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Integrated Assessment of Dispersed Energy Resources Deployment

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Preface

The electricity industry may well be standing at a technological threshold that leads to a new era built upon the most fundamental change in power systems engineering and organization since the original small isolated power networks of the nascent industry first began to be interconnected. The technical challenges, risks and rewards are all major and sobering. We hereby step across that threshold and accept the consequences.

Table of Contents

List of Figures and Tables

Glossary

AM/FM	Automated Mapping/Facilities Management
ARB	California Air Resources Board
CaRFG2	California Phase II Reformulated Gasoline
CEC.	California Energy Commission
CEQA	California Environmental Quality Act
CERTS	Consortium for Electric Reliability Technology Solutions
CO	Carbon Monoxide
CPUC.	California Public Utilities Commission
dB	Decibel, a unit of sound pressure level
dBA	decibel unit of sound based on A-weighting scale
DEM	Digital Elevation Model
DISCO	Distribution Company
DOE	Department of Energy
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EOB.	Electricity Oversight Board
ESP	Electric Service Provider
GENCO	Generating Company
GIS	Geographic Information System
LBNL	Lawrence Berkeley National Laboratory
MTBE	Methyl-Tertiary-Butyl ether
NAC	Noise Abatement Criteria
NEM.	Net Energy Metering
NOx	Nitrogen Oxides
OIR.	Order Instituting Ratemaking
PLACE^{3}S	Planning for Community Energy, Economic and Environmental Sustainability
PM	Particulate Matter
PM-10	Particulate Matter less than or equal to 10 micrometers
PM-2.5	Particulate Matter less than or equal to 2.5 micrometers
ppm	Parts Per Million
ROG	Reactive Organic Gases
SCE.	Southern California Edison
SFBAAB	San Francisco Bay Area Air Basin
SJV	San Joaquin Valley
SJVAB	San Joaquin Valley Air Basin
SJVAPCD	San Joaquin Valley Air Pollution Control District
VOC	Volatile Organic Compounds

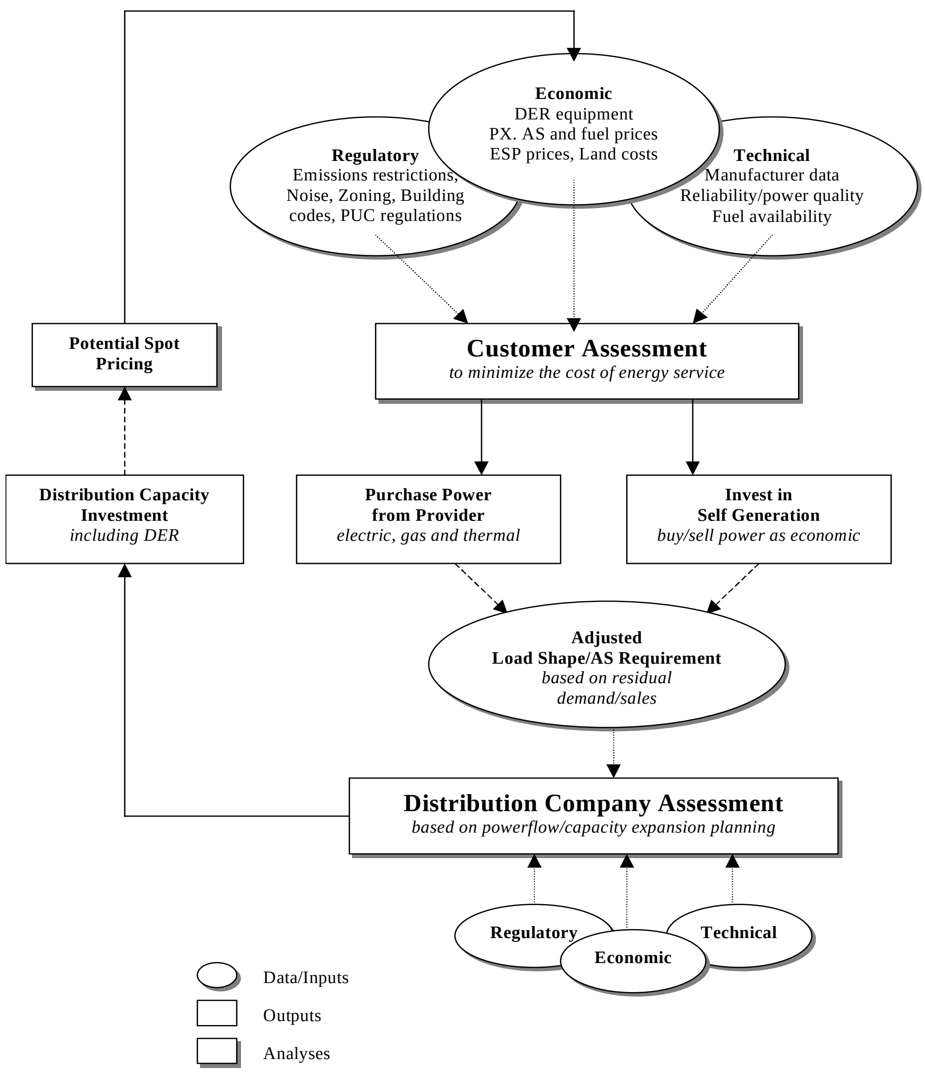
Executive Summary

The goal of this work is to create an integrated framework for forecasting the adoption of distributed energy resources (DER), both by electricity customers and by the various institutions within the industry itself, and for evaluating the effect of this adoption on the power system, particularly on the overall reliability and quality of electrical service to the end user. This effort and follow on contributions are intended to anticipate and explore possible patterns of DER deployment, thereby guiding technical work on microgrids towards the key technical problems. An early example of this process addressed is the question of possible DER adopting customer disconnection. A deployment scenario in which many customers disconnect from their distribution company (disco) entirely leads to a quite different set of technical problems than a scenario in which customers self generate a significant share or all of their on-site electricity requirements and additionally buy and sell energy and ancillary services (AS) locally and/or into wider markets. The exploratory work in this study suggests that the economics under which customers disconnect entirely are unlikely.

A complete analysis of DER deployment would include forecasting of customer adoption under various important constraints, such as economics and regulation. The customer adoption decision may be driven by the desire for higher system reliability, as under the CERTS sensitive load scenario, or simply by the cost effectiveness of DER at meeting on-site power requirements. In either case, a customer by customer analysis is most likely to accurately predict adoption. Simulation of the effects of customer adoption on the power system and the likely responses to these effects by the institutions that operate it is the other side of the DER adoption coin. This is the CERTS distribution support scenario. Only by looking at both sides of the meter can the promise and problems of DER be fully evaluated, the technical problems identified and tackled, and appropriate public policies to guide the transition to a distributed power system be crafted. The wider CERTS program is focused on the technical challenges that possible operation of local power system neighborhoods as partially or wholly electrically isolated microgrids will pose.

The approach taken here to the study of DER deployment is universal yet localized. Both sides of the meter, the customer and disco sides, are considered together with their geographic relationship assuming a heightened role. Both customers and discos are concerned with achieving an electricity supply system that meets their performance requirements at least cost. To put together a model of how the customer and the disco will interact and how DER adoption will be driven, the opportunities and limitations created by the two central pieces, the state of DER technology itself and the regulatory environment in which the actors operate, must be evaluated. Decentralization of the power system and the increasing role of customers whose main objective is clearly not the orderly development of the power system will mean local considerations will increasingly influence decisions regarding power system expansion. That is, local constraints on use of DER by customers, both regulatory and economic, will increasingly determine systemwide outcomes.

