area has a customer service outage record of 103 minutes per year per interrupted customer, as compared to 16 minutes for Utility 1. The system has very little switching capability since it has a radial structure. Fuses are used to sectionalize branches on outage while keeping other loads served. The reliability records showed that 45% of the interrupted customers had their service restored in less

EXHIBIT 6-43

SUBSTATION STORAGE-OPERATING MODE
UTILITY 2

than one hour. From the outage record, a probability density function for the outage duration was developed, as shown in Exhibit 6-44.

Losses for the study area were higher than for Utility 1. The losses were 6.7% for the transmission and subtransmission systems. The distribution system losses amounted to another 3.9%. The number of conflicting days as a function of the local load reduction is illustrated in Exhibit 6-28. The number of conflicting days is significantly more than that of Utility 1 because of the flatter seasonal peak loads.

As in the case studies for Utility 1, the value of unserved energy was taken to be \$1.17/kWh. The cost of delivered fuel to dispersed locations is assumed to be the same as that at the center generating stations, and the round-trip efficiency of dispersed storage devices is assumed to be the same as for large centralized storage devices of the same type.

6.3.5 Case Study Results

The results pertaining to the four technologies studied are presented in Exhibit 6-45 through Exhibit 6-48. Interpretation and analysis of these assessment results are provided in Section 9.2.

EXHIBIT 6-44

OUTAGE DURATION PROBABILITY DENSITY FUNCTION
UTILITY 2

*DENOTES THE PROBABILITY AN OUTAGE DURATION WOULD BE EXCEEDED.

EXHIBIT 6-45

DISPERSION CREDIT:
LEAD-ACID BATTERY
UTILITY 2

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	67.6	51.9	46.2	47.8	29.5	19.2
RELIABILITY	1.1	1.2	1.3	3.7	4.0	4.2
DISPERSAL COST	-13.2	-58.3	-86.9	-82.7	-122.7	-158.1
PRODUCTION COST	-2.0	-7.1	-12.3	-60.7	-81.2	-47.9
REPLACEMENT CAPACITY	-13.9	-17.5	-16.9	-12.9	-11.4	-13.0
TOTAL	39.7	-29.9	-68.6	-104.8	-181.7	-195.7

EXHIBIT 6-46

DISPERSION CREDIT:

ADVANCED BATTERY

UTILITY 2

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	67.6	51.9	46.2	47.8	29.5	19.2
RELIABILITY	1.1	1.2	1.3	3.7	4.0	4.2
DISPERSAL COST	-5.9	-32.4	-49.3	-57.0	-75.5	-91.9
PRODUCTION COST	-2.0	-7.1	-12.3	-75.4	-34.1	-26.3
REPLACEMENT CAPACITY	-13.9	-17.5	-16.9	-12.9	-11.4	-13.0
TOTAL	46.9	-4.0	-31.0	-93.7	-87.5	-107.9

EXHIBIT 6-47

DISPERSION CREDIT:

FUEL CELLS

UTILITY 2

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	86.2	66.1	53.9	60.9	37.6	24.4
RELIABILITY	2.1	2.2	2.2	8.4	8.0	7.9
DISPERSAL COST	10.9	7.5	5.6	-35.1	-21.7	-5.3
PRODUCTION COST	52.2	61.4	68.6	39.8	13.0	145.4
REPLACEMENT CAPACITY	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	151.4	137.2	135.3	74.0	37.0	172.4

EXHIBIT 6-48

DISPERSION CREDIT:

DIESELS

UTILITY 2

ASSESSMENT COMPONENT	SUBSTATION STRATEGIES (\$/KW OF INSTALLED DSSG)			FEEDER STRATEGIES (\$/KW OF INSTALLED DSSG)		
	ONE YEAR	TWO YEARS	THREE YEARS	ONE YEAR	TWO YEARS	THREE YEARS
DISTRIBUTION CAPACITY	86.2	66.1	58.9	60.3	37.6	24.4
RELIABILITY	2.1	2.2	2.2	8.4	8.0	7.9
DISPERSAL COST	14.9	15.5	16.1	30.5	28.2	25.1
PRODUCTION COST	-35.0	-42.8	-44.9	-60.9	-87.6	-62.7
REPLACEMENT CAPACITY	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL	68.3	41.0	32.4	38.9	-13.7	-5.3

7. DCSG METHODOLOGY

This chapter describes the four assessment steps and components in the methodology developed for evaluating Dispersed Customer-Side Storage and Generation (DCSG) (see Section 2.2). The assessment steps are:

- Conventional Distribution Planning
- Development of DCSG Strategies
- Simulation of DCSG Options
- Evaluation of DCSG Options

The sections below describe the functions, procedures, and models used in each of the four assessment steps. Since many of these are similar to the steps for DSSG assessment in Chapters 4 and 5, only the differences are discussed in detail. The discussion below presumes the knowledge of terminologies, definitions, and symbols presented in Chapters 4 and 5.

7.1 DISTRIBUTION EXPANSION WITH DCSG

7.1.1 Conventional Distribution Planning: Step 1

The first planning step in the DCSG methodology is Conventional Distribution Planning, which is exactly the same as that for DSSG (Section 4.1).

7.1.2 Development of DCSG Strategies: Step 2

Defining DCSG strategies is the second step in the methodology. Each DCSG strategy consists of a selected rate of penetration, constitute the "with" policy. The full cooperation of customers owning and using these devices is assumed.

In general, the rate of penetration and locations of the customer-side devices are not controlled by the utility, although they may be influenced by the utility rate structure and the cost characteristics of the technology. This study of distribution impacts will not derive the rate of penetration of the new technology as a function of rate incentives. This subject will be addressed in the comprehensive methodology development described in Chapter 1. The locations of the customer-side devices would also be difficult to predict, since attractiveness of DCSG devices depends upon the location, economic status, and energy needs of a wide range of potential customers.

The simulation approach assumes an initial penetration rate of DCSG devices in the utility system at designated locations. By varying the penetration rate and locations, the sensitivity of the distribution system with respect to these variables can be obtained.

Options to implement a strategy are determined by various operation and control schemes. For example, charging blocks of thermal storage devices at full capacity in varying sequence is one such option.

7.1.3 Simulation of DCSG Options: Step 3

Simulating the operation of DCSG options in the electric distribution system is the third step in the methodology. Each DCSG option is simulated to obtain revised distribution and system loads. The new loads then determine a different distribution expansion plan. The Load Model and the DCSG Operations Model are used in the simulations.

The Load Model is described in Section 4.3. Here DCSG is treated as an individual appliance at Level 1.

The DCSG Operations Model is used to simulate the generation performance of DCSG devices. The "generation" of customer solar power and the discharge of thermal storage devices generally are not determined

by utilities but rather by natural conditions. For example, the output of heat from storage space heating depends largely on the temperatures inside and outside the houses or buildings. Solar generation depends on the variation of solar isolation or wind availability. There are various models to predict the generation of the customer devices.

