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The Integration of Renewable Energy Sources into Electric Power Transmission Systems

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POWER SYSTEMS TECHNOLOGY • PROGRAM •

MANAGED BY
MARTIN MARIETTA ENERGY SYSTEMS, INC.
FOR THE UNITED STATES
DEPARTMENT OF ENERGY

ORNL-6827

THE INTEGRATION OF RENEWABLE ENERGY SOURCES INTO ELECTRIC POWER TRANSMISSION SYSTEMS

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July 1995

Work sponsored by the
Office of Energy Management
U.S. Department of Energy

POWER SYSTEMS TECHNOLOGY PROGRAM

Prepared by the
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managed by
LOCKHEED MARTIN ENERGY SYSTEMS, INC.
for the
U.S. DEPARTMENT OF ENERGY
under contract DE-AC05-84OR21400

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ACRONYMS AND ABBREVIATIONS

APS	Arizona Public Service Company
AWEA	American Wind Energy Association
BPA	Bonneville Power Administration
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
EHV	extra-high voltage
EOR	East of the Colorado River
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
HVDC	high-voltage direct current
Hz	hertz
kWh	kilowatt-hour
LCRA	Lower Colorado River Authority
LRS	Laramie River Station
m	meter
MAPP	Mid-Continent Area Power Pool
min	minute
MJ	megajoule
MW	megawatt
MWa	average megawatt (= 8670 MWh)
MWh	megawatt-hour
NERC	North American Electric Reliability Council
ODOE	Oregon Department of Energy
OEM	Office of Energy Management
OMB	Office of Management and Budget
ORNL	Oak Ridge National Laboratory
PNUCC	Pacific Northwest Utilities Conference Committee
p.u.	per unit
PUD	public utility district
PV	photovoltaic
RAS	Reliability Assessment Subcommittee (NERC)
s	second
SCE	Southern California Edison
SEIA	Solar Energy Industries Association
SPP	Southwest Power Pool
SPS	Southwestern Public Service Company
TNP	Texas–New Mexico Power
TU	Texas Utilities Electric Company
V	volt
var	volt-ampere reactive (reactive power)
Western	Western Area Power Administration
WIND-REAP	Regional Energy Assessment Program (for wind power)

WSCC	Western Systems Coordinating Council
WT	wind turbine
WTU	West Texas Utilities
ZECO	Zaininger Engineering Company

FOREWORD

The Conference Report on the Energy and Water Development Appropriations Act, 1992 [H.R. Conf. Rep. 177, 102nd Cong., 1st Sess., at 56 (1991)] contains the following:

> The conferees agree with the Senate report language discussing a Department analysis of the need for transmission capacity.

The Senate Report on the Energy and Water Development Appropriations Act, 1992 [Sen. Rep. 80, 102nd Cong., 1st Sess., at 80 (1991)] contains the following:

> The Committee directs the Department to work with representatives of the solar and wind energy industries to develop an analysis of the need for transmission capacity, whether new or upgraded, to support the development of renewable energy resources. The Department should consult with the power marketing administrations in developing the plan. The Committee believes the Pacific Northwest Utilities Conference Committee Blackfeet Area Wind Integration Study primarily achieves the objectives of this provision for the Pacific Northwest.

The DOE Office of Energy Management (OEM), under the Assistant Secretary for Energy Efficiency and Renewable Energy, was given responsibility for this project. The case study assessments in this report provide an indication of the available transmission capacity in key resource areas and an estimated level of new or upgraded lines and apparatus required to support the development of relatively high-capacity renewable resources.

It is important to note that this work is not intended to serve as a detailed design study. Prior to actually integrating solar and wind systems into the power grid, extensive generation capacity expansion studies should be conducted to determine the adequacy of the transmission system.

ACKNOWLEDGMENTS

This research effort was sponsored by the Office of Energy Management of the U.S. Department of Energy (DOE) under contract DE-AC05-84OR21400 with Lockheed Martin Energy Systems, Inc., manager of the Oak Ridge National Laboratory (ORNL).

The authors wish to thank and acknowledge a number of organizations and individuals for their valuable assistance during the course of this research effort. We thank Bob Brewer and Phil Overholt of DOE; Jim VanCoevering of ORNL; Randall Swisher of the American Wind Energy Association; and Scott Sklar, Rick Sellers, and David Meakin of the Solar Energy Industries Association for their support and guidance in this effort.

This project could not have been accomplished without the assistance of the eight utilities that provided valuable data and participated in this work. These were the Arizona Public Service Company; the Bonneville Power Administration; the City of Tallahassee Electric Department, Tallahassee, Florida; the Lower Colorado River Authority; Southern California Edison; Southwestern Public Service Company; Texas Utilities Electric Company; and the Western Area Power Administration. Southern California Edison provided capacity and cost data that was used by the Zaininger Engineering Company in the Southern California case study. The utility data, assistance, and suggestions provided by these utilities and by the Zaininger Engineering Company are gratefully acknowledged.

EXECUTIVE SUMMARY

Assessments of the need for additional transmission capacity to develop renewable energy resources were requested by the Conference Report, H.R. 102-177, for the Energy and Water Development Appropriations Bill, 1992, Public Law 102-104. This report documents assessments of the capability of existing transmission systems to support the integration of wind and solar plants in specific renewable resource areas. The assessments evaluate existing transmission capacity and identify the need for new or upgraded transmission lines.

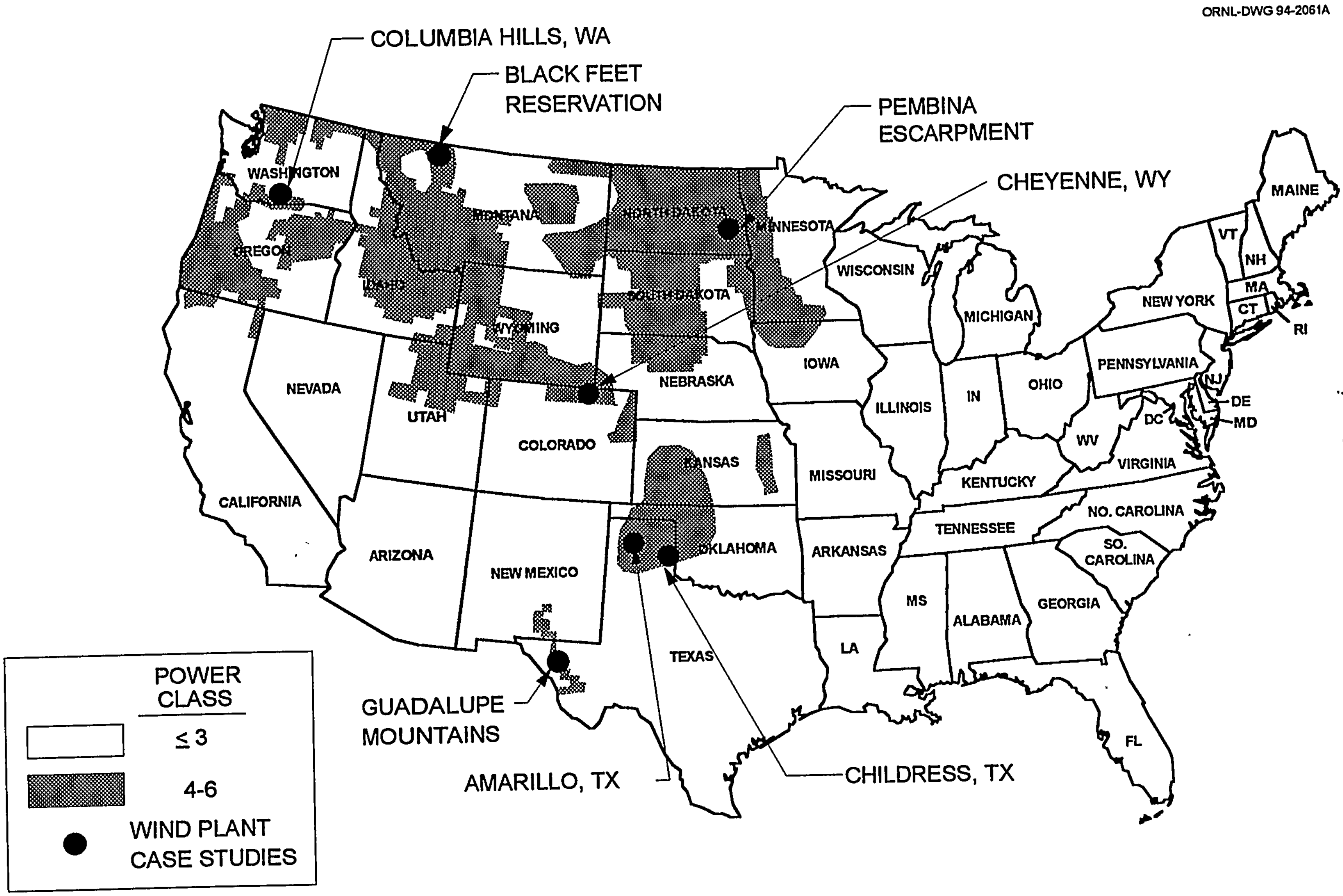
Over the 20-year period from 1990 to 2010, the Energy Information Administration (EIA) estimates that 172 GW of new generation capacity will be needed to meet the expected growing demand for electricity and to offset power plant retirements. Renewable energy generation will be considered in meeting this capacity growth. Renewable energy technologies such as photovoltaic (PV), solar thermal electric, and wind turbine (WT) are nonconventional, environmentally attractive sources of energy that can be considered for electric power generation.

Although many of the areas with abundant renewable energy resources (very sunny or windy areas) are located far from major load centers, electrical power can be transmitted over long distances of many hundreds of miles through high-voltage transmission lines. However, power transmission systems in many areas of the nation often operate near their limits with little excess capacity for new generation sources. Adding new transmission lines to develop renewable resources can significantly increase the capital costs of electric utilities.

The need for new or upgraded transmission lines to support the integration of wind and solar electric generation was evaluated by utility case studies in high-resource regions. The case study sites are shown in Figs. 1 and 2 for the wind and solar plants, respectively. Recommendations of these study sites were received from the American Wind Energy Association and the Solar Energy Industries Association. Electric utilities and companies that participated in the case studies included Arizona Public Service Company (APS); Bonneville Power Administration (BPA); the City of Tallahassee Electric Department, Tallahassee, Florida; the Lower Colorado River Authority (LCRA); Southern California Edison (SCE); Southwestern Public Service Company (SPS); Texas Utilities Electric Company (TU); and Western Area Power Administration (Western). SCE provided transmission capacity and cost data that were used by the Zaininger Engineering Company (ZECO) in the Southern California case study.

CASE STUDY RESULTS

The power capacity levels for renewable energy electric plants that can be integrated into the existing transmission systems were determined in the case studies. In selected case studies high-capacity plants and the required transmission system upgrades were considered. For the purpose of this study, "plant capacity" is defined as the actual power dispatched into the transmission system during the season or period of highest resource availability. The results from selected low-capacity wind and solar case studies are listed in Tables 1 and 2, respectively. For these cases little or no upgrade of the existing transmission systems is required.



NOTE: Not all wind resource areas are shown.

Fig. 1. Wind resource areas and the seven wind plant case study sites.

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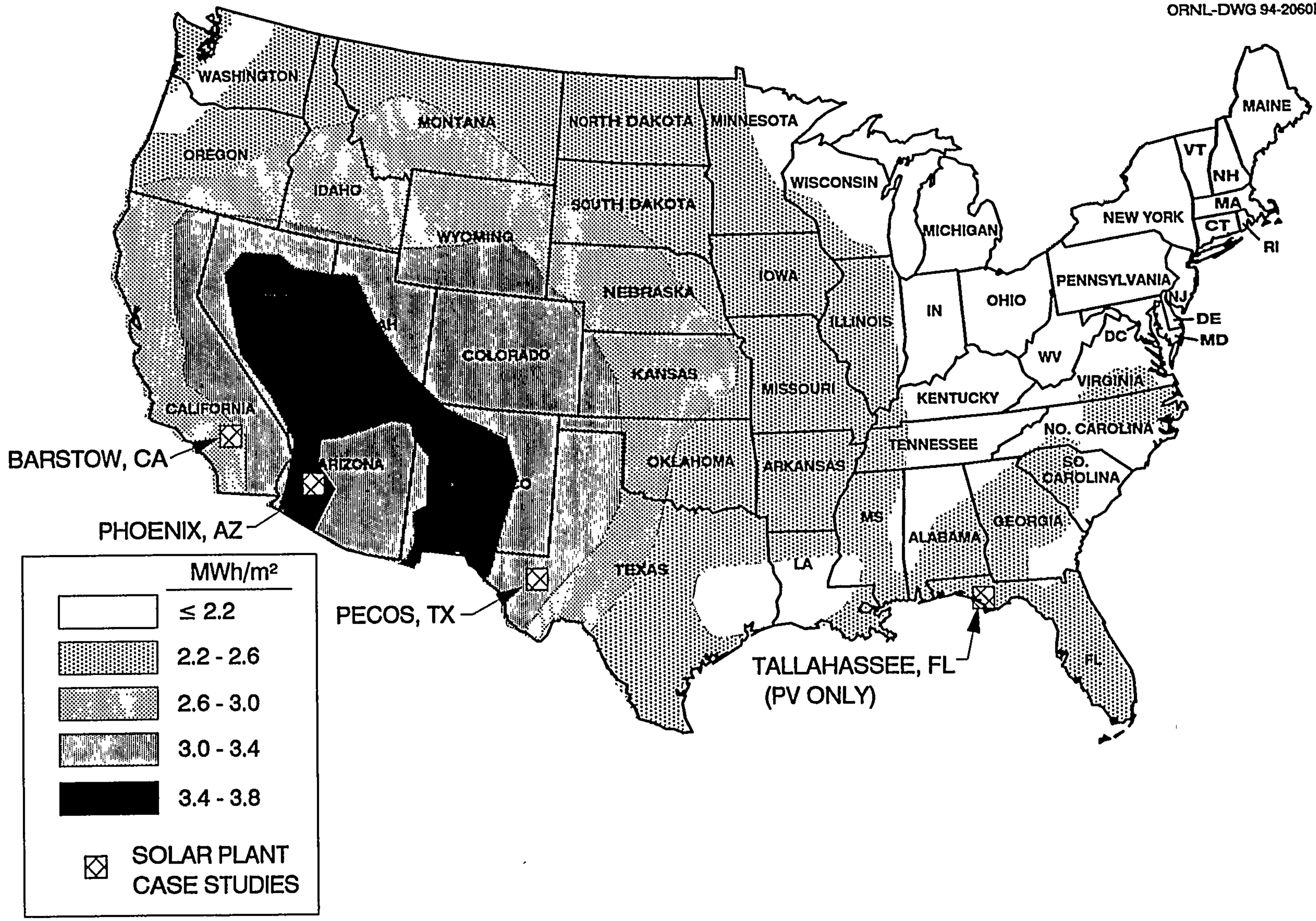

Fig. 2. Average annual solar radiation and the four solar plant case study sites.
Radiation data source for two-axis tracking: National Renewable Energy Laboratory.

Table 1. Summary of selected wind low-capacity case study results

Case study	Resource area	Preformed by	Capacity (MW)
Blackfeet Area[a]	Montana	Pacific Northwest Utilities Conference Committee	100
Western Region	Northeast Colorado and South Wyoming	Western Area Power Administration	50
Pembina Escarpment	Northeast North Dakota	ORNL and Western Area Power Administration	50
Columbia Hills	Columbia River Gorge in Washington	Bonneville Power Administration	50
Delaware	Delaware Mountain area in West Texas	Lower Colorado River Authority	50
Amarillo	Amarillo, Texas	Southwestern Public Service Company	100
Texas Panhandle	Texas Panhandle	Texas Utilities Electric Co.	50

[a]Study conducted by PNUCC.

Table 2. Summary of selected solar low-capacity case study results

Case study	Resource area	Preformed by	Capacity (MW)
Mojave Desert	Southern California	Zaininger Engineering and Southern California Edison	100
West Texas	Pecos, Texas area	Lower Colorado River Authority	100
Tallahassee	Florida Panhandle	City of Tallahassee	30
Phoenix Vicinity	Southwest Arizona	Arizona Public Service	100

For high-capacity plant integration, most cases would require extensive upgrade of the transmission system through the installation of new lines, replacing transformers, etc. Exceptions in this study are solar plants in the Southwest. A summary of the high-capacity cases is shown in Table 3. The cost estimates in Table 3 are the incremental transmission costs associated with the high-capacity plants.

Table 3. Summary of selected high-capacity wind and solar case study results

Case study	Resource	Capacity (MW)	Comments
Blackfeet area[a]	Wind	3000	Over 680 miles of new double-circuit 500-kV line required. Cost estimate: $1–1.4 billion
Pembina Escarpment	Wind	1000	Would require two new 300-mile 345-kV lines from the site to the Twin Cities area of Minnesota. Cost estimate: $472 million
West Texas	Solar	2000	Would require 680 miles of new 345-kV lines. Cost estimate: $328 million
Texas Panhandle	Wind	2000	Over 500 miles of new 345-kV line required. Cost estimate: $287 million
Mojave Desert	Solar	1500	Can be integrated into the existing system at little or no cost[b]
Phoenix vicinity	Solar	1000	Can be integrated into the existing system for load centers in Arizona; California load centers would require new lines

[a]Study conducted by PNUCC.
[b]Proposed sites are downstream of the major power-flow bottlenecks.

Although a comprehensive economic analysis was not part of this study, the added costs required to strengthen the transmission systems were estimated for some selected cases to provide an indication of the impact of this investment on the overall renewable energy production and delivery costs. To estimate the incremental levelized transmission costs, a real fixed charge rate of 9.6% and utility construction cost estimates from the case studies were used. The utility construction cost estimates were not developed from detailed assessments but are based on experience with similar lines, engineering judgment, and rules of thumb provided by utility transmission planning departments. Actual costs could vary by as much as 20%. Plant capacity factors of 30% for wind plants and 40% for solar central receiver plants were used to estimate the energy production. The 40% capacity factor for solar central receiver plants is a DOE design target. The annualized transmission cost estimates shown in Table 4 represent only the capital costs associated with the transmission upgrades; operation and maintenance costs and embedded costs (costs associated with using portions of the existing transmission system) are not included. The incremental transmission costs were calculated for a low load factor case, assuming that the renewable energy plant is the only user of the transmission line, as well as for an average load factor case.

Table 4. Estimated incremental transmission costs for selected mid- to high-capacity cases (1993 dollars)

			Incremental transmission cost[a] (¢/kWh)	
Case study	Plant/ capacity	Load center	Low load factor	Average load factor
Blackfeet area[b]	Wind/3000	Portland	1.7	0.8
Pembina Escarpment	Wind/1000	Minneapolis	1.7	0.8
West Texas	Solar/2000	Central Texas	0.4	0.3
Texas Panhandle	Wind/2000	Dallas	0.5	0.3
Mojave Desert	Solar/1500	LA basin	~0	~0
Phoenix vicinity	Solar/1000	Phoenix	~0	~0
Western Region	Wind/250	Denver	1.0	0.4
Delaware Mountain site	Wind/250	Odessa, TX	0.8	0.4
Columbia Hills	Wind/250	Portland	~0	~0

[a]The low load factor is the renewable energy plant capacity factor; the average load factor is 61%, the national average for 1992.
[b]The Blackfeet area costs are converted to 1993 costs from the costs provided in Chapter 4.

The real fixed charge rate of 9.6%[1] is based on a real interest rate of 7%[2] and a 30-year depreciation life plus 1.5% for insurance and retirement dispersion. This discount rate has been adjusted by the Office of Management and Budget (OMB) to include provision for earning a return to meet federal and local taxes that private businesses must pay as well as the cost of capital they pay for debt and equity. This is a real rate and therefore does not include a factor for inflation, which normally increases the fixed charge rates that utilities use to

1. P. R. Barnes et al., *The Feasibility of Replacing or Upgrading Utility Distribution Transformers During Routine Maintenance*, ORNL-6804, Oak Ridge National Laboratory, October 1994.

2. OMB Circular A-94, October 1992.

account for their levelized capital costs. Even so, the real fixed charge rate may be somewhat lower than the real rate a privately owned utility would use for its assessment, based on current costs of capital and taxes. For instance, a calculation by PERI/NREL indicates a range for real fixed charge rates of 10.2 to 10.9%.[3] Using these slightly higher real fixed charge rates would increase the transmission capital costs in Table 4 by 6 to 14%. Including inflation of about 4% would result in a nominal fixed charge rate (based on 9.6% real fixed charge rate) of about 13 to 14%. Using a nominal fixed charge rate of 14% would increase the transmission capital costs in Table 4 by about 46%. A nominal fixed charge rate includes inflation and reflects costs in terms of current dollars (dollars that tend to decline in future purchasing power because of inflation). The real fixed charged rate used in Table 4 reflects costs in terms of constant purchasing value of a dollar across time.

SUMMARY AND CONCLUSIONS

Eleven case studies, including the Blackfeet area wind integration study, have examined the transmission requirements for interconnecting renewable-energy electric generation plants into regional power transmission systems. These studies have been summarized and documented in this report. Each case study considered at least two sites located in high- to moderate-resource regions. Seven of the case studies were conducted for wind plants; three of the wind plant studies evaluated high-capacity (1000-MW or greater) cases. There were four solar plant case studies; three of the solar plant studies included high-capacity cases.

The case studies focused on whether integration of renewable resources would require upgrade or expansion of the existing transmission system. In addition, a preliminary estimate of cost for construction of the required transmission facilities was developed for selected cases. All studies are based on analysis methods and transmission technologies currently in use by U.S. utilities.

Issues that may affect the viability of the renewable energy generation options were identified but not explored in the case studies. For instance, obtaining adequate land use rights is an important constraining issue in development of generating plants of all types, as well as transmission systems, and is not unique to renewable facilities. Other issues not explored are those related to transmission access and pricing for delivery of power to the indicated load centers. In general, dispatchability of renewable generation, spinning reserve requirements, and regulation of output during resource fluctuations were also not addressed in detail.

High-potential renewable resource concentrations tend to be located far from major load centers in sparsely populated areas. The economics of scale and access to the resource favor siting of generating plants in these areas, but transmission capacity is needed to deliver the output to the load center. In this regard, high-capacity, remote, renewable generation is not greatly different from such conventional generation options as mine-mouth coal plants or hydroelectric generation, both of which are constrained as to siting by the resource location.

These studies define a maximum transfer capability for the system under certain specified conditions. Once constructed, the portion of maximum transfer capability which is actually available at any given time varies with load and generation dispatch, as well as with the status of voltage control equipment such as reactors and capacitors. Advanced

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3. Personal communication, Wind Energy Program, U.S. Department of Energy, December 21, 1994.

technologies, such as flexible ac transmission (FACTS) power controllers, real-time control systems, and fast-acting energy storage technologies (batteries and superconducting magnetic energy storage, or SMES) will alleviate some transmission system constraints without construction of new transmission lines. Advanced, low-cost converter station technologies for high-voltage dc transmission will make less expensive transmission options available. These technologies will affect the future availability of transmission but are currently in the development stage and were not considered in these analyses.

In general, the results of the case studies indicate that it appears possible to integrate renewable resources on the order of 25 to 50 MW to supply local load without significant upgrades to the transmission grid. For renewable resources up to about 100 MW, minor system upgrades are needed, with a cost of about $20/kW. An exception to this observation exists for the case of southern California, where the transmission grid is designed for imports of power from the Pacific Northwest and Arizona. Accordingly, the transmission congestion points are located well north of Los Angeles and at the Colorado River on the Arizona-California border. For this reason, renewable energy resources up to 1500 MW can be integrated into the existing system without significant upgrades.

Other case studies indicate that significant transmission upgrades will be required to integrate any new large-scale generation addition, including renewables. This is due either to the complete lack of transmission facilities of the required capacity, as in the case of central and west Texas, or the fact that power flows from the renewable resource to the preferred load center add to existing transmission congestion, as in the Pembina Escarpment area of North Dakota and Minnesota. Based on analyses contained in this report, high-capacity plants in many areas can be expected to require new lines or major upgrades to the transmission system at upgrade costs on the order of $125 to $472/kW. The construction costs equate to an additional levelized cost for the use of the resource ranging from 0.5 to 1.8 cents/kWh.

These case studies have identified opportunities for development of renewable electric generation within the constraints of existing transmission capacity in amounts between 25 and 100 MW in all of the regions examined. Availability of transmission capacity for high-output plants is much more location-specific, and with some exceptions, significant development will normally require considerable investment in transmission facilities.

RECOMMENDATIONS

Prior to actual development of solar and wind systems for grid integration, extensive studies of the expansion of site and resource-specific generation capacity should be conducted to determine the adequacy of the transmission system for the anticipated direction and magnitude of power transfers.

Changes in calculating the required regulating margin will need to be assessed before renewable generation can be operated in a routine manner at penetration levels above approximately 10% of the total generation for any given control area. Renewable generation will become more valuable as it becomes more controllable and dispatchable. To this end, development of such technologies as advanced control systems capable of dispatching large numbers of individual generators to maintain a preset output level, as well as storage systems capable of decoupling resource availability and energy supply, should be undertaken. Special operating and dispatch strategies for intermittent generation such as renewable energy plants should be examined as part of a detailed design study.

ABSTRACT

Renewable energy technologies such as photovoltaics, solar thermal power plants, and wind turbines are nonconventional, environmentally attractive sources of energy that can be considered for electric power generation. Many of the areas with abundant renewable energy resources (very sunny or windy areas) are far removed from major load centers. Although electrical power can be transmitted over long distances of many hundreds of miles through high-voltage transmission lines, power transmission systems often operate near their limits with little excess capacity for new generation sources. This study assesses the available capacity of transmission systems in designated abundant renewable energy resource regions and identifies the requirements for high-capacity plant integration in selected cases. In general, about 50 MW of power from renewable sources can be integrated into existing transmission systems to supply local loads without transmission upgrades beyond the construction of a substation to connect to the grid. Except in the Southwest, significant investment to strengthen transmission systems will be required to support the development of high-capacity renewable sources of 1000 MW or greater in areas remote from major load centers. Cost estimates for new transmission facilities to integrate and dispatch some of these high-capacity renewable sources ranged from several million dollars to approximately one billion dollars, with the latter figure an increase in total investment of 35%, assuming that the renewable source is the only user of the transmission facility.

1. INTRODUCTION

1.1 BACKGROUND

Assessments of the need for transmission capacity to develop potential renewable energy resources were requested by the Conference Report, H.R. 102-177, to the Energy and Water Development Appropriations Bill of 1992 (Public Law 102-104).

Over the 20-year period from 1990 to 2010, 172 GW of projected new capacity will be needed to meet the growing demand for electricity and to offset power plant retirements.[1] Renewable energy generation will be considered in meeting this capacity growth. Renewable energy technologies such as photovoltaic (PV), solar thermal electricity, and wind turbine (WT) are nonconventional, environmentally attractive sources of energy that can be considered for electric power generation. Many of the areas with abundant renewable energy resources (very sunny or windy areas) are far removed from major load centers. Electrical power can be transmitted over long distances of many hundreds of miles through high-voltage transmission lines. Unfortunately, power transmission systems in many areas of the nation often operate near their limits with little excess capacity for new generation sources. The addition of a new line to develop the renewable resource can significantly increase the capital cost; the cost of a new high-voltage line typically ranges from about $500,000 to $1,000,000 per mile, depending on voltage and terrain.

1.2 PURPOSE AND APPROACH

The purpose of this project is to assess through case studies the capability of existing transmission systems to support the integration of renewable resources. The existing transmission capacity affecting that capability and the identification of the need for new or upgraded transmission lines to support the integration of wind and solar electric generation were evaluated by utility case studies in high resource regions. The resource regions and generation output levels for the case studies were determined with the assistance of the American Wind Energy Association (AWEA) and the Solar Energy Industries Association (SEIA). Some utilities involved in the case studies are presently working with solar and wind plant vendors. Two power marketing adminstrations, BPA and the Western Area Power Administration (Western), participated in the study and provided initial planning guidance.

The case studies involved low-capacity cases that can generally be accommodated by the existing systems and by the systems as planned in the near future—i.e., over approximately the next 10 years. For the existing configuration of the transmission system and available data on resource location, points of interconnection were identified in coordination with the host utility for resources of differing sizes. Some case studies also considered high-capacity cases; some of these cases require significant transmission system upgrades to accommodate the high power levels.

1.3 SCOPE AND CONTENT

Integration issues that were studied included evaluation of existing transmission capacity and operating procedures affecting that capacity and identification of the need for new or upgraded transmission lines. Where significant transmission system upgrades were required, preliminary estimates of the probable range of construction costs were provided. To put these construction cost ranges in context, an equivalent annualized cost adder for the resource in cents per kilowatt-hour was provided. The subtransmission and transmission system associated with collecting the power from the renewable sources was not considered in this study, since it is a part of the power plant. Wheeling, siting, and transmission access issues for these case studies were not analyzed in this report. Detailed economic analyses of renewable energy electric generation plants are far beyond the scope of this project.

In Section 2, the technical aspects associated with transmission capacity and generation expansion studies are discussed. Sections 3 through 14 describe the case studies; in some of these studies both a low-capacity case of 100 MW or less and a high-capacity case of more than 100 MW were considered. A summary and conclusions are presented in Section 15.

2. GENERATION EXPANSION STUDIES

The transmission requirements for the integration of wind/solar energy resources are dictated by well-established utility expansion planning criteria. These criteria emphasize the necessity for high reliability in the extensively interconnected ac transmission systems that are characteristic of the modern electric power system. Section 2.1 discusses transmission capacity and expansion planning. Section 2.2 provides a perspective on the origins of the utility industry's focus on reliability, and why it is important. Section 2.3 describes the primary analytical tools and typical expansion planning design criteria. An overview of the expansion planning process is given in Sect. 2.4. Finally, the approach taken in this study to determine the transmission requirements for wind/solar generation is explained.

2.1 TRANSMISSION CAPACITY AND EXPANSION PLANNING

High-potential renewable resource concentrations tend to be located far from major load centers in sparsely populated areas. The economics of scale and access to the resource favor siting of generating plants in these areas, but transmission capacity is needed to deliver the output to the load center. In this regard, high-capacity, remote, renewable generation is not greatly different from such conventional generation options as mine-mouth coal plants or hydroelectric generation, both of which are constrained as to siting by the resource location.

Existing transmission systems in remote areas fall into two classes—high-voltage bulk transmission and local service transmission. High-voltage bulk transmission lines from base load generators may cross a remote area on the way to a load center. Such transmission is sized to meet the requirements of the resource for which it was constructed and is therefore often operated near its design limits. Local transmission lines are sized to serve local load and may be of limited capacity in relation to the size of a proposed generation resource.

Transmission expansion planning is a complex but procedurally well-developed engineering task that is supported by sophisticated analytical tools and well-established acceptability criteria. Transmission planning is concerned principally with providing adequate system capacity to prevent cascading system outages in the event of the sudden loss of the most important system element. Cascading is defined as the loss of electric service to customers not directly affected by the failed facility; it may be the result of overloads of other system elements or of instability of generating units caused by the disturbance. Studies are usually based on transmission loadings at the time of system peak load, although instability and voltage control can cause problems during outages under light loads, and light load performance must be verified in any detailed system study. These studies define a maximum transfer capability for the system under certain specified conditions. Once constructed, transmission systems operate in a continuum of changing system conditions, and transmission capacity is not a single number. The portion of maximum transfer capability actually available at any given time varies with load and generation dispatch, as well as with the status of voltage control equipment such as reactors and capacitors. Nomograms, developed from a large number of operating studies, relate system load and other factors to usable transmission capacity.

Transmission systems were originally developed as radial systems delivering power from a single generation resource to a given load. With time, the addition of other generators, and the overlay of more transmission lines, networks were formed. These networks currently appear to go everywhere. In reality, transmission system performance is still very dependent on the location and output of the generators in relation to the load to be served, and therefore, preferred flow directions and loading patterns develop. In this regard, a transmission system is much like an urban highway system with its traffic patterns governed by the location and size of residential subdivisions in relation to preferred work locations. The capacity of a highway system is determined largely by traffic congestion at a few intersections during rush hour, and while any increase in traffic through the congested area will geometrically increase delay, traffic at other locations or in other directions moves fairly freely. Such is the case with transmission systems. Transmission capacity limits are the result of "congestion" at a few critical facilities resulting from a particular generation pattern or load pattern. Any effort to move additional power in a critical direction will result in further system performance degradation and unacceptable reliability. As with highways, increasing capacity at a congested transmission intersection is neither easy nor cheap, and, continuing the highway analogy, it behooves developers to locate new resources in ways that do not add to the existing transmission congestion, to avoid the need for significant upgrades. This can be done by siting and sizing facilities such that they do not exceed local load, or by siting facilities in relation to the intended load centers such that the resulting power flows are counter to otherwise occurring flows and do not add to transmission congestion.

Given the nature of the interconnected network, determining the dimensions of "local load," or figuring out what truly is "counterflow," is a nontrivial process requiring detailed study for each site-specific situation. In general, the results of the case studies indicate that it appears possible to integrate renewable resources on the order of 25 to 50 MW to supply local load without significant upgrades to the transmission grid. With minor upgrades to the systems, resources up to about 100 MW can be integrated, for an upgrade cost on the order of $20/kW of renewable resource. There are exceptions to this observation. For instance, in southern California, the transmission grid is designed for imports of power from the Pacific Northwest and Arizona. Accordingly, the transmission congestion points are located well north of Los Angeles and at the Colorado River on the Arizona/California border. This means that the term "local load" encompasses most of the Los Angeles and San Diego area loads and that very large renewable resource plants in the Mojave Desert dispatching power west and south would still be serving "local load" as far as the transmission system is concerned. Such plants could be accommodated without major transmission upgrades. An example of counterflow design is the analysis of integrating large solar plants in western Arizona. The transmission system between Arizona and California is loaded in the westward direction, and any attempt to dispatch renewable resource power from Arizona to California would incur large transmission investment costs. However, a renewable resource located in western Arizona could serve loads to the east, principally Phoenix, with little transmission investment, since the output is dispatched counter to the prevailing flows.