The Figure shows a schematic of a global integrated method for analyzing DER adoption in a neighborhood of the distribution network. This example is customer centered. Given the customer's needs for electrical and energy services and the perceived regulatory, economic, and technical conditions, the customer makes its DER adoption decision. The load shape faced by the disco will contain both sources and sinks and nodes that operate as both. The network will experience multi-directional power flow, and, consequently, system weaknesses will be variable and mobile. Given its need to design, build, and operate an adequate and safe network, the disco will plan and execute its network development plan, which will require various equipment investments including some DER acquisitions. The decisions made by the disco will in turn affect power quality and cost and, together with the numerous other elements that establish the customer's environment, will drive customer DER decisions. The direction of this work is towards an approach that is integrated, iterative, and comprehensive. In this report several of the components seen in the Figure are addressed but to date no integration has been achieved.



An Integrated Approach to Finding Patterns of DER Adoption

The objective of the customer adoption model is to minimize the cost of supplying electricity to a specific customer by installing distributed generation and self-generating part or all of the customers electricity requirement. Being able to solve this problem for individual customers is the first step towards developing an adoption model for neighborhoods or large customer sites around a feeder, which might operate as a microgrid. A spreadsheet customer adoption model was built and applied to load curves from a commercial data base for the following generic test customer types: grocery, restaurant, office, mall, and hospital. All are assumed to be in the Southern California Edison (SCE) service territory. The customers face standard tariffed rates and are assumed able to sell any power generated beyond their own requirements at the California Power Exchange (CalPX) price. In this example, only 4 types of fuel cell and 2 models of microturbine are available for the customers to install, and customers acquire generating units one-by-one. That is, the lumpiness of the technologies is expressly recognized, as is the likelihood that different technologies are preferable for different duty cycles. Natural gas is the assumed fuel in all cases, and possible combined heat and power (CHP) or enhanced reliability opportunities are not considered. The objective function is simply to minimize the customer's total electricity bill, with the customer load taken as given. More units of the distributed generation technologies are adopted until the lowest possible bill is achieved.

In the base case, distributed generation turned out to be cost effective to partially meet the load of all customers. This is because the capacity factor has a large influence on the economics of these technologies and, under normal conditions, these technologies are only economic when running almost 100% of the time. In other words, all of the customers had a large enough energy requirement to fully occupy at least one generator, making it cheaper than purchased power. However, none of the customers installs enough generation to fully meet its peak. That is, the distribution company is left to accommodate a lower but more peaky residual load from every test customer.

In a low fuel price scenario, gas prices roughly equivalent to the cheapest available in California are substituted for tariffed large customer rates (2.8 $/GJ versus the 5.70 of the base case). Customers naturally install more generation, 4 of the 5 customer types considered (hospital, office, grocery and restaurant) installed capacity equal to or above 77% of the maximum load. The restaurant installs a surprising 99% of its peak, and comes the closest of any case to a possible disconnect from the grid. The exception is the mall, which has the lowest load factor at 0.36, resulting in installation of only 58% of peak. Note that as fuel prices fall, not only does operating generation at lower capacity factors make installation of more capacity attractive, but also selling excess electricity to the CalPX earns positive revenues for more hours, also encouraging higher installed capacities.

Under a high fuel price scenario (7.6 $/GJ, or roughly equivalent to residential rates) on the other hand, it was not economical to any customer to install any capacity. This result is simply due to the fact that high levelized costs eventually exceed the tariffed price of electricity, making it unattractive at any capacity factor. Low and high interest rate scenarios were also run with no noticeable changes taking place, in part because the effect on costs of these scenarios was much less.

Summarizing, the customer adoption study performed suggests that distributed generation, not surprisingly, will be substituted by customers for more expensive purchases from energy service providers (ESPs). However, absent strong disincentives, such as standby charges or connection restrictions, customers will probably not disconnect from the grid due to economics. Although not considered in this analysis, the likely reliability benefits of remaining connected will obviously strengthen the desire to do so. Furthermore, it should not to be forgotten that it could be economical to install sufficient capacity to technically cover a customer’s needs and yet still be attractive to remain connected because of the revenues obtained from selling energy or ancillary services (AS) into the grid.

While the focus is on the customer side, the ultimate goal is to have a clear picture of the future development of DER options by electricity consumers. However, it is obvious that consumers and discos form an interconnected interactive system, and as a result, decisions made on one side of the meter have an effect on the other. Because of this relationship, this study also, at least in a simplified way, addresses the disco perspective on DER deployment. From the disco perspective, changing loads observed on the distribution system must be met by corresponding adjustments to the capability of the network. The existence of DER technologies has two effects. First, as already discussed, customer adoption changes the nature of the load to be met by the disco. And second, when planning adjustments to the distribution network, the disco will consider installing DER as an alternative to traditional upgrade options, such as increased conductor sizing. This is the CERTS distribution support scenario.

Because discos are likely to assess the need for network improvements based on a load flow analysis of each feeder, product information from 13 different distribution load flow software vendors was collected. All the technical characteristics were reviewed as well as the available demos. After this process, the Milsoft software WinMil® was purchased. After WinMil® was chosen, a sample distribution network, the IEEE 34 distribution test system, was used to validate the application. Finally, as the last step of this part of the work, a simple DER system support example was completed using the same feeder. The goal of this example is to test the capabilities of WindMil® for DER studies. Since the original feeder had voltage problems, the appropriateness of using distributed generation to solve this problem was analyzed. Several options were evaluated, but one of the best results obtained involved installing two generators of 200 kW each, which almost caused the voltage problems to disappear. Also, total power losses were reduced from 125 kW to 63 kW.

Since the electric utility regulatory environment is a key determining factor in the deployment pattern of DER, it was briefly surveyed. The regulatory situation is in a period of rapid change. Historically, regulation has not allowed customers to install small scale generation intended to operate in parallel with the distribution network. However, a liberalization process that began with the interconnection of qualifying facility generation and continued with interconnection rules for photvoltaics (PV) and other renewable generation is now dramatically accelerating. It seems quite likely that, at least in California, a basic interconnection agreement along the lines of the Texas one will be in place in a matter of months. However, it is by no means clear that ownership of DER by discos will be permitted nor what the rate design details will be, notably the ultimate level of standby charges. These details will have a major impact on the attractiveness of DER.

Numerous environmental issues need to be addressed when considering the possible impacts that could result from DER adoption. As a first step towards developing an environmental analysis capability, a brief evaluation of the possible air quality effects of installing microturbines in the San Joaquin Valley (SJV) was conducted. This is an area of poor air quality. Under stricter standards, the SJV has reduced its ozone levels significantly by lowering emissions over the past 20 years from both stationary sources and motor vehicles. However, PM-10 emissions in the SJV have increased somewhat over the same period. Based on this assessment of the southern SJV, it is concluded that impacts from installation of a 25-30 kW microturbine are far below any threshold of existing regulatory standards. With predicted NOx emissions amounting to only 3 emitting cars over the course of one year and CO equivalent to less than 1 car, the levels of emissions from a single turbine do not appear likely to cause concern. However, if penetration of emitting DER technologies, such as diesel generators, became significant pollution sources, clearly, the stance of pollution control districts might quickly become more hostile. Emissions that result from implementing DER technologies will reduce emissions at the central station, and some DER technologies have attractive emissions characteristics compared to most large stations. However, the currently planned new California capacity additions are remarkably low emitting and increased emissions from a new source within an air quality control district that offsets a source outside the monitoring zone could definitely result in opposition to implementation, irrespective of the net air quality effect.