To the electric utility, both solar generation and the "generation" of thermal storages would appear as negative loads, i.e., $-g_i(t)$ (see Section 4.3). The resulting modified load is given by:

$$\ell(l,t) - g_i(t)$$

The charging of thermal storage devices can be directly controlled by utilities to satisfy either bulk supply system objectives of minimizing production cost or distribution system needs of maintaining current and voltage limits. Storage charging would generally be under central control for bulk supply needs. However, on conflicting days when off-peak charging may violate distribution operating limits, the DCSG devices may be charged to avoid distribution violations. The number of such days depends on the penetration rate and the distribution system load profiles.

The model includes two basic charging operations:

$$s_i^1(t) = y_i$$

$$s_i^2(t) = y_i/2$$

where the notation is defined in Section 4.3.

Other basic operations may be defined. For example, charging at one-fourth of the capacity of y_i .

The charging operation would be effected in blocks, such that devices in each block have a common address code. Suppose a device i , is in block j , then the charging operation is defined by a combination of the basic operation.

$$s_i(t) = \alpha_j^1(t) \cdot s_i^1(t) + \alpha_j^2(t) \cdot s_i^2(t)$$

subject to:

$$\alpha_j^1(t) + \alpha_j^2(t) \leq 1; \alpha_j^1(t), \alpha_j^2(t) = 0 \text{ or } 1$$

Simulations require that the energy stored in each DCSG device equal the energy delivered later during the peak period, correcting for the conversion efficiency, ε , of the storage units. Thus:

$$E[g_i(t)] = E[s_i(t)] \cdot \varepsilon$$

The dispersed thermal storage communication system need transmit only the α_j codes at any instant to execute a charging operation for a block of devices. Separate control equipment is needed for each device to perform each basic operation.

The charging operation to satisfy either bulk supply or distribution needs can be affected by varying the start and the end of the charging period, the charging magnitude, and the grouping of devices in a common block. For example, thermal storage devices on the same primary circuit may be separated into three different charging blocks to levelize the off-peak load.

7.2 EVALUATION OF DCSG OPTIONS: STEP 4

The outputs of the previous three steps provide the information and data to: (1) evaluate the impact on the distribution system of planning and operating DCSG devices for bulk supply system needs under central control, without considering distribution system needs; (2) assess the cost-effectiveness of operating DCSG with consideration to distribution system needs under local control.

7.2.1 Distribution Impact Under Central Control

The distribution impact of DCSG under central control is measured by the sum of the Distribution Capacity and Reliability Components. Each component is calculated separately for each year, k , over the planning horizon. The sum is:

$$B_k = B_k^1 + B_k^2$$

where B_k^1 and B_k^2 are the distribution capacity and reliability components, respectively.

The Distribution Capacity Component, B_k^1 , is the difference in distribution expansion costs between the conventional expansion plan (where DCSG is not introduced) and the revised distribution expansion plan (where DCSG is introduced). The Distribution Capacity Component, which does not include DCSG capital costs, may be a benefit if distribution investments are deferred or cancelled by DCSG. It may be a cost if additional distribution investments are incurred.

The Reliability Component for DCSG is calculated in the same manner as for DSSG in Section 5.2. However, the Reliability Component for thermal storage devices is attributed to the extent that they replace existing or projected electric equipment.

7.2.2 Cost Effectiveness of Local Control

The cost effectiveness of operating DCSG devices to satisfy distribution needs is computed by comparing its cost with that of operating DCSG devices to satisfy bulk supply needs, according to the sum of four components:

$$B_k = \sum_{i=1}^4 B_k^i$$

The Distribution Capacity Component, B_k^1 , is the difference in expansion cost between the two control options with the same DCSG penetration rate and locations. The Reliability Component, B_k^2 , is the difference between the reliability value of DCSG under central and local control using the same method of computation as that of DSSG. The Communication and Control Component, B_k^3 , is the difference in the cost of control equipment. The Production Cost Component, B_k^4 , measures the cost difference between the central and local controls on conflicting days.

$$B_k^4 = H[L(t) \sum_i f_i(t) \beta_i, u_0(\cdot)] + \sum_i H[f_i(t), u_i(\cdot)] \\ - H[L(t) - \sum_i f_i^1(t) \beta_i, u_0(\cdot)] - \sum_i H[f_i^1(t), u_i(\cdot)]$$

where $f_i(t)$ and $f_i^1(t)$ are the device operating curves under central and local control, respectively.

8. DCSG CASE STUDIES

The DCSG methodology described in Chapter 7 was demonstrated on the same distribution systems on which DSSG case studies were made. This chapter describes the performance characteristics of the two customer-side thermal storage technologies, the case studies, and the results. The interpretation and analysis of the results are covered in Section 9.3 and Section 9.4.

8.1 PERFORMANCE CHARACTERISTICS

The two DCSG technologies which are analyzed are storage space heating and storage central air conditioning. Both can be generically classified as thermal storage devices or individually characterized as heat storage and cool storage devices, respectively.

Thermal storage devices are installed to store off-peak electric energy to be used for thermal applications during peak load hours. Heat storage devices store heat energy in a storage mass for water and/or space heating use during peak load periods. Cool storage devices chill a large mass during off-peak hours and use the cool mass thermodynamically to provide air conditioning during peak hours.

The common characteristics of devices which store off-peak energy for subsequent use during peak times are described in Section 3.3. Several unique technological characteristics distinguish thermal storage devices from electric storage devices.

Energy is stored thermally, rather than in electrical or chemical form. No conversion is required between the stored energy and end use of energy. Consequently electrical storage devices have more general applicability, but thermal storage devices are more efficient. Typical efficiency ranges from 90-95% versus 75% for batteries.

The operation of thermal storage devices is largely determined by climatic conditions. During days of extreme weather conditions, thermal storage devices may have a much smaller permissible charge time than electrical storage devices. Off-peak charging capacity therefore must be greater for thermal storage devices. Load diversity for customers with thermal storage devices is likely to be smaller than for those without because of the short charging period.

The power and the storage capacities of customer-side thermal storage devices depend on many factors: the hourly thermal energy requirements of the house, the daily temperature variations, and the time of day available for charging. The power capacity is determined by dividing the total daily thermal energy requirement of the house by the available off-peak charging hours. The energy storage capacity is obtained by summing the hourly thermal energy requirements during the peak period when charging is not permitted.

Several commercial cool storage systems using water, ice, or water-salt mixtures as storage media are currently available in the United States. Heat storage technology is hardly new. Practical residential heat storage devices have been in operation in Europe for over thirty years. Heat storage has had relatively less acceptance in the United States. A recent test program, however, has developed an "Americanized" heat storage device using ceramic brick as the storage medium [57].