2.2 THE EMPHASIS ON RELIABILITY IN EXPANSION PLANNING

One of the most profound changes in the 100-year history of the electric utility industry is the rapid evolution of highly interconnected systems. During the first 60 years of the industry, utilities were isolated systems serving limited geographical areas with solely local resources. Beginning about 40 years ago, coincident with the development of automated generation control, utilities began interconnecting neighboring systems to improve reliability and economics. Interconnection of neighboring utilities allows excess on-line generation capacity to be shared during an emergency condition such as the sudden failure of a large generating unit. This enables each utility in the interconnection to meet a given service reliability target with less surplus generation facilities than would be required if the utility were isolated. In addition, interconnection allows economy energy exchanges between utilities to exploit diversity in generation cost. The reliability and economic benefits of interconnected operation are so substantial that isolated utility systems have all but disappeared. Today there are four major regions or interconnections that serve virtually all of North America that are not operated as interconnected regions. These are known as the Eastern, Western, Texas, and Quebec Interconnections, as shown in Fig. 2.1. Further ac interconnection between these regions is not presently practical due to the massive capacity of tie lines that would be required to maintain synchronous operation between East Coast and West Coast generators. However, dc interties between the major interconnections are possible and are being developed to extend the benefits of interconnected operation still further.

Utilities quickly realized that in order for all utilities to reap the economic benefits of interconnection, each member utility would have to provide its fair share of resources to ensure the reliable operation of the interconnection. In essence the industry endorsed a basic premise that in any conflict between economics and reliability, reliability would have to come first. In 1968 the industry formed the North American Electric Reliability Council (NERC) to promote the reliability of its generation and transmission systems. NERC is divided into nine regional reliability councils and one affiliate, as shown in Fig. 2.2. NERC has extensively studied the interconnected utility structure and has developed guidelines for utilities to aid in planning and operating interconnected systems. In 1970 NERC created the Interregional Review Subcommittee, now called the Reliability Assessment Subcommittee (RAS), to continuously examine the reliability of the existing and planned generation and transmission systems of the nine regional reliability councils. On an annual basis the NERC subcommittee publishes a reliability assessment projecting the adequacy of generation and transmission 10 years into the future. The report is based on utility expansion plans provided through the regional reliability councils. Although compliance with NERC guidelines is voluntary, the individual utilities have been very responsive in adapting NERC guidelines into their planning and operating procedures.

In evaluating and incorporating renewable energy sources into their expansion plans, utilities will use their established principles and procedures. Specifically, wind and solar generation resources will be studied along with any additional transmission resources that may be required to preserve the reliable operation of the interconnection. New generation resources, no matter how economically attractive, cannot be separated from concomitant transmission requirements for two major reasons. First, all facilities within an interconnection operate synchronously—that is, at a single electrical frequency (60 Hz). This means that generators run at a common electrical speed. Generators that fall out of step, which can happen when the transmission system is too weak, can experience catastrophic failure or cause major damage to other components if they are not removed from the system. Secondly, the ac transmission network does not permit guaranteed point-to-point power transmission. Electricity will flow from sources to loads following all available paths, not just along the line or lines which constitute the most direct path. The dispatch of power at a new generating site may cause overload on a nearby line or even on a line that is geographically remote from the generating site. Removal of an overloaded line to avoid damage to the line weakens the transmission system and increases the possibility of further component outages. Therefore, when such overloads are encountered, projected, or anticipated from system studies, either the affected lines must be upgraded, or the power dispatched by the new source must be limited.

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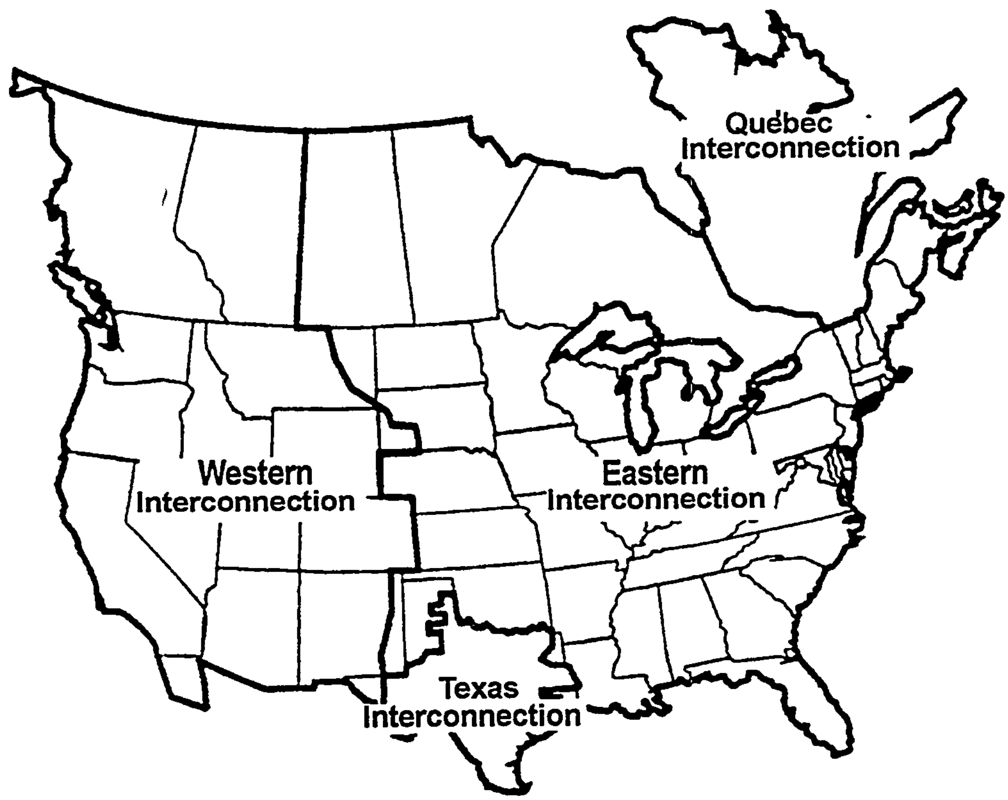

Fig. 2.1. Major interconnections in North America. Reproduced, by permission, from North American Electric Reliability Council, 1991.

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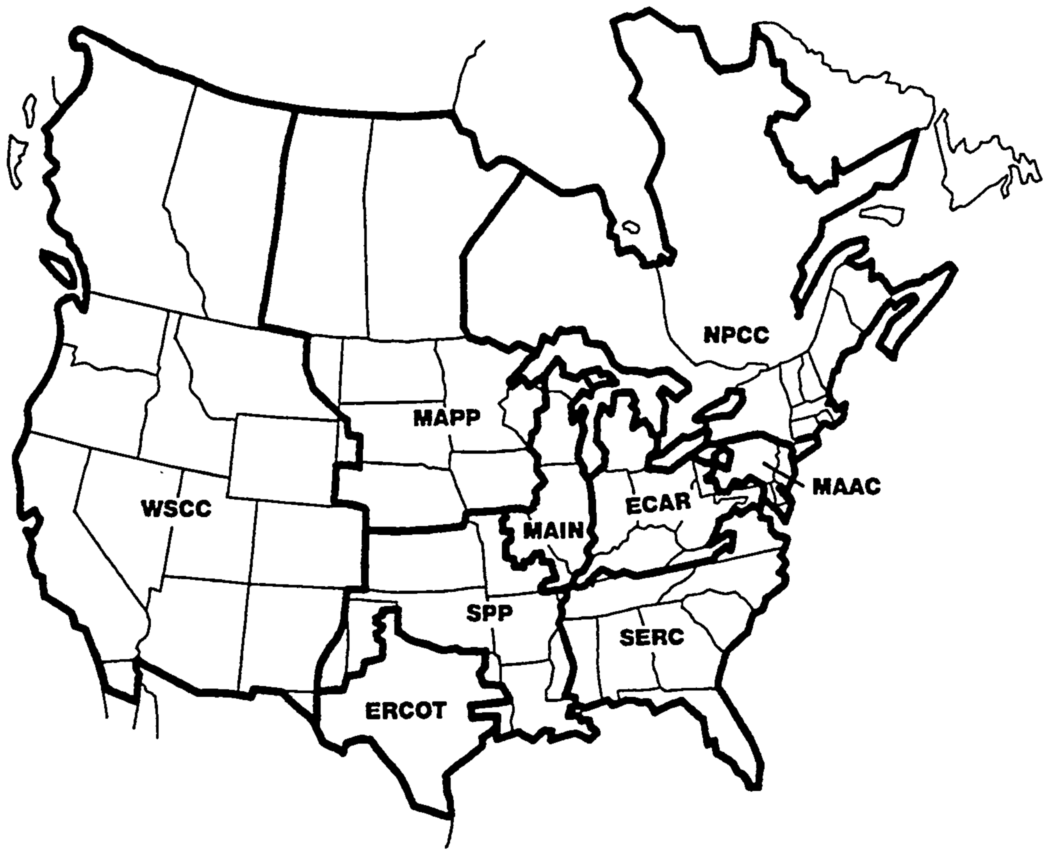

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

Fig.2.2. Makeup of the North America Electric Reliability Council. Reproduced, by permission, from North America Electric Reliability Council, *Reliability Assessment, 1994-2003: The Reliability of Bulk Electric Systems in North America,* September 1994.

2.3 ANALYTICAL TOOLS AND EXPANSION PLANNING CRITERIA

Electric utility generation expansion planning is a highly complex but mature engineering design process. The goal of the process is to schedule and site adequate generation and transmission facility additions to ensure that the future electric system operates reliably and at the lowest reasonable cost. Expansion planning is driven by proven design criteria which have evolved over many decades and are continuously reviewed and refined by NERC, the various regional reliability councils of NERC, and individual utilities. Planning studies are supported by several sophisticated analytical tools which accurately model the electric systems behavior. Several of the most common analytical tools are described below along with a typical set of design criteria.

2.3.1 Analytical Tools Used in Expansion Planning

Utility expansion planners are supported by detailed system databases and sophisticated computer programs which simulate system behavior. Some key analytical tools are computer programs called the power flow (or load flow), short circuit (or fault), transient stability, and production cost models. Each of these tools is briefly described below.

2.3.1.1 Power flow program

A power flow program is the basic analysis tool for electric utility engineers. Inputs to this program include a model of the transmission network, a specification of the location and magnitudes of customer loads, and a specification of the outputs of the various system generators. The program then calculates the voltage magnitude and phase angle at each bus in the system and the power flow associated with each transformer and line. Using this program the utility engineer can identify situations where unacceptably high or low voltages occur and where overloading of system components is experienced.

The power flow is used as a planning tool by specifying the load to be expected in future years and by adding new generation and transmission lines as necessary to keep voltage levels and component power flows within equipment rating levels. The power flow can also be used to study reliability. The deletion of any one system component (a single line or transformer, for example) is called an N-1 contingency. Removing the selected component from the system model and resolving the power flow allows the engineer to determine whether or not the system will still function satisfactorily following an unexpected equipment outage. Deleting two components from the system model, a so-called N-2 contingency, allows the engineer to study system performance following an even more serious equipment outage.

2.3.1.2 Short circuit program

Short circuits or faults are routine occurrences in most electric utility systems. Faults may be caused by lightning strokes, insulator failure, small animals, trees falling on transmission lines, conductor gallop initiated by the wind, or any number of other events. When faults occur, one or more conductors are shorted together and/or to the earth, and extremely large currents can flow into the fault. Such currents are typically so large that they would seriously damage power equipment and perhaps customer equipment if they were allowed to persist. Removing faults from the system is the task of the protection system, which includes circuit breakers, reclosers, sectionalizers and fuses. A short circuit program includes a model of the electric system and can calculate the voltages and currents that flow in the system when one or more system locations is subject to a fault. Typically the short circuit program results are used to specify the protection equipment ratings necessary to protect the system from damage.

2.3.1.3 Transient stability program

System disturbances, such as faults, line outages, sudden generator shutdowns, and sudden changes in load cause generator rotors to experience acceleration (or deceleration, depending on the circumstances). If all generators do not experience similar acceleration, one or more generators may lose synchronism with the remainder of the system. The stronger the transmission system the more likely it is that all generators will experience the same or nearly the same acceleration. Generators which fall out of step with the rest of the system must be taken off line, returned to the proper speed, and then resynchronized. The resynchronization period may require hours for large power plants, and during this interval the system loses the output of the generator. The system is weakened by this loss and vulnerable to additional outages that could cascade into a major blackout. Loss of generator synchronism is therefore a serious matter during utility operations. A transient stability program calculates the response of the system's generators to any specified disturbance. Using the program the utility engineer can determine whether or not all machines remain synchronous following the disturbance. When all generators remain synchronized, the system is said to be stable.

Planning engineers use the transient stability program to study the stability of the future electric system following disturbances. When instabilities are observed, the engineer may find transmission upgrades or changes in operating policy (such as limiting the output of a given generator) which render the system stable.

2.3.1.4 Production cost program

A production cost program is an economic model of the utility's generation operation. Typically the program time interval is on an hourly basis. The program includes the functions of unit commitment and economic dispatch.

Unit commitment refers to selecting from the available generation and transmission resources a subset that is capable of reliably and economically meeting the anticipated load on a given day. Equipment down for scheduled maintenance or on forced outage is not considered available for service. The selected generation equipment must have capacity sufficient to meet the anticipated peak load plus an additional amount called spinning reserve. The spinning reserve accounts for uncertainty in the predicted peak demand, and accounts for equipment outages, such as the loss of the largest generating unit. The selected generation must also have sufficient aggregate ramp rate (the ability to change output level over a short time period) to follow short-term variations in the load. When wind/solar generation is included, the utility may add additional spinning reserve to account for the intermittent nature of the wind/solar resource. It may also be necessary to increase the ramp rate requirement unless the wind/solar array output is under some form of regulation.

Economic dispatch is a well-known optimization procedure which allocates load to the various generating units so as to minimize cost.

A production cost simulation may be run for 10 or more years into the future using predicted future loads and accounting for scheduled generation additions. The output of a production cost simulation is the hour-by-hour cost of energy production for a given expansion scenario.

2.3.2 Design Criteria Used in Expansion Planning

The criteria below are used by one particular utility in the western United States. Criteria used by other utilities are similar but not necessarily identical.

For the example utility, power-flow, stability, and short circuit studies are conducted to evaluate system performance using the following criteria:

I. Power-flow studies
   A. Normal system conditions (long-term operation)
      1. Facility loading limits
         a) Lines should not exceed 100% of continuous seasonal rating or the established equipment or operating limits, as applicable.
         b) Transformers should not exceed highest nameplate rating or present rating consistent with installed cooling.
         c) Series capacitors should not exceed 100% of continuous ratings.
         d) Switching of reactive control devices (i.e., reactor or capacitor banks), as a general rule, shall not result in a bus voltage change of more than 0.03 per unit (p.u.).*
      2. Voltage levels
         Transmission bus voltages will be maintained between 0.95 p.u. and 1.05 p.u. of normal system voltage.
      3. Reactive power conditions
         Power factor criteria for customers' loads are set at 0.95 leading to 0.95 lagging. Reactive capabilities will be adequate for the requirements of the transmission system and contract obligations to customers. Interchange of reactive power at interconnections with other utilities should be kept to a minimum, unless other conditions are agreed to as being mutually advantageous to both parties.
   B. Post-fault system (no manual adjustment, short-term operation)
      1. Facility loading limits
         a) Lines not to exceed continuous seasonal rating or established emergency rating, as applicable.
         b) Transformers not to exceed emergency rating.
         c) Series capacitors not to exceed emergency rating.
      2. Voltage levels
         Transmission bus voltage levels will be maintained between 0.90 p.u. and 1.10 p.u. of normal system voltage. For operating studies voltages between 0.85 p.u. and 0.90 p.u. may in certain cases be acceptable.
      3. System adjustments
         No system adjustments other than automatic adjustments will be represented (no manual system adjustments such as shunt capacitor, reactor switching,

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* Per unit (p.u.) is defined as the ratio of a quantity to its base value. For example, 241.5 kV to a base value of 230 kV is 1.05 p.u.

generator rescheduling, voltage regulator, or phase-shifting transformer set point adjustments). Operator-initiated adjustments are not represented in the studies.

C. Post-recovery system (system manually adjusted for intermediate-term operation)
   1. Facility loading limits
      a) Lines not to exceed 100% continuous seasonal rating or the established equipment or operating limits, as applicable.
      b) Transformers not to exceed the continuous rating or operating limit, as applicable.
      c) Series capacitors not to exceed continuous rating.
   2. Voltage levels
      Transmission voltage levels will be maintained between 0.95 p.u. and 1.05 p.u. For operating studies, voltages between 0.90 p.u. and 0.95 p.u. may be acceptable in certain cases.
   3. System adjustments
      In addition to automatic system adjustment allowed for the postdisturbance case, manual system adjustments may be made for the postrecovery phase. These adjustments can include reactive device switching, adjustments of set points for load tap changing transformers, adjustments of set points for phase shifting transformers rescheduling of interarea transfers, corrective sectionalizing on the high voltage system, and dropping nonfirm load. The dropping of firm load and the use of low-voltage customer networks to shift load are not allowable adjustments.

II. Stability studies
   A. Fault simulation
      The system is tested to determine the critical (i.e., most severe) faults for the load/generation pattern under study. The system must be able to withstand permanent three-phase faults on any line, bus, or transformer with normal clearing, and it must be able to withstand a permanent single-line-to-ground fault on any line, bus, or transformer with delayed clearing due to breaker failure.
   B. Stability analysis
      All machines maintain synchronism as demonstrated by the relative rotor angles. The system should be well damped, with positive damping showing on all plots of all parameters monitored. Major transmission bus voltages should not drop below 0.70 p.u. at any bus in the system following fault clearing. No relaying should occur other than that required to clear the fault or initiate planned remedial actions.
   C. Remedial actions
      1. Hydro generation may be dropped for either an N-1 (single contingency) or N-2 (double contingency) disturbance.
      2. System islanding schemes are used for N-2 disturbances where appropriate.
      3. Automatic switching of reactive devices may be used for all disturbances.

III. Conditions studied
   Periodic evaluation is to be conducted to determine the need for facility additions, proper operating conditions, and the effects of facilities planned by neighboring systems. Facility addition studies are conducted for the period immediately before the facility is added, the period just after the addition of the facility and then at a period in the future to determine compatibility with future system development. The system is studied under projected summer or winter peak load conditions as appropriate and under off–peak load

conditions to determine reactive requirements, transfer capabilities, and/or the most severe stability conditions. Often a transmission system will be operating with all its components severely stressed during the time of day and season that requires maximum generation to meet load demands. The behavior of a transmission system for one or more simulated peak load periods is to be analyzed. However, some systems may have certain portions more highly stressed at times other than the time of peak system load due to the generation pattern involved. This should be evaluated also. The system may also be studied under various generation patterns to determine the effects of extreme hydro conditions or other factors affecting generation patterns.

Normal outages studied include loss of any single system element (line, transformer, generator, load, etc.). A lesser number of cases are run assuming multiple outages to determine if remedial actions of any type should be implemented for credible severe disturbances.

Typical power-flow analysis consists of establishing a benchmark (typically the present system design) and running outage studies. Then alternative cases are put together (system plus expansion facilities), and the same set of outages are run again. Comparison of the results of the alternatives the benchmark allows the effectiveness of the various alternatives to be gaged. The alternatives must remain within applicable reliability criteria.

The outcome of a utility expansion planning study with wind/solar sources will be both resource-site specific and utility specific. Utility-specific factors will include proximity of the renewable source to a suitable point of connection to the transmission system and the present capacity of the transmission system. A utility with existing and planned transmission facilities already near the minimum level required to support reliability will need more transmission upgrade to support new sources than a utility with abundant transmission capacity.

It may often happen that attractive renewable generation resources such as wind and solar lie in sparsely populated regions. The transmission systems in such areas are typically low voltage, such as 69, 115, or 230 kV, since they were originally designed solely to serve light local loads. Transmission capacity increases as the square of the transmission voltage, and consequently the proximity of renewable resources to low-voltage transmission circuits may limit the allowable penetration of the resource unless the transmission system is to be upgraded, inasmuch as, by design, portions of the transmission corridors that lead from the remote renewable resource to a large load center are too weak to support significant quantities of power delivery.

2.4 UTILITY EXPANSION PLANNING

The utility expansion planning process has four basic steps: (1) load forecasting, (2) developing a set of generation alternatives, (3) determining transmission requirements, and (4) economic analysis. An explanation of these steps is given below.

2.4.1 Load Forecasting

A load forecast is developed which projects new loads as well as load growth. The forecast is prepared using historical load data, knowledge of economic development in the service region, and long-range weather trends. The forecast time horizon may be 5 to 10 years into the future. Typically only the peak power demand and annual energy usage are predicted. Figure 2.3 is an example of a peak load demand forecast prepared by NERC. The projected load is then compared to the generating capacity of existing and planned additions less scheduled retirements, with adjustment for forced outages and scheduled maintenance (typically an availability factor on the order of 75% may be used). New capacity must be in place before the projected load exceeds the available generation.

Uncertainty in the load forecast may be accounted for using confidence bands. Prior to 1970 electric load growth was highly predictable, doubling approximately every 10 years (roughly 7% annually). In recent years, load growth in the United States has slowed to about 2% annually but with more uncertainty. This has caused utilities to look toward more frequent expansion involving smaller facilities with short construction lead times.

2.4.2 Generation Alternatives

The load forecast reveals the extent of peak capacity and energy deficiencies. In this step the type, size, and timing of new generation resources is determined. Typically the planner selects several generation alternatives, each of which meets the projected load. These alternatives will be subjected to a detailed economic assessment to determine what mix of generating types (coal, gas, oil, wind/solar, etc.) is best.

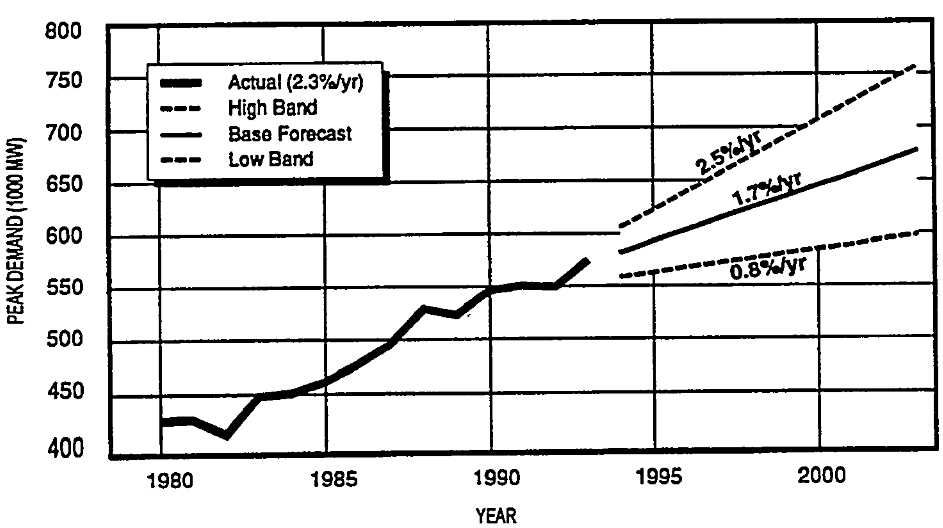

Fig. 2.3. U.S. summer peak demand forecast, 1992–2003. Reproduced, by permission, from North American Electric Reliability Council, *Reliability Assessment, 1994–2003: The Reliability of Bulk Electric Systems in North America*, September 1994.

2.4.3 Transmission System Planning

For each generation planning alternative defined, a transmission system necessary to support system reliability is designed. There may be more than one transmission plan that meets the reliability requirements, and if so, additional economic assessment is conducted to select the most attractive design. This step involves significant engineering analysis. Power flow studies are performed to ensure that the system load is served and no component is overloaded during normal operation, that the load is served, and that all components will be operated within their emergency ratings following any first contingency (the forced outage of a single line or generating facility). When component overloads are discovered, the expansion plan must add additional transmission capacity to eliminate the overload. The power flow program is a static analysis which presumes that all generators are operating synchronously. The synchronous stability of generators is checked using a transient stability program which calculates the response of the generator rotor dynamics to disturbances. Typically generator synchronism must be maintained by all generators following a three-phase fault that is cleared normally, and for any single line to ground fault with primary breaker failure (stuck breaker) and ultimate clearing by backup breaker. When generator synchronism problems are discovered, they must be eliminated by adding more transmission capacity or by limiting the load placed on the affected generator(s).

2.4.4 Economic Evaluation of Alternatives

The generation and transmission alternatives are analyzed for production and capital cost. Production cost may be calculated using a computer simulation of the utility's operation. In the simulation the utility's unit commitment is applied on a daily basis and the economic dispatch algorithm is applied to forecasted hourly demand over a simulation period of 10 or more years.

Unit commitment refers to the selection from among the facilities available for service a subset that is adequate to meet reliability criteria while minimizing production cost for the day. The unit commitment may include forced outage effects by treating generator availability on a given day as a random variable. Unit maintenance scheduling may also be included in the unit commitment simulation.

Economic dispatch refers to allocating the hourly load among the committed resources such that the cost of production is minimized. The economic dispatch may include security constraints in the form of spinning reserve requirements, generally taking the form of minimum run levels that must be assigned to regulating units, as well as environmental constraints on generator operation.

The predicted peak load from the load forecast may be resolved into hourly demand using some historically determined diurnal load shape that is adjusted by season and day of the week. Uncertainty in the load forecast may be accounted for by adding a suitable random fluctuation to the hourly demand and repeating the production cost simulation numerous times (a Monte Carlo approach). The production cost, including the effect of transmission losses, and the capital cost are then combined in a single economic figure of merit such as the present value of required revenue to own and operate the system over the planning time horizon. The best generation expansion alternative is then selected.

2.4.5 Special Operating Considerations for Large Renewable Resources

Spinning reserve is operating generating capacity that is held in reserve by a utility in case a generating unit fails unexpectedly. It is sized to at least equal the largest generating unit in the pool or other interconnected operating system entity. The large amounts of spinning reserve required by large units is one of the difficulties faced by utilities in integrating large nuclear or coal-fired units. To the extent that renewable generation is composed of concentrations of small units, even very large renewable resource developments would not increase system spinning reserve requirements. As penetration of such renewable resources increases, required spinning reserve as a percentage of total generation would be reduced.

Unit failure is not the only reason for holding operating capacity in reserve, however. Utilities maintain operating reserve capacity—referred to as regulating margin—to account for load variability. Analysis of power systems assumes that loads are constant and that the only disturbances affecting system performance are those which occur within the system, such as failures of generators or transmission equipment. In fact, loads are anything but constant. The load of any individual customer varies continuously, both predictably and randomly. The variation of load with changes in outdoor temperature or the onset of nightfall is predictable, while the moment-to-moment cycling of water heaters, elevators, or motors in industrial processes is random. Even predictable changes have an overlay of random variation because each customer reacts on a slightly different time scale; even two identical customers will not behave in exactly the same fashion. The utility system deals with these variations by two means—diversity and reserve capacity. The diversity effect of aggregating large numbers of customers is to reduce the moment-to-moment variation of load as a percentage of the total. Regulating margin requirements are calculated by reference to the maximum variation of load during any generation scheduling hour.

Large-scale renewable resources present the utility planner with an additional dimension to the regulating margin problem. To a greater or lesser degree, the output of an array of renewable generators is unpredictable in ways that conventional generation is not. The output of conventional generation responds to control and may operate at a fixed setpoint or may be varied in response to load changes. Short-term variation in the output of conventional generation is due mainly to forced outages, which, though of significant magnitude, are infrequent. Generation from wind and most solar technologies introduces into the equation the additional element of uncertainty in the moment-to-moment availability of the resource. Variations in wind speed or changes in insolation due to passing clouds, for instance, cause random variations in the output of the renewable generation resource. These variations would have to be factored into the calculation of the required regulating margin.

Strategies exist for ameliorating the impact of renewable generation on regulating margin requirements. Geographic diversity, or the use of multiple small renewable resources spread over a large area, may reduce variation, since not all generators would be affected by the same resource perturbation. Control schemes could be devised to regulate the output of the whole complex of renewable generators instead of that of individual machines, and storage devices may be employed to regulate renewable output, as is currently done with solar thermal installations. Alternatively, the whole question of the requirement for regulating margin may become moot as storage devices are distributed throughout the system, effectively decoupling instantaneous demand and the supply of electricity. Consideration of the impact of such advanced technologies as storage and/or control systems is beyond the scope of this analysis. An examination of the impact of large renewable resource penetrations on the required regulating margins is also beyond the scope of this study, even though such considerations have as great an impact on acceptability of renewable resources as the availability of transmission capacity.

2.5 STUDY APPROACH FOR DETERMINING THE TRANSMISSION REQUIREMENTS OF WIND/SOLAR GENERATION

The focus of this study was on the transmission requirements for the integration of wind/solar energy resources. The approach taken was to contract with utilities having attractive wind/solar resources in their service region to conduct planning studies with renewable resources. The utilities would use their own system data and their established planning procedures, criteria, and analytical tools. For each renewable energy region, the utility would conduct at least two site studies. These studies would determine the largest amount of wind/solar resource that could be integrated without adding transmission capacity beyond that required for connection to the utility system. In selected further studies the transmission requirements for high penetrations of the wind/solar resource would be determined.

3. TRANSMISSION CAPACITY CASE STUDIES

3.1 RESOURCES AREAS

Areas of high wind resource are scattered throughout the United States. The wind resource is classified by wind power classes according to the wind speed. The relationship between wind power classes and wind speed is shown in Table 3.1. For this study, wind power classes of 4–6 have been considered for potential wind plant sites. Many of the areas of the highest wind power classes (7+) are located in mountainous regions remote from the power grid. The *Wind Energy Resource Atlas of the United States* and a Pacific Northwest Laboratory report were used to determine resource areas.[3,4] The major wind resource regions accessible to transmission systems are located in the Texas Panhandle and portions of Oklahoma and Kansas, the north central United States, the Northwest, Maine, portions of California, and various mountain passes.

Table 3.1. Wind power classes and corresponding wind speeds

Wind power class	Wind speed (m/s) for height = 10 m	Wind speed (m/s) for height = 30 m	Wind speed (m/s) for height = 50 m
1	0–4.4	0–5.1	0–5.6
2	4.4–5.1	5.1–5.9	5.6–6.4
3	5.1–5.6	5.9–6.5	6.4–7.0
4	5.6–6.0	6.5–7.0	7.0–7.5
5	6.0–6.4	7.0–7.4	7.5–8.0
6	6.4–7.0	7.4–8.2	8.0–8.8
7	7.0–9.4	8.2–11.0	8.8–11.9

Source: D. L. Elliott, L. L. Wendell, and G. L. Gower, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, Pacific Northwest Laboratory, August 1991.

Solar data from the National Climate Data Center was used to identify resource areas.[5] Areas of high solar resource with an average annual solar radiation of 3 MWh/m^2 or above are located in the southwestern United States (see Fig. 3.2). The Southeast has a good solar resource of 2.2 to 3 MWh/m^2 average annual solar radiation, but the normal radiation is significantly reduced by clouds (about 1.4 MWh/m^2 average annual radiation). For this region, nonconcentrating photovoltaic (PV) technology is more appropriate, since it can utilize the total radiation including the diffused component.

3.2 CASE STUDIES

The resource regions and generation output levels for the case studies were determined with the assistance of AWEA and SEIA. Maps of the resource regions were used with overlays of transmission facility maps to identify areas of interest for case studies. AWEA and SEIA provided a list of electric utilities in the regions with an interest in renewable energy studies. Some utilities are working with solar and wind plant vendors in the regions, and this transmission planning study provided valuable information for their own generation plans.

The wind case studies are located in four primary regions: Texas, Washington/Oregon, North Dakota, and Colorado/Wyoming. Electric utilities that participated in the wind plant studies are BPA, Lower Colorado River Authority (LCRA), Southwestern Public Service Company (SPS), Texas Utilities Electric Company (TU), and Western. The wind case study sites, including the Blackfeet area and selected wind resource regions of power class 4 and higher, are shown in Fig. 3.1.

The solar case studies are located in the southern United States in four states: Texas, Arizona, California, and Florida. Electric utilities that participated in the solar plant case studies are Arizona Public Service Company (APS); City of Tallahassee Electric Department, Tallahassee, Florida; LCRA; and Southern California Edison (SCE). SCE provided capacity and cost data that were used by the Zaininger Engineering Company (ZECO) in the Southern California case study. The solar case study sites and the solar energy available on a flat surface with two-axis tracking are shown in Fig. 3.2.