Finally, the potential of Geographic information systems (GIS) as an integrating analysis tool was investigated. GIS offers a method by which numerous complex localized technical, regulatory, environmental, economic and demographic factors affecting DER adoption can be addressed and visualized. Since local issues will become critically important for DER deployment. Relevant noise and air quality regulations, cost of fuel delivery, impact on the grid, and even the technology chosen are all influenced by the physical location of the sites under selection. The power of GIS is that large quantities of this type of spatial information can be stored and processed efficiently, allowing local constraints to DER deployment to be considered at high levels of detail. Several examples of the use of GIS to address siting issues are reported.

Further, an initial assessment of GIS analysis activities at some discos in California was made in the summer of 1999. The level of sophistication of the GIS systems at the individual companies and municipalities was found to be quite varied, with most of the larger entities (500,000 or more customers served) currently using or in the process of developing a comprehensive AM/FM application.

The goal of this work is to create an integrated analysis method for anticipating possible patterns of DER deployment. In this first year, initial efforts have been made in five component analysis areas relevant to this broad objective. A simple model of customer DER adoption has been designed, built, and applied to some sample customer types, load flow analysis tools have been surveyed and a simple example analysis completed using one of them, the status of environmental and electric utility regulation has been examined, the environmental consequences of microturbine installation estimated, and the potential of GIS to provide an analysis framework has been explored

1. Introduction

1.1 Background

Electricity generating technology evolved steadily during the last century. Although early power systems were localized and not interconnected, for more than the first half of the 1900's, an apparently inexorable trend towards larger and larger generating stations connected to synchronized grids covering ever larger areas dominated thinking in the industry. The generating technologies available produced economies of scale that were real and significant, and capturing them through large scale centralized generation was the dominant industry imperative. This trend first began to reverse when the largest generating units, especially but not only nuclear ones, proved to be more expensive than history had suggested. The sources of rising costs were numerous, but certainly one key factor was the reliability problem created by dependence on large unreliable stations connected to distant customer loads by long transmission lines. That is, defending against the risk of large contingencies imposes high costs. Eventually, the trend towards larger scale stalled and then slowly reversed, a reversal that soon became accelerated by the emergence of competitive smaller scale thermal generation based on gas turbines.

Additionally, for the most part, harvesting renewable technologies has proven most economic at small scales. This changing technological reality eventually led policymakers to recognize that power generation was no longer a *natural monopoly*, that is, an industry in which bigger is always cheaper, and therefore the public is best served by just one provider, whose ability to exercise market power must then be curbed by regulatory oversight. The revolution set in motion by this realization has created the structure of the industry as we see it today in much of the U.S. and elsewhere around the world. Power generation is openly competitive and the operation of high voltage transmission and the system control function are in the hands of an independent system operator. Operation of the local radial distribution network and its related direct customer services remains in the hands of a regulated monopoly.

The emergence of distributed energy resources (DER) may well be the technological driver for the next electricity industry revolution. This revolution will take place in the heretofore little changed radial low voltage distribution network, and will create a power system that, particularly from the customer perspective, will look radically different from the one we know today. There are several drivers behind this revolution:

- continuous demand growth (recently at 5 %/a in California)
- decommissioning of the U.S. nuclear stations
- geographical, environmental, and political constraints on capacity expansion for generation, transmission, and distribution
- system reliability threats from system saturation and market instability
- privatization, deregulation and competitive markets
- emergence of new generating technologies with small ratings, ecological benefits, and low costs, often with combined heat and power applications

- development of power system electronics that permit safe and reliable operation of small power sources, including asynchronous ones

Distributed generation offers advantages with respect to central generation for both the customer and the grid.

customer:

- reduction of costs[1]
- improvement in reliability
- satisfaction of on-site thermal energy requirements

grid:

- postponement of transmission and distribution system upgrade
- improvement of power quality (e.g. local voltage control)
- enhancement of general service reliability
- reduction of transmission losses
- alleviation of congestion through peak load shaving
- displacement of more expensive reliability resources (e.g. Reliability Must Run[2])

The cost and other advantages of DER are powerful and will drive its early adoption. The existence of numerous small generators in lieu of a few large ones will require a major rethinking of the assumptions under which the power system is currently operated. However, in the longer run, the location of generation closer to loads, and improving ability to jointly control both generation and loads precisely and accurately creates the following even more revolutionary possibility. If local cells of the power system can be operated safely and within tolerable standards of power quality, then the prospect of neighborhoods of the current centralized power system wholly or partially decoupling from the grid to operate as *microgrids* become a real possibility. They may decouple only under emergency conditions, their attachment may be intermittent, or they may operate asynchronously. Any of these operating protocols would require a major shift in the current paradigm on which the engineering and regulation of power systems is based.

The notion that microgrids can and will become a reality provides the *deus ex machina* of this project, and of the wider Consortium for Electric Reliability Technology Solutions (CERTS) research effort in DER. The work undertaken here is a modest first step towards creating the framework in which the formation of microgrids can be predicted and the enabling research necessary to make them function, electrically, economically, environmentally, and politically can be pursued. Most importantly, insuring an efficient

[1] Note that in California, distribution costs are a large part of the electricity bill, around 30% (California Independent System Operator).
[2] Reliability Must Run are units called by the ISO to ensure that the system operates within specified reliability criteria. These units help meet interconnection reliability requirements, serve load in constrained areas and provide localized voltage or security support for the ISO.

and reliable power system a decade or two hence will depend heavily on our ability to operate microgrids in economic, safe and reliable ways.

1.2 Goal of this Work

The goal of this work is to create an integrated framework for forecasting the adoption of DER, both by electricity customers and by the various institutions within the industry itself, and for evaluating the effect of this adoption on the power system, particularly on the overall reliability and quality of electrical service to the ultimate user. A complete analysis of DER deployment would include forecasting of customer adoption under various important constraints, such as economics and regulation, and simulation of the effects of customer adoption on the power system and the likely responses to these effects by the institutions that operate it. Only by looking at both sides of the meter can the promise and problems of DER be fully evaluated and appropriate public policies to guide the transition to a distributed power system be crafted. The wider CERTS program is focused on the technical challenges that microgrids will pose. This effort and follow on contributions are intended to anticipate and explore possible patterns of DER deployment, thereby guiding technical work towards the key problems.

1.3 Approach

1.3.1 Introduction

The approach taken here to the study of DER deployment is universal yet localized. Both sides of the meter, the customer and disco sides, are considered together with their geographic relationship assuming a heightened role.