Cool storage devices considered for central air conditioning use in the United States have a charging capacity between 4 kW and 10 kW, and a storage capacity between 50 kWh and 125 kWh. Heat storage devices for central space heating have a charging capacity ranging from 12 kW to 30 kW, and a storage capacity from 100 kWh to 200 kWh. Generally the charging and energy storage capacities of heat storage devices are much greater than those of cool storage, because the energy requirements tend to be greater for space heating than for air conditioning. In addition

space heaters tend to be operated over a longer portion of the day than air conditioners. Consequently residential thermal storage devices have shorter off-peak charging periods further increasing the charging capacity.

Heat and cool storage devices generally have higher power capacities than air conditioners and space heaters, respectively. Thermal storage devices not only must satisfy the off-peak thermal requirement but must also store the energy required for later use during the system load peaks.

8.2 THERMALLY-LIMITED DISTRIBUTION SYSTEM: CASE DESCRIPTION

8.2.1 Utility Description

The bulk supply system characteristics of Utility 1 were described in Section 6.2. The utility had a residential central air conditioning saturation of 16.4% in 1975. Exhibit 8-1 shows the central air conditioning load curve used in DCSG simulations. The maximum diversified demand is 3.6 kW. The utility system load peak occurs in the summer, coincident with the maximum air conditioning load. Exhibit 8-2 illustrates the diversified load curves for residential customers with and without central air conditioning. The diversified peak demand for customers without air conditioning is 1.5 kW, while that for customers with air conditioning is 4.1 kW. Studies [58,59] have shown 15% higher load diversity for the first class of customers than for the second.

8.2.2 Conventional Distribution Planning

Section 6.2 describes conventional distribution planning for Utility 1.

EXHIBIT 8-1

RESIDENTIAL CENTRAL AIR CONDITIONING
WITH AND WITHOUT COOL STORAGE

UTILITY 1

EXHIBIT 8-2
RESIDENTIAL LOADS
UTILITY 1

EXHIBIT 8-3
CENTRAL CONTROL STRATEGY
UTILITY 1

BLOCK	COOL STORAGE CAPACITY (KW)			CHARGING ON	CHARGING OFF
	YEAR 1	YEAR 2	YEAR 3		
1	1529	2839	4249	10:30 P.M.	9:00 A.M.
2	1529	2839	4249	10:00 P.M.	8:30 A.M.
3	1529	2839	4249	11:00 P.M.	9:30 A.M.
TOTAL	4587	8517	12747		

8.2.3 Development and Simulation of DCSG Strategies

Strategies for cool storage were established with assumed penetration and locations. The total charging capacity of all cool storage devices was equated to the dispersed electric generation capacity installed in the substation strategies as listed in Exhibit 6-23. The resulting DCSG device penetrations from 1975 to 1977 were 5.0%, 8.5%, and 11.8%, respectively. This simulation assumed that cool storage gradually replaced existing air conditioning. The total air conditioning load represented about 60% of the maximum diversified demand of all residential load. The locations of the cool storage devices were assumed to be uniformly distributed throughout the system.

Simple all-on, all-off operations for charging were simulated, because the large number of cool storage units did not warrant more sophisticated communications and control systems. However, the individual control of a number of blocks of cool storage devices was simulated to achieve system articulation. An allowable off-peak charging period between 9:30 pm and 9:30 am was assumed. These assumptions result in a maximum diversified cool storage capacity of 6.2 kW, with an average energy storage capacity of 65 kWh.

A central control strategy for the bulk supply objective was simulated with three separate blocks controlling equal capacities. The capacities controlled by three blocks and their charging periods are tabulated in Exhibit 8-3. The payback (charging) controls were simulated to minimize production costs, similar to the forward-backward controller experimented in Europe [13]. The resulting load curves at the substation and at some selected feeders are illustrated in Exhibit 8-4 and Exhibit 8-5.

Local control strategies were simulated to minimize distribution loads on the feeders, with three control blocks on each feeder. The capacities of the block and their charging period are tabulated in

EXHIBIT 8-4
SUBSTATION LOADS
UTILITY 1

EXHIBIT 8-5
FEEDER 1 LOAD
UTILITY 1

EXHIBIT 8-6

LOCAL CONTROL STRATEGY
UTILITY 1

FEEDER	BLOCK	COOL STORAGE CAPACITY (KW)			CHARGING ON	CHARGING OFF
		YEAR 1	YEAR 2	YEAR 3		
1	1	229	422	636	10:00 P.M.	8:30 A.M.
	2	229	422	636	10:30 P.M.	9:00 A.M.
	3	229	422	636	9:00 A.M.	7:30 P.M.
2	1	207	386	575	10:30 P.M.	9:00 A.M.
	2	207	386	575	10:00 P.M.	8:30 A.M.
	3	207	386	575	9:30 P.M.	8:00 A.M.
3	1	303	556	842	10:30 P.M.	9:00 A.M.
	2	303	556	842	10:00 P.M.	8:30 A.M.
	3	303	556	842	9:30 P.M.	8:00 A.M.
4	1	370	689	1028	10:30 P.M.	9:00 A.M.
	2	370	689	1028	10:00 P.M.	8:30 A.M.
	3	370	689	1028	9:30 P.M.	8:00 A.M.
5	1	387	725	1077	10:30 P.M.	9:00 A.M.
	2	387	725	1077	10:00 P.M.	8:30 A.M.
	3	387	725	1077	9:30 P.M.	8:00 A.M.
7	1	33	61	91	8:30 P.M.	7:00 A.M.
	2	33	61	91	8:00 P.M.	6:30 A.M.
	3	33	61	91	7:30 P.M.	6:00 A.M.
TOTAL		4587	8517	12747		

Exhibit 8-6. The resulting load curves at the substation and at selected feeders are illustrated in Exhibit 8-4 and Exhibit 8-5. The exhibits show in general that local control strategies have peak values which are less than or equal to those peak values obtained from central control strategies. Local control strategies have a higher substation peak, however, due to the diversity among the feeders and the independent charging of the storage devices among the feeders.

8.2.4 Results

Exhibit 8-7 presents the non-coincident loads at the feeders and the substation for the central and local control strategies, as well as for the base case. The reduced loadings at the substation provide a benefit since the installation of substation transformers is deferred for one year. If the cool storage capacities remain constant after the third year, the reduced loadings would have a benefit for the Distribution Capacity Component in the future beyond the study period. The system investment for a new kilowatt of demand average \$21/kW. Utilizing this figure, the results of the cool storage case study show a benefit from the Distribution Capacity Component of \$5.9/kW for the central control strategy and \$6.0/kW for local control strategy. Analysis and interpretation of the results are provided in Section 9.3.

8.3 VOLTAGE-LIMITED DISTRIBUTION SYSTEM: CASE DESCRIPTION

8.3.1 Utility Description

The general supply system characteristics of Utility 2 were provided in Section 6.3. About 3.6% of the residential customers have electric space heating. In the simulations, the residential space heating curve illustrated in Exhibit 8-8 was used. Its maximum diversified demand is 4.9 kW. Exhibit 8-9 illustrates the diversified load curves for residential customers with and without central space heating.