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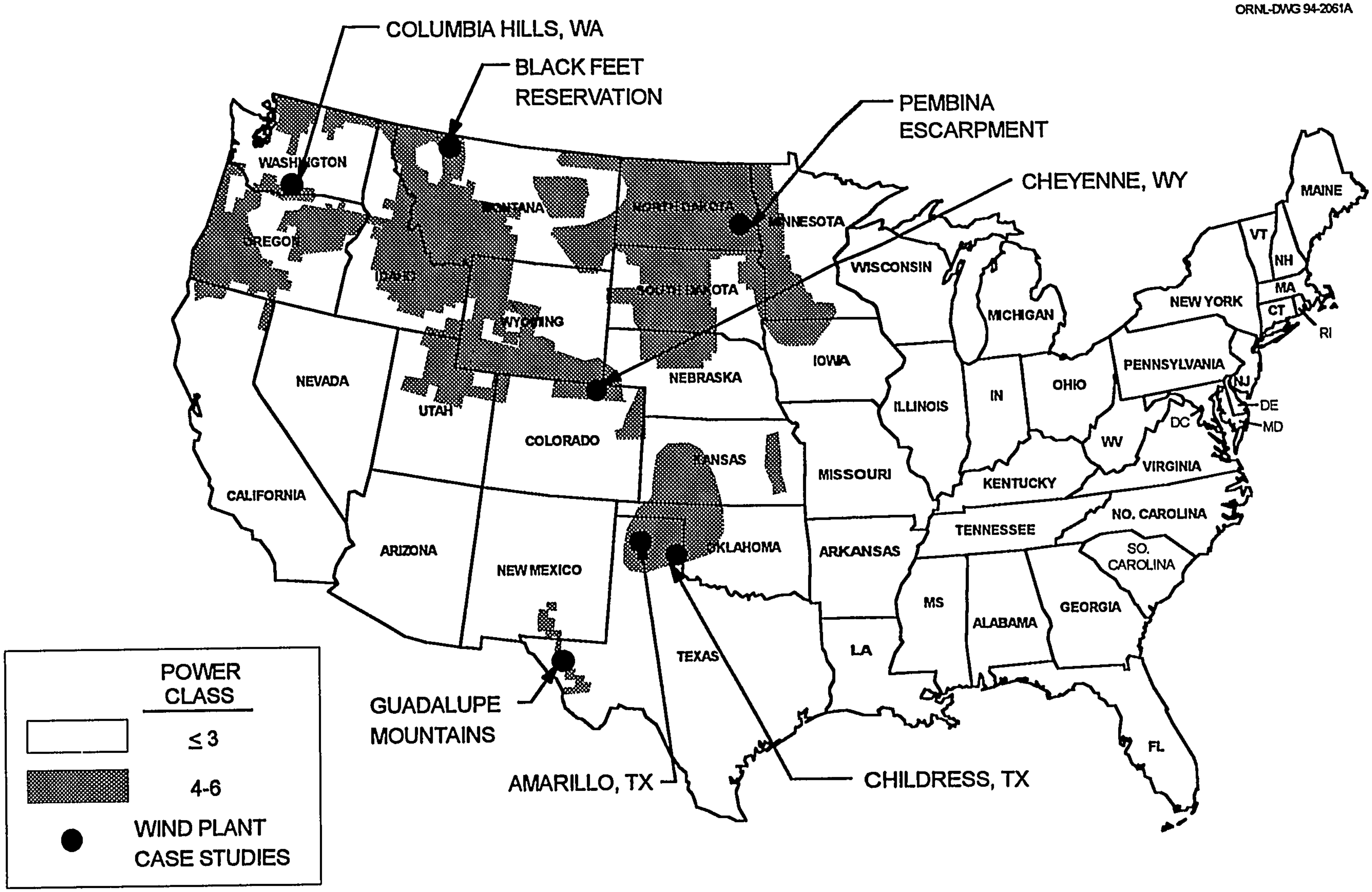

NOTE: Not all wind resource areas are shown.

Fig. 3.1. Wind resource areas and the seven wind plant case study sites.

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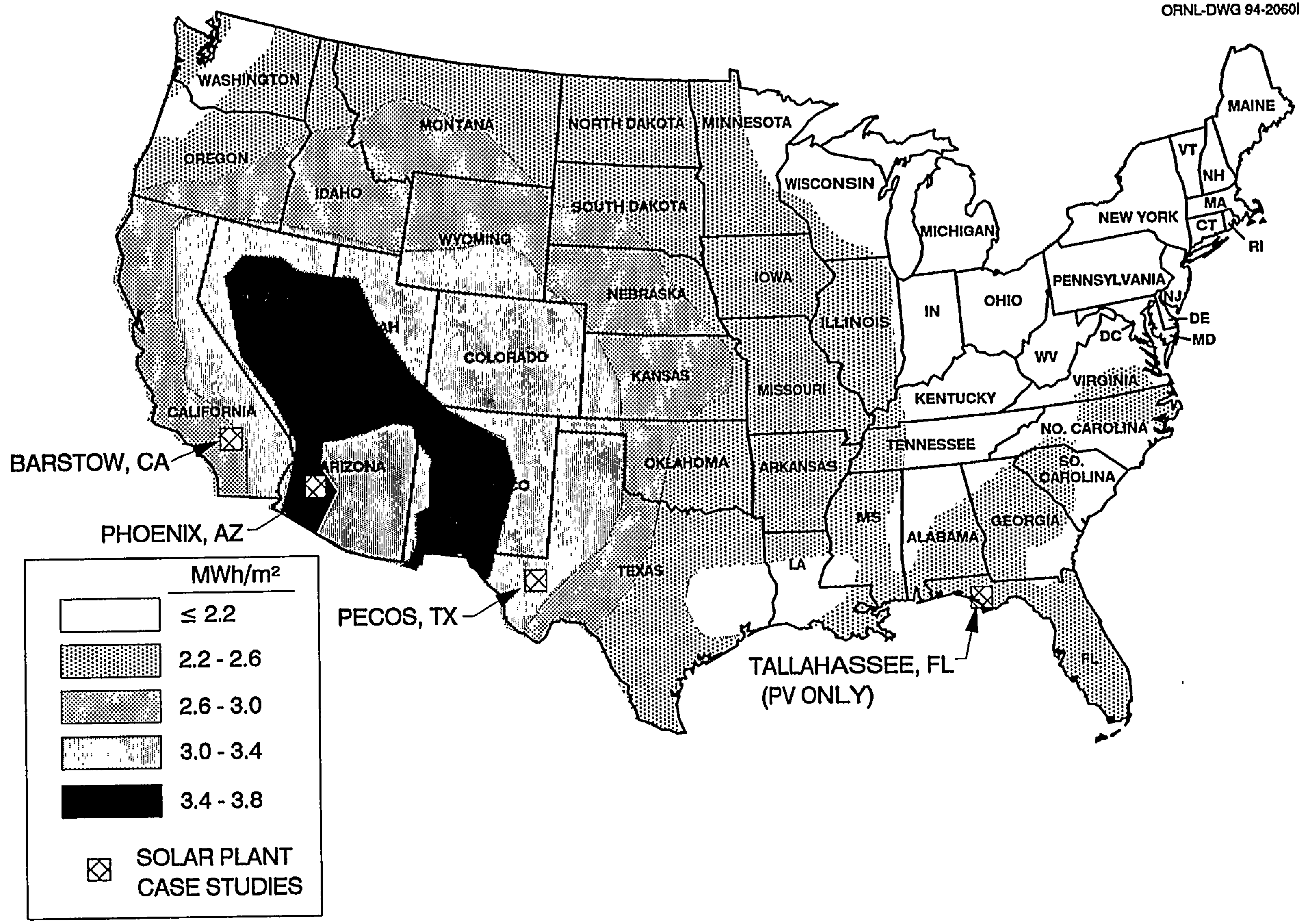

Fig. 3.2. Average annual solar radiation and the four solar plant case study sites. Radiation data source for two-axis tracking: National Renewable Energy Laboratory.

WIND PLANT CASE STUDIES

4. BLACKFEET AREA STUDY

4.1 INTRODUCTION

The Pacific Northwest Utilities Conference Committee (PNUCC) issued a report, *PNUCC Blackfeet Area Wind Integration Study*, in August of 1991.[2] This report prompted Congress to request an analysis of the need for transmission capacity to support the development of renewable energy resources. Since this work was considered adequate for the Pacific Northwest, it has been summarized and included in this report with the other case studies. The objective of this study was to develop a preliminary evaluation of the cost and feasibility of integrating the potentially large-scale Blackfeet area wind resources into the Pacific Northwest's power systems.

In 1980, Bonneville embarked on a 5-year, $3 million program to assess the wind resource potential in the region. The program, entitled WIND-REAP (Regional Energy Assessment Program), collected and analyzed wind data from over 300 specific areas in and adjacent to the region. Thirty-nine general areas were classified as "promising" based on a preliminary screening of site characteristics.

In 1989, the Northwest Power Planning Council and the Oregon Department of Energy (ODOE) collaborated to develop cost and availability estimates for regional wind energy resources. Using the WIND-REAP data and projected cost and performance information for commercially available wind turbine generators, the council and ODOE concluded that over 3400 MWa* of power were potentially available from promising wind resource areas. However, the wind energy potential at one area, the Blackfeet area in northern Montana, clearly dominated the results. Over 90% of the estimated 3400 MWa of wind resource potential was credited to this one area.

The PNUCC System Planning Committee reviewed the joint council/ODOE report, as well as other resource-related information, in the process of developing resource confirmation proposals. It was the consensus of the System Planning Committee that *resolution of transmission integration questions for the Blackfeet area was a key factor for future large-scale wind development.* If wind turbine machines located at the Blackfeet area could operate reliably and at a relatively high-capacity factor (i.e., 30% or slightly higher) and if the energy generated by these machines could be integrated cost-effectively to serve regional loads, then wind resources could play a large and important role in future resource decisions, actions, and expenditures. In order to resolve these issues, the System Planning Committee developed a wind confirmation program for the Blackfeet area, focusing on the new transmission facilities necessary to integrate a hypothetical, large-scale wind resource development located at the Blackfeet area. A task force was assembled in early 1991 to commence work on the program.

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*An average megawatt, denoted as MWa, provides an annual energy production of 8670 MWh.

4.2 SITING CONSIDERATIONS

The Blackfeet area is located within a larger geographic region termed the Rocky Mountain Front. The Rocky Mountain Front is characterized by both smooth, rolling terrain and proximity to the eastern flank of the Rocky Mountains. This combination of topography and location results in consistently high winds. While the entire Rocky Mountain Front has high wind resource potential, the Blackfeet area is predicted to have some of the best conditions for large-scale wind resource development. The Blackfeet wind resource area covers approximately 2700 square miles. Over 80% of this area is on the Blackfeet Indian Reservation; the remainder of the area is privately owned. The Blackfeet wind resource area is shown in Fig. 4.1.

4.2.1 Defining the Two Scenarios

The general direction for the study was to evaluate transmission integration for large-scale wind resource developments at the Blackfeet area. However, it would not be practicable to evaluate many possible sizes of wind resource developments. Consequently, the task force defined two development scenarios for the study:

1. **1000-MWa scenario.** This scenario includes the development of 3000 MW of wind turbine generation capacity at the Blackfeet area. To integrate this generation, 3000 MW of transmission capacity is required. Since the wind turbine generators are assumed to operate at a 33% capacity factor, this scenario would produce 1000 MWa.
2. **165-MWa scenario.** The 165-MWa scenario is based on the installation of 500 MW of wind turbine generation capacity at the Blackfeet area. Integrating this resource requires 500 MW of transmission capacity. With a 33% capacity factor for the wind turbine generators, this scenario would generate 165 MWa.

As a frame of reference, the total installed wind turbine generation capacity in the state of California is about 1600 MW. The 165-MWa scenario defined for the study represents a potential resource development approximately one-third the size of the total California wind-generation capacity. The 1000-MWa scenario represents a potential development almost twice the size of the total California wind generation capacity.

4.2.2. The Anticipated Load Centers

Since both the Seattle and Portland areas are experiencing growing demand for electricity, it is likely that additional cross-Cascade transmission to *both* of these load centers will be required in the future. This additional transmission would carry energy from existing and new resources, such as the wind project, to meet growing electricity demands in these two areas. Due to the probable timing of the wind project development and the likely sequence of transmission additions, it is anticipated that energy from the wind project would be integrated primarily into the Portland area.

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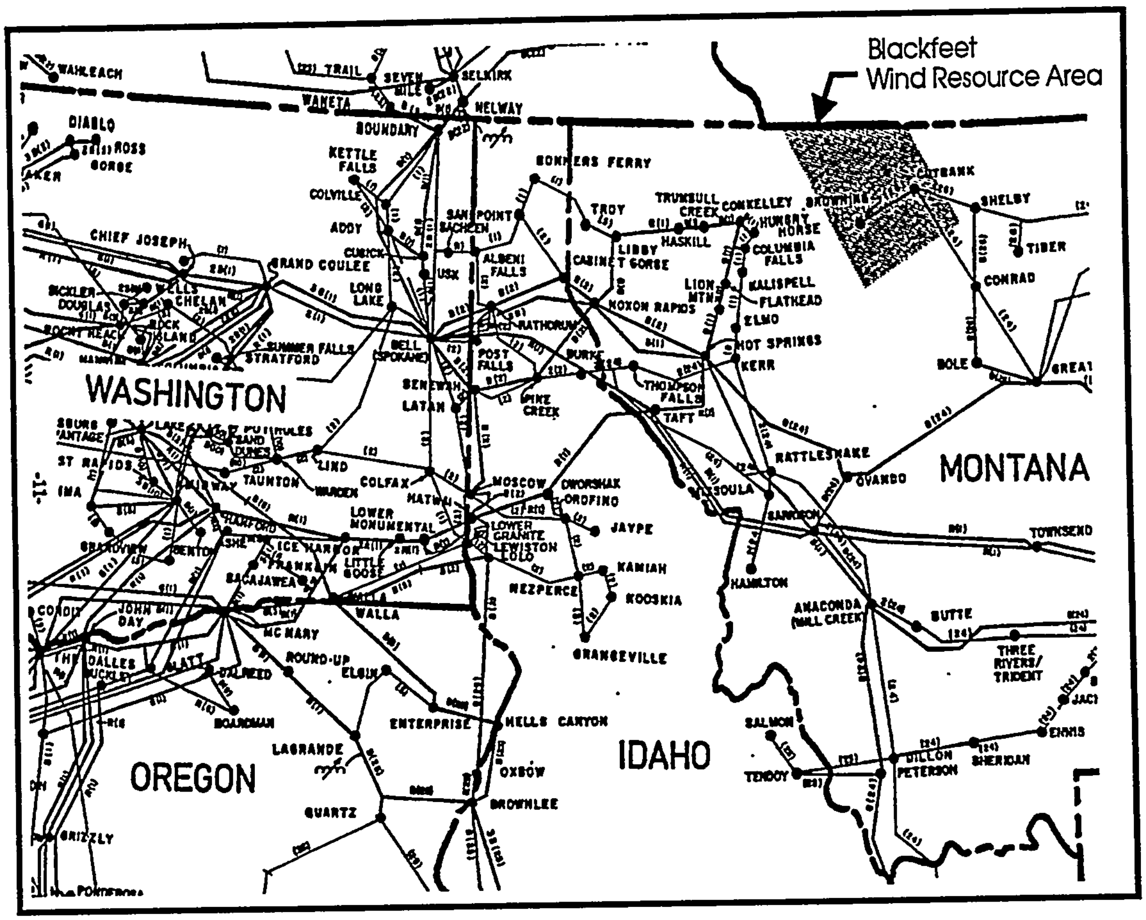

Fig. 4.1. Blackfeet transmission line map.

4.3 EVALUATION RESULTS

4.3.1 Simplifying Assumptions

The task force made several simplifying assumptions in order to focus the study on the key issues. The major assumptions included wind turbine generator characteristics, design considerations, and economic assumptions.

4.3.2 Phased Construction Approach

In order to evaluate the 1000-MWa scenario, the task force determined that "phased construction" development of the new transmission facilities was necessary because there is a fundamental difference between the addition of new transmission line capacity and the addition of wind project generation capacity.

Transmission lines provide large increments of capacity. For example, the transmission capacity of a 230-kV line is between 350 and 450 MW, while the transmission capacity of a 500-kV line is between 1000 and 1600 MW, depending on system stability factors, conductor size, etc. In contrast, wind generation capacity can be added in increments as small as 100 kW (i.e., 0.1 MW). Also, wind projects are developed gradually, as markets warrant and as site construction, development permits, and financing allow. (It is useful to note that the *entire* wind generation capacity in the state of California is approximately 1600 MW and was developed over many years. This capacity, if all at one location, could theoretically be integrated by a single new 500-kV transmission line.) With "phased construction" development of new transmission facilities, the gradual development of the wind resource could be accommodated while still planning for the ultimate transmission needs.

4.3.3 Energy Cost

There are two main components to the overall cost of energy from generating resources. The first component is the actual cost to generate the energy. This component includes amortization of the generating equipment and the operating and maintenance expenses. Based on information and financial assumptions contained in the 1991 Power Plan, this cost was estimated to be 10.4 cents/kWh for wind resources located at the Blackfeet area. Using current wind turbine technology, this cost would be less today.

The second component is the transmission cost. These costs can be translated into levelized costs using the financing assumptions for investor-owned utilities contained in the 1991 Power Plan.

For the 1000-MWa scenario, the levelized transmission cost is 2.6 cents/kWh for main grid integration and 3.2 cents/kWh for load center integration.* For the 165-MWa scenario, which integrates to the main grid at Grand Coulee substation, the levelized transmission costs are 4.2 cents/kWh. Transmission costs for both scenarios are a significant factor in resource selection. The costs are in nominal, levelized 1990 dollars and are given in cents per kilowatt-hour.

*The costs given in the Blackfeet study and in this chapter are in nominal 1990 dollars. When referenced elsewhere in this report, they have been converted to level constant 1993 dollars.

4.4 DISCUSSION

4.4.1 1000-MW Scenario

In addition to the threshold issue of cost-effectiveness, other issues would affect the development of the 1000-MWa scenario. The major issue would be the identification of markets and uses for 1000 MWa from wind resources. Given what is known about the region's load/resource situation and the markets available to the Northwest, it does not appear that 1000 MWa from wind resources would be used for some time.

In the view of the majority of the task force, the 1000-MWa scenario does not seem feasible unless a significant change occurs in either the economics or the projected usage of large amounts of energy from wind resources.

4.4.2 165-MW Scenario

In addition to the relative cost-effectiveness of the resource, development of the 165-MWa scenario would depend on many of the same factors as the 1000-MWa scenario. However, since the project would be smaller in scale, the associated development issues would be more manageable and the project coordination would be simpler. Also, it would be more likely to lower the transmission costs for the 165-MWa scenario than for the 1000-MWa scenario because cost-effective energy storage or complementary generation would be more feasible with a smaller project than with a larger project.

Based on these factors, the task force concluded that the 165-MWa scenario appears feasible for development if wind resources become cost-competitive.

4.4.3 Using Existing Transmission Facilities

It is possible that a relatively small wind resource project at the Blackfeet area could be developed to serve local loads using the existing transmission system reinforced with some new interconnecting facilities.

Based on some very preliminary assessments by regional utility system operation experts, it may be possible to integrate up to 100 MW capacity from the Blackfeet area to serve loads east of the Continental Divide. This would translate into a wind energy resource with an installed capacity of 100 MW, or about 30–35 MWa. Numerous technical and contractual issues would need to be resolved prior to implementing these arrangements. Issues that require resolution include wheeling arrangements and interconnection requirements. However, negotiations currently under way between the Blackfeet Tribe and wind developers to construct one or more projects in the 30- to 50-MW range may serve as a starting point for larger wind resource development in the Blackfeet area.

4.5 SUMMARY AND CONCLUSIONS

The Blackfeet area in Montana contains over 90% of the estimated wind resource potential in the region due to its relatively smooth terrain and proximity to the Rocky Mountains. PNUCC coordinated a preliminary evaluation of the cost and feasibility of integrating this resource into regional load centers. Two development scenarios were evaluated:

1000 MWa and 165 MWa. The primary findings and conclusions of the study are summarized below.

- There is minimal east-west transmission capacity available to integrate new resources located in Montana east of the Continental Divide. The existing transmission system interconnects the region's western load centers and in this part of Montana is fully utilized.

- New transmission facilities must be developed in order to integrate new resources of any appreciable size located in Montana east of the Continental Divide. Wind resources in the Blackfeet area and in other parts of the Rocky Mountain Front, new coal plants, and any other generating resource located in this area will require the development of major new transmission facilities.

- Based on a very preliminary assessment, a relatively small Blackfeet area wind project (up to approximately 30–35 MWa) could be integrated to serve loads east of the Continental Divide using the existing local transmission system.

- The development schedule for new transmission facilities is very long. *The permitting, siting, and construction process is projected to take between 8 and 12 years, depending on the size and complexity of the proposed facilities.*

- There are two feasible east-west transmission routes across the Rocky Mountains. Both of these cross the Continental Divide in Montana via Rogers Pass. One route follows the Garrison-Taft lines west from Garrison substation, and the other proceeds west through Jocko Pass.

- The cost for new transmission facilities to integrate the 165-MW average power scenario in 1991 was estimated to range from approximately $270 million to $320 million. The cost range is a function of the uncertainty in construction costs. For the study, it was assumed that the facilities would cost approximately $270 million.

- The cost for new transmission facilities to integrate the 1000-MW average power scenario in 1991 was estimated to range from approximately $980 million to $1.4 billion. The cost range is a function of both the route selection and the uncertainty in construction costs. For the study, it was assumed that the facilities would cost approximately $1.1 billion.

- With transmission costs included, the estimated energy costs for wind resources in the Blackfeet area exceed the estimated energy costs for new coal-fired generation.

- Recommended follow-on actions include investigation of storage mechanisms and other generation to increase the load factor of transmission facilities, further operational and system integration analyses, and close monitoring of the technological improvements and advances in wind turbine technology.

5. WESTERN AREA POWER ADMINISTRATION REGION STUDY

5.1 INTRODUCTION

This case study was performed by the Western Area Power Administration.[6] Attractive wind energy resources exist within the service area of the Western Area Power Administration (Western) in northeast Colorado and south central Wyoming. A feasibility study was conducted to assess the system impacts of developing from 50 to 250 MW of wind resources to supplement generation requirements of the metropolitan Denver area.

5.2 SITING AND STUDY CONSIDERATIONS

Three sites were considered in northeast Colorado: Holyoke, Frenchman's Creek, and Sterling (see Fig. 5.1). Western's established planning procedures and criteria were used in the study. Power flow studies were conducted for the peak load condition to determine how much wind generation could be added at each site without adding transmission resources beyond those necessary to connect the wind generation. It was assumed that the wind generation was coincident with the peak load. Because the transmission voltage in northeastern Colorado is relatively low (115 kV), the amount of wind generation that could be connected without overloading other facilities or reducing reliability was found to be from 25 to 50 MW per site. The permissible aggregate wind generation from all sites was limited to 75 MW to avoid overloading the transmission corridor that leads into the Denver area.

Similar results were observed for two sites in southern Wyoming—Medicine Bow and Archer (see Fig. 5.1). Without adding transmission capacity beyond that necessary to connect the wind generation, only 50 to 75 MW of wind generation could be added to a given site. Aggregate wind generation from both sites must be limited to about 125 MW to avoid overloading the transmission corridor from Wyoming to Colorado and that leading into Denver.

An additional study was performed to determine the requirements for adding up to 250 MW of wind generation at Medicine Bow. Substantial additional transmission resources were found to be required to maintain local system performance and reliability. The transmission bottlenecks into the Denver area would necessarily limit the scheduling of wind generation to serve Denver area loads.

5.3 EVALUATION RESULTS AND DISCUSSION

Key findings from the study are outlined below.

5.3.1 Study Results for Northeast Colorado

The transmission system in northeast Colorado is mostly 115 kV. This voltage level limits the size of any wind generation to the 25- to 50-MW range. Three possible sites were investigated in this study: Holyoke, Frenchman's Creek, and Sterling. Without system expansion beyond that necessary to connect the wind generation to the system, each of these sites can support 25 to 50 MW of wind generation. The wind generation can serve local loads

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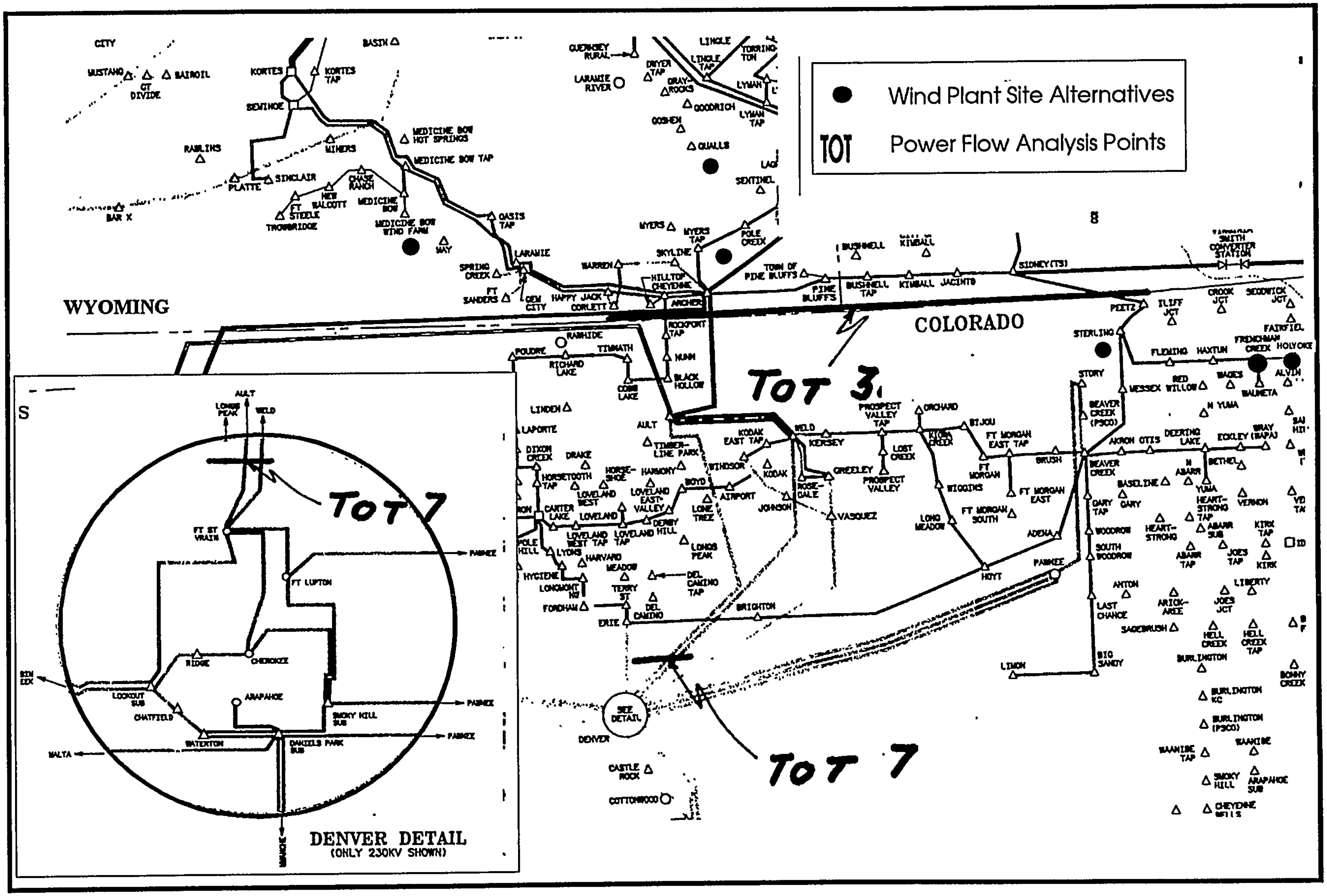

Fig. 5.1. Wind sites in the Western region.

and could also be scheduled into the Denver area. Generation above the 50-MW level tends to overload the 230-kV system out of Story and the local 115/69-kV system for single outage contingencies under peak system load conditions. In addition, there exists a transmission bottleneck just to the north of the Denver area known as TOT7 (see Fig. 5.1). TOT7 consists of the three 230-kV lines that connect Long's Peak, Ault, and Weld to St. Vrain. (The loading limit is set by an outage on any one of the 230-kV lines which results in overload of either of the other parallel lines.) TOT7 has a total capability of 770 MVA, of which Western has no ownership but could probably contract for wheeling purposes. The path is owned by Public Service Company of Colorado and the Platte River Power Authority.

Specific findings of the study for northeast Colorado are as follows:

1. If a wind resource were connected at the Holyoke 69-kV bus in the northeast corner of Colorado, the size is limited to 40 to 50 MW due to a transformer restriction at nearby Frenchman's Creek.

2. Up to 50 MW could be connected to the Frenchman's Creek 115-kV bus. Resources above this megawatt level cause overloading of the 115-kV system in the area. Also, for peak system conditions with levels of wind resource slightly above 50 MW, transmission limitations north of the Denver area will be reached (TOT7).

3. If a wind resource were connected at the Sterling 69-kV bus, the size is limited to 25 MW due to a transformer restriction at Sterling.

4. Up to 50 MW could be connected to the Sterling 115-kV bus. Resources above this level cause overloading of the 230-kV system out of Story for outage contingencies under peak system conditions. Transmission limitations north of Denver (TOT7) are also reached at about this same level.

5. Total wind generation at Sterling, Holyoke, and Frenchman's Creek would be limited to between 50 and 75 MW by steady-state flows into Denver (TOT7) on peak. Loading and voltage restrictions also exist on the 115/69-kV system in the area for nearby disturbances.

5.3.2 Study Results for Southern Wyoming

The transmission system in southern Wyoming consists of 345-kV and lower-voltage transmission. The Missouri Basin Systems Group owns and operates the 345-kV system emanating from the 1500-MW coal-fired Laramie River Station. This transmission is fully subscribed. Western owns 230-kV and 115-kV transmission in the area. The Medicine Bow and Archer areas were investigated for wind generation in this region.

Without further transmission additions, the Medicine Bow site could support up to 50 MW of wind generation, as could the Archer location, and a total of 100 to 125 MW is possible between both sites. This generation could be utilized for local area loads or, to the extent possible, scheduled to Denver area loads. Substantial upgrade to the transmission system was found necessary to enable 250 MW of wind generation to be connected at Medicine Bow. These additional facilities are enumerated below.

A transmission bottleneck known at TOT3 lies along the Wyoming/Colorado border (see Fig. 5.1) and consists of the Laramie River Station to Ault 345-kV line, the 115-kV Cheyenne to Rockport line, the LRS to Story 345-kV line, the Archer to Ault 230-kV line, the Sidney to North Yuma 230-kV line, and the Sidney to Peetz 115-kV line. This path presently has a maximum limit of 1424 MW with the system intact but must be reduced under certain operating conditions. Western presently has up to 370 MW of capacity in TOT3.

Specific results for the cases studied without adding transmission capacity beyond that necessary to connect the wind generation to the system are as follows:

1. Up to 50 MW of wind resource could be connected to the Medicine Bow 115-kV bus. Performance of the local system with this amount of resource is acceptable; however, when scheduling to the Denver area across the Wyoming-Colorado border under heavy load conditions, transmission limitations on TOT3 and TOT7 are encountered. Western currently has 370 MW of capacity in TOT3 and none in TOT7. Western's share of TOT3 is presently used to move Wyoming hydro, Virginia Smith high-voltage dc (HVDC) capacity, and/or thermal purchases into the Denver area.

2. Between 50 and 75 MW of wind resource could be sited near the Archer 230/115-kV bus. Performance of the local system with this amount of resource is acceptable. Again, when scheduling to the Denver area, transmission limitations are encountered on TOT3 and TOT7.

3. Total Medicine Bow/Archer wind generation would be limited to about 125 MW, with 50 MW at Medicine Bow and 75 MW at Archer. This simultaneous wind generation is acceptable for serving local area loads and local system outages. However, the transmission limitation across the Wyoming/Colorado border (TOT3 and TOT7) could limit schedules into Denver.

4. Wind resources of 50 to 75 MW could be connected to the Qualls/Pole Creek 115-kV system. The local system performance with this amount of wind resource is acceptable. Transmission limitations are encountered when scheduling to Denver area loads.

In order to connect up to 250 MW of wind generation at Medicine Bow, the following additional resources are required:

- 230-kV Spence–Miracle Mile (60 miles);
- 230-kV rebuilding of the Miracle Mile–Medicine Bow 115-kV line number 1 (47 miles);
- 230-kV substation at Miracle Mile with a 100-MVA 230/115-kV transformer having an overload rating of from 135 to 150%;
- 230-kV Medicine Bow–Lookout line (160 miles) or 230-kV Medicine Bow–St. Vrain line (110 miles); and
- 230-kV substation at Medicine Bow, 3 breaker ring bus with 300-MVA 230/34.5-kV transformer.

The estimated upgrade cost is $65 million. Power flow and stability cases with these additions showed only one minor overload on the Beaver Creek–Pawnee 230-kV line when transmission corridor TOT3 has heavy power flow (over 1300 MW).

It should be pointed out that contract path and market considerations may have significant bearing on the size and siting of a wind resource, particularly if it is sited north of the transmission bottlenecks TOT3 and TOT7. A wind resource will necessarily compete with Wyoming base-load coal resources for both the market in the Denver metropolitan area and the limited scheduling capacity across TOT7 (in which Western has no ownership) and TOT3 (in which Western has only about 26% of the capacity). Western's capacity in TOT3 is required to move summer Wyoming hydro and Virginia Smith HVDC capacity into the South Platte (Denver) area. Limited winter capacity may exist. TOT3 and TOT7 presently limit the imports into Denver during heavy summer load hours and during clockwise loop flow. Until this constraint is relieved, little if any firm surplus capacity exists.

5.4 SUMMARY AND CONCLUSIONS

The relatively low transmission voltage in northeastern Colorado (115 kV) limits the wind resource to about 25 to 50 MW per site if no transmission upgrade is to be included. Total wind generation from all sites is limited to 50 to 75 MW to avoid overloading the transmission corridor into the Denver area.

Wind generation in southern Wyoming is limited to about 50 to 75 MW per site if no transmission upgrade is included. Aggregate wind generation from all sites is limited to about 125 MW without transmission upgrade.

Adding 250 MW of wind generation at Medicine Bow requires substantial upgrade to the 230-kV transmission system. Transmission bottlenecks north of Denver could limit the scheduling of this generation into the Denver area.