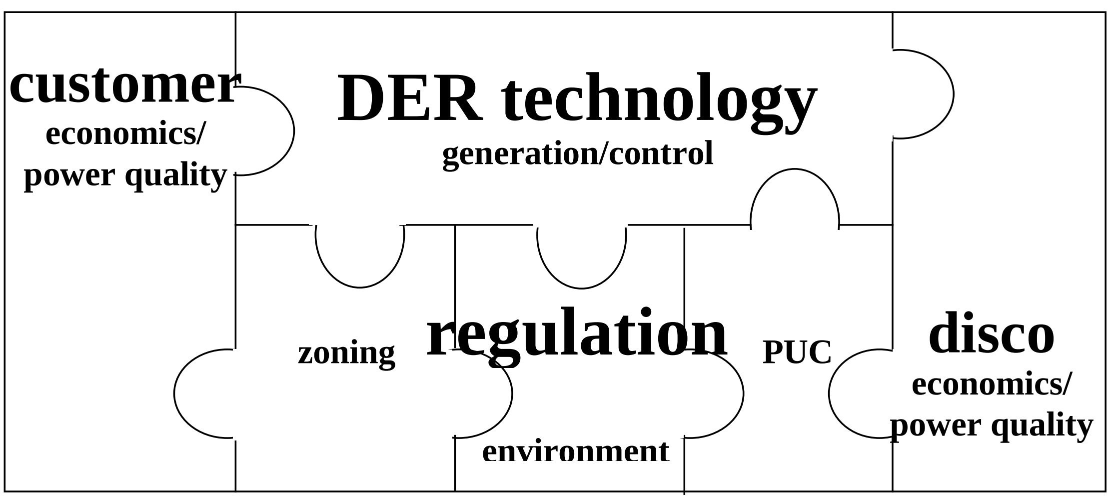


Figure 1: Conceptual Framework for Integrated Analysis of DER Adoption

The conceptual framework of this work is shown in Figure 1. There are four basic pieces to the jigsaw puzzle. On each end are the customer and the distribution company (disco). Both are concerned with achieving an electricity supply system that meets its performance requirements at least cost. To put together a model of how the customer and the disco will interact and how DER adoption will be driven, the opportunities and limitations created by the two central pieces, the state of DER technology itself and the regulatory environment in which the actors operate, must be evaluated.

New incentives and opportunities are being created through new technologies and competition in the electric sector that will enable both discos and customers to lower costs and customize electricity service. Therefore, the deployment of DER will be determined by decisions made on both sides of the meter, and the two sets of decision makers will each react to decisions made by the others, through information contained in price signals. However, decentralization of the power system and the increasing role of customers whose main objective is clearly not the orderly development of the power system will mean local considerations will increasingly influence decisions regarding power system expansion. That is, local constraints on use of DER by customers, both regulatory and economic, will increasingly determine systemwide outcomes. For example, the extent to which building codes permit installation of generators in buildings may be a key factor. While it is unlikely to entirely replace large-scale, centralized generation, DER can lower costs and meet performance and reliability functions, if properly sited (Rastler 1992). It is in the resolution and optimization of these localized siting issues that geographic information systems (GIS) can serve as a powerful, analysis tool for both the customer and disco sides.

1.3.2 Benefits of DER

DER include modular, dispersed generation and storage assets, customer energy management systems, distribution network equipment and automation, and the control technologies needed to operate an integrated local power system. These resources can be sited throughout a distribution company's service territory to optimize site-specific generator characteristics, electricity demand, economic factors, and environmental constraints. Similarly, distributed generation can offer consumers grid-independent power, enhanced reliability, cogeneration or combined heat and power applications, and in some instances may be the least cost power option. Potential benefits of DER include (Hennagir 1997, Hoskins 1998, Swanekamp 1997, Scott 1998):

- cost savings relative to retail tariffs
- potential to sell electricity into open markets
- standby capacity, offering improved service reliability and power quality
- fuel diversity (depending on the technology implemented)
- on-site cogeneration (capitalizing on the efficiencies of thermal production)
- peak-shaving in high load growth areas (deferral of T&D expenditures where constraints exist)
- reduction of electrical losses
- elimination of approval and permitting requirements for central station technologies and transmission
- reduced emissions for many technologies (e.g., PV).

1.3.3 Barriers to DER

Many of the technical issues related to attaching DER on the distribution side, such as dynamic stability, protection, automatic generation control, generation dispatch, and frequency and voltage regulation, become relevant only as the DER share of total generation becomes significant (Donnelly 1996). In the short term, DER assets can be readily utilized. The U.S. Department of Energy estimates that by 2020 as much as 20 percent of U.S. electricity may be from distributed generation (Hennagir 1997) and EPRI has predicted this fraction may eventually reach 30 percent (Feibus 1999). To achieve this penetration level, new engineering tools and operating strategies must be developed in the long-term to enable DER to capture a significant market share.

1.3.4 Customer Perspective

Whether to adopt onsite generation is a comparatively simple problem for the customer. Given the cost of equipment, the cost of alternative disco delivered power, fuel costs, the potential for revenues from the sale of excess generation, either into a pool or bilaterally, and reliability requirements, the viability of a project can be evaluated. The initial capital cost of many DER options may inhibit adoption. Accurate assessment of lifecycle cost and operating conditions are critical factors that must be considered when determining the true economic cost of potential installations.

A few commercial, industrial and even residential customers concerned with power quality and reliability have always looked at on-site generation options to improve service (Wald 1998, Best 1999, Friedman 1999). Two key changes to this evaluation resulting from restructuring are the potential to buy from and sell into energy markets directly and the detachment of generation from distribution, which alters the enthusiasm of the disco to accommodate customer-owned generation. Bidding or contracting to provide ancillary services is also an increasingly likely possibility. But now, distributed generation can be considered as both base load and as a standby resource.

Within the economic analysis, the source of greatest complexity in the evaluation of DER concerns economic relationships with wider electricity markets. Highly variable market electricity prices must be forecast, and the potential for sales of other ancillary services assessed. An additional possible future source of complexity in this assessment would be localized congestion pricing of disco service. While not currently seen by the end user, the costs of delivering electricity vary significantly locally; further unbundling of rates may mean these costs are passed more directly to customers through prices. Chapter 2 of this report details a generation asset adoption model for the consumer. The approach uses a customer load profile, tariff, and information about DER options to predict whether the customer will adopt DER, and what technologies. The model is currently centered on an individual customer's technology choice but the wider question of how small scale generation and local loads can technically and economically formed into microgrids remains. Some larger customer sites will essentially be *de facto* microgrids.

As an example of the type of large development that will be occurring, at a constrained feeder site east of the San Francisco Bay Area in northern California, a collaboration between PG&E (the distribution company), several small scale generator manufacturers, and Edison Development Corp (a subsidiary of Detroit-based DTE Energy Co.), with funding from both the California Energy Commission and the U.S. Department of Energy, has resulted in a demonstration project for distributed generation. This commercial and industrial zoned site, called the Pleasanton Power Park, incorporates both customer-side stand-alone generation and disco-benefiting grid-connected generation for peak load shaving. Because this facility is in the rapidly growing and heavily transmission constrained Southern Tri-Valley Area, adjacent to the Radium & Vineyard substations, it poses an excellent test case of avoided distribution system upgrade. The local feeder was identified as a potential site because it is currently at 98% capacity and demand growth is unlikely to slow. The site will eventually host a total of 100 MW of renewable and gas-generated power, and will serve as a net energy generator. One simple cycle gas turbine will be controlled by the ISO under an RMR contract. DER enables this heavy industrial site to exist in an area constrained by reliability and emissions constraints. Identifying similar situations and potential sites could be facilitated through GIS, by searching for similar load constrained and growth demand conditions as well as the appropriate zoning and transmission line access features.