EXHIBIT 8-7

DCSG RESULTS:
FEEDER AND SUBSTATION
PEAK LOADS UTILITY 1

LOCATION	TYPE OF OPERATION	PEAK LOAD KW (TIME)**		
		YEAR 1	YEAR 2	YEAR 3
FEEDER 1	CENTRAL	5936(5:00)	6039(8:00)	6634(8:00)*
	LOCAL	5936(5:00)	6039(8:00)	6687(8:00)
	BASE	6496(5:00)	6996(5:00)	7351(5:00)
FEEDER 2	CENTRAL	5708(2:30)	5794(5:00)	5934(7:30)*
	LOCAL	5707(2:30)	5794(5:00)	5934(8:00)
	BASE	6276(2:30)	6830(2:30)	7227(2:30)
FEEDER 3	CENTRAL	7654(5:00)	7729(5:00)	7756(7:30)*
	LOCAL	7654(5:00)	7729(5:00)	7756(8:00)*
	BASE	8416(2:30)	9014(2:30)	9435(2:30)
FEEDER 4	CENTRAL	8046(5:00)	8187(8:00)	8449(8:00)
	LOCAL	8046(5:00)	8187(8:00)	8448(8:00)
	BASE	8951(5:00)	9728(5:00)	10283(5:00)
FEEDER 5	CENTRAL	8236(5:30)	8567(8:00)	9171(7:30)*
	LOCAL	8236(5:30)	8567(8:00)	9171(7:30)*
	BASE	9184(5:30)	10021(5:30)	10622(5:30)
FEEDER 6	CENTRAL	7756(12:00)	7926(12:00)	8087(12:00)
	LOCAL	7756(12:00)	7926(12:00)	8087(12:00)
	BASE	7756(12:00)	7926(12:00)	8087(12:00)
FEEDER 7	CENTRAL	7293(12:30)	7860(10:00)*	8452(9:30)*
	LOCAL	7293(12:30)	7860(9:30)*	8450(9:30)*
	BASE	7371(12:30)	7990(12:30)	8429(12:30)
SUBSTATION	CENTRAL	48762(2:30)	49111(2:30)	53179(7:30)*
	LOCAL	48990(2:30)	49533(2:30)	52270(7:30)*
	BASE	52961(2:30)	56914(2:30)	59728(2:30)

*A.M.

**ALL TIMES P.M. UNLESS NOTED

EXHIBIT 8-8
RESIDENTIAL SPACE HEATING WITH
AND WITHOUT HEAT STORAGE
UTILITY 2

EXHIBIT 8-9

DIVERSIFIED RESIDENTIAL LOADS
UTILITY 2

8.3.2 Conventional Distribution Planning

Conventional distribution planning for Utility 2 was discussed in Section 6.3.

8.3.3 Development and Simulation of DCSG Strategies

Strategies for storage space heating were simulated using assumed penetration and locations. The total installed capacity was equal to the sum of the dispersed electric storage capacities for the substation strategies defined in Exhibit 6-42. The resulting penetrations from 1975 to 1977 were 17%, 29% and 34%, exceeding the penetration of the electric space heating. The simulations assumed that storage space heating first replaced existing space heating and then became attractive to new customers. The locations of the heat storage devices were assumed to be uniformly distributed throughout the system. The resulting capacities installed at each substation are tabulated in Exhibit 8-10.

Simple on-off controls were simulated for off-peak charging, as in the cool storage case of Utility 1. An allowable off-peak charging period between 12 midnight and 7:00 am was assumed. This implies a maximum diversified heat storage charging capacity of 21.5 kW, with an average energy storage capacity of about 150 kWh.

A central control strategy for bulk-supply objectives was simulated with three blocks controlling equal capacities. The capacities and the charging period under each control block are listed in Exhibit 8-10. The payback operation was designed to minimize production cost, similar to the forward-backward controller. The resulting load curves at selected substations and the total distribution load are illustrated in Exhibit 8-11 and Exhibit 8-12.

EXHIBIT 8-10

CENTRAL CONTROL STRATEGY
UTILITY 2

BLOCK	HEAT STORAGE CAPACITY (KW)			CHARGING ON	CHARGING OFF
	YEAR 1	YEAR 2	YEAR 3		
1	1149	1941	2324	12:00 A.M.	5:00 A.M.
2	1149	1941	2324	1:00 A.M.	6:00 A.M.
3	1149	1941	2324	2:00 A.M.	7:00 A.M.
TOTAL	3347	5823	6972		

EXHIBIT 8-11
TOTAL DISTRIBUTION LOADS
UTILITY 2

EXHIBIT 8-12
SUBSTATION 1 LOAD
UTILITY 2

A local control strategy to minimize distribution loads at the substations was simulated with three control blocks for each substation. The capacities and their charging period are tabulated in Exhibit 8-13. Revised load curves are illustrated in Exhibits 8-11 and 8-12.

8.3.4 Results

Exhibit 8-14 lists the coincident peak load at each substation for the central and local control strategies and for the base case without storage space heating. The result shows negligible distribution capacity benefits for the central control and local control strategies. Analysis and interpretation of the results are provided in Section 9.4.

EXHIBIT 8-13

LOCAL CONTROL STRATEGY
UTILITY 2

SUBSTATION	BLOCK	HEAT STORAGE CAPACITY(KW)			CHARGING ON*	CHARGING OFF
		YEAR 1	YEAR 2	YEAR 3		
1	1	333	687	815	1:00	6:00
	2	333	687	815	3:00	8:00
	3	333	687	815	12:00	5:00
2	1	333	686	815	1:00	6:00
	2	333	686	815	3:00	8:00
	3	333	686	815	12:00	5:00
3	1	242	284	347	1:00	6:00
	2	242	284	347	3:00	8:00
	3	242	284	347	12:00	5:00
4	1	241	284	347	1:00	6:00
	2	241	284	347	2:00	7:00
	3	241	284	347	12:00	5:00
TOTAL		3447	5823	6972		

*ALL TIMES DENOTE A.M.