6. PEMBINA ESCARPMENT STUDY

6.1 INTRODUCTION

A case study has been performed by the Oak Ridge National Laboratory investigating the feasibility of integrating wind resource generation in the eastern North Dakota area (Pembina Escarpment) into the upper Mid-Continent Area Power Pool (MAPP) power system. The study used power-flow analysis to evaluate the capability of the existing transmission system and the upgrades needed to connect 1000 MW of additional generation to supply load in the North Dakota and eastern Minnesota region. Costs were determined only for the additional transmission required to export power from the wind generation facility to the extra-high-voltage transmission system south of Minneapolis/St. Paul.

6.2 SITING CONSIDERATIONS

All of North Dakota and South Dakota, and part of Minnesota, fall within a class 3 or higher wind density classification. This study is limited to the class 5 area in eastern North Dakota. The location of the class 5 wind resource relative to the existing transmission system is shown in Fig. 6.1. This area is known as the Pembina Escarpment.[3]

No environmental or explicit land use constraints were found in the area that would restrict siting wind generation. There has, however, been resistance to new transmission facilities for aesthetic reasons. Supporting facilities would need to be developed because the prospective sites are undeveloped and in remote areas.

Development of wind resource generation in the Pembina Escarpment area would require coordination among several utilities, since some transmission and distribution facilities are jointly owned. Figure 6.2 shows the major utilities surrounding the Pembina Escarpment area. Also, the wind resource area is located in a different utility service territory than the existing transmission system south of Minneapolis/St. Paul.

6.3 EVALUATION OF INTEGRATION CAPABILITY

6.3.1 Evaluation Criteria

The MAPP planning reliability criteria were used to identify system limitations due to the unplanned removal of a single transmission line. All studies were based on the MAPP 1993 series 1998 Summer Shoulder Peak Model, which includes extreme transfer conditions in the MAPP area. Transfer capability into and out of the MAPP area was monitored for the range of transmission line outages considered. Because of the high level of transfers in the case, some facilities were overloaded in a contingency situation without the addition of wind generation. Only the facilities that were overloaded due the addition of wind generation were identified as needing upgrade. In the MAPP area, large power transfers from remote sources are stability-limited, but stability limits were not considered in this study because of difficulties encountered in the stability analysis program with the MAPP data.

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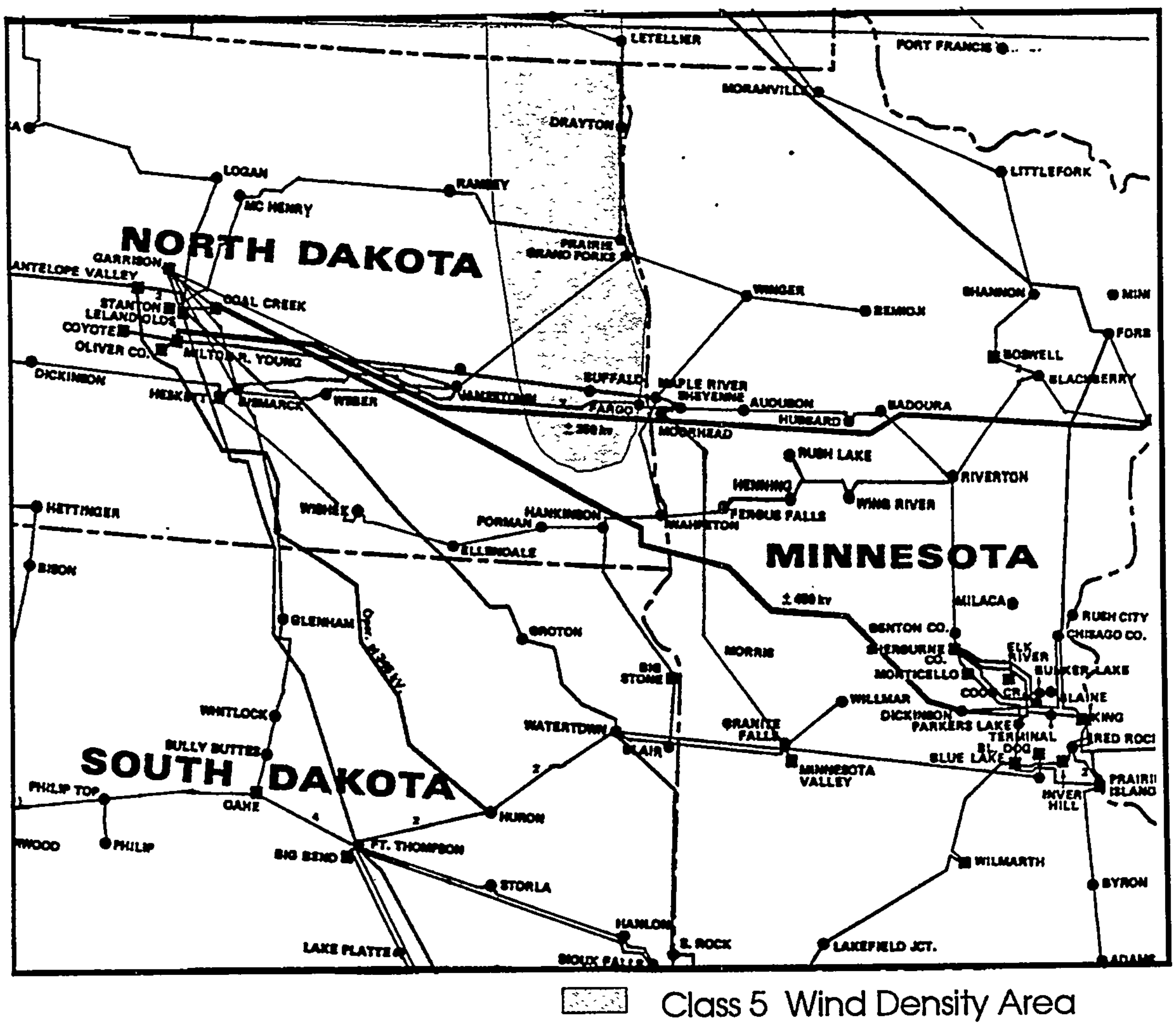

Fig. 6.1. Major transmission lines (≥230 kV) in upper MAPP-US area.

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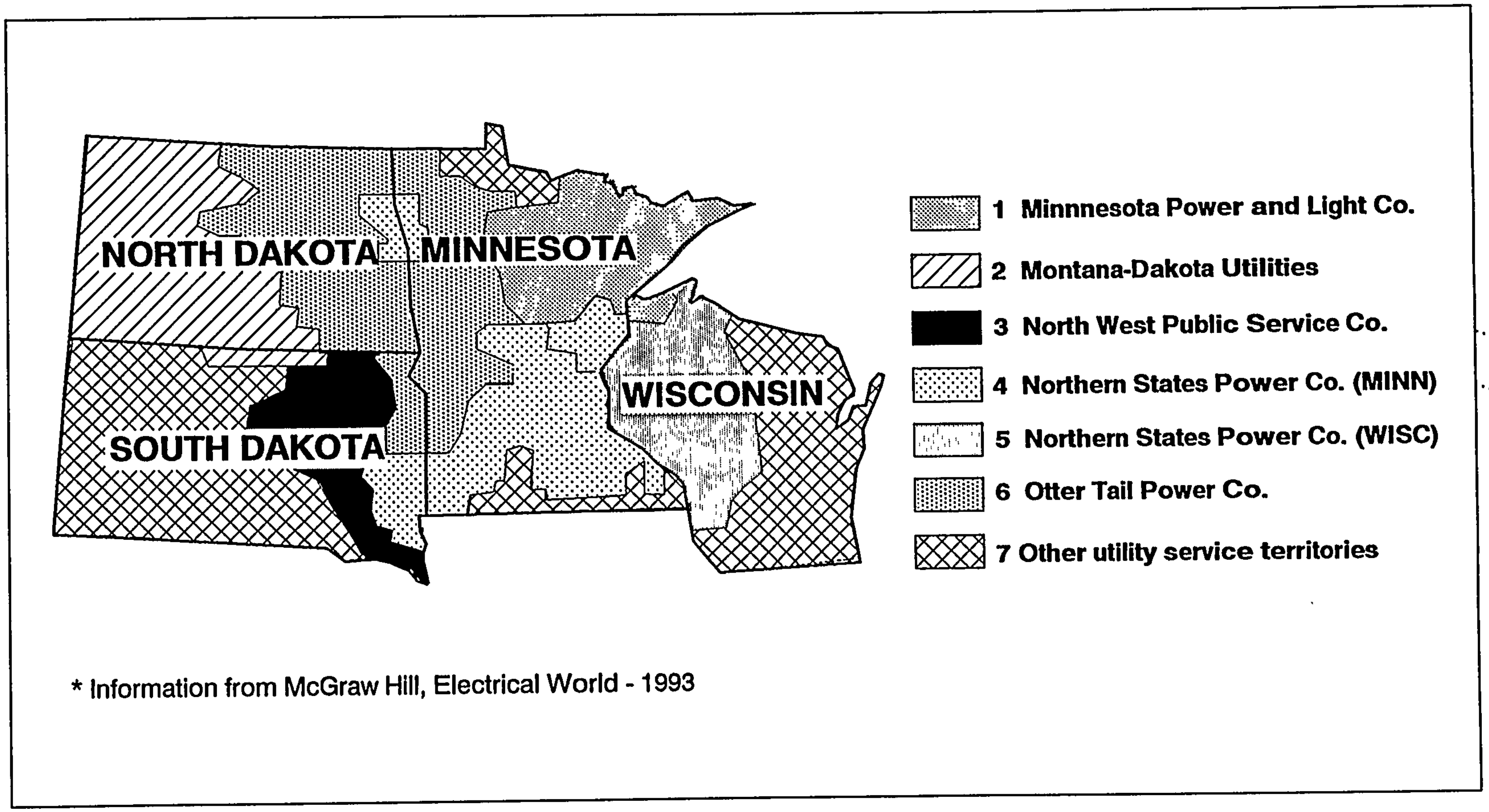

Fig. 6.2 Major utility service territories in Pembina Escarpment area.

6.3.2 Capability of the Existing System

Low-capacity wind generation (100 MW or less) can be incorporated into the existing system to support local load. Additional generation capacity, in excess of local load (100 to 500 MW), could be exported if transmission facilities are upgraded. Facility upgrade requirements become increasingly significant as generation additions are increased above 100 MW.

6.3.3 Integration of High-Capacity Wind Generation

Higher levels of wind generation will require approximately 300 miles of new transmission capacity (345 kV or greater, or dc) from the Pembina Escarpment region to the extra-high-voltage transmission system south of Minneapolis/St. Paul. The existing transmission system is already heavily used for south-east power transfers to midwestern load centers, such as Minneapolis/St. Paul. This would mitigate dynamic stability concerns as well as provide the additional transfer capacity. The estimated cost for this new capacity is $472 million for a 345-kV system and $500 million for a 500-kV system.

6.4 DISCUSSION

Single branch outage contingencies were considered under three basic wind generation dispatch scenarios: (1) displaced Twin Cities generation, (2) displaced west North Dakota generation, and (3) displaced central North Dakota generation. The generation in central North Dakota was considered to be local to the wind generation site.

The transmission system was designed to deliver power from the coal-fired plants in central North Dakota to load centers in eastern Minnesota. The transmission system is therefore quite heavily utilized to provide power to these load centers. In the late 1990s, many lines near major transmission paths will have little capacity remaining.

Outage of the 500-kV line between Roseau and Forbes caused line overloading on the 115-kV and 230-kV lines in the Prairie, Jamestown, and Maple River areas as the power flows were redistributed. Outages of 230-kV and 345-kV lines between western North Dakota and the Twin Cities cause a redistribution of power flows in the same area. For this reason, if generation is added in the Pembina Escarpment area, many small upgrades are necessary to mitigate the impact of remote contingencies on regional power transfers.

Because of the large amount of power that is transferred long distances, from west North Dakota and Canada to eastern Minnesota and Chicago, transient stability, not thermal limits, will be a limiting factor. Wind generation projects in the Pembina Escarpment area with capacity in excess of the local load will require additional transmission capacity to export the power to a major load center. Three hundred miles of transmission lines will provide approximately 1600 MVA of export capacity. Transient stability analysis was not performed for this portion of the study.

6.5 SUMMARY AND CONCLUSIONS

Studies indicate that in the Pembina Escarpment region, small wind resource generation capacity (less than 100 MW) can be incorporated into the local power grid to serve local load and displace local generation. Intermediate-capacity (100–1000 MW) integration will require many facility upgrades or additions at the 115-kV and higher level to ensure that the heavy power transfers in the upper MAPP-US area are not impacted. High-capacity options will require major transmission facility additions (dc lines, 345 kV or higher) from North Dakota's Pembina Escarpment area to the major transmission system south of Minneapolis/St. Paul.

7. COLUMBIA HILLS STUDY

7.1 INTRODUCTION

This case study was performed by the Bonneville Power Administration (BPA).[7] The potential wind energy sites considered in this study are in the Columbia River Gorge of Washington State, an excellent location for a wind energy facility. The specific area studied is called the Columbia Hills area.

Three wind energy alternatives were considered in this study. The first is a 25-MW peak wind facility integrated through Klickitat County Public Utility District (PUD). This power will be purchased by BPA. The second alternative is a 50-MW wind facility integrated onto BPA's 230-kV grid. The power generated from this facility will be transferred to three northwest utilities. The third alternative is an expansion of the 50-MW facility to 250 MW.

7.2 SITING AND STUDY CONSIDERATIONS

The three wind-generation alternatives evaluated in this study are described below, along with some key considerations in conducting the study.

7.2.1 25-MW Alternative

The 25-MW facility would be integrated through Klickitat County PUD's 115-kV transmission system (the John Day Tap, shown in Fig. 7.1). The generators are 480-V, 275-kW induction machines. The generators are connected to the system with a 75-kVA shunt capacitor bank in parallel. A 24-kV collection system is used to bring the power to a central site for transformation to 115-kV through wye-delta-wye windings. The point of delivery to BPA is about 7.5 miles away, near BPA's Goldendale substation. The connection is a simple tap of the 26-mile radial line that serves Goldendale out of BPA's Chenoweth substation. The power will be purchased by BPA from the wind plant owner.

7.2.2 50-MW Alternative

The 50-MW facility would be integrated onto BPA's 230-kV grid either at a new substation on one of two sites on the Big Eddy–Midway 230-kV line or at Harvalum substation (see Fig. 7.1). The generators are induction machines operating at a variable frequency, with a four-quadrant, pulse-width-modulated ac to dc to ac converter. The inverter operates at 480 V and can produce or absorb reactive power even with no wind. A 34.5-kV collection system would be used to bring the power to a central site for transformation to 230 kV through wye-delta-wye windings. The power would belong to three northwest utilities and would be transferred for them by BPA.

7.2.3 250-MW Alternative

The 250-MW facility, using the same technology and delivery point as in the 50-MW alternative described above, was studied to determine the impact of larger wind-power integration.

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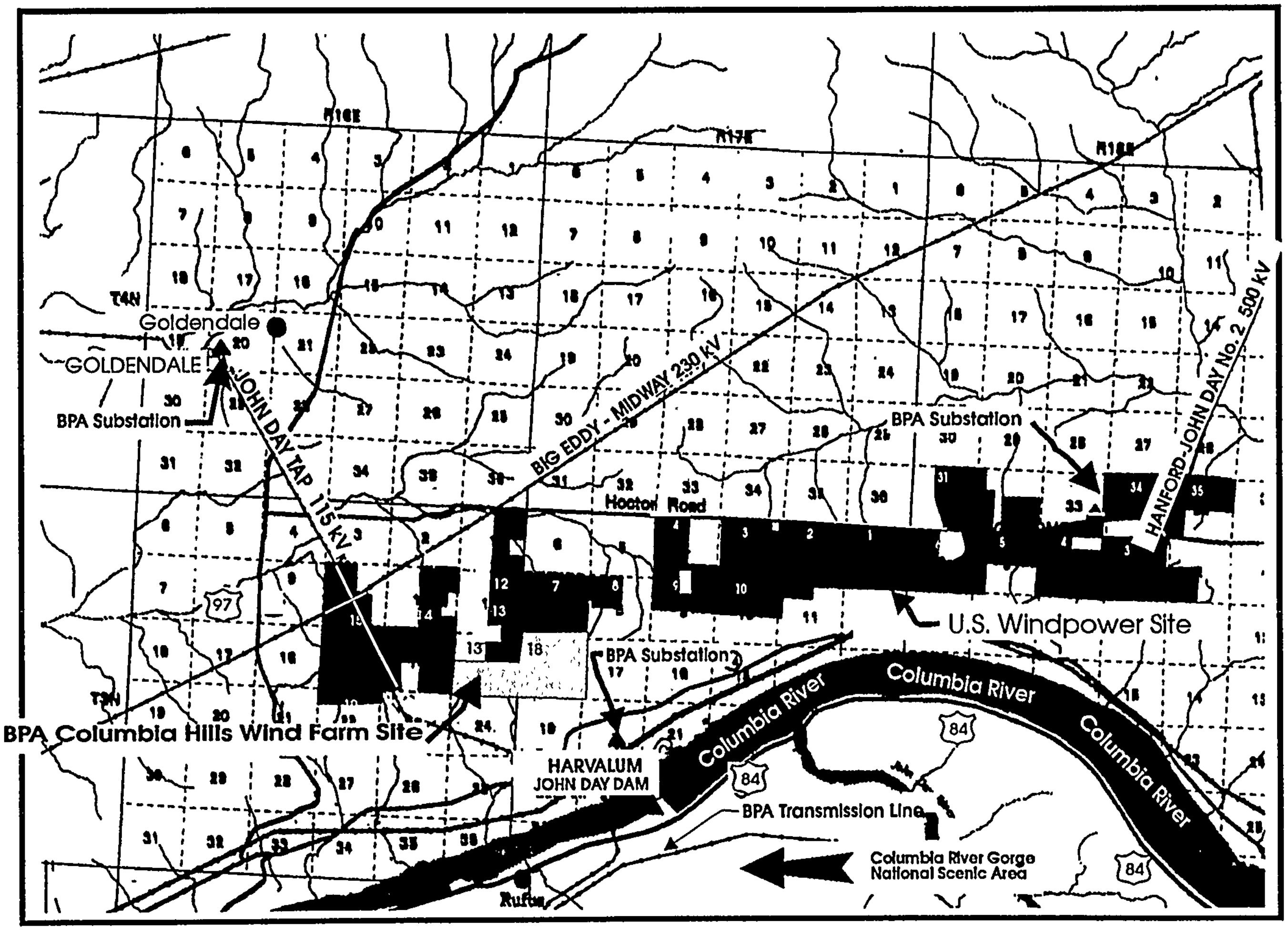

Fig. 7.1. Klickitat County proposed wind projects: Columbia Hills.

7.2.4 Study Considerations

Environmental review processes are now being conducted on the Columbia Hills wind development proposals by BPA and Klickitat County. The principal environmental issues identified for the study include (1) impacts to resident and migratory bird populations from operating wind turbines; (2) impacts to other wildlife and habitats; (3) impacts to cultural resources; (4) aesthetic and visual impacts; and (5) land use impacts. Experience from the California wind farms indicates that birds, especially birds of prey (raptors), may be struck by or collide with operating wind turbines. The environmental studies will analyze the potential impacts to the avian populations, especially those that are threatened or endangered. The Columbia Hills were historically used by Native Americans for traditional and ceremonial purposes, and studies will determine to what extent their culture may be impacted by development of the proposals. Wind turbines modify the existing landscape, and visual impacts to and from key viewpoints will be analyzed. The proposals would be built on lands zoned for agricultural purposes and would be at variance with the current land use plan. A conditional use permit would have to be issued prior to project development.

BPA uses an iterative approach to planning, with many stages of review. The system performance requirements are load-oriented. They describe how various portions of the system must perform for various load levels. It is possible, however, to create or alleviate line overload problems by adjusting generation and intertie schedules without changing load levels. Although the criteria is deterministic, there is an implied probabilistic-cost-benefit methodology. The spirit of this methodology is used to set up the generation pattern and intertie schedules for generator integration studies.

In addition to planning for an acceptable level of probability of overload, voltage violations, and stability, system planning works with those people who must operate and maintain BPA's transmission facilities to obtain input on planning issues. Each of the affected parties may add their own criteria, based either on policy or on their best judgment. BPA is developing generation integration standards with input from all the concerned parties within BPA.

Plans are developed as if a single utility owned all relevant generating, transmission, and distribution facilities in order to minimize duplication of facilities, environmental impacts, and costs, and to maximize system efficiency.

Specific assumptions made in this study were as follows:

1. None of the projects will adversely affect fault current, voltage stability, or angular stability.
2. Automatic generation control issues will not be studied because of the relatively small size of the wind generation facilities relative to the size of the BPA system.
3. Power produced by these projects will displace generation on the Mid-Columbia dams.

7.3 EVALUATION RESULTS AND DISCUSSION

Integrating new generation into an existing transmission system is a complex process. Technical issues associated with each wind energy alternative are outlined in this section. These analyses require a detailed knowledge of transmission system analysis tools as well as an understanding of how the specific transmission system responds under different operating conditions.

In the course of the study, BPA evaluated the transmission capacity for each of the wind generation alternatives. The key results for each alternative are discussed below. A more detailed discussion is contained in the original BPA report.[7]

7.3.1 25-MW Alternative

Generation additions change the balance of power carried from the Dalles area to the Portland/Willamette Valley area on 115-, 230-, and 500-kV transmission lines. The Dalles–Hood River 115-kV line is the limiting link. There is a reluctance to reconductor this line because it traverses difficult terrain where new access roads would have to be built. The generators that have the most impact on the Dalles–Hood River line are those that are integrated on the 115-kV system. These generators include the Klickitat project, some units at the Dalles Dam, a co-generator at SDS Lumber near Hood River, and some units at the Bonneville Dam. The Dalles units, like the Klickitat project, increase loading on the Dalles–Hood River line. The SDS generator and the Bonneville units decrease the loading.

The Klickitat project would complicate the operation of the power system. The impact of the Klickitat project on the maximum or minimum generation at the Dalles and Bonneville facilities was investigated. The Klickitat project would make it somewhat easier to overload the Dalles–Hood River line for an outage of the Big Eddy–Ostrander 500-kV line. At peak output of Klickitat generation, the Bonneville Dam units feeding the 115-kV bus would need to increase output by 10 MW. The thermal limit of the Dalles–Hood River line at a wind speed of 2 ft/s was made the limiting factor. The actual impact would be somewhat less because of the greater capacity due to the additional cooling of the line by the wind. The practice of modifying generation output to alleviate an overload or the threat of an instability for a contingency is an exception to present operating procedures. This practice is now limited to the major interties for the region but may become standard practice for many of the intraregional lines as well. Power system security tools are under development to help the operators make the best use of the transmission facilities. These tools will take the latest real-time data, model the transmission network, and report on critical contingencies, and may suggest corrective actions.

Output from the Klickitat project would be incorporated into BPA's load control area. BPA would be responsible for scheduling and maintaining reserves for the project. Little change in the hour-to-hour output of the project is expected.

Generator output data would be sent to BPA's control center by BPA's microwave telemetry. A leased telephone line would be required for BPA's remote metering system (RMS). RMS collects and stores metering data until it is periodically downloaded to a central site. The phone line can also be used for voice communication.

The alternate feed for the Goldendale area involves operating a section of the Big Eddy–Midway 230-kV line at 115 kV. When the alternate feed is used, the power flowing through the Kennewick–Pasco–Richland 115-kV grid might need to be restricted to an acceptable level by changing generation patterns. An outage of the Hanford–Vantage 500-kV line without the restriction could cause cascading line failure. The level of Klickitat's project generation would have very little effect on the power flowing through the 115-kV grid under the alternate feed scenario when the power produced offsets generation on the Mid-Columbia.

The rate of decay of excitation of induction generators (or motors) after disconnection from the power grid is decreased with shunt capacitor compensation. If the excitation continues too long after a line-to-ground fault, damage to line-to-ground-connected electrical equipment may occur from high voltage due to neutral shift. Arrestors used to prevent overvoltage transients are particularly sensitive to damage from neutral shift. An effectively grounded system would hold the neutral shift to an acceptable level. BPA has required the transformer serving the induction generators to be effectively grounded on the transmission side to protect its arrestors.

7.3.2 50-MW Alternative

The Columbia Hills 50-MW (Kenetech/US Windpower) project involves three utilities that would own the output from the wind generation project. They have requested a point of integration and wheeling on the BPA system. Reaching agreements with so many different entities is often a difficult process, and BPA is in the early stages of negotiating with the participating utilities. There is no single "correct" answer to address any of these issues. Each situation is unique depending on where the generation is integrated on the system, and each of these issues must be addressed regardless of where the integration is to occur.

For the Columbia Hills project three interconnection site options have been proposed:

1. the BPA Big Eddy–Midway 230-kV line at a point east (on the Midway side) of the location where the Klickitat PUD 115-kV line crosses the BPA line, with the John Day tap line used as the emergency feed;
2. at a location near the intersection of Hoctor Road and the Big Eddy–Midway 230-kV line, an option very similar, electrically, to the option above; or
3. the Harvalum substation.

The utilities that are requesting an interconnection with the BPA system will indicate their preferred option; however, the technical studies, economic analysis, and environmental review will dictate the most suitable site. Another siting alternative that uses shared facilities may need to be considered in order to reduce environmental impact.

Because the Columbia Hills wind generation integration will involve BPA, a federal agency, this project requires state and federal environmental review. In this case an environmental impact statement is required. The environmental review will include public involvement. The principal environmental issues identified for the study are (1) impacts on resident and migratory bird populations from operating wind turbines, (2) impacts on other wildlife and habitats, (3) impacts on cultural resources, (4) aesthetic and visual impacts, and (5) land use impacts.

The following issues affecting integration options are of particular interest on this project:

1. Most of the wind projects are on hillsides. Minimizing road construction reduces erosion and the scarring of the hillsides. This concern favors the substation site near the Hoctor Road crossing, which is in a relatively level area.

2. Shared facilities is another issue. The two wind generation projects are adjacent. Klickitat County wants these projects to share facilities to reduce the environmental impacts. Unfortunately, these projects are now designed for different collection and transmission voltages and are progressing on different schedules. It is difficult for all parties to agree. When the environmental impact statements are publicly reviewed, there may be more pressure to combine facilities.

BPA has a policy of maintaining and operating a continuous path on its transmission lines. An issue to be resolved is who purchases the breaker(s) and/or other equipment in the continuous path of the line. Sometimes utilities object to sharing costs for equipment they do not own and operate.

BPA requires that the substation be designed and constructed to BPA specifications and will provide estimates for the design and construction. The utilities that own the output from the project will have the option to design and construct the substation; however, this option has not been negotiated. New construction in existing BPA facilities required to accommodate wind facilities will be done by BPA, to be reimbursed by the project's owners.

The Columbia Hills wind project would require interchange telemetering to transfer the output power data from the wind project to owner utilities for management of their load control areas. The responsibility for maintaining reserves and scheduling for the unpredictable nature of the wind generation would rest with the project owners. However, each of the three utilities and BPA have a share in the Mid-Columbia hydro projects. The three utilities have indicated that they would use the Mid-Columbia for their reserves. If this is the case, the Mid-Columbia hourly coordination group would end up "load-following" this wind generation; this has an impact on the way the generation is operated. Since BPA is a member of the hourly coordination group, BPA would be indirectly involved in scheduling for load-following.

This project is much less likely than the Klickitat project to cause an overload on the Dalles–Hood River 115-kV line when an outage occurs on the Big Eddy–Ostrander 500-kV line.

The alternate feed for the Goldendale area involves operating a section of the Big Eddy–Midway 230–kV line at 115 V. When the alternate feed is used, a restriction on the operation of the power grid must be imposed. The power flowing through the Kennewick–Pasco–Richland (Tri-Cities) 115-kV grid must be restricted to an acceptable level. The 50-MW alternative would have only a small effect on the power flowing through the 115-kV grid under the alternate feed scenario when the power produced offsets generation on the Mid-Columbia.

Integration of 50 MW of wind-farm generation has virtually no impact on line overloads even with an additional 250 MW of generation integration at Harvalum.

The four-quadrant, pulse-width-modulated inverter adds a great deal of flexibility to the reactive capability of this source. It can add to the voltage stability of the converters of the dc intertie at Celilo under heavy import or export conditions. There are possible improvements under light load conditions as well. If there were no wind, the full reactive capability of about 50 Mvar might be used to buck the voltage under light load conditions to allow the harmonic filters to be put on line. Filters raise the voltage.

If the integration occurs at Harvalum, the reactive capability would be helpful for an outage of the Big Eddy–Harvalum line. Horse Heaven, a connection along the Harvalum–McNary line, is the only feed for Harvalum for this outage. The voltage at Harvalum is dependent on the load at Horse Heaven. Under some conditions the load at Horse Heaven could be high enough to cause low voltages at Harvalum. The real and reactive output from the wind farm could ensure the voltage security of Harvalum.

7.3.3 250-MW Alternative

The impact of 250 MW integrated on the 230-kV grid on the Dalles–Hood River line should be equal to the impact of the 25-MW Klickitat project—i.e., an additional 10-MW increase in generation at the Bonneville units feeding the 115-kV bus will be necessary to prevent the Dalles–Hood River line from overloading for an outage. Reconductoring the Dalles–Hood River line is an alternative to rescheduling generation.

The alternate feed for the Goldendale area would involve operation of a section of the Big Eddy–Midway 230-kV line at 115 kV. When the alternate feed is used, a restriction must be imposed on the power flowing through the Kennewick–Pasco–Richland 115-kV grid, but at the 250-MW level it could be difficult at certain times to restrict the power on the grid. There could also be some cost from lost revenues and/or purchase of replacement power. Reinforcement to this grid is an option.

Integration of 250 MW of wind-farm generation would have very little impact on line overloads.

The additional 200 MW of wind power integration would require some consideration of power supply forecasting. Fluctuations of 275 MW due to wind power output swings are nearly as large as the 280 MW local operating reserves BPA now maintains. Predicting what the generation level will be for the next hour will become important. The advanced power electronics technology used in the project can smooth out the power from wind gusts and lulls. The use of variable frequency on the induction generators allows the rotor to store the energy of wind gusts before it is changed to electrical energy.

Wind gusts can increase wind speed by 50%. This will raise the energy by a factor of 3 because the power that can be extracted from the wind is proportional to the cube of the wind speed. Gusts are the result of turbulence over a dimension of less than 300 m. Because wind farms are larger than this, their total output is relatively stable even in gusty (turbulent) wind conditions.

The Dalles–Hood River line is most likely to be sensitive to wind generation under abnormally cold winter weather conditions, which have the likelihood of occurring once in 20 years. For a small wind plant integrated on the 115-kV system, the increase in thermal rating with wind speed is likely to match the increase in wind power with wind speed. This would not be true for a large wind project.

Scheduling for the Klickitat Project would be bundled with some miscellaneous generation that includes various small generation projects. Standard assumptions are made about this miscellaneous pool, and adjustments are made to the load-following units later if there is an error in the assumptions. A reasonable standard assumption is that 30% of peak output capability will be available. When the wind projects are peaking, 70% of that peak is likely to be displaced on the load-following units. The load-following units are likely to be on the Mid-Columbia.

Maintenance is necessary for reliable service. A three-breaker ring bus with BPA ownership of a continuous path and designed and constructed to BPA specification would provide the needed operational flexibility without the need to coordinate an outage with foreign utilities operating the generation project.

7.4 SUMMARY AND CONCLUSIONS

Integration of wind generation projects onto the transmission system is a complex task requiring experienced transmission planners. The challenges of successful integration are highly dependent on the characteristics of the project, the transmission system, and the types and amounts of loads being served. Specific comments for the three wind generation cases considered in this study are given below.

7.4.1 25-MW Alternative

The induction generators of the 25-MW facility would slightly lower the transfer limit between the Dalles area and the Portland area if integrated through the Chenoweth 115-kV substation. This is the result of changing the balance of power carried on the 115-, 230-, and 500-kV lines. From a planning perspective the concern is reduced because the wind necessary to produce the wind power will also provide additional cooling of the transmission lines. The cooling will increase the capacity of the transmission line enough to nearly cancel the reduced transfer capability. From an operational point of view, without the awareness of the wind, the response might be to adjust the generation levels at the Dalles and Bonneville dams.

The induction generator units will require BPA to provide additional var generation and voltage regulation services. Uncertainty about the rate of excitation decay under fault conditions and subsequent system isolation requires the implementation of additional system protection features.

7.4.2 50-MW Alternative

The 50-MW facility has some significant integration issues that need to be addressed if the Big Eddy–Midway 230-kV line is used. These concerns are the number, arrangement, and ownership of breakers for an acceptable plan of service; how maintenance outage will impact the Richland-area 115-kV grid; and the possibility of unnecessary environmental impacts if the projects do not combine facilities.

7.4.3 250-MW Alternative

Integration of 250 MW from Columbia Hills at Harvalum Substation can be accomplished without substantial reduction in system reliability or system reinforcements. A resag of the Big Eddy–Harvalum 230-kV line would be required if, in addition to the wind generation, a separate 250-MW gas turbine project under consideration were also integrated at Harvalum. The integration point might need to be at Harvalum if combined use of wind-generating facilities is required for environmental reasons.

Integration of an additional 200 MW from Columbia Hills on the Big Eddy–Midway line will require generation restrictions for the outage of the Columbia Hills–Big Eddy portion of the line or substantial transmission reinforcements.

Predicting the near-term output from wind projects for scheduling will become more important as the wind generation level rises to the level of spinning reserve. Real-time power system security assessment and transmission system planning for new facilities will be impacted by the additional system stresses caused by generation at this level.