1.3.5 Distribution Company Perspective

The methods and tools that discos currently employ to develop distribution systems are ones deeply rooted in the history of industry. The adoption of DER by discos will, for some time, be guided by analysis based on the notion that distribution systems are inherently simple and that safety concerns are absolutely paramount. Prior to deregulation, customers had typically been grouped for tariffication by utilities according to their classification (industrial, commercial or residential) rather than their geographic relationship (Lamarre 1993). In addition, generation expansion planning has, by and large, ignored geography entirely and focused squarely on the problem of ensuring that total generating capacity can meet peak customer demand, as if the two can reasonably be assumed to reside side-by-side. Designing and building the transmission and distribution system to deliver power to customers was a secondary aspect of planning. In distribution planning, the minimum cost generating system was assumed to be in place, and the high cost of distribution was not reinjected into the capacity planning analysis. Strong economies of scale in generation, the assumed relatively small across the board costs associated with delivery, and the long lifetimes of utility assets justified this approach. Improved small scale generating technologies are now challenging the first assumption, unbundled rates are uncovering the fallacy of the second, and the economic benefits of new utility assets are being eroded by the difficulties associated with siting new facilities. This final point is key. Even if the economics of central station generation prevails, limits on the number of physical sites available and barriers to installing large new facilities at them and the transmission needed to link them to customers inevitably brings geography into the equation. Last, but by no means least, restructuring has undermined the entire assumption of centralized capacity planning and facilities operations.

Discos, at least for the near term, will be making their DER adoption decisions by applying familiar economic and engineering tools. Specifically, alternative solutions to distribution network problems will be found using power flow models, and choices between them made based on the principles of engineering economics. When weighing potential expansion options for distribution networks, distribution companies will perform several optimizations, including generator choice (technology and size), generator location, storage/generation supply, and network security and stability (Hadjsaid 1999). For distribution modeling, a primary goal when determining generator location is to minimize losses. More complex optimizations can incorporate additional factors, such as optimum capacitor location, load balancing for transformers and feeders, and reliability for important customers (Hadjsaid 1999). Economic optimization evaluates the cost of various technology options (i.e., both traditional utility equipment installation as well as DER options), and assesses their viability. In other words, the disco must respond to customer generation and purchase patterns in ways that keep the distribution network with acceptable operating limits.

1.3.6 Expansion Planning for the Power System with DER

For customers, deciding upon power supply options involves balancing power consumption with net generation while also considering time of use pricing of electricity. For discos, optimal operation and planning analysis for distribution or generation options typically considers both operation cost savings and security margins. While these factors are sufficient for coarse-level site selection, deployment of DER is contingent upon a number of other demographic and regulatory issues. Noise restrictions, regional emissions/air quality regulations, PUC regulatory requirements, fuel access, zoning restrictions, and land availability and cost are all site-specific considerations that must be incorporated into the planning analysis. The optimal solution for both distribution and economic models is dependent upon demographic and regulatory factors, which are not typically considered during the traditional optimization process. Emphasizing electrical and economic factors can result in overlooking the importance of regulatory restrictions (e.g., noise and emissions concerns) and other site-specific parameters, which are often fatal barriers to deployment. For example, a factor influencing the cost of energy from medium sized gas turbines is the pressure at which natural gas is distributed to the site (Hoskins 1998). If a compressor is required, the capital cost of installation increases significantly and building code requirements become more stringent. Without incorporating such site-specific parameters, the economic modeling will not yield the optimal solution.

Figure 2 shows a schematic of a global integrated method for analyzing DER adoption in a neighborhood of the distribution network. The approach is customer centered. Given its needs for electrical and energy services and the regulatory, economic, and technical conditions it perceives, the customer makes its DER adoption decision. Given its decision, the customer could become a net generator or a net consumer. However, it will most likely act as both at various times and under various circumstances, although its ability to do this will rest heavily on the extent to which regulation permits variable behavior.

The load shape faced by the disco will contain both sources and sinks and nodes that operate as both. The network will experience multi-directional power flow, and, consequently, system weaknesses will be variable and mobile. Given its need to design, build, and operate an adequate and safe network, the disco will plan and execute its network development plan, which will require various equipment investments including some DER acquisitions.

The decisions made by the disco will in turn affect power quality and cost and, together with the numerous other elements that establish the customer's environment, will drive customer DER decisions.

The direction of this work is towards an approach that is integrated, iterative, and comprehensive. It will allow analysis of distribution system development not only under current economic, technical, and regulatory regimes but also allow for consideration of emerging technologies. The intent is to put customer adoption at the center and to explicitly bring spatial considerations into the analysis at the outset by using GIS as a core rather than a peripheral tool. In this report several of the components seen in Figure 2 are addressed but to date no integration has been achieved.

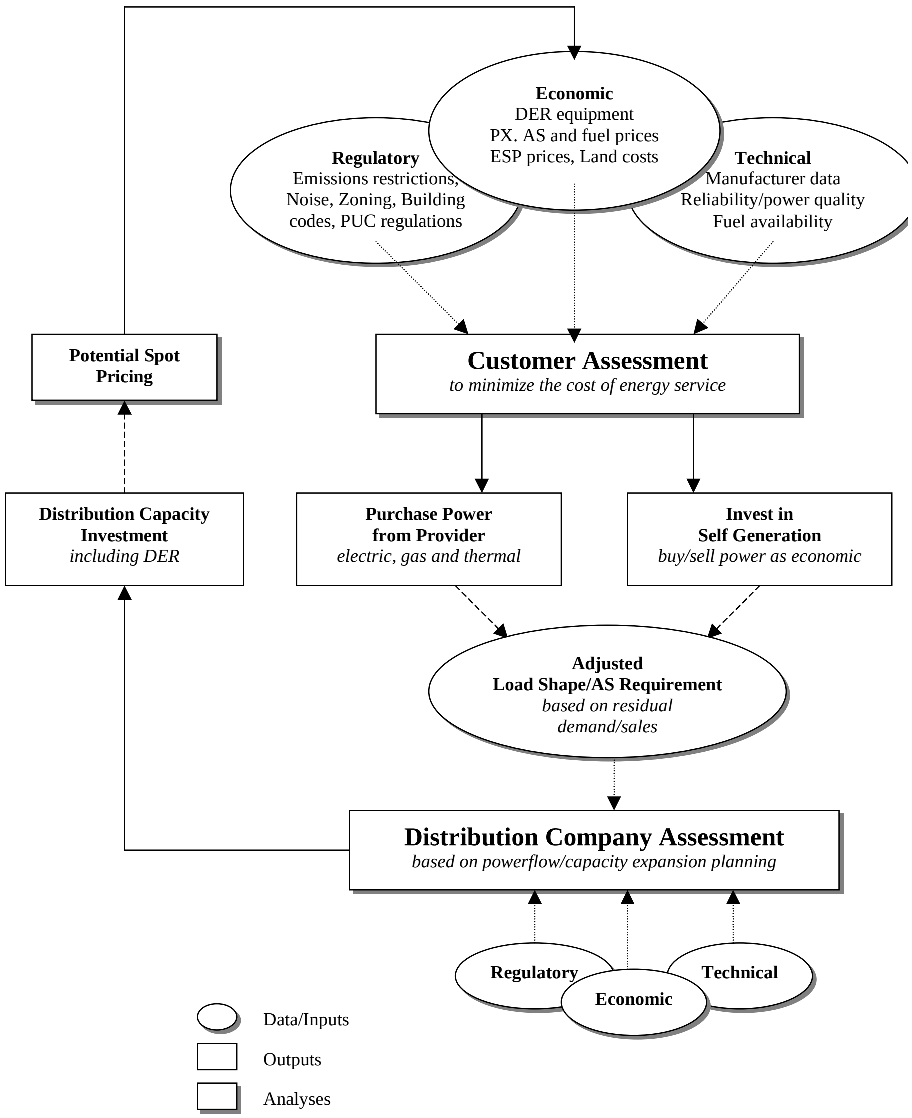


Figure 2: Distributed Energy Resources Integrated Selection Process.