EXHIBIT 8-14

DCSG RESULTS:

SUBSTATION AND
SUBTRANSMISSION SYSTEM PEAK LOADS
UTILITY 2

LOCATION	TYPE OF OPERATION	PEAK LOAD - KW (TIME)**		
		YEAR 1	YEAR 2	YEAR 3
SUBSTATION 1	CENTRAL	3871(11:00)*	4483(2:00)*	5085(2:00)*
	LOCAL	3871(11:00)*	4425(3:00)*	5022(3:00)*
	BASE	3872(7:00)	4220(7:00)	4600(7:00)
SUBSTATION 2	CENTRAL	3471(6:00)	3995(2:00)*	4512(2:00)*
	LOCAL	3471(6:00)	3906(3:00)*	4459(3:00)*
	BASE	3571(7:00)	3893(7:00)	4243(7:00)
SUBSTATION 3	CENTRAL	3390(6:00)	3696(6:00)	4029(6:00)
	LOCAL	3390(6:00)	3696(6:00)	4029(6:00)
	BASE	3512(7:00)	3829(7:00)	4173(7:00)
SUBSTATION 4	CENTRAL	3009(7:00)	3280(7:00)	3575(7:00)
	LOCAL	3009(7:00)	3280(7:00)	3575(7:00)
	BASE	3133(7:00)	3413(7:00)	3720(7:00)
SUBTRANS- MISSION SYSTEM	CENTRAL	13690(6:00)	14922(6:00)	16265(6:00)
	LOCAL	13690(6:00)	14922(6:00)	16265(6:00)
	BASE	14087(7:00)	15354(7:00)	16737(7:00)

* A.M.

** ALL TIMES P.M. UNLESS NOTED

9. CASE STUDY RESULTS

The results of the DSSG and DCSG case studies, presented in Chapters 6 and 8, are analyzed in this chapter. Important phenomena and insights that may be applicable to other systems are emphasized. The results for each utility are described separately.

The Dispersion Credit is expressed in dollars per kilowatt of installed DSG capacity. The Dispersion Credit can be interpreted as a reduction or increase of the capital cost (in \$/kW) of the dispersed technology. Suppose the annualized Dispersion Credit in constant dollars is $B_1, B_2, B_3, \dots, B_n$, and the installed DSG capacities are $C_1, C_2, \dots, C_n$. Then the total Dispersion Credit expressed in \$/kW of DSG capacity is equal to:

$$\frac{\sum_{i=1}^n B_i}{a \sum_{i=1}^n (1+r)^{-i} C_i}$$

where a is the annual carrying charge for the dispersed technology, and r is the real discount rate adjusted for escalation. The above expression takes into account the differences between the annual carrying charge of a dispersed device and that of the conventional distribution equipment.

9.1 THERMALLY-LIMITED DISTRIBUTION SYSTEM: DSSG CASES

This discussion falls into three parts. The first part discusses assessment component results. The second part analyzes the overall assessment results. Finally, the sensitivity of the assessment

EXHIBIT 9-1
DISPERSAL COST COMPONENT
UTILITY 1

results is analyzed. The results of the DSSG strategies are tabulated in Exhibit 6-31 through Exhibit 6-34.

9.1.1 Assessment Component Results

The Distribution Capacity Component is the dominant benefit component for all DSSG strategies. This component increases (becomes more beneficial) as the location of the DSSG devices moves from substation to feeder levels because of the feeder capacity saving. The different \$/kW figures for storage and generation in Exhibits 6-31 through 6-34 reflect different annual carrying charges and different operational limitations.

The Reliability Component is insignificant when compared to other components, reflecting the very reliable performance of Utility 1's distribution system. Storage achieves about half the Reliability Benefit of generation because of its energy limitation.

The Dispersal Cost Component is different for dispersed storage and generation. This difference is seen in both substation and feeder strategies. For dispersed storage, the longer the device remains at one location the more the Dispersal Cost Component decreases (becomes less beneficial). This decrease is largely due to the increasing storage capacity requirement to avoid local equipment overloading. For dispersed generation in feeder strategies, the same phenomenon is also observed because of the diseconomy of scale encountered when smaller devices are placed at feeders. In substation strategies for dispersed generation, however, prolonged service improves the Dispersal Cost Component. These phenomena are illustrated in Exhibit 9-1 using results from substation strategies for lead-acid batteries and fuel cells.

For both dispersed storage and generation, moving the location of DSSG devices from substation to feeder levels decreases (worsens) the Dispersal Cost Component. The phenomenon is illustrated in Exhibit 9-2

EXHIBIT 9-2
DISPERSAL COST COMPONENT FOR THREE YEAR PLACEMENT
UTILITY 1

using the results from strategies where the DSSG equipment is operated at one location for three years. The decrease in the Dispersal Cost Component is most drastic and critical for storage because additional storage capacity must be installed due to local diversity among feeders. The Dispersal Cost Component is a benefit (positive) for dispersed generators at substations because smaller capacities are installed than otherwise would be required centrally. The substation location provides a saving in electric line losses which more than offsets the loss due to the diseconomy of scale of the smaller devices.

The Production Cost Component consists of fuel and maintenance costs, each of which is different for dispersed storage and generation. First, consider the fuel cost sub-component which is illustrated in Exhibit 9-3. For dispersed storage the fuel cost sub-component is insignificant when compared to other components. The same amount of energy must be generated for both centralized and dispersed storage. Dispersed generation shows significant savings in fuel cost partly due to the assumption that the cost of fuel delivered to dispersed locations is the same as for a central generating station.

As illustrated in Exhibit 9-4, the maintenance cost sub-component of DSSG feeder strategies initially is negative, but improves significantly the longer the device remains in service since the diseconomy of scale is less important for larger capacities. The maintenance cost sub-component is the most important factor contributing to the dominantly negative Production Cost Component for dispersed generation, particularly at the feeder level.

The Replacement Capacity Component is significantly negative for dispersed storage. In order to increase the Replacement Capacity Component additional energy storage capacity must be provided at much higher costs. Dispersed generation can be operated to avoid this penalty by extending its operating hours, thus incurring some production cost increases during days of conflicting objectives.

EXHIBIT 9-3
FUEL COST COMPONENT
UTILITY 1

EXHIBIT 9-4
OPERATING AND MAINTENANCE COST COMPONENT
UTILITY 1

EXHIBIT 9-5
DISPERSION CREDIT:
SUBSTATION STRATEGIES
UTILITY 1

The importance of the Replacement Cost Component decreases with increasing installed capacity. The penalty for feeder strategies is less than that of substation strategies because more storage capacity is installed at the feeder level for load diversity reasons.

9.1.2 Overall Assessment Results

The aggregated assessment results are plotted in Exhibit 9-5 and Exhibit 9-6 for substation and feeder strategies, respectively. The figures provide some interesting insights concerning the dispersion effects of penetration, location, and operation. For the particular distribution system studied, the results show a range of net Dispersion Credit from + \$60/kW to -\$334/kW.

Net Dispersion Credit decreases over time with increasing dispersed storage capacity largely due to the increasing penalty of the Dispersal Cost Component, as explained above. Net Dispersion Credit improves over time with increased penetration of dispersed generation. This improvement is due to the gradual disappearance of the diseconomy of scale for operating and maintenance costs.

For both dispersed storage and generation, substation placement gives a significantly higher Dispersion Credit. Feeder placement results in a severe penalty for dispersed storage because of the requirement for increased energy storage capacity due to increased load diversity. Feeder placement yields poorer overall performance for dispersed generation largely because of the diseconomy of scale in operating and maintenance costs of smaller capacities at feeder levels.