8. DELAWARE MOUNTAIN SITE STUDY

8.1 INTRODUCTION

The Lower Colorado River Authority (LCRA), located in Austin, Texas, performed a study to determine the transmission facilities required to support renewable resource generation in West Texas.[8] This study identifies facilities needed at the point of interconnection between the generation facility and the existing transmission system, as well as the transmission system improvements needed to deliver the power to the major load centers in central Texas.

West Texas is a prime location for the development of wind generation facilities. In terms of potential wind sites, the study area encompasses three class 5 wind regimes and one class 6 wind regime. As a point of reference, this class 6 wind regime represents a wind profile comparable to those experienced in Altamont Pass, Techachapi Pass, and San Gorgonio Pass in California, where almost 80% of the world's total wind generation is now located. See Fig. 8.1 for a profile of statewide wind resources.

Included in this study are transmission plans for three small-scale renewable resource generation sites ranging in size from 25 MW to 100 MW and one medium-scale (250-MW) renewable resource generation site located at Culberson County. The impacts of renewable resource generation on area facilities owned and operated by Texas Utilities (TU), West Texas Utilities (WTU), and Texas–New Mexico Power (TNP) were quantified.

8.2 SITING CONSIDERATIONS

Figure 8.2 illustrates the location of the evaluated sites and their geographic relationship to wind resources in the area. The sites are described as follows:

Site no.	Site name	Bus voltage
1	Culberson County	138 kV
5	Alpine	69 kV
7	Alamito	138 kV

8.3 EVALUATION RESULTS

8.3.1 Evaluation Criteria

The transmission system in West Texas was evaluated using the planning criteria of the Electric Reliability Council of Texas (ERCOT). Transmission plans were developed to provide adequate service under single contingency conditions. The single contingency conditions studied included the loss of any single-circuit transmission line or any two

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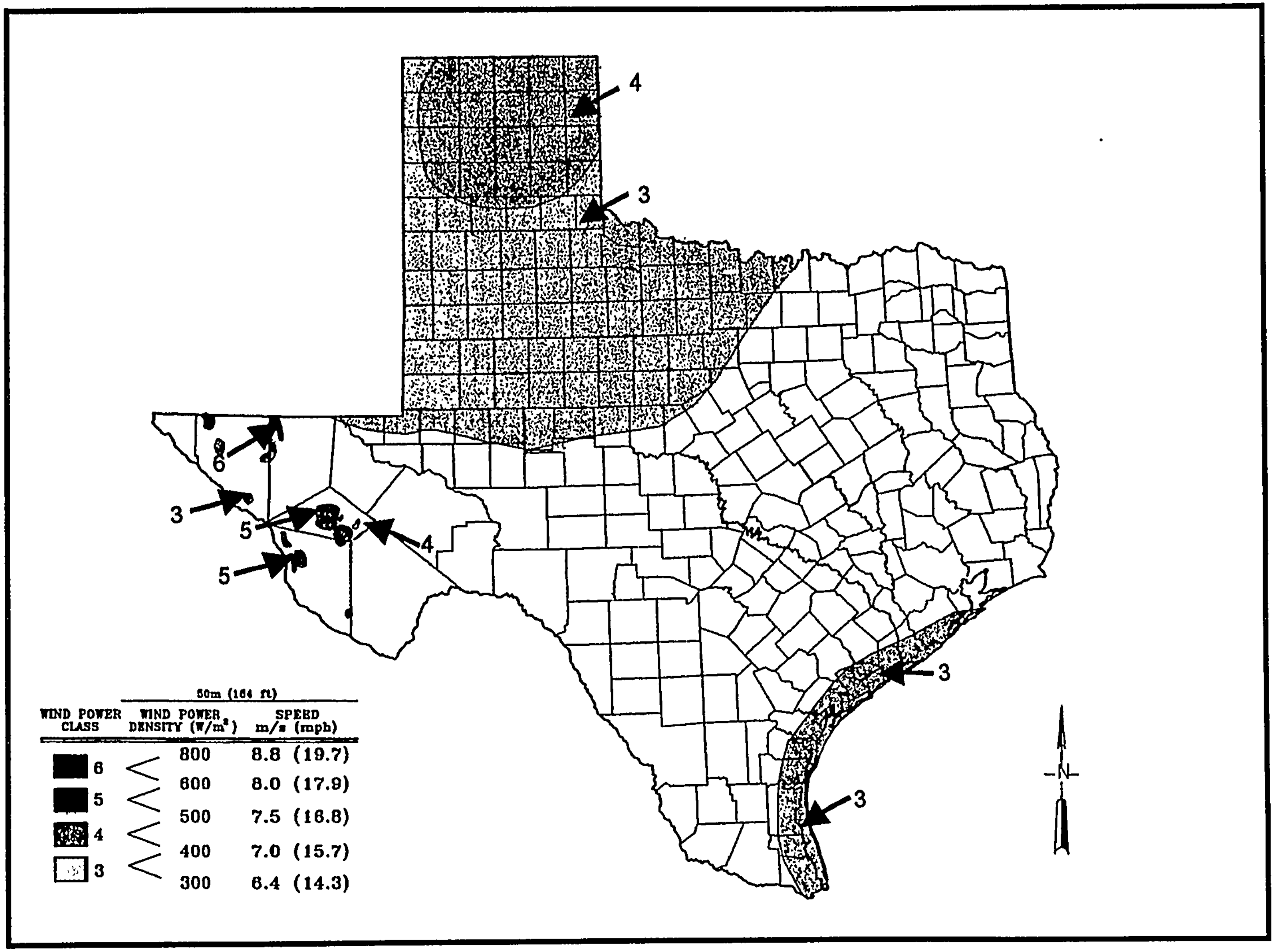

Fig. 8.1. Texas statewide wind renewable resources.

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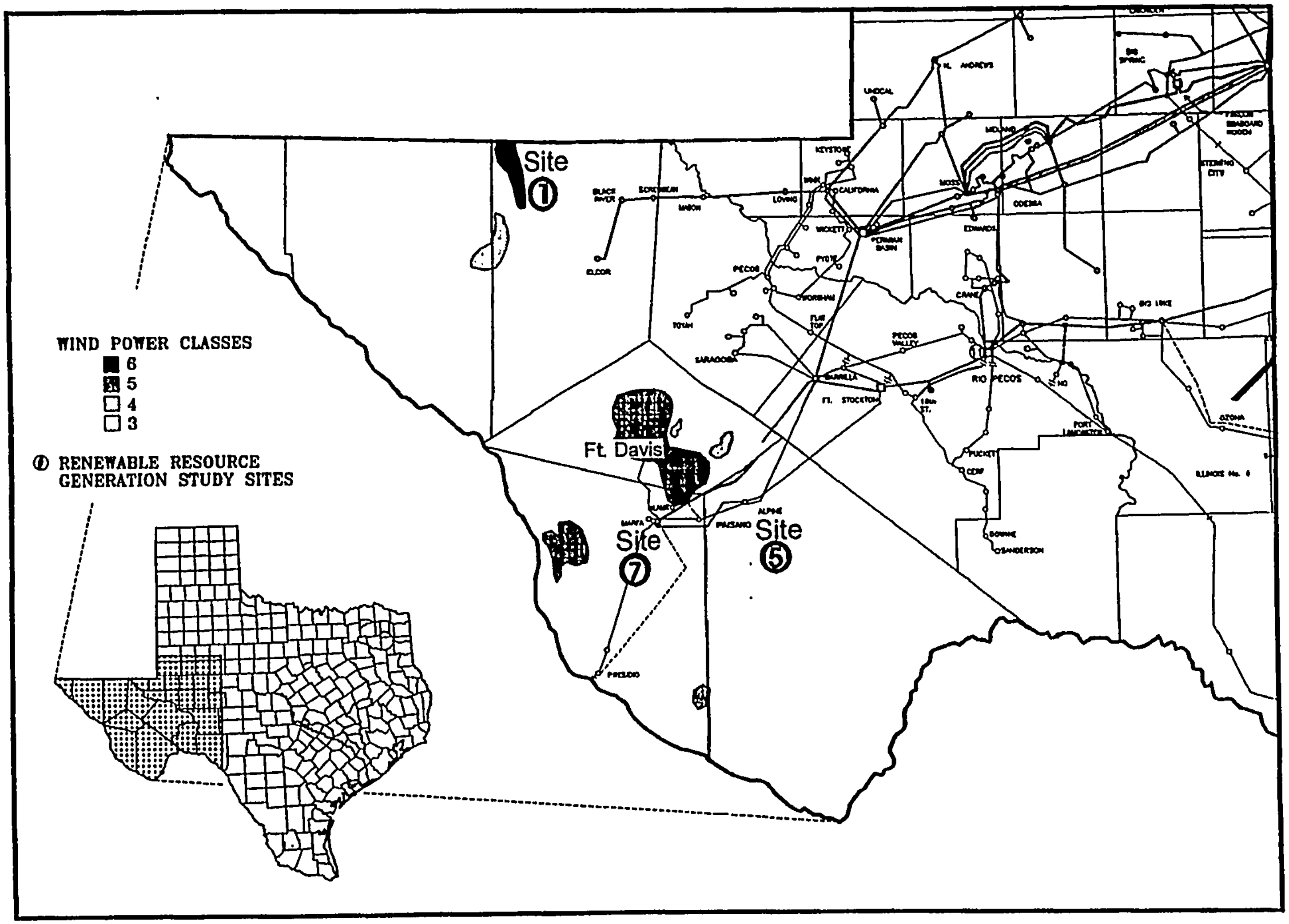

Fig. 8.2. Renewable resource generation study sites, existing transmission facilities, and renewable resources.

transmission lines that are constructed on a single set of structures. The transmission plans for the site were developed to avoid exceeding the thermal capacity of any transmission line or piece of equipment.

The voltages on the transmission system were reviewed for all conditions studied to ensure that a voltage collapse condition was not imminent. The major focus of the study was on the thermal ratings of the equipment and on ensuring adequate voltages under contingency conditions. It was assumed that marginal voltages in a specific area could be improved by providing reactive compensation.

The renewable resource generation sites were tested under various operational scenarios to bracket probable future conditions on the transmission system. The study was based upon the 1994 Summer Peak ERCOT power flow case.

8.3.2 Capability of Existing System

Thermal constraints identified in the study of small-scale renewable resource generation capabilities ranging from 25 MW through 100 MW have been classified as being of two types: local area limitations and parallel path transfer limitations. In general, local area limitations are isolated system deficiencies in the immediate area. This type of limitation is directly dependent upon the location of the generation source. Parallel path transfer limitations include limitations on the bulk transmission system (345-kV network) and the underlying 138-kV and 69-kV subsystems. These limitations are less dependent upon specific site locations. Instead, they are a function of the amount of power that is being transferred across the transmission grid from generation regions to the major load centers.

With renewable resource generation levels at 25 MW, no additional local area limitations were found at any of the three sites under all but the most extreme generation scenarios (all existing generation in West Texas at maximum output).

With renewable resource generation levels at 50 MW, all sites except Alamito can be integrated into the network without the need for additional improvements in the immediate area under all but the most extreme generation scenarios. Under the most extreme generation scenario all sites will require additional improvements in the immediate area to be integrated into the network.

With renewable resource generation levels at 100 MW under normal generation scenarios, all sites will require additional improvements in the immediate area to be integrated into the network.

Thermal overloads on parallel path circuits were encountered when existing area generation was increased to represent heavy generation loading conditions. As new small-scale renewable resource generation sources were added up to 100 MW in the area, additional parallel path overloads were experienced.

8.3.3 Medium-Scale Renewable Resource Generation Sites

The impacts of a 250-MW (medium-scale) renewable resource generation site at Culberson County was studied under conditions of maximum existing local generation. With medium-scale renewable generation the existing transmission system is unable to support power flows out of Permian Basin, since 138-kV circuits from Permian Basin east into the Moss/Odessa area overloaded during contingency conditions. The estimated upgrade cost is $56 million.

8.3.4 Operating Procedure Modifications

Utilities in the area have developed operational guidelines to limit selected unit generation and the resulting thermal overloads on existing lines parallel to the 345-kV network from the Permian Basin area into the Dallas/Fort Worth metroplex. Any renewable resource generation facilities added in the area will have to be integrated into existing operational guidelines to be operated effectively. As part of the required improvements, operational procedures have been identified where possible to further avoid the need to reconductor 69-kV and 138-kV circuits along parallel paths with the 345-kV network. Opening certain lines during key outages on the 345-kV system can avert thermal overloads during these major power transfers. If existing area generation is allowed to increase above existing economic dispatch levels, various levels of parallel path system improvements to avoid thermal overloads will be required.

8.4 DISCUSSION

The severity of integration problems is clearly a function of both the size of the renewable resource generation facility and the amount of area generation. As more power is supplied into the transmission system in an area, either in the form of new renewable resource generation sites or by increasing the output of existing generation facilities, more lines and autotransformers will exceed their thermal ratings.

8.5 SUMMARY AND CONCLUSIONS

Strictly from the standpoint of evaluation criteria, viable renewable resource generation sites exist in West Texas. Wind profiles in this area will support these types of generation sources.

Under the normal operating condition scenario, all of the small-scale renewable resource generation sites operated at 25 MW or 50 MW (except Alamito at 50 MW) can be integrated into the existing transmission system simply by connecting the facility into the existing grid.

The best site for wind generation facilities is located in the class 6 wind regime in Culberson County. This location will require that a new 25-mile 138-kV transmission circuit be built from the Blackriver area into the generation site. Because only a single transmission exit out of the Culberson County site will exist initially, any outages along this 100-mile circuit into Wink will force the generation facilities in Culberson County to be taken out of service. A second limitation lies in the fact that the capacity of the existing 138-kV transmission line into this area is only 84 MVA. A second 138-kV line will be required if and when the amount of ERCOT wind generation in Culberson County exceeds 84 MVA.

The addition of renewable resource generation facilities in excess of 100 MW will require extensive transmission construction including the construction of new 345-kV facilities. Renewable resource generation facilities of 250 MW at Culberson County will require the construction of a new 345-kV circuit from Permian Basin to Moss.

9. AMARILLO AND GUADALUPE SITES SPP STUDY

9.1 INTRODUCTION

Southwestern Public Service Company (SPS, Amarillo, Texas) has completed a case study to investigate the integration of wind renewable energy resources up to 250 MW into its electric power transmission system.[9] Integration issues to be studied include the evaluation of existing transmission capacity, barriers to integration, operating procedures affecting capacity, and the identification of the need for new or upgraded transmission lines. Wind resources near Amarillo in Hutchinson County, Texas, and in the Guadalupe Mountains in Culberson County, Texas, were investigated. SPS is a member of the Southwest Power Pool (SPP), which is a part of the Eastern Interconnection.

9.2 SITING CONSIDERATIONS

In order to investigate the potential for using wind energy, two generation sites and three load centers were investigated, as shown on Fig. 9.1. The generation sites are G1, near the Pringle substation in Hutchinson County, Texas; and G2, the Guadalupe Mountains in Culberson County, Texas. Although there is limited transmission available in the Guadalupe area, the Lower Colorado River Authority (LCRA) is developing a project in the area, and an environmental assessment has been performed for this project. No environmental assessment was performed for the other site, and no consideration was given to the availability or proximity of water and gas supplies in the area.

The three electrical grids surrounding or connected to SPS are the proposed load centers. These are L1, the Western Systems Coordinating Council (WSCC) grid west of the HVDC interchange at Eddy County; L2, a possible HVDC interchange to ERCOT located near the SPS Midland substation; and L3, a load center located on the north side of the SPP.

At this time there are no environmental constraints that SPS is aware of that would prevent the installation of a wind farm or an expanded transmission system.

9.3 EVALUATION RESULTS

9.3.1 Evaluation Criteria

The summer peak load-flow models for the years 2000 and 2005 were used. Summer conditions normally put the greatest amount of stress on SPS's transmission system. The year 2000 and 2005 models have all anticipated line additions and upgrades and all additionally planned generation resources. Load centers outside SPS's service area were selected for all cases.

9.3.2 System Capability

In general, it is practical to export up to 100 MW from a power-flow standpoint with minimum internal system improvements. The Pringle, Hutchinson County, location is representative of many suitable locations in the Panhandle of Texas that have high potential wind generation. If the generation source ties in at Pringle, the existing substation can accommodate an additional wind resource up to approximately 200 MW. A second 230/115-kV, 225-MVA autotransformer must be added for the 250-MW case. Many other suitable locations are close to lower voltage transmission lines (69 or 115 kV), which would support small wind farms of perhaps 25 or 50 MW. Upgrades of these lower-voltage lines to 115 kV or 230 kV would be needed in order to connect to the 230-kV backbone system, which is better able to transfer large blocks of power. Once the 230-kV backbone system is reached, then the power flows should be approximately the same for different Panhandle locations.

To gain access to the wind resources of the Guadalupe Mountains, two new 60- to 70-mile 230-kV transmission lines would be required. The first line would go to the Eddy County HVDC intertie, and the second line would go to the Potash Junction interchange.

It should be noted that additional power transfers into WSCC and ERCOT are not presently possible because of the lack of adequate transmission and HVDC capacity. A 200-MW bi-directional HVDC interconnection would have to be added to the Eddy County HVDC to be able to ship power west to the WSCC. A 300-MW bi-directional HVDC interconnection, switching equipment, and static var controller with a range of 200-Mvar capacitive and 100-Mvar inductive would have to be added at Midland to be able to transmit power to ERCOT. A 53-mile 345-kV transmission line operated at 230 kV would be required between SPS's Midland County and Borden County interchanges. A short transmission line would also have to be built on the ERCOT side to connect the HVDC at Midland to the Texas Utilities transmission system.

9.4 SUMMARY AND CONCLUSIONS

In general, it is practical to export up to 100 MW from a power-flow standpoint with minimum internal system improvements. The Pringle, Hutchinson County, location is representative of many suitable locations in the Panhandle of Texas that have high potential for wind generation. To gain access to the Guadalupe Mountains' wind resources, two new 60- to 70-mile 230-kV transmission lines would be required. Power flows into both WSCC and ERCOT are not presently possible due to the lack of adequate transmission and HVDC capacity.

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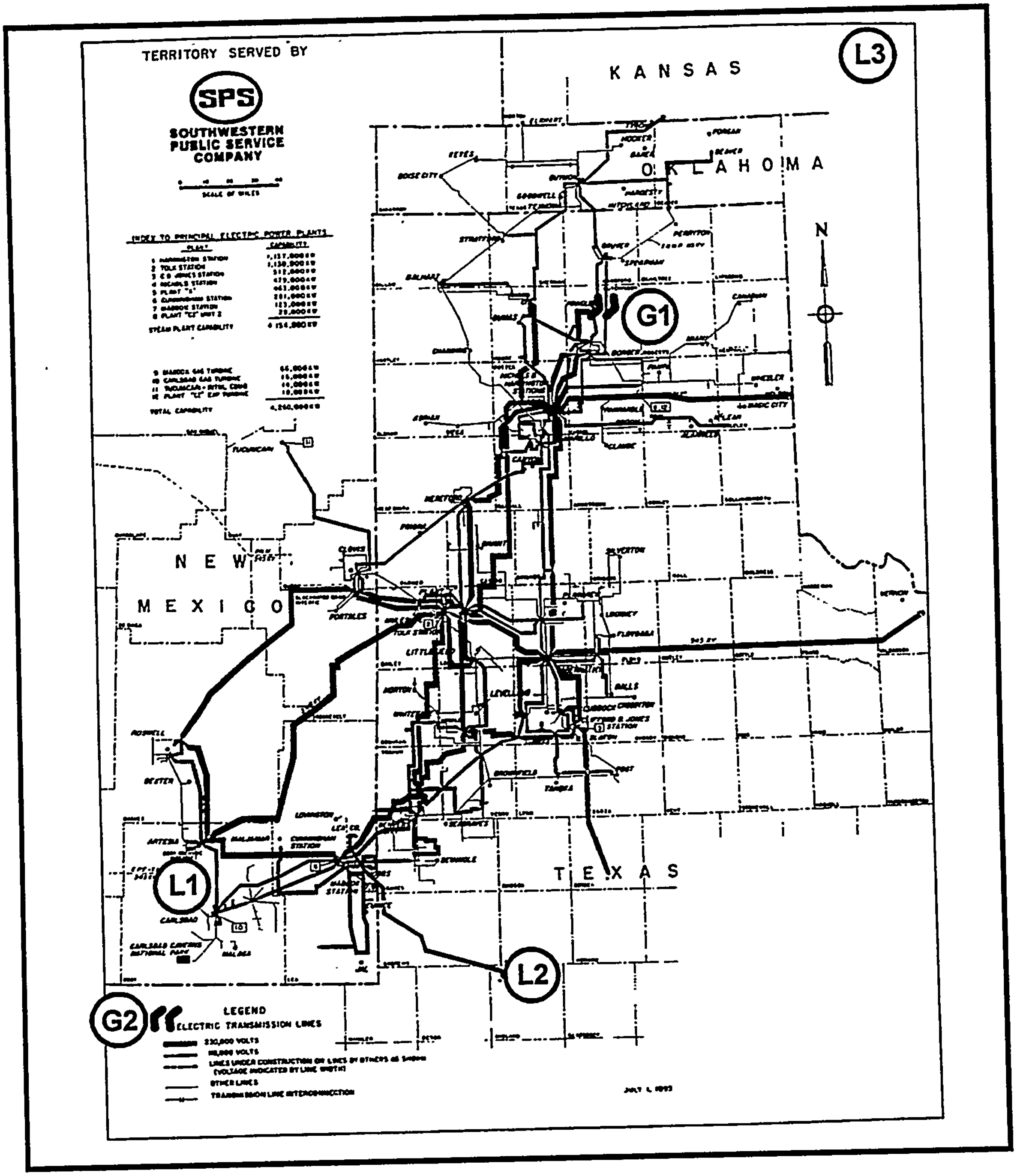

Fig. 9.1. Generation sites G1 and G2 and load connections L1, L2, and L3.

10. TEXAS PANHANDLE ERCOT STUDY

10.1 INTRODUCTION

Texas Utilities Electric Company (TU), located in Dallas, Texas, has completed a case study on behalf of the U.S. Department of Energy investigating the facilities required to integrate wind energy resources in the vicinity of Childress, Texas, into the ERCOT electric power transmission system.[10] The purpose of this study was to determine the capability of the existing transmission system in the vicinity of Childress and to identify the upgrades or additions necessary to connect 2000 MW of wind generation to supply power to the Dallas/Fort Worth area. Existing company and regional planning criteria were observed in the identification of system limitations.

10.2 SITING CONSIDERATIONS

The attached maps show the assumed location of the wind resource (Fig. 10.1) and the proposed transmission lines with existing facilities (Fig. 10.2). No environmental assessment was performed, and no consideration was given to the availability or proximity of water and gas supplies for cases which would require additional facilities.

10.3 EVALUATION RESULTS

10.3.1 Evaluation Criteria

The TU Electric Planning Guide, which ensures that the criteria in the ERCOT Planning Guide are met, was utilized to determine allowable line loadings, voltage drops, and other planning criteria. No degradation in TU's west-to-east transfer limit was allowed for any scenario. This includes both the Morgan Creek-to-Graham transfer limit and the Graham-to-Metroplex transfer limit. While total costs were not explicitly evaluated, the additional facilities identified represent the integration options expected to require the least total capital cost.

10.3.2 Capability of Existing System

Both presently and for the foreseeable future, the capacity of this resource would be limited to 50 MW with no additional facilities other than those required for connection. For resource capacity levels between 50 MW and 120 MW, additional facilities would be required, at a capital cost of approximately $2 million. Facility costs escalate rapidly for resource capacity levels above 120 MW.

10.3.3 Integration of 2000 MW

The proposed configuration for connecting the 2000-MW wind generation facility includes a 345-kV substation at Childress and three 345-kV lines routed to existing TU substations. A fourth 345-kV line is proposed from Graham (TU) to west Denton (Texas Municipal Power Agency) to northwest Carrollton (TU). Other upgrades include the

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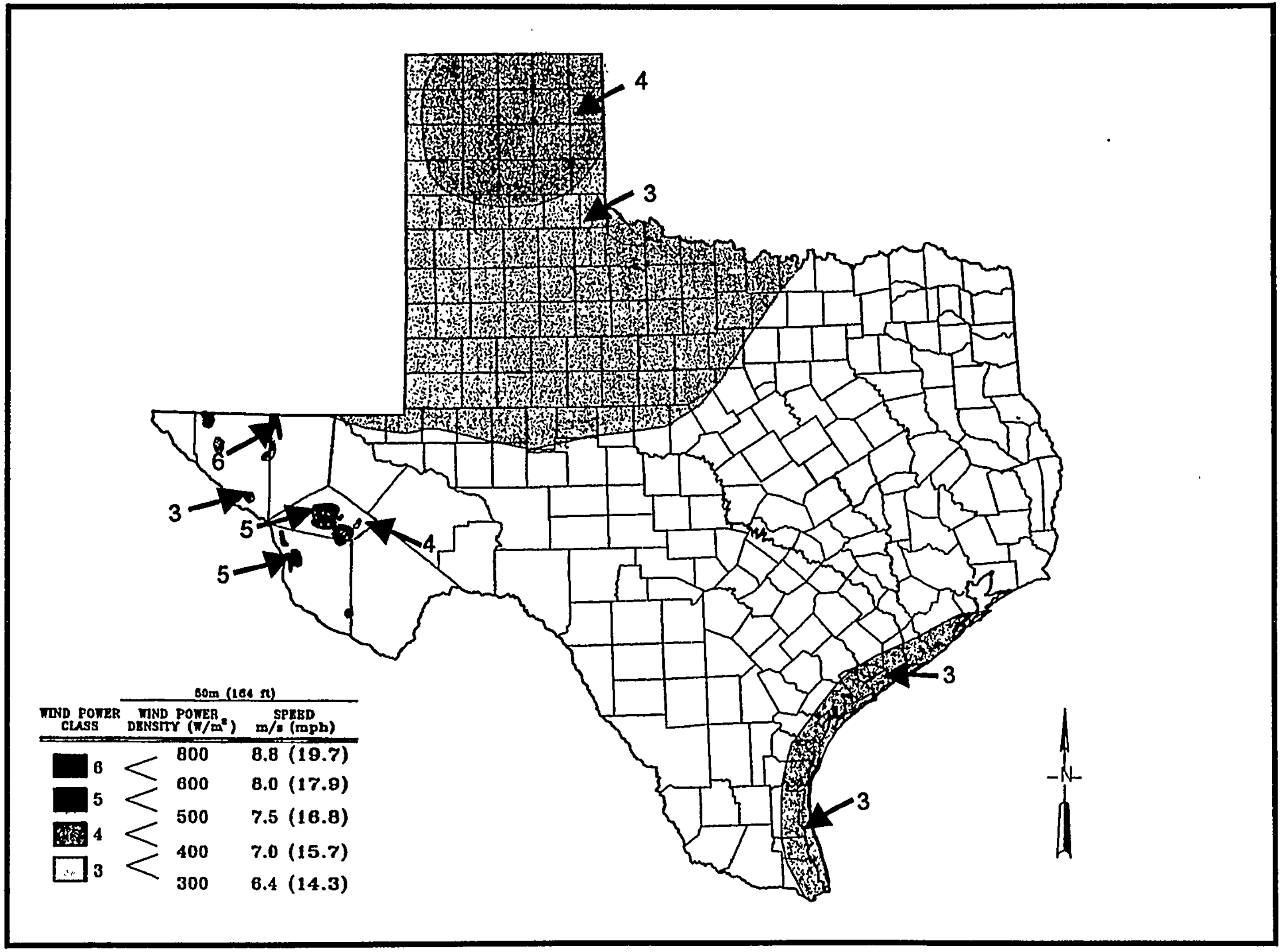

Fig. 10.1. Texas statewide wind renewable resources.

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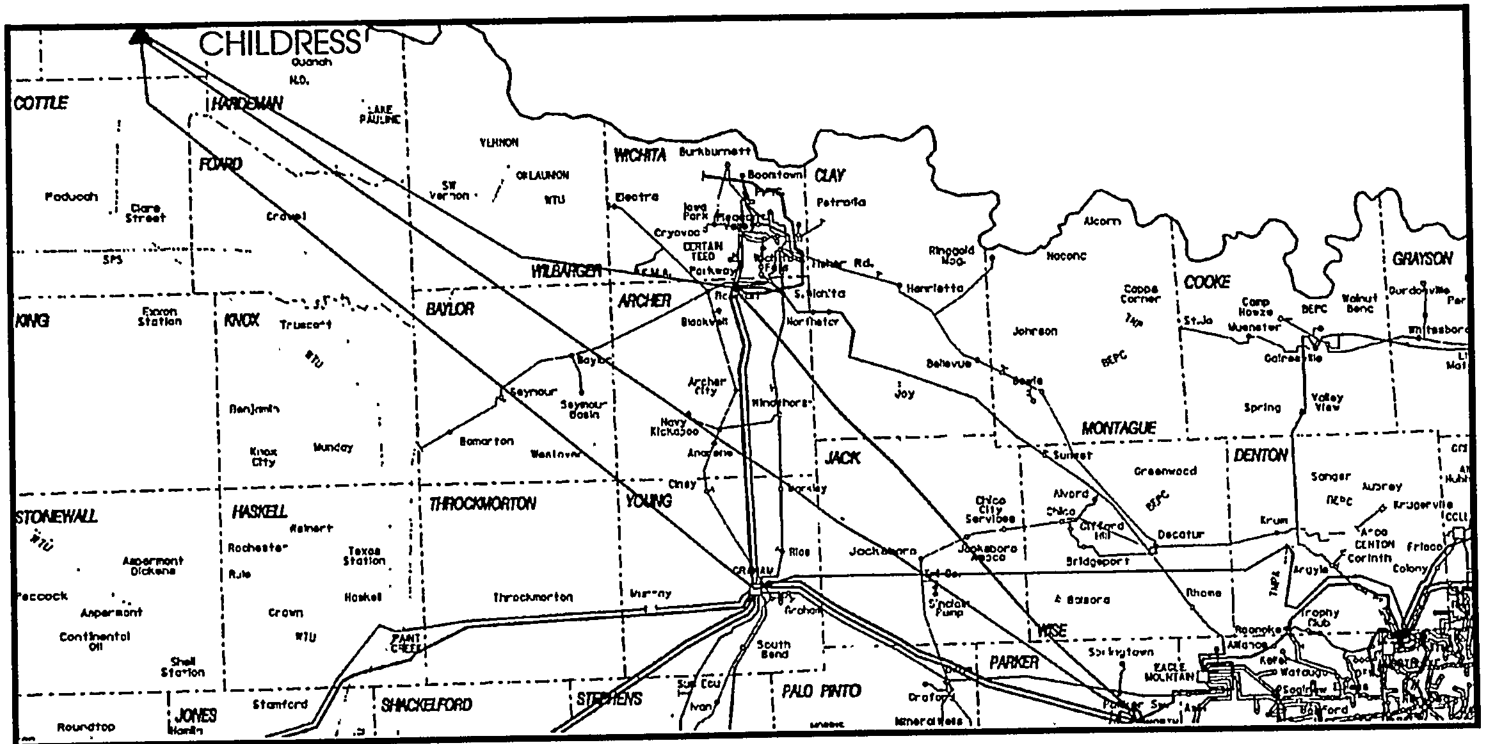

Fig. 10.2. The existing and proposed transmission system in the Childress vicinity.

reconductoring of several 138-kV line sections in the Dallas/Fort Worth area and the addition of a second 138/69-kV autotransformer at WTU's southwest Vernon substation. In all, a total of 520 miles of 345-kV line would be constructed, and a total of 41 miles of 138-kV line would be upgraded, at a total capital cost of approximately $287 million.

10.4 DISCUSSION

10.4.1 Major AC Study Concerns

Three major concerns were particularly important to the study: (1) TU's west-to-east transfer limits (as previously mentioned), (2) voltage control, and (3) system stability. Maintaining the transfer capability was directly addressed, and the facility additions were required for that purpose.

10.4.2 Voltage Levels

The concern for voltage control arose as a result of the line additions required to accommodate the power transfer. During minimum generation levels at the Childress site, the line charging on the long 345-kV circuits would result in high voltages. Studies show that a total of 305 Mvar of 345-kV line reactors will be required to maintain voltage levels within the required range.

10.4.3 Stability

The concern for stability was addressed by reviewing the results of previous studies of similar resource additions. As a result, no new transient or dynamic stability studies were performed as a part of this effort, primarily because the introduction of this resource does not appear likely to significantly affect the stability of the existing system.

10.4.4 HVDC Line Alternative

In addition to the investigation of the requirements for integrating the resource into the ERCOT system using alternating current facilities, the system was studied to determine the additions required for transferring 2000 MW of power over dc lines from the Childress site to the Dallas/Fort Worth metroplex. An option was identified which included two dc lines which originated at the Childress site and terminated at two sites in the metroplex (Parker and northwest Carrollton). The dc option would replace the need for all 345-kV construction, but the 138-kV upgrades would still be necessary.

10.5 SUMMARY AND CONCLUSIONS

Studies indicate that the existing system in the Childress area is capable of supporting 50 MW. However, to integrate a full 2000 MW into the ERCOT system to supply power to the Dallas/Fort Worth metroplex, over 500 miles of 345-kV circuits (or over 400 miles of dc line) would need to be added to the system, including almost as many miles in new right-of-way. The estimated cost for new line is $287 million.

SOLAR PLANT CASE STUDIES

11. MOJAVE DESERT REGION STUDY

11.1 INTRODUCTION

This case study has been performed by Zaininger Engineering Company for the Oak Ridge National Laboratory (ORNL) using transmission study results, representative transmission cost estimates, and other information supplied by Southern California Edison (SCE) planning personnel. SCE has developed information for independent power producers on capacity limits and costs associated with integrating generation into their transmission systems. This information was used for this study in evaluating the transmission capacity for integrating high-capacity solar plants in the Mojave Desert region.