1.4 Dispersed Energy Resources (DER)

1.4.1 Introduction

Dispersed energy resources come in many forms and a clear definition of DER remains elusive. One general definition might be all sources of energy services that can be harvested sufficiently close to their ultimate users to be economically developed without high voltage (> ~100 kV) transmission. Clearly, many energy sources fall within this definition, including: many forms of small scale fossil fired generation (such as micro-turbines, fuel cells, and reciprocating engines); customer end-use efficiency enhancements (such as efficient lighting and space conditioning); and small scale renewable generation (such as photovoltaic systems, small wind turbines, etc.). The approach taken is intended to be general enough to allow future incorporation of a wider range of DER technologies, including those traditionally considered to lie on the demand side. For pragmatic reasons, however, the focus of this work is on generation technologies economic at capacities of 500 kW, or less, that can be installed at customer sites, and that can be connected at distribution system voltages.

Two technologies now reaching commercialization are of particular interest because of their small scale, modular design, combined heat and power (CHP or cogeneration) potential, and their ability to operate in an environmentally acceptable manner using ubiquitous natural gas fuel. These two technologies are microturbines, that is small asynchronous turbines, and fuel cells. Because of the immediate interest of these technologies, and their potential is the focus of Chapter 2.

1.5 Report Outline

This report is organized into 7 chapters. While each of the major sections, 2 through 6, can stand fairly independently of the others and may seem somewhat unconnected, each section represents an effort in this first year of the project to begin constructing one of the pieces shown in Figure 2. The chapters are arranged as follows:

1. Introduction

2. Customer Adoption Model

Chapter 2 describes a customer adoption model, to date only implemented on a spreadsheet, that takes a customer load profile, the appropriate tariff structure, and information describing the DER technologies available and attempts to predict how many units of which technologies will be chosen by example customers. The selection is based solely on economics without regard for regulatory or other constraints on DER deployment.

3. Distribution Company DER Adoption

Chapter 3 begins to address the electricity distribution company's (disco) system development problem. The disco has to manage its system given the demand it faces, including the effect of customer DER adoption. There are two key points. 1. Disco's use load flows to design and plan their systems so as to stay in compliance with power quality standards. 2. In addition to the standard equipment they currently have available (e.g. capacitors), they can now use DER as well. This chapter describes some distribution system load flow models and shows an example of how the disco might trade off traditional system upgrades against a DER option.

4. Regulatory Issues

Chapter 4 begins the discussion of regulatory issues relevant to DER deployment. The focus is on the California situation.

5. Environmental Issues

Chapter 5 addresses the environmental issues relevant to DER deployment. The focus is again very much on the California situation, and specifically addresses the environmental issues of the southern central valley area, which has been identified as a particularly favorable area for DER adoption.

6. Integrating Geographic Analysis and Site Selection

Chapter 6 specifically addresses the benefits of a GIS oriented approach to analysis of DER adoption.

7. Conclusion

2. Customer Adoption Model

2.1 Goals

The objective of the customer adoption model is to minimize the cost of supplying electricity to a specific customer by optimizing the installation of distributed generation and the self-generation of part or all of its electricity. Being able to solve this problem for individual customers is the first step towards developing an adoption model for neighborhoods around a feeder, which might operate as a microgrid.

The main questions to be answered in this work are:

- Which is the best distributed technology or combination of technologies for a specific customer to install?
- What is the appropriate installed capacity of these technologies to minimize cost?
- Will disconnecting from the grid be attractive to any kind of customer from an economic point of view? Because customer loads are generally small relative to the scale of generators available and the cost of missed economies of scale may be severe at this end of the spectrum, an adoption algorithm that explicitly addresses the lumpiness of available equipment is highly desirable.

2.2 Implementation and Assumptions (Customer Adoption Algorithm)

For this study, it will be assumed that the customer wants to install distributed generation to minimize the cost of the electricity consumed on site. At the same time, it should be possible to determine the technologies and capacity the customer is likely to install, to predict when the customer will be self-generating electricity or buying or selling to the grid, and to determine whether it is worthwhile for the customer to disconnect entirely from the grid

Known variables and inputs into the model are:

- the customer load profile,
- the customer's tariff (SCE tariffs will be applied),
- the capital, O&M, and fuel costs of the various available technologies,
- the basic physical characteristics of the technologies,
- the California Power Exchange (CalPX) price at all hours of the year.

Outputs to be determined by the optimization are:

- technology or combination of technologies to be installed,
- capacity of each technology to be installed,
- when and how much of the capacity installed will be running,
- total cost of electricity,
- if the customer should, from an economic point of view, remain connected to the grid.

2.2.1 Assumptions

Some of the main assumptions of the model follow:

- The distributed generator generates electricity in excess of its own need only when the variable cost[3] of the unit (or units) running is less than the CalPX price. If the PX price is less than the variable cost, the unit only produces electricity to be consumed by the customer, because it would be losing money if it were selling to the grid.[4] In other words, if the PX price is greater than the variable cost, then self-generated electricity will be sold into the grid; if the PX price is less than the variable cost, self-generated electricity will not be sold into the grid.
- The customer is not allowed to sell and buy at the same time. The customer can only sell self-generated electricity, else when the PX price exceeds the tariff price, the customer would want to "arbitrage" an infinite output by buying at the tariff price and selling at the PX price.
- All the electricity generated in excess of that consumed is sold to the grid. No technical constraints to selling back to the grid at any particular moment are considered. On the other hand, if more electricity is consumed than generated, then the customer will buy from the grid at tariff rates. No other market opportunities, such as sale of ancillary services or bilateral contracts are considered.
- In this study, the possibility of optimizing the load profile of the customer to minimize costs (or even to get some revenues from the grid) is not considered, although this possibility should be studied in the future.
- Any deterioration in output or efficiency during the lifetime of the equipment is not considered.
- Start-up cost is not included in the study and economies of scale in O&M cost for units of the same technology are not taken into account.
- For every hour, it is assumed that the tariff price always exceeds the variable cost, so whenever a unit is installed and the customer's load has not been completely met, then the unit will definitely be running (at least to meet the customer's residual load).
- Possible combined heat and power application of distributed generation is not included in this analysis.
- The service reliability implications of installing generation, positive or negative, are not considered.

2.2.2 Algorithm

The way the problem will be addressed is the following:

[3] Variable cost is the fuel cost plus the variable Operation and Maintenance Cost.
[4] Here the consideration of other factors related to electricity generation, such as the costs of shutting down or adjusting the output, are not taken into account although they may affect the economics as they pertain to selling power to the grid.

- A net cost (**NC**) function is built which includes the cost of the electricity purchased from the grid (**C_p**), the cost of the self-generated electricity (**C_g**) and the revenues of the electricity sold to the grid (**R_s**).[5]

Net Cost Function (NC) = NC (installed technologies)
= cost of purchases from the grid + cost of self-generation – revenues of sales to grid
$= C_p(.) + C_g(.) - R_s(.)$

Note that the last two terms of the **NC** function, **Cg** and **Rs**, represent the net cost of the self-generated electricity, once the revenues from selling into the grid have been taken into account.