Testing of various operating options for dispersed storage indicates that a tradeoff exists between the Dispersal Cost Component and the Replacement Capacity Component. Additional energy storage capacity is needed to reduce the Replacement Capacity penalty by changing the operating mode. It was found in the cases studied, however, that

EXHIBIT 9-6
DISPERSION CREDIT:
FEEDER STRATEGIES
UTILITY 1

improving the Replacement Capacity Component could not be justified by additional storage capacity. Flat generation is the best operating strategy for dispersed storage, since it minimizes the storage capacity needed to meet targeted distribution needs. For dispersed generation, the tradeoff between increased energy production and the Replacement Capacity penalty demonstrates that avoiding the Replacement Capacity Penalty is always preferred. Mixed generation as illustrated in Exhibit 6-26 for substation strategies, and full generation, as illustrated in Exhibit 6-27 for feeder strategies, are the best operating strategies tested. Both avoid the Replacement Capacity cost and minimize the required hours of operation.

9.1.3 Sensitivity Analysis

The above case study results show the importance of the Dispersal Cost Component for storage and the Production Cost Component for generation. The sensitivities of both are further analyzed by increasing fuel delivery cost to dispersed generators and degrading the round-trip efficiency of storage devices. The results are illustrated in Exhibit 9-7 and Exhibit 9-8 for lead-acid batteries and fuel cells at substations for one year.

The results for fuel cells show that the Dispersion Credit is very sensitive to additional fuel delivery costs. With a 9% increase in fuel costs to dispersed locations the Dispersion Credit fell from \$60/kW to -\$7/kW.

The results for lead-acid batteries show that the Dispersion Credit is very sensitive to degraded efficiency. With a drop in efficiency from 75% for centralized storage to 70% for dispersed storage, the Dispersion Credit fell from \$13/kW to -\$5/kW.

The importance of the Distribution Capacity Component in the overall assessment of dispersed devices is underlined by the following.

EXHIBIT 9-7
DISPERSION CREDIT SENSITIVITY TO
DISPERSED FUEL COST INCREASE*

*FUEL CELL SUBSTATION STRATEGY

EXHIBIT 9-8

DISPERSION CREDIT SENSITIVITY TO DEGRADED
DISPERSED STORAGE EFFICIENCY*

*LEAD-ACID BATTERY SUBSTATION STRATEGY

example. Assume that after a designated number of years of operating DSSG devices to obtain distribution benefits, the devices are allowed to remain in the same location to be operated to satisfy only the bulk supply needs. In the subsequent years the dispersed devices would not incur the Distribution Capacity and Replacement Capacity Components. For the substation strategies, the Dispersion Credit of lead-acid batteries drops from \$13/kW to -\$31/kW. The Dispersion Credit of fuel cells decreases slightly from \$60/kW to \$58/kW, although there are continued fuel savings for the dispersed generators.

9.2 VOLTAGE-LIMITED DISTRIBUTION SYSTEM: DSSG CASES

This section presents the assessment component results, the overall assessment results, and sensitivity analysis for Utility 2. The results of the DSSG strategies are tabulated in Exhibit 6-45 through Exhibit 6-48. All figures are expressed in dollars per kilowatt of installed DSSG capacity. Most of generic phenomena described for the case study of Utility 1 also hold for Utility 2. The discussion below emphasizes the differences between the two sets of results.

9.2.1 Assessment Component Results

As in the case studies for Utility 1, the Distribution Capacity Component provides the single most important benefit. Because of the deferment of the large conventional investment for the subtransmission system, the Distribution Capacity Component dominates all other components. This benefit is smaller for the feeder strategies than for substation strategies because the DSSG placement along feeders was unable to relieve the voltage regulation problem of the subtransmission system.

The phenomena observed for the Reliability Component for Utility 2 is similar to those described in Section 9.1 for Utility 1. The component values for substation strategies are much smaller than those

for feeder strategies because the transmission and subtransmission systems have a much higher reliability than the distribution system. Therefore DSSG devices at substations provide proportionally less unserved energy during an emergency.

In the case of the Dispersal Component, similar generic phenomena described for Utility 1 also hold for Utility 2 as illustrated in Exhibit 9-9 and Exhibit 9-10. The Dispersal Component for storage is significantly negative because of diversity. Dispersed storage devices generate energy between 2 pm and 5 pm due to local problems, while the bulk supply system load was leveled by pumped storage plants.

The same behavior of the Production Cost Component discussed for Utility 1 can be observed for Utility 2 as illustrated in Exhibit 9-11 and Exhibit 9-12. The Production Cost Component for diesel engines is a penalty because of their more frequent use for distribution problems.

Similar trends observed in the behavior of the Replacement Capacity Component for Utility 1 also holds true for Utility 2.

9.2.2 Overall Assessment Results

The overall assessment results are plotted in Exhibit 9-13 and Exhibit 9-14. For the distribution system studied, the results show a range of net Dispersion Credit from \$172/kW to -\$196/kW.

As in case studies for Utility 1, Dispersion Credit decreases over time with increased dispersed storage capacity due to the increased penalty of the Dispersal Cost Component. Furthermore, extra storage capacity was installed to relieve the voltage problem. The Dispersion Credit for dispersed generation decreases initially and then increases with higher penetration over time, because of the gradual disappearance of the diseconomy of scale in operating and maintenance costs.

EXHIBIT 9-9
DISPERSAL COST COMPONENT
UTILITY 2

EXHIBIT 9-10
DISPERSAL COST COMPONENT
UTILITY 2

EXHIBIT 9-11
FUEL COST COMPONENT
UTILITY 2

EXHIBIT 9-12

OPERATING AND MAINTENANCE COST COMPONENT

UTILITY 2

EXHIBIT 9-13
DISPERSION CREDIT:
SUBSTATION STRATEGIES
UTILITY 2

EXHIBIT 9-14
DISPERSION CREDIT:
FEEDER STRATEGIES
UTILITY 2

Placement of DSSG devices at substations gives a significantly higher Dispersion Credit than feeder placement. This phenomenon was also observed for Utility 1 for the same general reasons cited in the results analysis. The substation strategy places the devices at the end of the radial subtransmission system, where the voltage regulation problems occur and consequently has a higher Dispersion Credit. Other generic phenomena on feeder strategies observed for Utility 1 also apply to Utility 2. Alternate feeder placement of DSSG devices shows that a large DSSG device along a feeder yields a higher Dispersion Credit than several smaller units because of the economy of scale in both Dispersal Cost and Production Cost Components.

The voltage limited system requires less additional energy generation to help alleviate distribution voltage regulation problems. As loads throughout the system decrease, the voltage regulation at the problem locations improves, and additional generation is avoided. The operating options used in the case studies minimize energy generation during the bulk supply system peak while avoiding the distribution voltage problems.