This section examines the capability of the late 1990's SCE transmission system to support the installation of high-capacity solar electric power plants in southern California's Mojave Desert region. Important solar plant siting considerations are discussed. Maximum solar penetration levels with no SCE transmission system reinforcement are estimated for power connected to various SCE substation locations. Incremental SCE transmission reinforcement costs are estimated for larger solar megawatt penetration levels over 750 MW.

11.2 IMPORTANT SITING CONSIDERATIONS

The primary factor in determining the annual energy production of a solar electric power plant is solar insolation. The higher the solar insolation the lower the cost per kilowatt-hour, everything else being equal. The Mojave Desert region in southern California contains excellent solar resources, as shown in previous work.[11,12]

Another major siting factor when comparing the economics of alternative plant sites in an excellent solar resource region is relative transmission costs to deliver the solar electric power to utility load centers. This study compares the relative transmission costs for alternative high-capacity solar electric power plant sites located in the Mojave Desert region.

Environmental land use constraints may also be an important siting consideration when comparing alternative solar plant locations in the Mojave Desert region. A solar plant in the desert will require a significant amount of land. Assuming 10 acres per megawatt, a 1000-MW solar plant would then cover about 10,000 acres, or about 16 square miles. (This acreage does not have to be contiguous, as solar plants can be designed in a modular fashion.) In addition, transmission corridors will be required to deliver the solar power to the SCE interconnection point.

The California Desert Protection Act of 1994 (Public Law 103-433) sets aside a significant amount of desert land to be preserved as wilderness areas, national parks, and national preserves. A map obtained from SCE showing many of these areas, along with SCE major transmission corridors, is presented in Fig. 11.1. Although beyond the scope of this study, environmental land use considerations are expected to play a significant role in siting future high-capacity solar plants in the Mojave Desert region.

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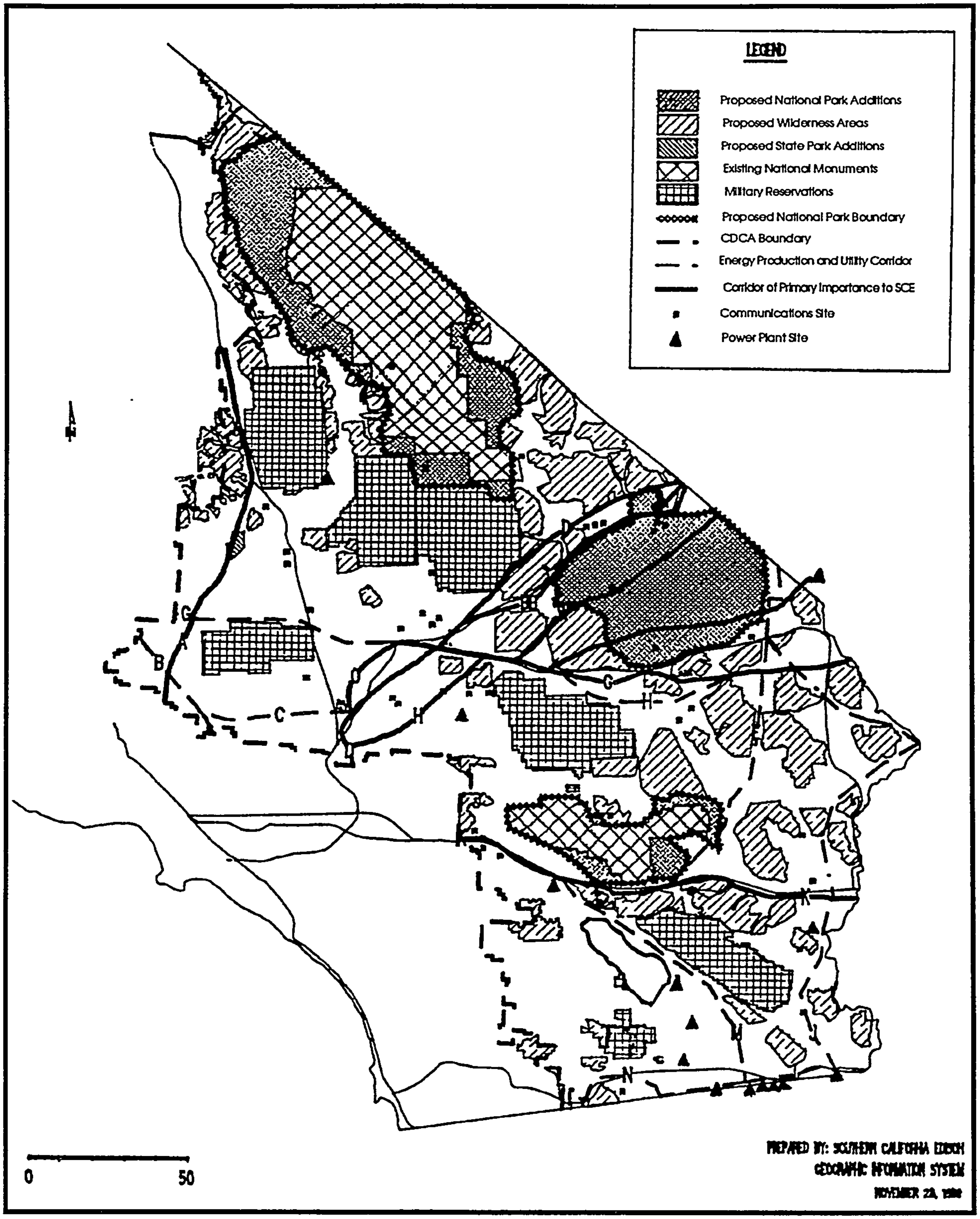


Fig. 11.1. Southern California Edison transmission corridors and areas to be restricted by the California Desert Protection Act of 1994.

11.3 APPROACH AND ASSUMPTIONS

11.3.1 Evaluation Approach

SCE has developed transmission cost tables to provide transmission-related costs, and these have been approved by the California Public Utilities Commission (CPUC) for purposes of preparing and evaluating bids.[13] This report shows six SCE radial transmission intertie systems, which are reproduced in Diagrams 1–6 of Appendix A to this chapter. The approximate locations of three key substations—Vincent, Lugo, and Devers—are indicated on Fig. 11.1 to put the geographic locations of these six radial transmission intertie systems in perspective with respect to the Mojave Desert region.

The cost tables document[13] contains the results of a comprehensive transmission planning study. In particular, the report contains remaining existing megawatt capacity without reinforcement and incremental SCE transmission reinforcement costs associated with interconnecting various levels of new resource capacity up to 750 MW, in some cases, at major SCE bulk transmission substations in these six radial transmission intertie systems. The report considered ongoing system expansion plans and load forecasts for 1997. The study was performed using Western Systems Coordinating Council and SCE transmission planning criteria. Details of the study criteria, assumptions, and assessment methodology used for this study are presented in Appendix B of this chapter.

The evaluation procedure for this case study was to review the data in the cost tables document and work with SCE transmission planning personnel to estimate the electrical generation capacity and relative transmission costs of interconnecting high-capacity solar electric plants totaling 1000–2000 MW at various locations on the SCE system. First, the SCE transmission report was reviewed and interpreted to establish potential SCE substation locations in the Mojave Desert region, where large, high-capacity solar plants could be interconnected without requiring significant SCE transmission system reinforcement. Then differences in the costs to transmit the solar power from alternative solar plant sites to the SCE interconnection point were identified and added to the SCE transmission reinforcement costs to determine the relative transmission costs.

The potential SCE substation locations, solar plant penetration levels, and associated transmission reinforcement requirements and costs were then reviewed with SCE transmission planning personnel during a site visit. The results of the case study were then prepared and sent to SCE transmission planning personnel for review and comments to verify the proper use of information from the SCE transmission cost tables. SCE provided general comments, in lieu of technical analysis, in reviewing this report. SCE noted that the addition of 1000 MW to any system is very significant and should be coordinated with system needs.

These transmission cost tables are presently being used by SCE as part of the process to evaluate bids for new capacity additions to serve projected SCE loads in the mid- to late 1990s. If some of the winning bids (which may or may not be for solar plants) are added to the SCE substations in the Mojave Desert region discussed in the next section, the available solar capacity stated in this report should be reduced by the capacity of any new resources added at that substation.

11.3.2 Bulk Transmission Cost Assumptions

For a high-capacity (several-hundred-megawatt) solar electric power plant installed in the Mojave Desert region, the transmission costs can generally be broken down into the following components:

- transmission costs associated with collecting the power within the solar plant,
- transmission costs to interconnect the power into the SCE bulk transmission system, and
- transmission costs to reinforce the existing SCE transmission system where necessary to deliver the power to the Los Angeles and San Diego load centers.

For this study, which considers only generic solar plant sites, transmission costs associated with collecting the power within the solar plant are considered common to all siting alternatives, and potential differences in these costs are ignored. The power is assumed to be transmitted from the solar plant to the SCE transmission system interconnection point using standard SCE bulk transmission system voltages of 230 kV or 500 kV, since hundreds of megawatts of solar power are to be connected into the SCE transmission system.

Total installed cost assumptions for adding bulk transmission facilities are presented in Table 11.1. These assumptions were discussed with SCE transmission planning personnel, who agreed that the figures appear reasonable for current generic long-range planning. SCE is not responsible for use of the numbers discussed.

Table 11.1. Bulk transmission facility installed cost assumptions

Item	Facility installed cost[a]
1100-MVA 500/230-kV transformer	$10M
Two 500-kV breakers	$5.6M
Two 230-kV breakers	$2.2M
Single-circuit 230-kV line, 1–1590 MCM ACSR	$440K/mile
Single-circuit 230-kV line, 2–1590 MCM ACSR	$620K/mile
Double-circuit 230-kV line, 2–1590 MCM ACSR	$1040K/mile
Single-circuit 500-kV line, 2–2156 MCM ACSR	$820K/mile

[a]Costs do not include cost of land or land rights, and related costs in developing a new substation, such as control house grading, fence, yard lights, and station service.

11.4 EVALUATION RESULTS

11.4.1 Solar Power Interconnected at the Lugo Substation

Review of the SCE transmission cost tables report and conversation with SCE transmission planners indicate that interconnecting the power from large-capacity solar plants into the Lugo substation is an attractive option from a site-specific transmission perspective.

According to the SCE report, at least 750 MW can be connected to Lugo without requiring reinforcement of the SCE transmission system.

Further conversation with SCE transmission planning personnel indicated that it is uncertain if 1000 MW can be connected at Lugo without additional transmission reinforcement. If more than 750 MW of power is injected into the Lugo substation, the 500-kV transmission system in the Los Angeles area might need to be reinforced. Cursory review indicated that installing 40 miles of 500-kV line plus four 500-kV breakers costing approximately $50 million could be required. Of course, if over 1000 MW were installed, a detailed transmission planning study would be required to more accurately determine SCE transmission reinforcement requirements.

Basically, there are three ways to inject the solar power into the Lugo substation:

1. build transmission to connect power into the existing transmission system that is north of Lugo, shown in Diagram 3 of the SCE report (reproduced in Appendix A);
2. build transmission to connect power into the existing Nevada to Lugo transmission system, shown in Diagram 4 of the SCE report; and
3. build transmission directly into Lugo, Victor, and/or Victorville substations.

The first alternative assumes that a solar plant is located near and interconnected to the SCE transmission system near the Kramer substation (Boron, California), shown in Diagram 3. The existing SCE transmission system can handle only 35 MW without requiring uprating. According to the SCE report, $47.3 million will allow the interconnection of up to 245 MW of solar power. An additional $22.4 million, or a total of $69.7 million, will allow up to 720 MW of solar power to be interconnected near the Kramer substation. If the solar plant were located near Dagget, an additional $1.9 million, or a total of $71.6 million, would be required to allow the interconnection of up to 500 MW of solar power. If the interconnection point is further north on this transmission system, the interconnection cost becomes more expensive.

The second alternative assumes that a solar plant is located and interconnected to the SCE system near the Mead–El Dorado–Lugo transmission system shown in Diagram 4. According to the SCE report, this system requires $28.3 million to interconnect from 1 to 152 MW. An additional $235.3 million, or a total of $263.6 million, will allow the interconnection of up to 750 MW to this transmission system. (This $235.3 million includes the cost of a more than 200-mile 500-kV line from Nevada to Lugo.)

The third alternative is to build 230-kV or 500-kV transmission lines from the solar plant directly to, and interconnect to, the SCE transmission system at the Lugo substation. A variation of this alternative is to interconnect to the SCE transmission system at the Victor substation. In this case, there would be no SCE transmission system reinforcement costs until about 750 MW of solar plants are interconnected.

The second part of comparing the relative transmission costs between the three alternatives is comparing the costs of delivering the solar power from the solar plant site to the SCE transmission system interconnection point. These costs include the cost of the transmission line from the solar plant to the interconnection point, plus the substation termination costs at the interconnection point. Assuming rights-of-way can be acquired for all alternatives, the relative transmission line cost, at the first approximation, is a function of the distance from the interconnection point and of whether 230-kV or 500-kV lines are used, as shown in Table 11.1. Substation costs include both termination costs at the interconnection point and the cost of transformer additions if appropriate. The SCE bulk substation bus reliability criterion is a breaker-and-a-half scheme, which typically requires two breakers at the interconnection point.

Assume, for example, that 1000 MW of solar power is transmitted 50 miles or less and interconnected at Lugo. Conversations with SCE transmission planners indicated that this power should be either connected at 500 kV or converted to 500 kV at the substation. If the power were transmitted using a single-circuit 230-kV line with 2-1590 MCM ACSR bundle conductors, the line cost, breaker cost, and 230/500-kV transformer cost would total about $43.2 million. If the power were transmitted at 500 kV, the line cost and breaker cost would total about $46.6 million. If the solar plant were located closer to Lugo and the power had to be delivered only 25 miles, delivering the power at 230 kV would cost about $27.7 million, and at 500 kV about $26.1 million. Comparing these costs with the SCE transmission reinforcement costs of the first two alternatives, and ignoring their transmission delivery costs to the interconnection point, transmission costs for this third alternative are still less costly if high-capacity solar plants can be sited within 50 miles of the Lugo substation.

11.4.2 Other Interconnection Points

According to the SCE report, there is some excess transmission capacity on the Big Creek–Magunden transmission system shown in Diagram 2 (Appendix A). If a solar plant were located and interconnected near Pastoria, at least 750 MW could be injected without additional transmission reinforcement. If the solar plant were located further north near Magunden, 400 MW of solar power could be injected without transmission reinforcement. At least 750 MW can be injected for a transmission reinforcement cost of $26.2 million.

Approximately 600 MW of solar generation can be interconnected to the Devers substation without transmission reinforcement. For transmission reinforcement cost of $39.9 million, 1,140 MW of solar power can be injected at the Devers substation.

Solar power totaling 180 MW can be interconnected to the Palo Verde–Devers transmission system near Palo Verde substation without transmission reinforcement costs. An incremental cost of $290.2 million will allow the interconnection of up to 988 MW. (See Diagram 5, Appendix A.)

Solar power totaling 25 MW can be interconnected to the Coachella–Devers transmission system near the Mirage substation without transmission reinforcement. Up to 565 MW of solar can be interconnected near Mirage for a transmission reinforcement cost of $48.1 million. Up to 750 MW of solar can be interconnected near Mirage, for an additional cost of $49.8 million, or a total of $97.9 million (see Diagram 6, Appendix A). As stated in Sect. 11.3.1, some of the winning bids will reduce the available capacity at these locations.

11.4.3 Combining Solar Plant Interconnections

The combined impacts of interconnecting solar plants at several locations on the SCE transmission system will vary on a site-specific basis. The total combined impacts are a function of the transmission facility ratings as well as changes in generation dispatch during peak load conditions. Calculating combined multiple solar plant impacts on transmission system reinforcement requirements requires a load-flow study showing flows within the Los Angeles transmission network. However, the combined impacts on the Los Angeles transmission network will tend to be less if the generation being displaced by solar is outside the Los Angeles area. As stated previously, cursory review indicated that installing 40 miles of 500-kV line plus four 500-kV breakers in the transmission network, costing approximately

$50 million, would be required if over 1000 MW of solar were installed at Lugo. This level of transmission reinforcement is expected to also apply if over 1000 MW solar is interconnected at multiple locations. However, a transmission study will be required to establish actual transmission reinforcement requirements and costs.

11.5 CONCLUSIONS AND OBSERVATIONS

Some conclusions and observations resulting from this case study are as follows:

- Approximately 750 MW of high-capacity solar plants could be interconnected to the Lugo substation in the Mojave Desert region without SCE transmission system reinforcement.

- Cursory review indicates that if more than 750 MW of solar power is interconnected to the Lugo substation, approximately $50 million in transmission reinforcement to the Los Angeles area transmission system may be required. Detailed transmission studies are required to accurately determine transmission reinforcement requirements and costs.

- Another 750 MW of solar plants can be connected to other transmission substations in the area.

- Environmental land use constraints may be an important siting consideration when comparing alternative solar plant locations in the Mojave Desert region.

- Available solar megawatt capacity levels at Lugo and other substations in this report will be reduced by the capacity of new resources added at those substations. New resources may result from the bidding process by independent power producers that is currently under way at SCE. A total of about 686 MW of power is being bid. Much of this capacity out for bid would be located in areas that would not affect the available transmission capacity for the solar plants.

- A total of 1500 MW of solar plants can be interconnected at little or no cost. The addition of new solar resources will need to be coordinated with system need.

APPENDIX A. SIX SCE RADIAL TRANSMISSION INTERTIE SYSTEMS

Diagram 1

Midway-Vincent Radial Intertie System
(Existing)

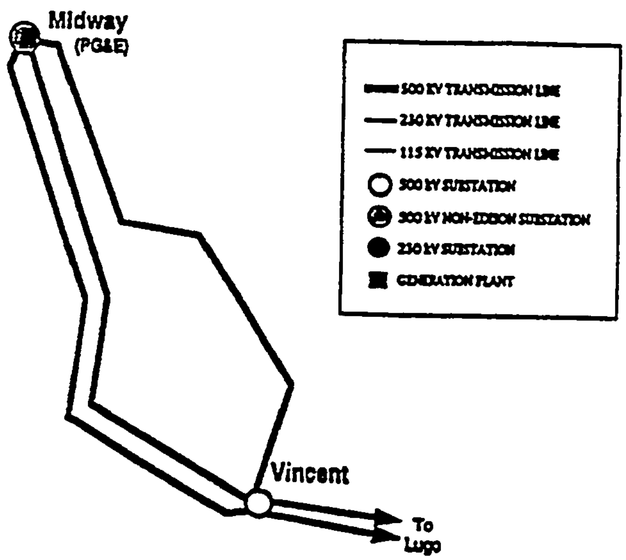


Diagram 2

Big Creek/Magunden Radial Intertie System
(Existing)

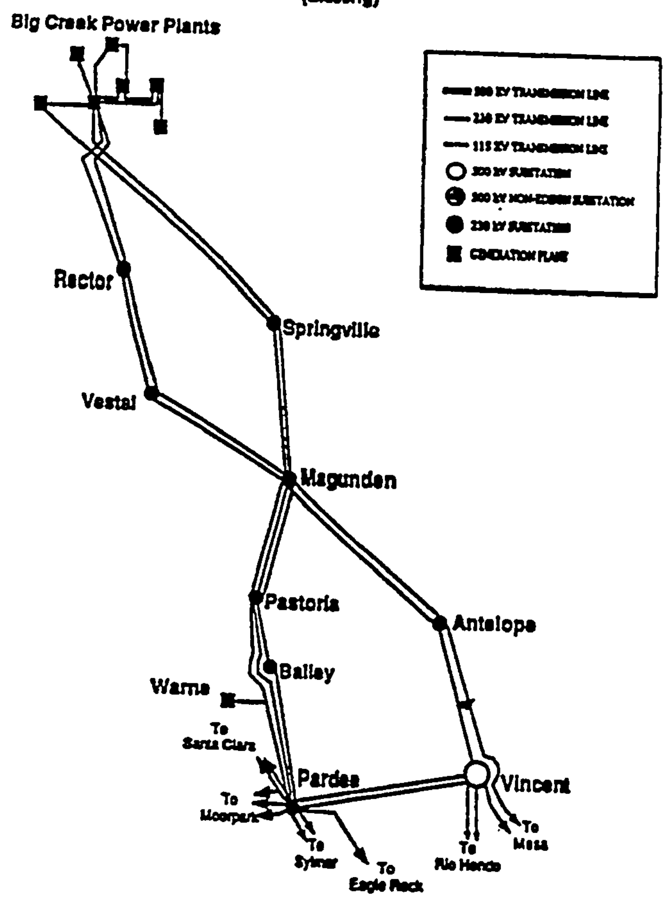


Diagram 3

North of Lugo Radial Intertie System
(Existing)

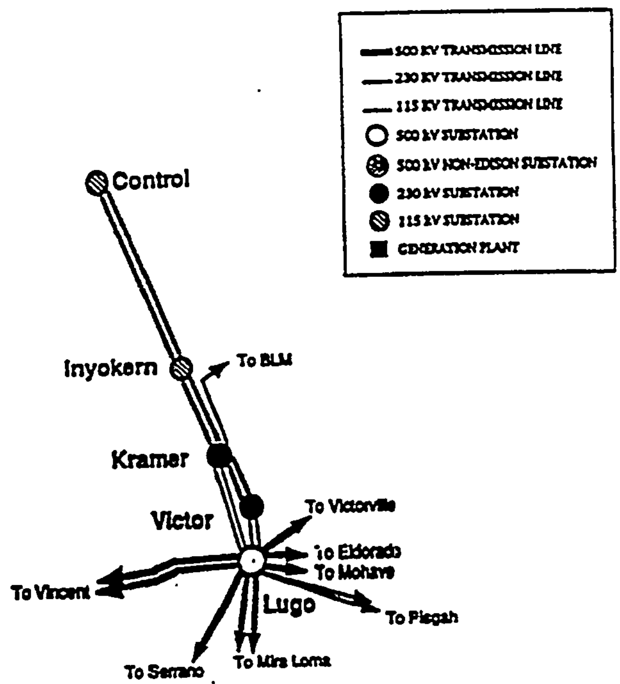


Diagram 4

Mead-Eldorado-Lugo Radial Intertie System
(Existing)

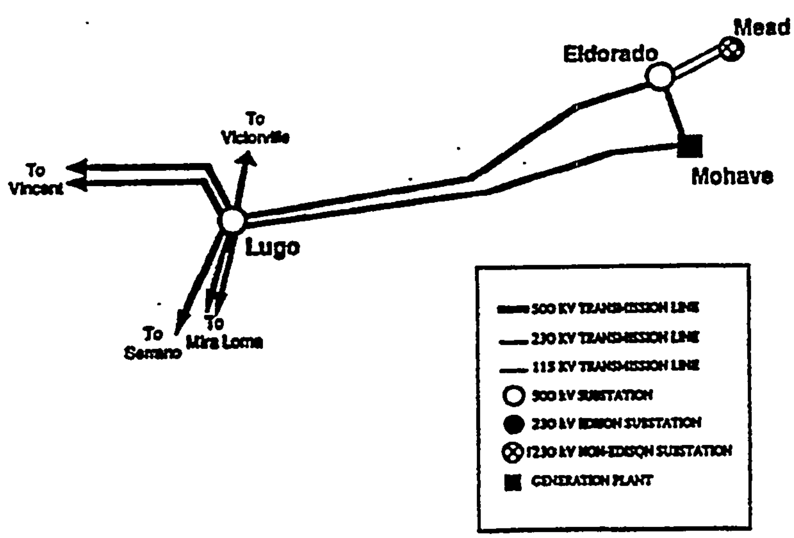


Diagram 5

Palo Verde-Devers
Radial Intertie System
(Existing)

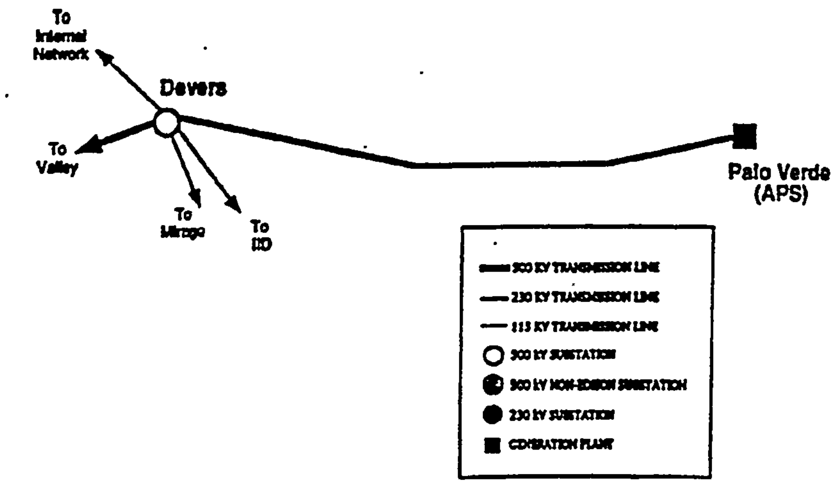
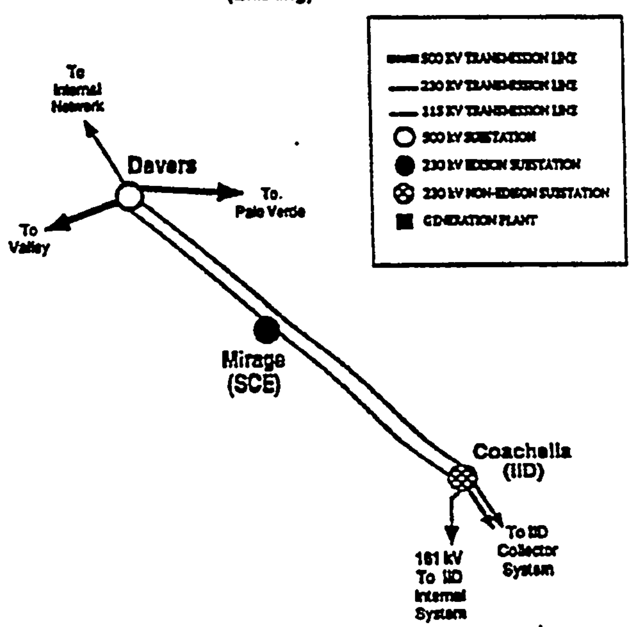


Diagram 6

Edison-IID
Radial Intertie System
(Exisiting)



APPENDIX B. WESTERN SYSTEMS COORDINATING COUNCIL AND SCE TRANSMISSION PLANNING CRITERIA

The following text is extracted from "Southern California Edison Transmission Cost Tables," Exhibit B of the *Bidding Manual*, modified to comply with CPUC Decisions, D92-09-078, D92-11-060, D93-01-049, D93-03-020, D93-06-099, August 11, 1993. References within this appendix to numbered transmission cost tables are to the SCE document

LONG TERM TRANSMISSION PLAN (LTTP)

I. INTRODUCTION

The Investor Owned Utilities (IOU) and the California Public Utilities Commission (CPUC) have agreed to develop a bidding process to fulfill future generation needs of the IOUs. The Transmission Access OII was established to determine how transmission-related costs will influence the selection of new generating resources. Consequently, the California Public Utilities Commission (CPUC) has directed the Investors-Owned Utilities to identify and submit transmission-related cost information.

A Long Term Transmission Plan (LTTP) was developed to determine a) the Remaining Existing Capacity (REC) available at each major substation where new generation can be accommodated without new transmission facilities, and b) new transmission facilities or Incremental Facility Additions (IFA) required, if any, to integrate new resources (up to 1,000 MW at some locations) at those major substations in the Edison system.

Transmission-related costs occur in three main categories: new facilities, transmission losses and other cost adders. New facilities are required when the REC at a substation is zero or insufficient to accommodate a predetermined level of new generation.

Transmission losses will affect the overall cost of the bid price in the delivery of the new resource and will depend on the location of this new resource.

Cost adders are incurred in the cases where the available transmission capacity is currently used for transactions such as economy purchases or to provide transmission service to other parties. Cost adders are also incurred if an incremental expansion is available that does not involve a new transmission line, and where the low cost expansion could be used for transmission service to other parties.

The results of the Long Term Transmission Plan study were summarized in the Transmission Cost Tables distributed by Edison on March 27, 1992. Cost of new facilities required for each substation and the amount of capacity these facilities add are identified in Table 1. Also identified in this Table I are the loss factors for capacity and energy. Information regarding cost adders is provided in Tables 2, 2A–2E, 3, 3A, in the same document.

Details of this study are summarized in the workpapers which are attached to this report. Also described below are the Study Criteria, assumptions and planning tools used in performing the LTTP.

II. STUDY CRITERIA

In performing planning studies Edison will apply its own planning criteria and the Western Systems Coordinating Council (WSCC) Criteria. WSCC criteria are followed anytime a facility is added which has the potential of affecting other WSCC members.

The main points of both criteria are summarized as follows:

1. Interconnection paths are rated for single contingency events known as N-1 in accordance with WSCC Reliability Criteria for System Design. Remedial actions are not included in planning new facilities under single contingency outage criteria. Remedial actions are allowed when planning for double contingency or N-2 events.
2. Loadings on any line shall not exceed the normal pre-established rating of that line with all lines in service.
3. Steady state voltage levels on Edison's 230 kV substations should be maintained at 92% (211.6 kV) or better during base case and single contingency outage conditions (N-1). An exception is Devers where the minimum voltage allowed is 90% (207.0 kV) because of the substation voltage control capability.
4. Voltage levels on Edison's 500 kV substations should be maintained at 96.6% (483.0 kV) or better during base case and single line outage conditions. Exceptions include Devers, Mira Loma, Serrano and Valley substations where minimum voltage can be 94.5% (472.5 kV) during base case or single line outage conditions because of these substations' voltage control capability.
5. Edison criteria require that transient voltage swings do not reduce the substation voltage below 75%. Other WSCC utilities such as IID require these voltages to be 80% or higher.
6. Single line outages and double line outages should not result in overloadings in excess of 115% and 135% respectively of normal thermal ratings on 230-kV lines. Loadings on 500 kV lines shall not exceed their individual emergency ratings.
7. Loadings on existing 500 kV transformers can not exceed their predetermined emergency ratings. For Edison, continuous loading on 500/230 kV transformer banks shall not exceed 150% of its normal rating for one hour or less immediately following an outage condition and 110% for 24 hours under N-1 conditions.
8. Systems should be planned such that the interconnections can carry all the scheduled power without relying on other interconnection paths.
9. The short circuit duty at Edison substations should not exceed the interrupting capability of circuit breakers anywhere in the system.

III. STUDY ASSUMPTIONS

This study was performed with the following assumptions:

a. This LTTP was performed under 1997 heavy load conditions. Power flow and voltage variables were also investigated with a light load condition in areas where it is appropriate. Stability, however, was checked under heavy load conditions only unless noted otherwise.

b. To determine REC at different substations, power deliveries at the different substations were simulated by modelling fictitious generators at those substations listed in Table 1.

If the new generation is located at a distance from the substations not listed in Table 1, then added facilities may be different. New facilities may be required to compensate for these deficiencies. The farther away the new NUGS are, the more facilities will be required.

c. For 230 kV substations, except for interconnection substations, three levels of generation were investigated, 100, 300 and 500 MW. Where REC is available, the REC could fall in between these numbers or be greater than 500 MW.

d. The following facilities were assumed to be in service by 1997:

- The California/Oregon Transmission Project (COTP).
- The Westwing/Mead/Adelanto/Lugo 500 kV project.
- A fourth 500/230 kV, 1120 MVA transformer bank at Mira Loma.

e. Cost of new IFAs does not include facilities required in other control areas.

f. Existing SVC, and those added as IFAs, are assumed to produce voltage support for all outages under transient and steady state conditions.

g. *Dynamic voltage support*

Edison electrical system is an integral part of the Southern California Import Transmission System which includes the following five major paths: Pacific DC Intertie (PDCI), the Midway-Vincent 500 kV path, the North-of-Lugo 230 kV path, the Intermountain Power Project DC line and the West-of-the-River path.

Each of these major paths has a non-simultaneous rating used for scheduling purposes. These major paths bring resources from outside into the LA Basin and San Diego areas to serve load in the Edison, Los Angeles Department of Water and Power (LADWP), and San Diego Gas & Electric (SDG&E) control areas including Resale Cities load.

The sum of the non-simultaneous ratings of the five major paths described above is about 18,000 MW. However, the simultaneous capability of those five paths is about 14,500 MW. Edison's share of this simultaneous capability is about 7,100 MW which is adequate to bring its firm resources, to meet its Firm Transmission Service obligations to others, to accommodate expected loop flow, and to accommodate the 110 MW of remaining existing capacity on the Palo Verde-Devers path.

This simultaneous capability is determined by system stability. The amount of power that can be delivered to the Southern California System is limited by the ability of this system to remain stable under the critical contingency involving a three phase fault at Palo Verde followed by loss of the Palo Verde-North Gila 500 kV line. The critical variables are voltage swing and damping in Southern California, more specifically in the Devers and Lugo areas. Damping has to do with the ability the system has to recover, that is, the ability to eliminate voltage oscillations that occur as a result of the fault.

The Southern California Import Transmission system cannot accommodate new resources coming from outside on either of the major paths described above unless dynamic voltage support is added in this system to increase its ability to remain stable under the critical outage of the Palo Verde-North line. If no dynamic voltage support is added, Edison existing firm uses will be in jeopardy. Dynamic voltage support can be added cost effectively by adding Static Var Compensators (SVC) at substations where voltage swings and oscillations are critical such as Devers in the Edison system.

h. *Base case assumptions*

1. *Loads, internal generation and interchange schedules*
The total Edison summer peak load simulated in this case is 18,273 MW, consistent with the preferred resource plan currently in effect. Edison's internal generation simulated in the case is 12,195 MW.