- The objective is to minimize the **NC** function with respect to the capacities to be installed, **k**, and the technologies to be selected; **k_j** represents the capacity of technology **j** to be installed.

$$\min_{k_j} NC = C_p(.) + C_g(.) - R_s(.),$$

from j = 1 to **n**, where n is the number of technologies considered.

2.2.3 Definitions of the Three Terms of the Net Cost Function

Cost of the self-generated electricity C_g ($):

For every hour **h**, **C_g** is a function of:

1. the amount of self-generated electricity produced, or the sum of outputs of all the installed capacity is actually running during that hour, **Σr_{ih}**, [6]

2. the cost of self-generated electricity: LEC[7] (levelized energy cost) which is flat for a given time and includes capital costs spread over the equipment lifetime, fuel costs and O&M costs.[8]

Hence, for every hour **h**, **C_{gh}** can be defined as:

$$C_{gh} = \sum_{i}^{m} r_{ih} \cdot LEC_i \,,$$

where **i** is each installed technology. As will be noticed later, **i** also refers to the step of the optimization process at which this technology is added.

[5] In a future further stage of model development, the costs of the outages, which will be different if connected versus disconnected to the grid, should be included.
[6] Running capacity during the hour **h**, of the technology added **i** is r_{ih}.
[7] For the definition of LEC (levelized energy cost), please see section 2.3.4.
[8] In this study start-up costs have not been considered, but in a more advanced study they should be included in the model to calculate the LECs.

Revenues from electricity sold to the grid R_s ($):

The revenues obtained from selling to the grid electricity produced in excess of the customer's consumption will be determined using the following assumptions:

1. The customer receives the California Power Exchange price (**PX_h**) in every hour **h** when selling into the grid, which is meant to be a lower bound estimate of the price paid to self-generators.[9]

2. The amount of electricity sold to the grid is energy generated minus energy consumed onsite in any hour. This value can only be positive or zero. The energy generated depends on how much capacity is running during the hour, and the electricity consumed onsite, **$Load_h$**.

Hence, for a specific hour **h**:

$$R_{sh} = \left(\sum_i r_{ih} - Load_h \right) \cdot PX_h$$

Cost of the electricity purchased from the grid C_p ($):

C_p is a function of:

1. The amount of electricity that is purchased from the grid every hour **h**. This value, calculated as energy consumed minus energy generated, is always greater than zero because the customer sells to the grid when it is negative,

$$Load_h - \sum_i r_{ih}$$

2. The tariff applied to the customer, which depends on the service voltage and peak power. The tariff has different components: a fixed charge, an energy charge, and a demand charge. The energy charge depends on the amount of electricity consumed and the demand charge depends on the peak demand in every month. These two terms, energy and demand charge vary for the different seasons (winter or summer) and for the different hours of the day (on-peak, off-peak and mid-peak).

If the tariff charges are split for every hour **h** (as opposed to every month), then **C_{ph}** would be:

$$C_{ph} = f_h + \left(Load_h - \sum_i r_{ih} \right) \cdot t_{ehs} + \frac{(\text{Max Load}_{month})}{\text{hours in a month}} \cdot t_{dhs}$$

where:

f_h is the hourly share of the tariff fixed charge,

[9] The price self-generators actually receive for electricity sold to the grid will depend on the contracts they hold. The CalPX price is used as a lower bound estimate of this price. Note that no generator will contract to sell electricity below the expected CalPX price.

$\mathbf{t_{ehs}}$ is the energy charge coefficient for the season **s** (winter or summer) at the hour **h**,
$\mathbf{t_{dhs}}$ is the demand charge coefficient for the season **s** (winter or summer) at the hour **h**,
$\mathbf{Max\ Load_{month}}$ is the maximum demand for the month considered,
and hours in a month divides the demand charge term to split those costs on an hourly basis because $\mathbf{C_{ph}}$ is accounted for every hour.

2.2.4 Implementation of the Algorithm

Because generation technologies are "lumpy" technologies,[10] the minimization process is a discrete optimization problem. The following algorithm, which was adopted to solve this problem, involves optimizing step by step the adoption of each generator in turn.[11]

1. Determine the minimum load[12] of the customer during the period considered (one year). For that minimum load, find the cheapest technology by considering how the Capacity Factor (CF) is going to affect the LEC (levelized energy cost) of that technology, as follows:

– If Min Load > nameplate rating: for the cheapest technology (looking at the LEC for CF = 1), the capacity to be installed to cover the "base load"[13] is the overall capacity of the integer number of elements of that technology whose overall rating will be less than or equal to the minimum load. In other words, up to the minimum load point, install as much of the cheapest technology as possible.
– If Min Load < technology rating: the CF must be recalculated because in this case it will be equal to or less than 1, depending on whether or not the installed generation will be running continuously. This decision depends on the PX price at any point in time.
– To recalculate the CF, **hour by hour**, the following comparison is done:
–
   a. if Load > Rating, then the unit will be running at full capacity,
   b. if Load < Rating, then:

      – if the PX price > Variable Cost, unit running at full capacity,
      – if the PX < Variable Cost, unit running at capacity equal to the Load.

[10] By lumpy it is meant that the available rated capacity of each technology is limited, that is, it is not possible to select an optimal capacity to be installed because the technologies are only available in certain sizes. This affects the way the algorithm is implemented.
[11] The optimization of every step when adding technologies does not mean that the result is the optimization of the whole process.
[12] The minimum load is selected because if it is economic to install a chosen technology with a capacity less than the minimum load, then it will be economical to install that technology up to the minimum load because the conditions (LEC) remain the same, that is CF = 1.
[13] Base load is defined in this model as the load that is always provided along the time period considered. Due to the lumpiness of the technologies, it will be less or equal to the minimum load in this study because only by coincidence could the minimum load be met exactly by an integer number of elements (units) of the cheapest distributed generation technology.

After doing this comparison, the CF and the LEC is recalculated (in an iterative way). It is important to verify at this point that the technology considered remains the cheapest option with the new LEC. Otherwise, the technology with the cheapest recalculated LEC should be implemented. Once both the CF and LEC are determined, the net costs of the electricity generated (that result from installing the capacity to meet the base load) is calculated and it becomes the starting point for the cost optimization.

At the end of this first step the capacity installed is $\mathbf{k_1}$ and the running capacity $\mathbf{r_1}$ is known for every hour of the time period considered, as shown in Figure 3. Note that $\mathbf{k_1}$ must be an integer multiple of the available technology size.