9.2.3 Sensitivity Analysis

The sensitivities of the results to both increased fuel delivery costs for dispersed generators and to degraded round-trip efficiencies for dispersed storages are studied. The results are illustrated in Exhibit 9-7 and Exhibit 9-8 for lead-acid batteries and fuel cells placed at substation locations for one year.

Similar generic conclusions for Utility 2 follow those for Utility 1. An exception is that the Distribution Capacity Component for Utility 2 was much higher than for Utility 1. With a delivered fuel cost which is 35% higher at the substations than at the central generating station, the Dispersion Credit for fuel cells for one year drops from \$151/kW to -\$13/kW. The results for lead-acid batteries show that the

Dispersion Credit is very sensitive to degraded efficiency. With a decrease in efficiency from 75% for centralized storage to 70% for dispersed storage, the Dispersion Credit for lead-acid batteries for one year at the substation falls from \$40/kW to \$17/kW.

The importance of the Distribution Capacity Component is further demonstrated in the case studies for Utility 2. This component helps make all DSSG technologies more attractive for Utility 2 than for Utility 1. Further, if the DSSG devices remain in the same locations and are operated with bulk supply objectives, the Dispersion Credit for the lead-acid batteries at substation strategies decreases from \$40/kW to \$123/kW while the Dispersion Credit of fuel cells drops from \$151/kW to \$79/kW.

9.3 THERMALLY-LIMITED DISTRIBUTION SYSTEM: DCSG CASES

As cool storage devices gradually replace existing air conditioning loads, the devices generally reduce peak loadings at the feeders and substations. A careful examination uncovers several interesting generic phenomena applicable to both central and local control strategies.

The feeder impacts vary. Cool storage reduces loading on some feeders more than other feeders, as illustrated in Exhibit 9-15. The extent of the load reduction depends on the customer mix on each feeder. For feeders that have no residential load and therefore no cool storage, there is no impact. Feeders having many customers who install cool storage would require increased investment, particularly if those feeders previously experienced current or voltage problems. The locations of cool storage devices are important factors in assessing the impact of DCSG upon the distribution system.

The time of occurrence of peak loads may change as penetration of cool storage increases. As illustrated in Exhibit 8-7, cool storage

EXHIBIT 9-15

DCSG RESULTS

*RATIO OF PEAK LOAD WITH STORAGE TO THAT OF THE BASE CASE

shifted the substation peak load from 2:30 pm to 7:30 am in the third year with 12% penetration. Cool storage tends to shift the feeder peak loads to different times of the day, depending on the customer mix. Potentially, this implies that current overloading may occur at any hour, complicating distribution planning.

Higher penetration may yield diminishing peak load reduction. For example, although the cool storage capacity was increased by 39% between the second and third years, the load reduction at the substation actually decreased by 19%. This result was due to the appearance of a new peak load in a previously non-peak period. This peak shift was caused by replacing air conditioning load with a higher cool storage load. With further increase in penetration, the new peak may be no lower than the old peak load and may, in fact, be higher. This underscores the importance of the degree of penetration in evaluating the impact of DCSG on distribution systems.

Central and local control strategies give similar generic results for Utility 1 as described above. The differences between the two control strategies are insignificant. Local control strategies result in slightly lower feeder loadings, but the amount was insufficient to claim large distribution investment savings. Central control strategies have a lower substation loading. The result shows a Distribution Capacity benefit of \$5.90/kW for the central-control strategy and \$6.00/kW for the local control strategy. Both have nearly equal production costs.

Comparisons with battery storage cases shows that cool storage devices are not as effective in reducing the peak loads. Unlike batteries, cool storage cannot give the necessary load reduction at the time and place desired by the planner.

9.4 VOLTAGE-LIMITED DISTRIBUTION SYSTEM: DSCG CASES

Similar generic phenomena described for cool storage also apply to heat storage in Utility 2. The discussion below compares the generic differences between the two case studies.

As in the cool storage case, heat storage reduced the total distribution system peak. However, the impacts on the substations vary since the load magnitude depends upon the mix of customers served by each substation. Because the penetration of heat storage was much higher than the existing central space heating penetration, the peak loadings at Substation 1 and Substation 2 in the second and third year exceeded those of the base case without heat storage. This effect is shown in Exhibit 8-14.

The times of occurrence of peak loads changed for some substations. Substation 3 and Substation 4, having small residential loads, showed no change in the time of peak. However, heat storage devices shifted the peaks of Substation 1 and Substation 2, which have significant residential load, from 7 pm to 2 am and 3 am.

As in the cool storage case, increased penetration yields a proportionally smaller reduction of the total distribution peak load as shown in Exhibit 9-15. In the third year, almost no reduction of the total distribution peak load occurred, although the heat storage capacity increased from 29% to 34%. The reason is the appearance of peak load in a previously off-peak period, caused by the replacement of a small space heating load by a much larger heat storage load. Once again, this underlines the importance of penetration in assessing the impact of heat storage on distribution systems.

Central and local control strategies have almost the same impact. The resulting load reductions were insufficient to reduce or defer the conventional distribution expansions, resulting in negligible

Distribution Capacity savings. Both had approximately the same production cost.

An interesting result from the heat storage case studies was a significant bulk supply production cost penalty. This was due to the fact that the bulk supply system was operating with pumped storage plants, with a high daily load factor of 84%.

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10. CONCLUSIONS

Significant insights into the impact of DSG on distribution systems were gained during methodology development, model building, and case-study analysis. This chapter presents conclusions extrapolated from the case studies, points to future research and development for DSG technologies, outlines new advanced planning and control methods, and describes the application of the methodology to DSSG and DCSG.

10.1 CASE STUDY CONCLUSIONS

10.1.1 Supply-Side DSG

The results confirm that the Distribution Capacity Component is one of the most important dispersion benefits, as indicated in Exhibit 10-1. However, in attempting to obtain this benefit, penalties may be incurred, as shown by negative components for most cases in the same exhibit. Because the distribution and bulk supply requirements may differ due to load diversity and disparity of operating objectives, DSSG devices may be used for periods of extended operation. The additional energy generated results in additional storage capacity cost for dispersed storage (as demonstrated by the proportionally large Dispersal Cost Component) and a higher fuel and operating cost for dispersed generation (as demonstrated by the proportionally large Production Cost Component). Coupled with diseconomy of scale in capital cost and operating and maintenance cost, this additional generation may result in substantial dispersion penalties, as illustrated for the worst cases in Exhibit 10-1.

To summarize, the net dispersion effect is, in most cases, expected to range from a small benefit to a large cost, suggesting that caution and careful analysis are required before implementation. In special cases, however, where distribution and DSSG technology characteristics are favorable, significant positive benefits are realizable.

EXHIBIT 10-1

ASSESSMENT COMPONENTS OF SELECTED CASES

Several distribution system characteristics that can lead to net positive dispersion benefits are given below.