Edison's schedules include its firm resources, firm transmission service commitments, short term firm purchases and 110 MW of remaining existing capacity available on the Palo Verde-Devers path.

The total power flow for main paths in the system are shown below:

Pacific AC Intertie	4186 MW
East of the River (EOR)	6244 MW
Pacific DC Intertie	2717 MW @ NOB
Midway-Vincent	622 MW
North of Lugo	758 MW
Intermountain Power Project DC	1920 MW
West of the River (WOR)	8591 MW

The flow on the SCE-IID intertie is included as part of the WOR flow.

2. *1997 system configuration*

The base case was modified to include the following transmission facilities:

— Westwing-Mead-Adelanto 500 kV project: about 400 miles of new 500 kV line, a phase shifter installed on the Westwing-Mead section, 45% series compensation, and about 750 Mvars of dynamic voltage support.

— A fourth AA 500/230 kV transformer bank at Mira Loma to meet load growth in the eastern region of the Edison service territory.

The Devers-Palo Verde #2 project was not simulated in the base case.

IV. STUDY METHODOLOGY

a. Identify the substations to be used for delivery of power from NUGs.

b. Determine the remaining existing capacity (REC) at each of these substations according to the following procedure:

1. For non-network facilities or transmission paths with specific rating the procedure is as follows:
   — Determine the existing total capacity at the substation.
   — Determine all firm commitments, existing and future.
   — Subtract firm commitments from capacity to determine the REC.
2. For network substations the procedure is as follows:
   — Simulate stressed condition likely to occur in the system before proceeding to determine REC.
   — Add generation at each substation and check system performance. If system performance is adequate, then the amount of generation added represents the capacity available at that substation.
   — Repeat this procedure for 100, 300 and 500 MW.
   — Determine REC at the substation by subtracting commitments not simulated in the case such as generation off line from this available capacity.

c. Determine Incremental Facility Additions and new REC as follows:

1. If capacity at the substation is fully committed, add the next logical and efficient facility.
2. Perform the necessary analysis to determine the capacity of the path with the facility added. Check stability, when applicable, thermal overloads, voltage and short circuit conditions so that Edison and WSCC criteria are met.
3. The resulting capacity increase due to the IFA is the difference between the new capacity and the existing capacity at that substation.

V. PLANNING TOOLS USED IN ANALYSIS OF SYSTEM PERFORMANCE

The performance of the system was investigated by performing power-flow and stability analyses.

Power-Flow Analysis

Power-flow models were used to calculate power flow on transmission lines and to anticipate voltage conditions at substations. These power flows and voltages should be within preestablished reliability and safety limits for a) conditions with all lines in service, and b) for outage of transmission lines out of service.

If, after adding new generation to the system, these limits are not met, then upgrade alternatives are developed and power-flow analysis repeated to determine if upgrades bring power flows and voltage levels within acceptable limits.

Stability Analysis

Stability analyses are performed to determine if generators in the system maintain synchronism with one another following disturbances in the system. If the generators do not remain in synchronism, the system is not considered stable. Unstable systems could result in disruptions of power to widespread areas.

If, after adding new generation to the system, the system becomes unstable, then upgrade alternatives are developed and stability analysis repeated to determine if upgrades restore stability to the system.

Adding generation resources outside the LA basin area system have the following adverse effects: first the support provided by the generators' voltage control capability and inertia is distant from the LA Basin, reducing system stability.

Secondly, flow is added to the intertie system increasing the stress on that system and the potential for system instability. System stability can be recovered by reinforcing the system, adding dynamic voltage support by installing Static Var Compensators (SVC) or a combination of the two.

VI. LOSS ADJUSTMENT FACTORS

The methodology for determining the Loss Adjustment Factors involves using the base case power flows, increasing Edison load in an amount equal to the size of generation being evaluated and designating the interconnection substation as the slack or swing bus.

The studies for loss adjustments factors were performed in three phases: Phase I, with no IFA; Phase II, radial collectors and IPAs; and Phase III, energy loss adjustments factors. The summary, detailed description of the methodology and the workpapers are presented in the Losses Section of the workpapers.

VII. TRANSMISSION COST ADDERS

a. Edison Interties/Existing Capacity (Tables 2 and 2A–2E)

Tables 2 and 2A–2E identify the Transmission Cost Adders for integration of NUG power on each of Edison's intertie paths. The Transmission Cost Adder is defined as the greater of either foregone Net Present Value (NPV) of Transmission Service Revenues or foregone NPV of Inter-utility Economy Transactions Savings in 1997 dollars for each of Edison's intertie paths. A complete explanation of the methodology in determining the Transmission Cost Adders on Tables 2 and 2A–2E is located in the section titled "Table 2 Work Papers."

b. Midway-Vincent Path/Additional Capacity (Tables 3 and 3A)

Tables 3 and 3A identify the Transmission Cost Adders for integration of NUG power on Edison's Midway-Vincent 500 kV intertie. The Transmission Cost Adder is defined as the foregone Net Present Value of Transmission Service Revenues in 1997 dollars for the Non-Reserved Incremental Transmission Capacity on the Midway-Vincent intertie. A complete explanation of the methodology in determining the Transmission Cost Adders on Tables 3 and 3A is located in the section titled "Table 3 Work Papers."

12. WEST TEXAS STUDY

12.1 INTRODUCTION

The Lower Colorado River Authority (LCRA) performed a study to determine the transmission facilities required to support solar generation in West Texas.[8] This study identifies facilities needed at the point of interconnection between the generation facility and the existing transmission system, and the transmission system improvements needed to deliver the power to the major load centers in Texas.

West Texas is a prime location for the development of solar generation facilities. In terms of solar site potential, the normal direct access solar radiation in the area varies from 24 to 26 megajoules (MJ) per square meter per day. This level of direct access solar radiation, particularly in the western quadrant of the study area, is well above the solar site location criteria of 23.7 MJ/m^2 per day used in this study. See Fig. 12.1 for a profile of statewide solar resources.

Included in this study are transmission plans for ten small-scale renewable resource generation sites ranging in size from 25 MW to 100 MW; two 250-MW (medium-scale) renewable resource generation locations at Permian Basin and Rio Pecos; and one 500-MW to 2000-MW (large-scale) renewable resource generation hub located at Permian Basin. Sites were evaluated individually. The impacts of renewable resource generation on area facilities owned and operated by Texas Utilities (TU), West Texas Utilities (WTU), and Texas–New Mexico Power (TNP) were quantified.

12.2 SITING CONSIDERATIONS

Figure 12.2 shows the location of all sites evaluated and their geographic relationship to solar resources in the area. Table 12.1 lists the sites and their bus voltage.

Table 12.1. Sites evaluated for West Texas study

Site no.	Site name	Bus voltage (kV)
2	Dollarhide	138
3	Worsham	69
4	Permian–Barrilla Tap	138
5	Alpine	69
6	Barrilla	138
7	Alamito	138
8	Fort Stockton	138
9	Wink	138
10	Permian Basin	138
11	Rio Pecos	138

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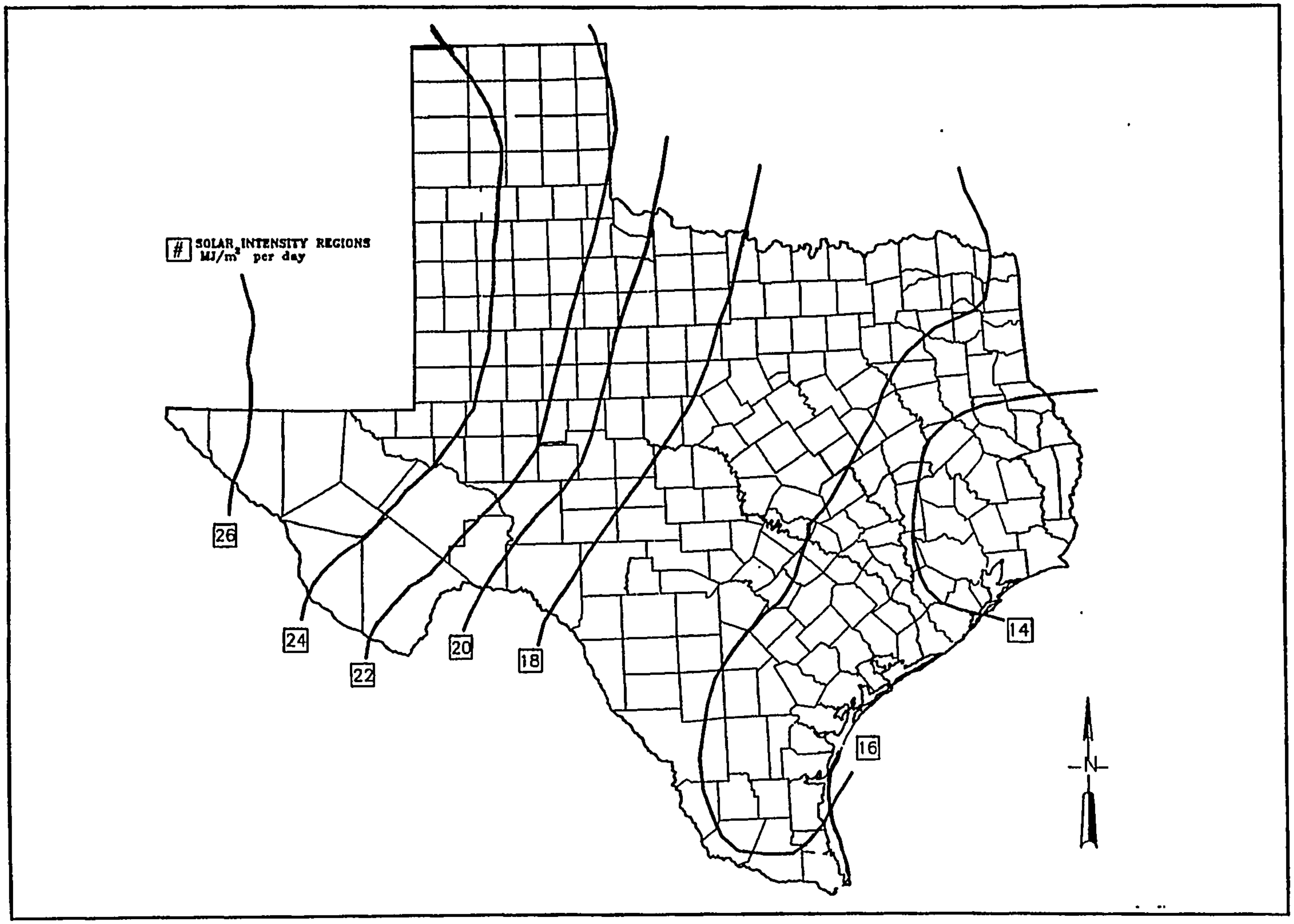

Fig. 12.1. Texas statewide solar renewable resources.

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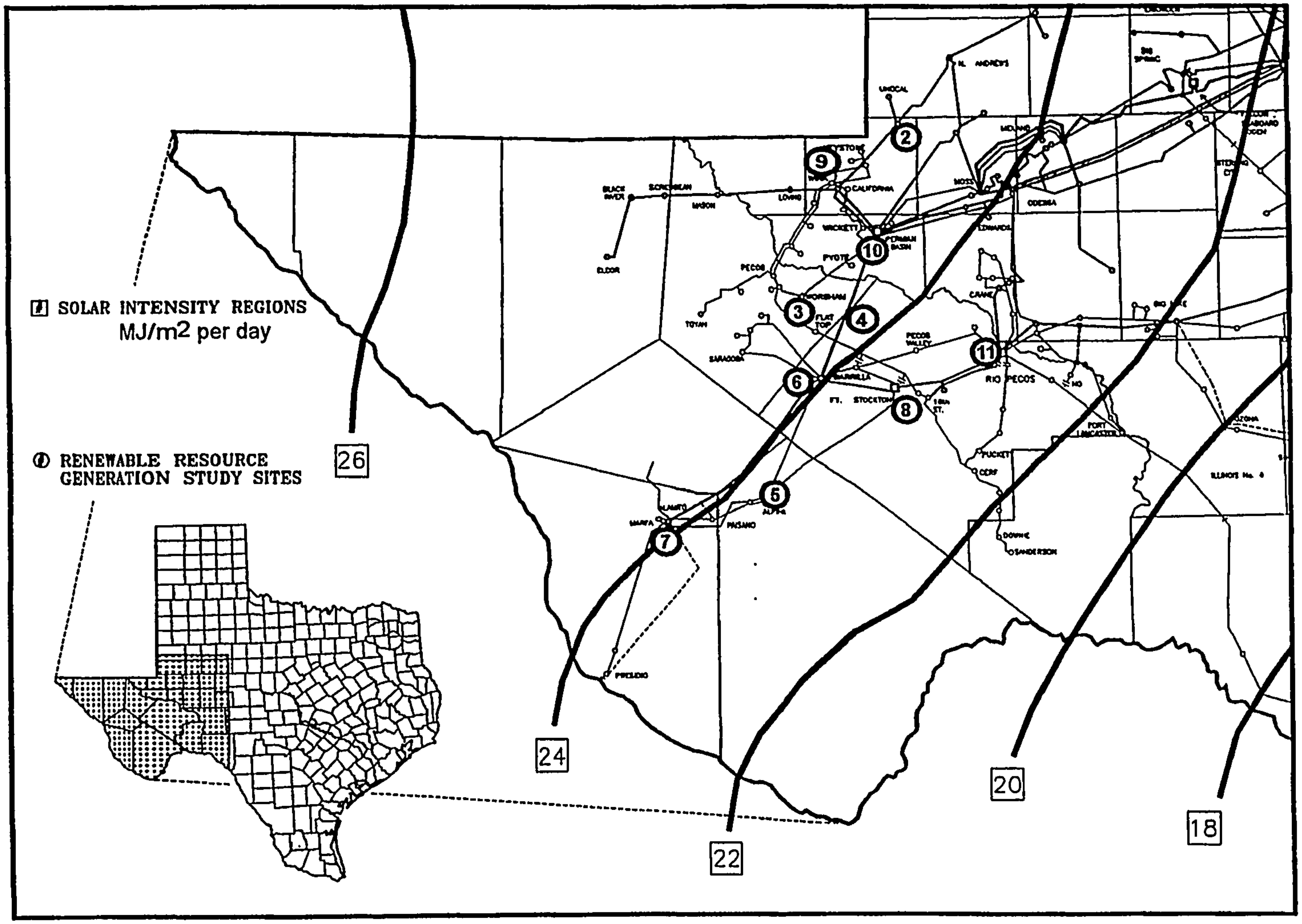

Fig. 12.2. Renewable resource generation study sites, existing transmission facilities, and renewable resources.

12.3 EVALUATION RESULTS

12.3.1 Evaluation Criteria

The transmission system in West Texas was evaluated using the ERCOT Planning Criteria. Transmission plans were developed to provide adequate service under single contingency conditions. The single contingency conditions studied included the loss of any single-circuit transmission line or any two transmission lines that are constructed on a single set of structures. A total of 202 contingency conditions were modeled in these studies. The transmission plans for each site were developed to avoid exceeding the thermal capacity of any transmission line or piece of equipment.

The voltages on the transmission system were reviewed for all conditions studied to ensure that a voltage collapse condition was not imminent. The major focus of the study was on the thermal ratings of the equipment and on ensuring adequate voltages under contingency conditions. It was assumed that marginal voltages in a specific area could be improved by providing reactive compensation.

The renewable resource generation sites were tested under various operational scenarios to bracket probable future conditions on the transmission system. All studies were based upon the 1994 Summer Peak ERCOT power flow case.

12.3.2 Small-Scale Renewable Resource Generation Sites

Thermal constraints identified in the study of small-scale renewable resource generation sites with capabilities ranging from 25 MW through 100 MW have been classified as being of two types: local area limitations and parallel path transfer limitations. In general, local area limitations are isolated system deficiencies in the immediate area. This type of limitation is directly dependent upon the location of the generation source. Parallel path transfer limitations include limitations on the bulk transmission system (345-kV network) and the underlying 138-kV and 69-kV subsystems. These limitations are less dependent upon specific site locations. Instead, they are a function of the amount of power that is being transferred across the transmission grid from generation regions to the major load centers.

With renewable resource generation levels at 25 MW, no additional local area limitations were found at any of the ten sites under all but the most extreme generation scenarios. Under the most extreme generation (all existing generation in West Texas at maximum output) scenario, only the Fort Stockton and Rio Pecos sites can be integrated into the network without the need for additional improvements in the immediate area.

With renewable resource generation levels at 50 MW, all sites except Alamito can be integrated into the network without the need for additional improvements in the immediate area under all but the most extreme generation scenarios. Under the most extreme generation scenario all sites will require additional improvements in the immediate area to be integrated into the network.

With renewable resource generation levels at 100 MW under normal generation scenarios, all sites except sites Worsham, Alpine, and Alamito can be integrated into the network without the need for additional improvements in the immediate area. Under extreme generation scenarios, all sites will require additional improvements in the immediate area to be integrated into the network.

Thermal overloads on parallel path circuits were encountered when existing area generation was increased to represent heavy generation loading conditions. As new small-scale renewable resource generation sources are added up to 100 MW in the area, four additional parallel path overloads are experienced.

12.3.3 Medium-Scale Renewable Resource Generation Sites

Two locations were selected to evaluate 250-MW (medium-scale) renewable resource generation sites. These locations were Permian Basin and Rio Pecos. The impacts of these generation sites were studied under conditions of maximum existing local generation. With medium-scale renewable resource generation sites at 250 MW, the existing transmission system is unable to support power flows out of Permian Basin, since 138-kV circuits from Permian Basin east into the Moss/Odessa area overloaded during contingency conditions.

12.3.4 Large-Scale Renewable Resource Generation Sites

For output levels of 500 MW and above (large-scale), a single hub located at Permian Basin was selected. The impacts of this large-scale renewable resource generation site were studied under conditions of maximum existing local generation. At levels of 500 MW and above, the existing transmission system is unable to support power flows out of Permian Basin because 138-kV circuits from Permian Basin east into the Moss/Odessa area overload during base case conditions.

12.3.5 Operating Procedure Modifications

Utilities in the area have developed operational guidelines to limit selected unit generation and the resulting thermal overloads on existing lines parallel to the 345-kV network from the Permian Basin area into the Dallas/Fort Worth metroplex. Any renewable resource generation facilities added in the area will have to be integrated into existing operational guidelines to be operated effectively. As part of the required improvements, operational procedures have been identified where possible to further avoid the need to reconductor 69-kV and 138-kV circuits along parallel paths with the 345-kV network. Opening certain lines during key outages on the 345-kV system can avert thermal overloads during these major power transfers. If existing area generation is allowed to increase above existing economic dispatch levels, all of the small-scale renewable resource generation sites evaluated will require various levels of parallel path system improvements to avoid thermal overloads.

12.4 DISCUSSION

The severity of integration problems is clearly a function of both the size of the renewable resource generation facility and the amount of area generation. As more power is supplied into the transmission system in an area, either in the form of new renewable resource generation sites or by increasing the output of existing generation facilities, more lines and autotransformers will exceed their thermal ratings.

12.5 SUMMARY AND CONCLUSIONS

Strictly from the standpoint of evaluation criteria, viable renewable resource generation sites exist in West Texas. Direct access solar radiation levels exist in this area which will support these types of generation sources.

Under the normal operating condition scenario, all of the small-scale renewable resource generation sites operated at 25 MW or 50 MW (except Alamito at 50 MW) can be integrated into the existing transmission system simply by connecting the facility into the existing grid. Under this same scenario and at output levels of 100 MW, the sites that require no improvements apart from those required to address preexisting system overloads are Dollarhide, Permian–Barrilla Tap, Barrilla, Fort Stockton, Wink, Permian Basin, and Rio Pecos. Given the solar intensity regions in the area, it appears that these seven sites, all of which are located on the 138-kV network, represent essentially equivalent locations for potential solar generation facilities with capacities of 100 MW.

The addition of renewable resource generation facilities in excess of 100 MW will require extensive transmission construction, including the construction of new 345-kV facilities. Renewable resource generation facilities of 250 MW at Permian Basin will require the construction of a new 345-kV circuit from Permian Basin to Moss. The Rio Pecos location can support the addition of a medium-scale renewable resource generation facility with upgrades to the existing 69-kV and 138-kV networks. With a 500-MW renewable resource generation facility at Permian Basin, two new 345-kV lines from Permian Basin into Moss will be required.

Studies of a 1000-MW large-scale unit at Permian Basin indicted that additional 345-kV circuits will be required from the Odessa area into Red Creek near San Angelo, and from Red Creek to Comanche. An additional 345-kV line extension will be required from Red Creek to Kendall as renewable resource generation facilities at Permian Basin are increased to 2000 MW. For this case, approximately 680 miles of new 345-kV lines would be required at an estimated cost of $328 million.

13. TALLAHASSEE STUDY

13.1 INTRODUCTION

This case study was performed by the Electric Department of the city of Tallahassee, Florida. Tallahassee is a potential solar resource region.[14] The load center for this utility is the city of Tallahassee and its surrounding suburban communities.

The purpose of this case study was to investigate the integration of photovoltaic (PV) renewable resources into the city's electric transmission system. In conducting this study,

- several PV plant configurations were considered;
- PV system data was acquired from a consultant;
- different sites near the city's transmission system were considered;
- power-flow models were developed and analyzed; and
- nontransmission barriers to the integration of PV were examined.

13.2 SITING CONSIDERATIONS

The PV alternatives considered were those believed to be most suitable for the city's particular system characteristics. The largest single-site plant modeled had a peak summertime output of 30 MW. Not only is the land area for any larger plant limited, but because of the system load shape, peak demand reduction impact diminishes rapidly after the first 30 MW. As an alternative multiple smaller (10-MW) plants were studied to determine their impact on the system.

Some issues which will cause problems for the PV resource are not related to the electric system. These are the environmental, social, and economic issues.

Sites near three substations were chosen as the PV plant locations (Fig. 13.1). These sites were chosen on the basis of land availability, environmental restrictions, and potential benefit to system operations. For the purposes of this study, the PV plants were modeled on the high voltage side of the transformers, and the output set at unity power factor.

Land availability is a severe restriction in the Tallahassee area. PV collectors require a lot of land (about 10 acres per megawatt generated). The consideration of multiple sites for several smaller generators rather than one large one (i.e., three 10-MW plants vs one 30-MW plant) is a result of this land restriction.

Another potential problem is the objection of residents who would not want a PV plant sited near their homes. It is not known if objections would be strong, as they are to other types of generating facilities, but this social aspect is always unpredictable.

The sites chosen for this study have sufficient space to build the PV resources. Other environmental constraints may prevent their use, however. Many undeveloped sites in the Tallahassee area are subject to wetlands regulations or are the habitat of protected endangered species such as the gopher tortoise. Much of the land to the southwest of Tallahassee is restricted national park land.

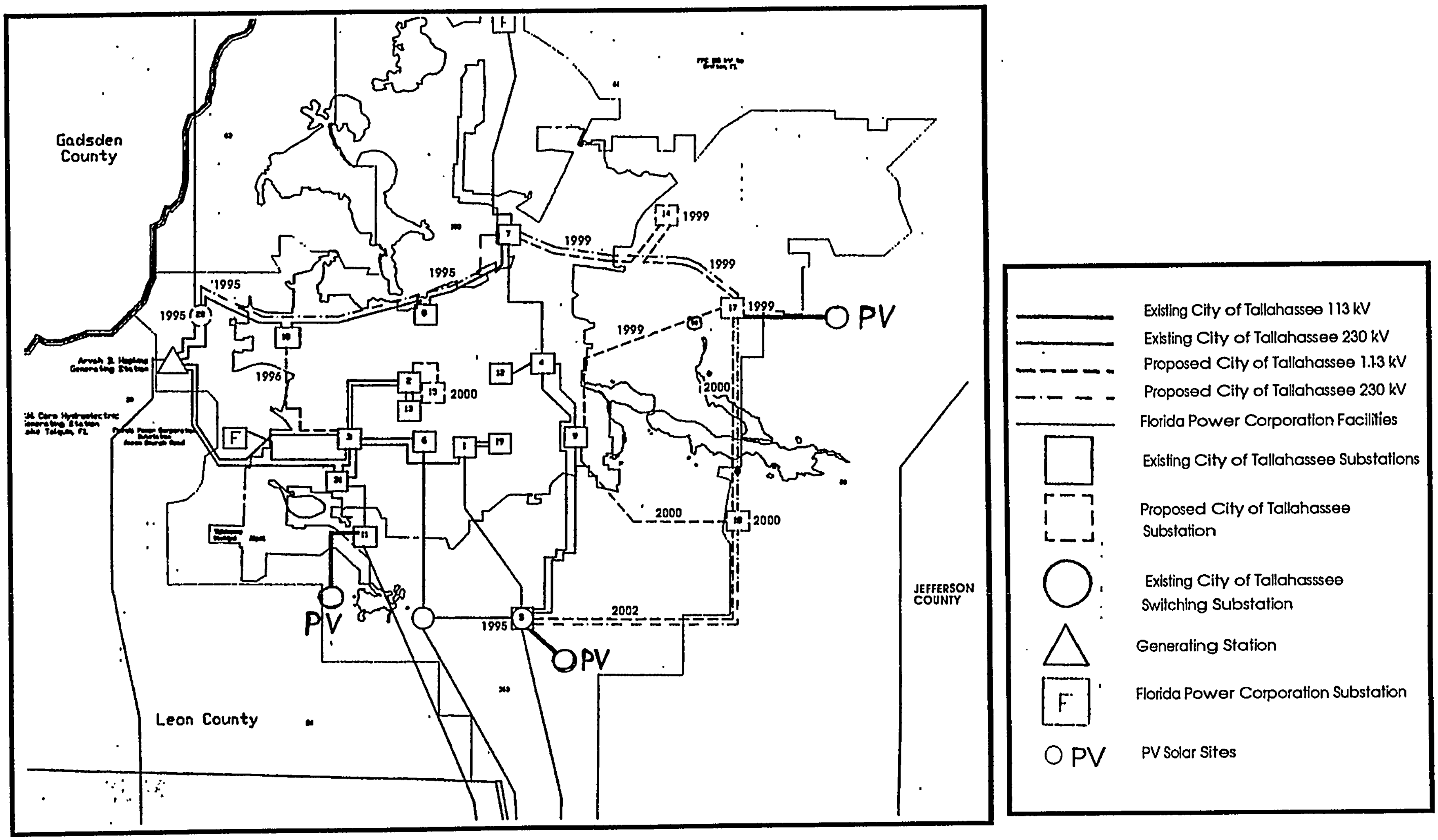

Fig. 13.1. City of Tallahassee electric transmission system: 10-year plan as of March 1994.

13.3 EVALUATION

13.3.1 Evaluation Criteria and Assumptions

To begin the evaluation of the integration of PV on the transmission system, the base case power-flow models for both the current (1994) system and the future (2002) system.

The method of evaluation was similar to normal transmission system analyses. A standard set of contingencies was tested on the power flow model for both the base cases (without PV plants) and the PV cases. The output results were reviewed for any violations of system operating criteria. System operating criteria include voltage levels at the distribution buses, power flow (both real and reactive) on the transmission lines, and generator commitment requirements. If operating criteria are violated in certain circumstances, then alternative ways are sought to operate the system such that the problem can be mitigated.

A number of assumptions about the city's electric system and the PV plants were made prior to modeling the PV and running the power flow cases. For the electric system, 2002 is considered a key year because planned transmission and generation expansions are to be complete by then. Therefore, it was assumed that the study results for a PV plant installed in 2002 would not be affected by major future additions for several years.

Technical information about PV systems was obtained from Zaininger Engineering Company (ZECO), which supplied PV penetration charts (Fig. 13.2), hourly output charts (Fig. 13.3), and comparisons (Fig. 13.4) of the city's load profiles before and after incorporating PV into the generating mix (system load data to ZECO for use in these comparisons). Based on this information, 30 MW of PV peak output was the maximum amount of PV that could be used to shave the system peak. Any more resulted in new peaks being created in other hours. It is expected that this maximum would increase to about 33 MW in the year 2002 case, since peak demand is forecast to grow by 10% and the daily load shape is not expected to change. Also, the maximum output of a PV plant on a typical hazy summer peak day is only 85% of the nameplate rating. Thus, the nameplate capacity for the 30 MW of output is about 35 MW. Regardless, the derated quantity is used in the power-flow study, since it is the actual power flow that is important for the analysis.

Other technical assumptions made were as follows:

- The reactive output of the units was assumed to be zero. In other words, the output power factor is unity.
- The inertia of the PV plant is zero. Therefore, no system stability runs were necessary for this amount of PV. For much larger PV plant capacities, zero inertia could result in a stability problem.
- The PV plant was modeled on the high-voltage (115-kV) system.
- There were available interconnection points at the selected substations (substations 5, 11, and 9 in the 1994 case; and substations 5, 11, and 17 in the 2002 case). Substations 9 and 17 are electrically close and the impact of locating the PV plant at substation 9 instead of 17 in 2002 is insignificant. (Substation 17 does not exist in 1994.) These stations are considered to be weaker areas of the system. It is intended that the PV installations will serve to strengthen these areas.

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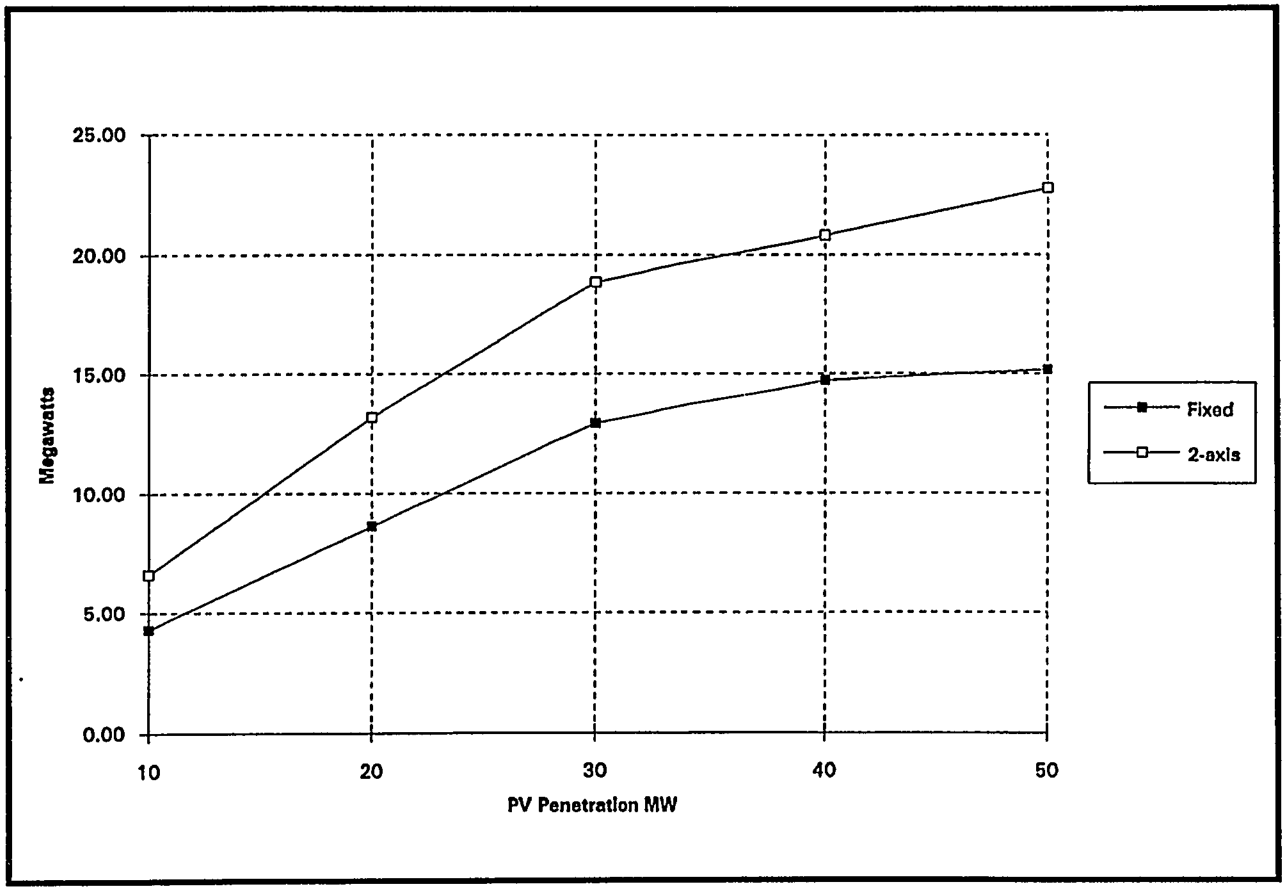

Fig. 13.2. Peak load reduction (average PV output), June 29, 1993.

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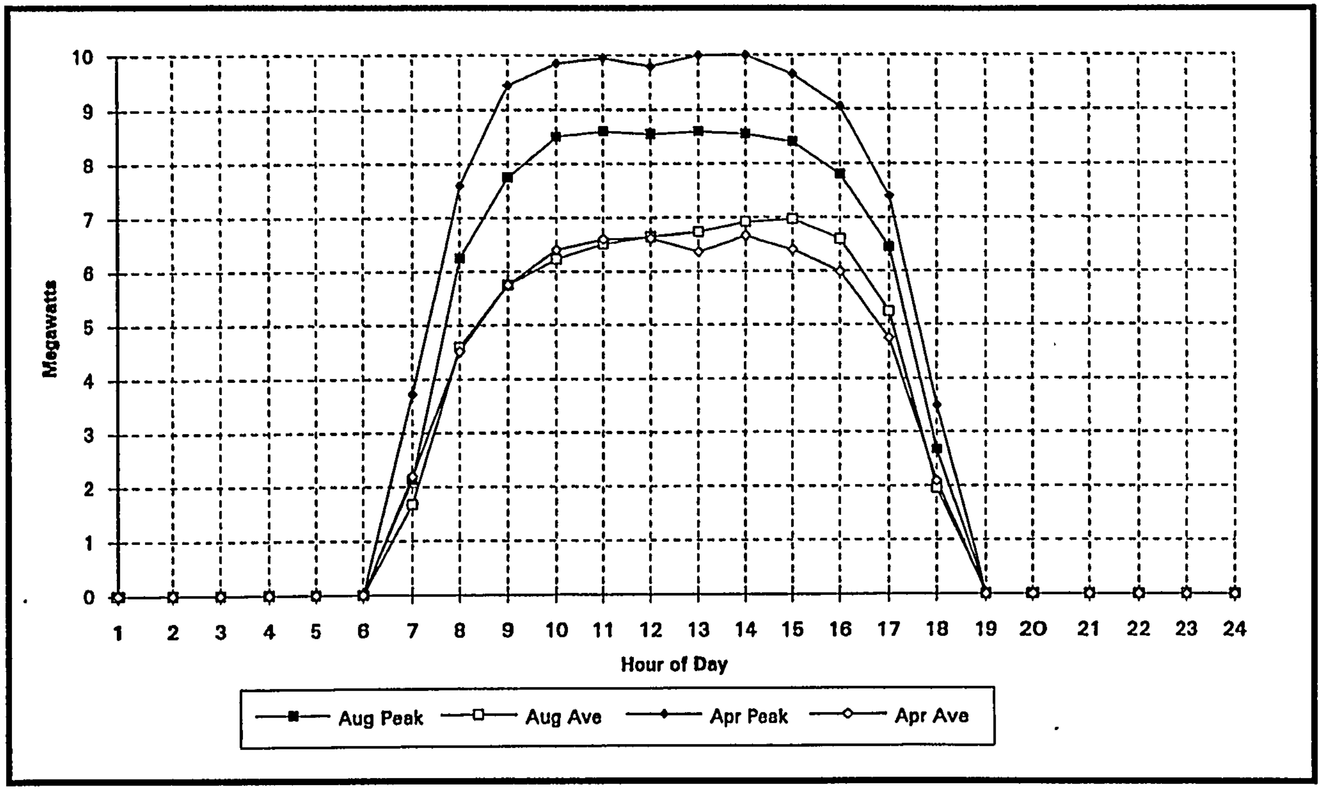

Fig. 13.3. 10-MW two-axis tracking PV plant.

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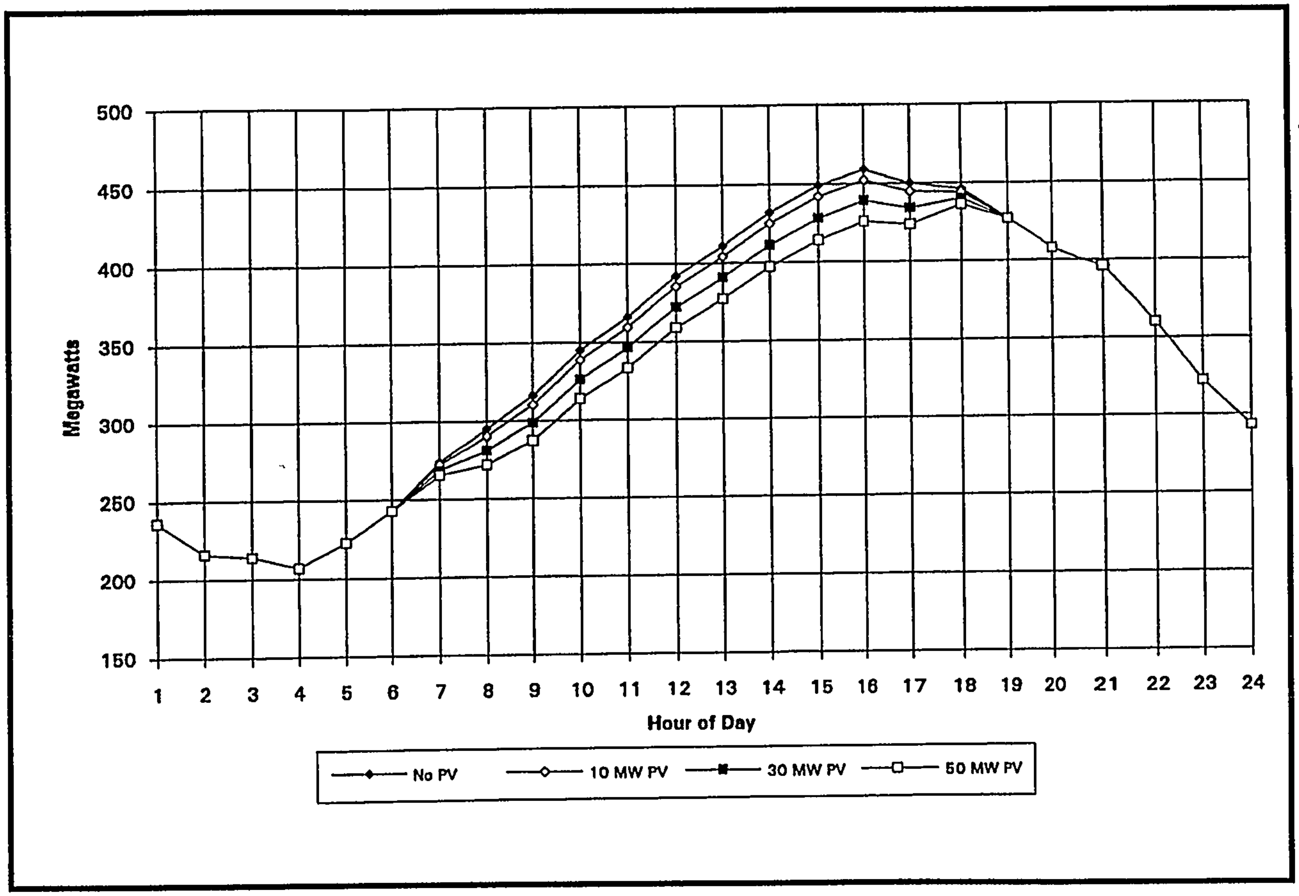

Fig. 13.4. Net system load, two-axis PV, July 29, 1993.

13.3.2 Evaluation Results

After compiling all the data the following initial findings were reached:

- There are no deficiencies in 1994 or 2002 transmission systems which act as barriers to the integration of PV.
- Unit commitment may be affected in some instances.
- There are some nontransmission barriers such as land availability, wetland regulation, and endangered species protection.

The load-flow cases tested the integration of 30 MW of PV resources in two different configurations. First, the capacity was distributed equally among the three sites (10 MW each.) Then, all 30 MW was sited at substation 5, the site with the greatest land availability.

Analysis of the power flow cases showed no problems with transmission capacity—that is, there were no line overloads. Use of the PV resources did, however, affect the commitment of some generation during the peak periods. Comparing the base case (no PV) to the PV case for 1994, it can be seen that the Purdom plant has one less generator committed when the PV resources are available. This could become a problem if the PV is relied upon to supply the load, since PV power is considered less reliable than conventional sources. The PV resource (operated as var neutral) also results in a lower voltage at the Purdom bus. Quick-start GTs are available to alleviate this condition, however. Other locations on the transmission system experience little or no difference in voltage.

Unit commitment is not a problem in the future (2002) system because a new large (100-MW) generator is planned to be added to the Purdom plant site. With this large source added, the plant will not be subject to commitment decisions as a result of the PV resources.

Additionally, there should be no problem with harmonics if the PV system power converters are designed properly. Also, for such a relatively small resource with no inertia, a stability study is considered unnecessary.

In summary, the existing and future transmission systems have sufficient capability to allow the integration of 30–40 MW of PV renewable resources.

13.4 INTEGRATION ISSUES

Evaluation of the ability to *electrically* integrate PV resources into the transmission system is not the only issue. Additional integration issues are presented in this section.

13.4.1 Need for Transmission System Upgrade

As shown in the previous section, there is no need for any transmission upgrade to handle the generation from the PV resource. The PV systems are relatively small compared to the city's electric system as a whole. There is little change in line flow with or without PV. The transmission is fully capable of delivering the renewable energy output to the load centers.

13.4.2 Operating Procedure Issues

Because PV power is not considered firm, events such as cloud cover will not significantly affect the operation of the system. However, spinning reserve will actually increase because the PV is backing down existing generation, thereby increasing the available spinning reserve. A stability issue is not expected because of the relatively small size of the resource and its zero inertia. Overall, any operating procedure issues are minimal. The only important impact is the reduction in peak demand by the generation of electricity by the PV plants.

13.4.3 Design Considerations

Air clarity in the Tallahassee area impacts the output of the PV plant. The output on a peak day in August (humid and hazy) is only about 85% of the output on a peak day in April (dry and clear). If the PV resource is planned for summer peak reduction, this impact must be considered in the design.

13.5 SUMMARY AND CONCLUSIONS

1. Small-capacity (10-MW to 30-MW) PV resources are useful in helping to meet peak system demand, assuming the resource is available. Such small resources also have little impact on issues like unit commitment and system stability.

2. Studies showed that 30 MW of PV peak output was the maximum amount of PV that would reduce the system peak.

3. There are some issues which will be very difficult to overcome in the Tallahassee area. Land use, environment, protected species, and the attitude of the residents must be considered in siting PV plants.

4. At locations where PV resources are feasible, the City of Tallahassee's electric transmission system has sufficient capacity to allow the integration of the PV renewable capacity.

14. PHOENIX VICINITY STUDY

14.1 INTRODUCTION

The Arizona Public Service Company (APS) performed a study to determine the transmission facilities required to support solar generation in southwest Arizona.[15] This study identified two sites for high-capacity solar plants to be interconnected to the existing transmission system and evaluated the system capability to deliver power to the major load centers in Arizona and California. Only the present system was considered; no studies were conducted on the planned future system configuration, since the present system was found to be capable of accommodating high-capacity plants.

Southwest Arizona is one of the best solar resource areas in the country. Both solar thermal and photovoltaic (PV) plants will perform well in this region. The solar power generated can be expected to supply part of the peak load.

14.2 SITING CONSIDERATIONS

Arizona lies in that portion of the United States which is least affected by persistent cloud cover and which receives the most sunshine annually. Solar radiation resources will play a major role in the selection of sites for solar power plants. The factors that APS selected as important to the siting of a solar power plant include the following:

- solar radiation and cloud cover;
- water resources for generating steam and disposing of waste heat;
- land resources for constructing plants and substations;
- natural gas resources for backup generation;
- environmental, legal, and political constraints; and
- transmission of electricity from the plant to the loads.

The most important factor in the development of an electric power generating system utilizing solar energy is the relationship between cloud cover and the amount of solar radiation received at the ground. Southwest Arizona has the highest number of clear days per year in the country, over 200 days per year. Water resources are also a very significant consideration. The need for water to generate steam and dispose of waste heat is much the same for a solar thermal plant as it is for other types of power plants. Another natural resource variable considered in siting a solar power plant is land availability, which is determined from the nature of land use. The presence of national parks, cities, military installations, and Indian reservations eliminates such areas from further consideration.

Access to natural gas resources (natural gas pipelines) might also become an important siting factor. Alternative fuels such as natural gas could be used for backup to solar generation on cloudy days or might be considered as a potential source for further expansion of generating capacity.

Finally, transmission availability to integrate the power into the Arizona transmission network becomes a decisive factor in the site selection. A more detailed assessment of the performance of the transmission system and its capability and transfer limits should be undertaken to optimize the integration and power delivery to Arizona load centers.

The site evaluation factors described above are shown in Table 14.1 for each of the proposed sites. On the basis of the evaluation, two alternative sites for the Solar I Project (high-capacity sites: 1000 MW) and two alternative sites for the Solar II Project (low-capacity sites: 100 MW) were selected. These are listed in Table 14.2.

14.3 EXISTING SYSTEM CAPABILITY

The Arizona extra-high-voltage (EHV) transmission system consists of two major east-to-west transmission paths (Fig. 14.1) for which maximum path transfer capabilities (transfer limits) are defined as follows:

1. **Four Corners West transmission path**, consisting of the flows on the Four Corners–Moenkopi 500-kV and the Four Corners–Cholla 345-kV number 1 and 2 lines. Flows on this transmission path are east to west due to the large amount of generation located in northwestern New Mexico. The 2300-MW nominal limit was determined on the basis of voltage deviation and thermal constraints.
2. **East of the Colorado River (EOR) transmission path**, consisting of the flows on the following transmission lines:

   - Navajo–McCullough 500-kV line
   - Moenkopi–El Dorado 500-kV line
   - Liberty–Mead 345-kV line
   - Palo Verde–Devers 500-kV line
   - Palo Verde–North Gila 500-kV line

   Flows on this path are also east to west, delivering power from the Palo Verde nuclear generating station and Four Corners/San Juan generating stations to the California utilities who own shares of these resources. The present east-to-west nonsimultaneous rating is 5700 MW and is due to the continuous rating of the series capacitors on the EHV transmission lines.*

14.4 HIGH-CAPACITY PLANTS

The integration of high-capacity (1000 MW) plants were considered for two sites. The two alternative sites selected and evaluated for this project are

1. **Wintersburg site**, located near the Palo Verde nuclear power plant, and integrated to the EHV transmission network by a short 500-kV line to the Palo Verde 500-kV substation (see Fig. 14.2).
2. **Bouse site**, located 60 miles northwest of the Palo Verde nuclear power plant, and integrated to the EHV transmission network by a 500-kV line in and out from the Bouse Solar power plant and interconnected to the existing Palo Verde–Devers 500-kV transmission line (see Fig. 14.2).

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*Load level in Arizona is at 85% of summer peak for our study base case. The transfers on other paths are at reasonable levels to allow 5700-MW transfer on the EOR transmission path.

Table 14.1. Site evaluation for the solar plants in Arizona

Proposed site	Annual sunshine (%)	Water depth (ft)	Gas proximity/ pipe diam.	Land ownership[a]	Comments	Rating for 1000-MW plant	Rating for 100-MW plant
Kingman	85	500	2.5 miles/ 34 in.	BLM, state, private			
Parker	90	*b*	15 miles/ 30 in.	BLM, national park			
Bouse	90	280	25 miles/ 30 in.	APS	CAP water available	PREFERRED (1)	
Prescott	83	150	30 miles/ 30 in.	BLM, state, private			
Wintersburg	90	150–200	10 miles/ 30 in.	BLM, state, private		PREFERRED (2)	
Gila Bend	90	50–100	15 miles/ 30 in.	Military, BLM, Indian reserv.			PREFERRED (1)
Casa Grande	86	200	0.1 miles/ 30 in.	State, private, Indian reserv.			PREFERRED (2)
Saguaro	85	250	12 miles/ 30 in.	BLM, state			
Yuma	90	200–500	10 miles/ 30 in.	BLM, military	Water of poor quality; no bedrock		
Three Points	85	150–200	15 miles/ 30 in.	Private, state			

[a]BLM = Bureau of Land Management; APS = Arizona Public Service.
[b]Surface at cost.

Table 14.2. Preferred alternative sites for Phoenix vicinity study

Site no.	Site name	Bus voltage (kV)	Capacity (MW)
High-capacity sites			
1	Bouse	500	1000
2	Wintersburg	500	1000
Low-capacity sites			
3	Gila Bend	230	100
4	Casa Grande	230	100

Based upon the technical studies performed for this project, the following conclusions are made:

1. The Wintersburg Solar I Project is technically feasible and can accommodate 1000 MW of generation scheduled from the solar power plant to load centers in Arizona areas (load in Arizona at 95% summer peak) during the high transfers (5700-MW flow on EOR path) into California. Power-flow and stability single-contingency analysis revealed no power-flow or stability problems under most critical system disturbances in the study area.

2. The Bouse Solar I Project is technically feasible and can accommodate 1000 MW of generation scheduled from the solar power plant to load centers in Arizona areas (load in Arizona at 95% summer peak) during the high transfers (5700-MW flow on EOR path) into California. Power-flow and stability single-contingency analysis revealed no power-flow or stability problems under most critical system disturbances in the study area.

3. Scheduling power from either the power plant site at Wintersburg (1000 MW) or Bouse (1000 MW) to the northern states (Colorado, Idaho, Montana, etc.) or to the west (California) would produce excessive loading on the EOR transmission path, resulting in overloading the EHV transmission lines and causing power system instability.

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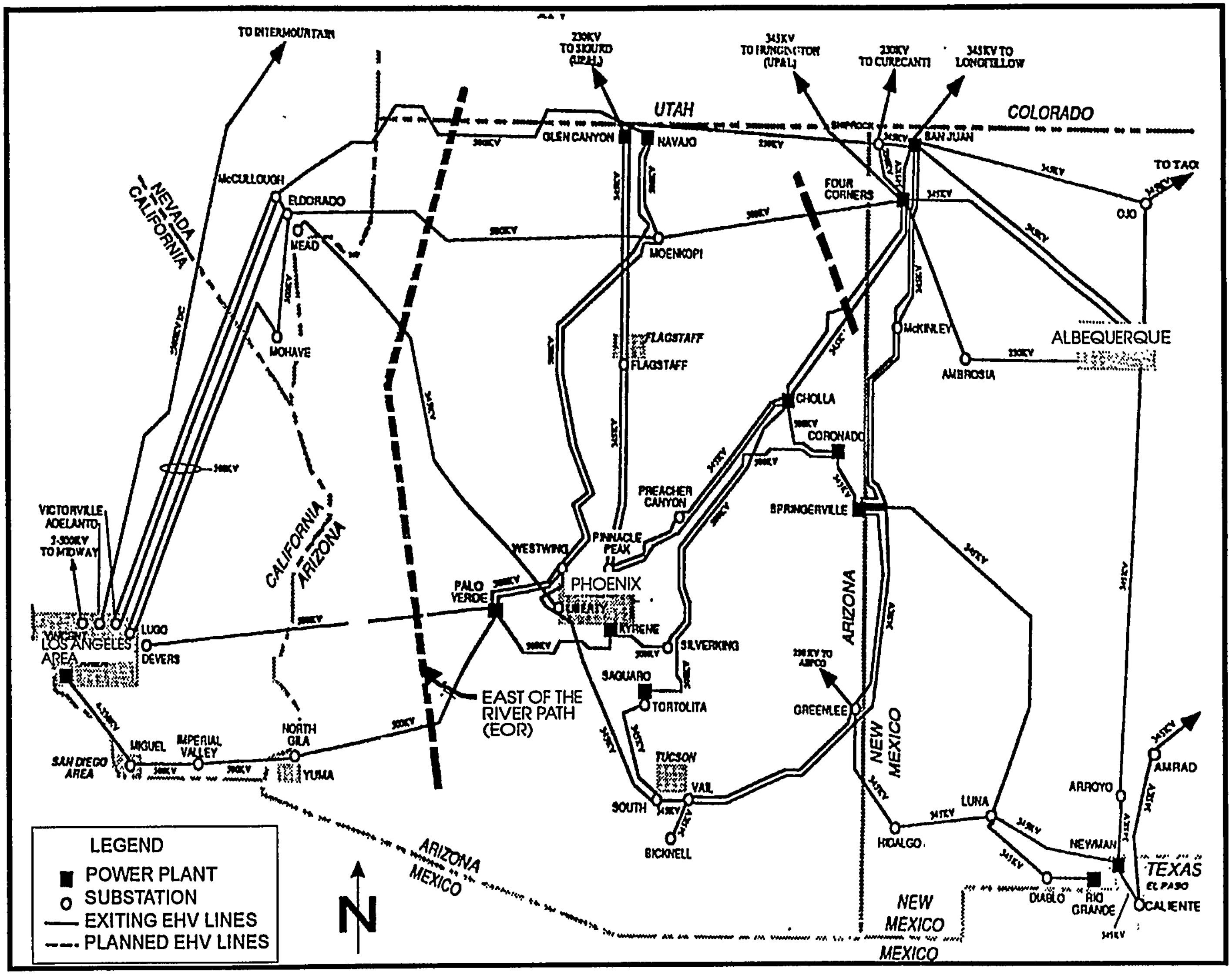

Fig. 14.1. Extra-high-voltage transmission system in the southwestern United States.

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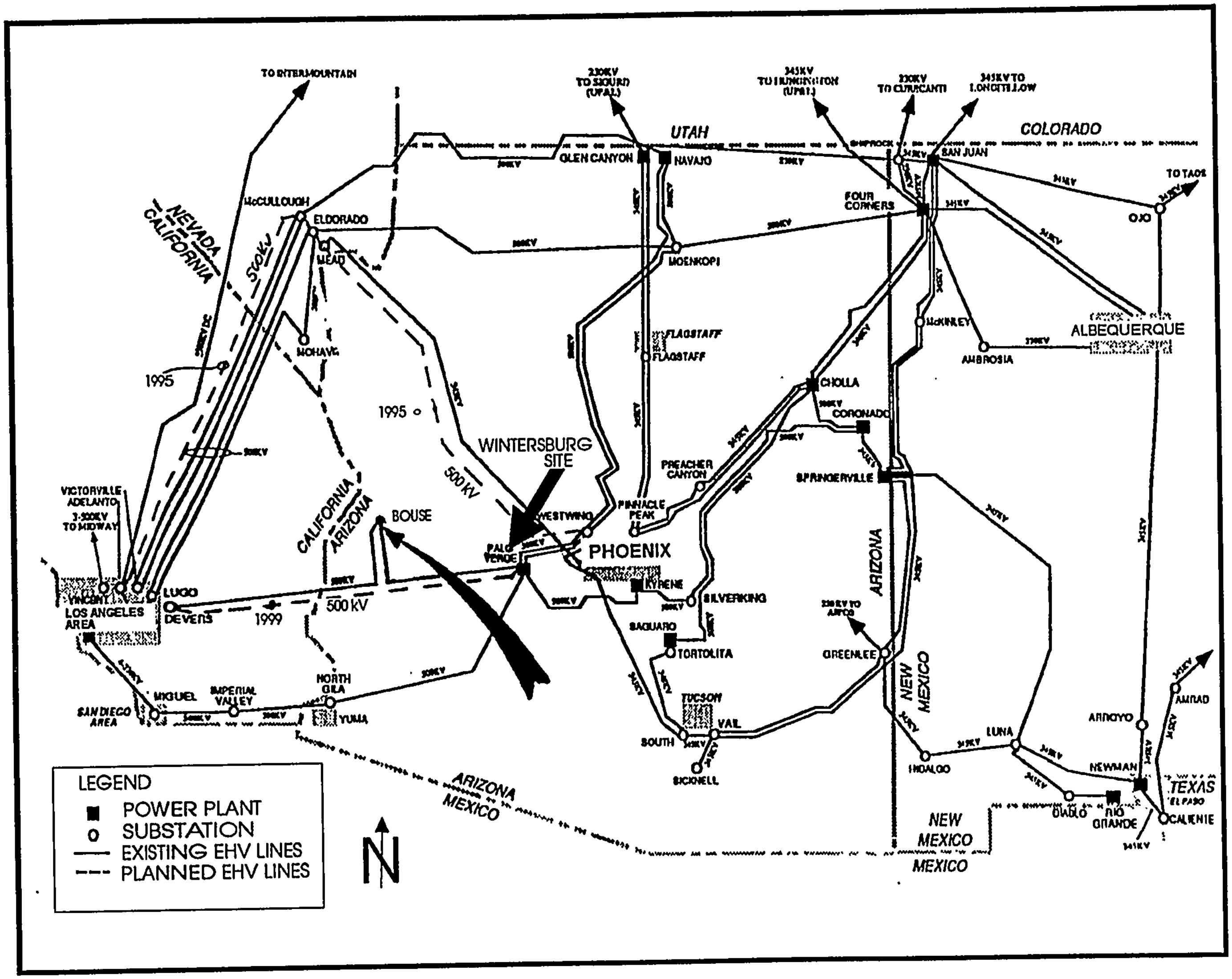

Fig. 14.2. The Wintersburg and Bouse solar plant sites.

14.5 LOW-CAPACITY PLANTS

Two alternative sites were selected and evaluated for this project:

1. **Gila Bend 230-kV site**, located 60 miles southwest of the Phoenix metropolitan area and integrated to the 230-kV transmission network by a short 230-kV tie line to the existing Gila Bend 230-kV substation (see Fig. 14.3).
2. **Casa Grande 230-kV site**, located 50 miles south of the Phoenix metropolitan area and integrated to the 230-kV transmission network by a short 230-kV tie line to the existing Casa Grande 230-kV substation (Fig. 14.3).

Based upon the technical studies performed for this project for 1994 system study conditions, the following conclusions were made:

1. The Gila Bend Solar II Project is technically feasible and can accommodate 100 MW of generation scheduled from the solar power plant to load centers or to replace generation in the Phoenix metropolitan area. Power-flow single-contingency analysis revealed no power-flow problems under most critical system disturbances in the study area.

   A higher solar power plant generation level of 200 MW scheduled to the Phoenix metropolitan area would require additional transmission out of Gila Bend 230-kV substation. The anticipated line addition would be the Gila Bend to Santa Rosa 230-kV line, for which APS already has state siting approval and which it plans to build in 2003.

2. The Case Grande Solar II Project is technically feasible and can accommodate 100–200 MW of generation scheduled from the solar power plant to load centers or to replace generation in the Phoenix metropolitan area. Power-flow single contingency analysis revealed no power-flow problems under most critical system disturbances in the study area.

14.6 CONCLUSIONS

The APS transmission system can accommodate the integration of both low-capacity and high-capacity solar plants. Most of the power generated by these plants would be used to supply local loads, since the tie lines to California are normally loaded to near-capacity.

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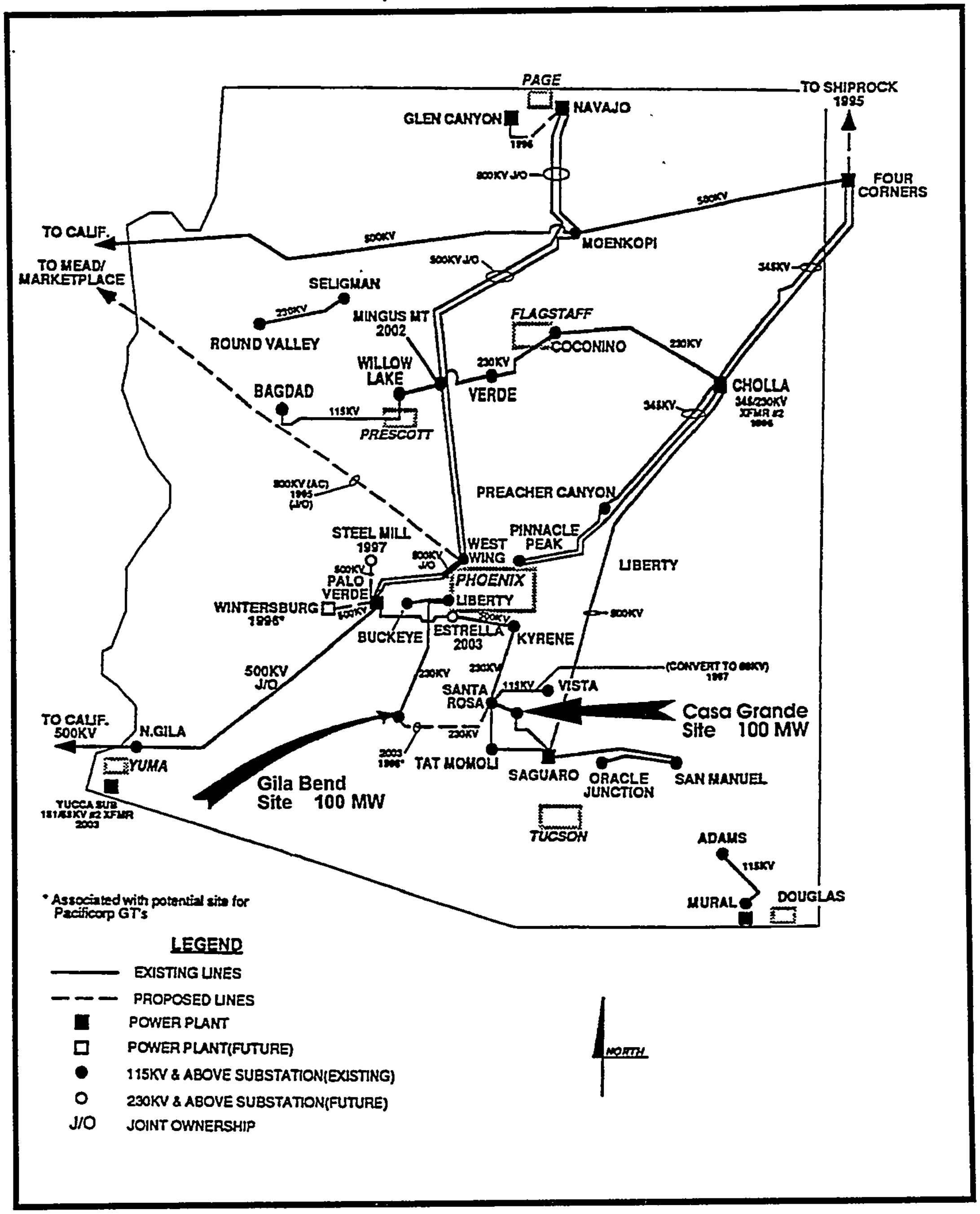

Fig. 14.3. 100-MW solar sites in Arizona.

15. SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

15.1 SUMMARY AND CONCLUSIONS

Eleven case studies, including the Blackfeet area wind integration study, have examined the transmission requirements for interconnecting renewable-energy electric generation plants into regional power transmission systems. These studies have been summarized and documented in this report. Each case study considered at least two sites located in high- to moderate-resource regions. Seven of the case studies were conducted for wind plants; three of the wind plant studies evaluated high-capacity (1000 MW or greater) cases. There were four solar plant case studies; three of the solar plant studies included high-capacity cases.

The case studies focused on whether integration of renewable resources would require upgrade or expansion of the existing transmission system. In addition, a preliminary estimate of cost for construction of the required transmission facilities was developed for selected cases. All studies are based on analysis methods and transmission technologies currently in use by U.S. utilities.

There are issues that may affect the viability of the renewable energy generation options that were identified but not explored in the case studies. For instance, obtaining adequate land use rights is an important constraining issue in development of generating plants of all types, as well as transmission systems. Other issues not explored include those related to transmission access and pricing for delivery of power to the indicated load centers. In general, dispatchability of renewable generation, spinning reserve require-ments, and regulation of output during resource fluctuations were also not addressed in detail.

High-potential renewable resource concentrations tend to be located far from major load centers in sparsely populated areas. The economics of scale and access to the resource favor siting of generating plants in these areas, but transmission capacity is needed to deliver the output to the load center. In this regard, high-capacity, remote, renewable generation is not greatly different from such conventional generation options as mine-mouth coal plants or hydroelectric generation, both of which are constrained as to siting by the resource location.

These studies define a maximum transfer capability for the system under certain specified conditions. Once constructed, the portion of maximum transfer capability which is actually available at any given time varies with load and generation dispatch, as well as with the status of voltage control equipment such as reactors and capacitors. Advanced technologies, such as flexible ac transmission (FACTS) power controllers, real-time control systems, and fast-acting energy storage technologies (batteries and superconducting magnetic energy storage, or SMES) will alleviate some transmission system constraints without construction of new transmission lines. Advanced, low-cost converter station technologies for high-voltage dc transmission will make less expensive transmission options available. These technologies will affect the future availability of transmission but are currently in the development stage and were not considered in these analyses.

In general, the results of the case studies indicate that it appears possible to integrate renewable resources on the order of 25 to 50 MW to supply local load without significant upgrades to the transmission grid. For renewable resources up to about 100 MW, minor system upgrades are needed, with a cost of about $20/kW. An exception to this observation exists for the case of southern California, where the transmission grid is designed for imports of power from the Pacific Northwest and Arizona. Accordingly, the transmission congestion points are located well north of Los Angeles and at the Colorado River on the Arizona-

California border. For this reason, renewable energy resources up to 1500 MW can be integrated into the existing system in southern California without significant upgrades.

Other case studies indicate that significant transmission upgrades will be required to integrate any new large-scale generation addition, including renewables. This is due either to the complete lack of transmission facilities of the required capacity, as in the case of central and west Texas, or the fact that power flows from the renewable resource to the preferred load center add to existing transmission congestion, as in the Pembina Escarpment area of North Dakota and Minnesota. Based on analyses contained in this report, high-capacity plants in many areas can be expected to require new lines or major upgrades to the transmission system at upgrade costs on the order of $125 to $472/kW. The construction costs equate to an additional levelized cost for the use of the resource ranging from 0.5 to 1.8 cents/kWh.

These case studies have identified opportunities for development of renewable electric generation within the constraints of existing transmission capacity in amounts between 25 and 100 MW in all of the regions examined. Availability of transmission capacity for high-output plants is much more location-specific, and with some exceptions, significant development will normally require considerable investment in transmission facilities.

15.2 RECOMMENDATIONS

Through case studies this report documents the need for careful assessment of transmission requirements prior to integration of renewable resources. Prior to actual development of solar and wind systems for grid integration, extensive studies of the expansion of site and resource-specific generation capacity should be conducted to determine the adequacy of the transmission system for the anticipated direction and magnitude of power transfers.

Changes in calculating the required regulating margin will need to be assessed before renewable generation can be operated routinely for any given control area.

Renewable generation will become more valuable as it becomes more controllable and dispatchable. To this end, development of such technologies as advanced control systems capable of dispatching large numbers of individual generators to maintain a preset output level, as well as storage systems capable of decoupling resource availability and energy supply, should be undertaken. Special operating and dispatch strategies for intermittent generation such as renewable energy plants should be examined as part of a detailed design study.

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