Dispersion is most attractive when:

1. The potential for Distribution Capacity benefits is great, as when an immediate need exists for large conventional distribution capacity investment which can be deferred by a small DSSG capacity.
2. Distribution and bulk supply peak loads occur during different seasons avoiding conflicts between distribution and bulk supply needs. Alternatively, if distribution and bulk supply peak loads occur in the same season, dispersion can be desirable provided the peaks occur together on a small number of days and they are highly coincident on these days.
3. An opportunity exists to operate a large dispersed generator (1-10 MW) in one location for an extended number of years.
4. Planning flexibility exists to use dispersed storage for only a few years, after which time the DSSG is replaced by conventional capacity additions if loads continue to grow.
5. The delivered cost of fuel for dispersed generation is comparable to the cost of fuel for central generation.
6. Distribution system requirements can be met by placing DSSG devices in the substation or on a primary feeder near the substation.
7. The distribution system requirements are in a remote service location having significant losses.
8. The distribution reliability benefits are significant, as when the DSSG service area has customers with special requirements for service continuity during system outages.

The following DSSG characteristics favor dispersion into the distribution system:

9. The device is a generator, rather than a storage unit.
10. The device performance is not degraded due to dispersion.
11. The DSSG device is very reliable, requiring no extra maintenance when dispersed.
12. The storage device is mobile, with small installation and removal costs, allowing it to be used in several different locations during its useful life.
13. The DSSG technology has no significant economy of scale for capacities greater than about one megawatt.

The introduction of dispersible storage and generation into the electric distribution system will complicate present planning and operating practices. Present distribution practices relying on established guidelines and engineering judgment may prove insufficient because this experience has been accumulated for systems without DSSG. Planning with DSSG requires 24-hour load data for parts of the distribution system, but such data are usually unavailable or are difficult to collect. Since distribution benefits alone may not justify the total DSSG cost, planning of DSSG in distribution systems will require coordination with the bulk supply system planning to obtain benefits for both systems. Daily operation of DSSG requires reconciliation of distribution and bulk supply needs to assure the realization of planned benefits.

10.1.2 Customer-Side DSG

The impact of thermal storage devices on distribution systems depends strongly on the penetration and on the location of the devices. As shown in Exhibit 9-15, when the new devices replace existing and projected electric equipment for heating and cooling, they may offer distribution investment savings. However, beyond this saturation, new devices contribute to the off-peak load, without decreasing the daytime load. Eventually, new peaks develop during off-peak periods. In these situations, distribution investment will be increased, particularly for thermal storage units at locations that may already have distribution problems.

The impact of thermal storage units on the distribution system also depends on weather conditions and bulk power and distribution system load shapes. For example, if available charging hours are reduced by sustained extreme weather conditions, the off-peak charging capacity would be increased, causing a more pronounced peak during the previously off-peak period.

The application of local controls to avoid the development of peaks in previously off-peak periods offers little or no net benefits. With small penetration of thermal storage devices, local control could yield a small benefit when used to relieve feeder problems. However, under conditions of substantial penetration, local control might be ineffective to solve the distribution problems. The use of local control to help distribution operation introduces a new complexity to current operating practices.

10.2 FUTURE TECHNOLOGY AND ADVANCED METHODS R&D

10.2.1 Supply-Side DSG

Future R&D for DSSG technologies may be directed at lowering the installation and removal costs of storage devices. In addition, R&D is needed to reduce the frequency of maintenance without affecting performance and to narrow the diseconomy of scale in capital and operating costs for 10 MW and smaller devices.

Lowering the installation and removal costs of small Dispersed Storage Devices would encourage mobility and allow their use in several different locations during their useful life. This may require the devices and the associated equipment to be lightweight and trailer-mountable. This may also require standardization of interface equipment so that the storage devices can be "plugged in" at different points in the distribution system.

Reduced frequency of DSSG device outage due to routine maintenance and lower forced outage rates would significantly lower the costs of fault detection, switching, and repair at different locations. More data is needed regarding device reliability, the maintenance costs of dispersed units, and the potential improvement on performance due to reduced frequency maintenance. R&D efforts should emphasize moving the outage frequency closer to conventional distribution equipment outage rates rather than toward those of conventional generating units.

Narrowing the diseconomy of scale in both capital and operating costs would reduce the dispersion penalty. The emphasis should be placed on low-cost, small DSSG units. When there is no significant diseconomy of scale, a bank of small DSSG devices would have higher reliability than a single unit at about the same cost.

Future R&D into advanced methods for planning and control of DSSG devices may be directed toward maintaining voltage regulation, estimating 24-hour load profiles, planning DSSG for cogeneration, and estimating the cost of increased planning and data collection efforts for DSSG.

The use of real power generation to relieve voltage problems requires a model to determine the optimum coordinated operation of a set of dispersed devices to meet voltage constraints. The operation of any device could affect the voltages at different parts of the distribution system in varying degrees. The optimum control problem is to coordinate their operation to relieve the voltage problem.

Algorithms to estimate continuous load profiles at different levels of the distribution system are rudimentary. Sophisticated methods exist for estimating peak loads at distribution transformer levels and above. Since planning DSSG requires continuous load information, such a model would be very useful.

There are opportunities to use DSSG in a cogeneration mode. Excess generation can be fed back to the distribution system from the customer entry. Waste heat can be utilized. Models are needed to integrate such technologies into conventional distribution planning and utilize such devices to reduce distribution investments.

The incorporation of DSSG into the distribution system significantly complicates the present distribution planning and operating practices. The cost of the increased planning complexity is not

known. Study is needed regarding the close coordination of the bulk supply and distribution planning staffs since in most utilities the two planning groups are separate.

10.2.2 Customer-Side DCSG

Future research on predicting the penetration and locations of DCSG devices is needed. With new forecasting tools, distribution planners would be in a better position to anticipate changes in the peak loads and plan accordingly.

Models are needed to optimize the tradeoff between charging duration and capacity (power and storage) under various weather conditions and system load profiles. These models would improve the data used in the simulation of DCSG operations. Models are also needed to control the operation of the large number of blocks of DCSG devices minimizing total system costs and considering stochastic weather conditions.

10.3 APPLICATIONS OF THE METHODOLOGY

By taking a distribution planning approach, the general methodology developed is suitable for use by most utilities when planning DSG in distribution systems. The methodology properly reflects the net system costs and benefits of using DSG as a distribution planning alternative and includes the effects of such use on bulk-supply systems. The utilities can apply their existing planning models and data base in the planning steps following the assessment procedures described. This may significantly reduce the time and effort required for DSG studies. The assessment component calculations are simple and flexible enough to accommodate the available data.

The methodology can also be applied to assess the effects of storage and generation technologies with a particular set of

technological and cost characteristics. The use of historical system data as performed in the case studies may significantly reduce the time and effort for such assessment studies, particularly for those persons who are not distribution planners or who are unfamiliar with the particular area and delivery system. The distribution investment deferment method can also be used to quickly estimate the distribution capacity saving in such assessment studies.

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