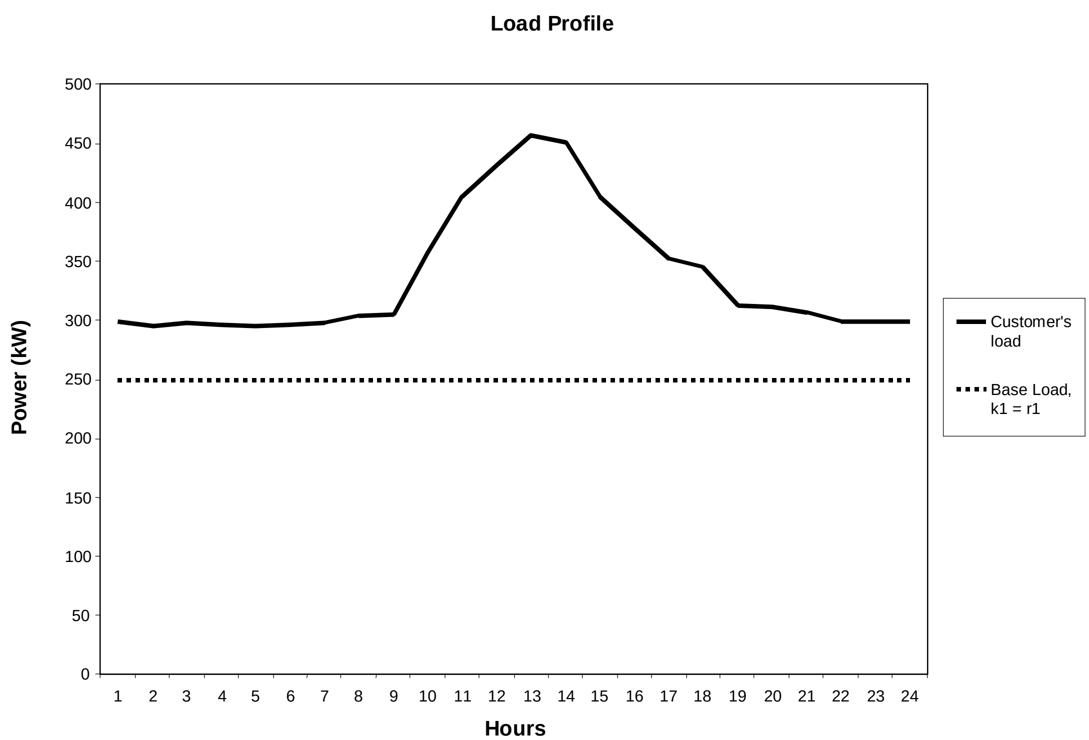


Figure 3: Base Load Determined for the Load Profile (Step 1)

2. Once the base load has been met with a choosen technology and capacity, $\mathbf{k_1}$ (capacity of the first technology installed), for a certain LEC_1 for that block of technology installed, then it is necessary to try to add more capacity of the same or another technology. Therefore, for each technology, when and how much the customer will generate will be evaluated. By recalculating the CF and LECs for each technology, it is possible to determine the cheapest technology to be added in a second step.

The procedure to evaluate when the customer will or will not generate is the following, on an **hour by hour** basis:

- If Residual Load[14] > $\mathbf{k_i}$, ($\mathbf{k_i}$ is the capacity rating of the next technology to be added), then the next unit to be added will be generating at full rating, this means running capacity $r_i = k_i, \forall h$
- If Residual Load < $\mathbf{k_i}$, then potential sales to the PX must be considered as follows:
-
    a. If PX > Variable Cost$_i$ (here, **Variable Cost$_i$** means the Variable Cost for the capacity of the next technology to be added), then the next unit will be generating at full rating, i.e., running at capacity $r_i = k_i$,
    b. If PX < Variable Cost$_i$, then the next unit will be generating at a capacity equal to the Residual Load: running capacity r_i = Residual Load = Load - Σ r_i, where i = 1 to m –1 and **m** is the mth step in which more capacity is added.

These two steps (**a** and **b**) are repeated for every technology, and for every technology it is necessary to iterate, since $\mathbf{LEC_i}$ depends on the $\mathbf{CF_i}$, which will vary depending on prevailing PX prices.

Once all technologies have been examined according to this procedure, comparing the result of the function NC for the customer will lead to the choice of technology that results in the least cost. This technology will be adopted and the residual load curve calculated, so that step 2 can be repeated.

Figure 4 shows an example of this process. There, for the hypothetical customer, the base load has been met (and the running capacity r_1 = installed capacity $\mathbf{k_1}$); in the second step, another technology has been added with an installed capacity $\mathbf{k_2}$ and a running capacity $\mathbf{r_2}$. As the graph shows, however, this technology is not running at full capacity the whole time. Sometimes it runs only enough to meet the customer's load. It is noticeable that in this case, the second technology is producing electricity in excess of the customer's needs for several hours, from approximately 18:00 to 22:00. Therefore, it is selling into the grid for those hours during which the variable costs of operating the technology are less than the PX prices. After step 2, a new technology has been added with a capacity $\mathbf{k_2}$.

[14] Residual Load is the difference between the customer load and the load already met by the previously added capacity (the load met by the capacity added in the prior steps). Residual load is a function of time, for every hour it is different. It can be expressed as: Residual Load = Load – Running Capacity, whereas Running Capacity for that certain hour is: Σ r_i , where i = 1 to m –1, the **m**th step of the capacity addition under consideration.

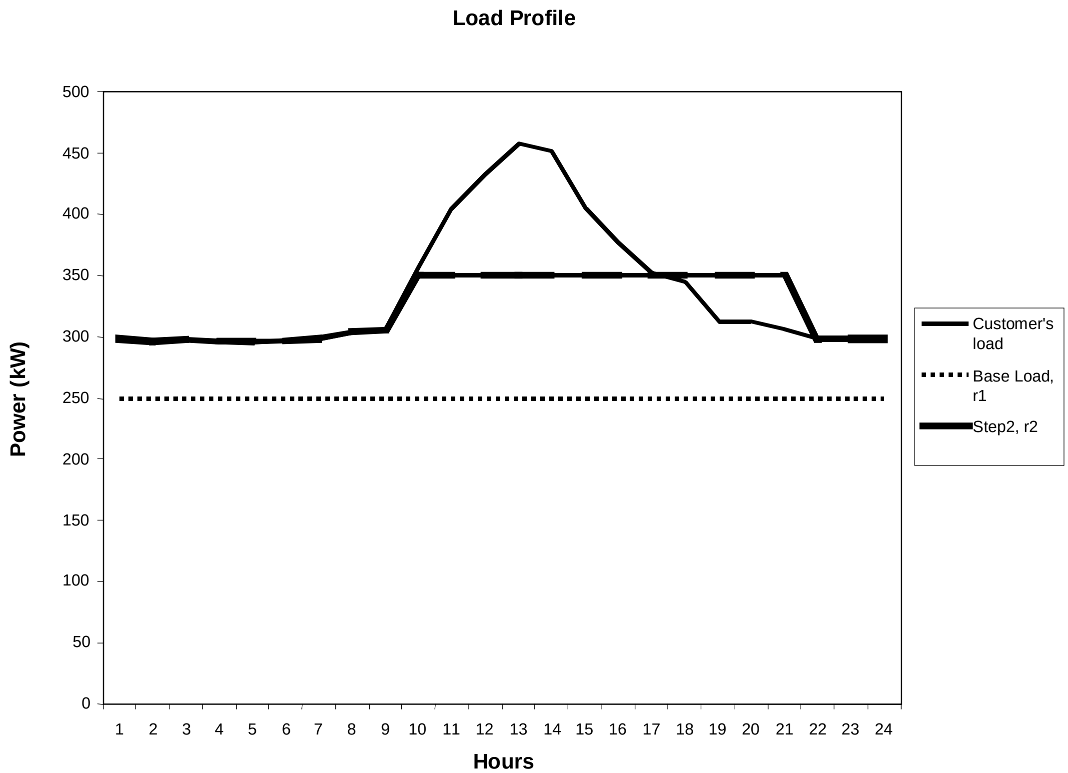


Figure 4: After Step 2, There are Two Technologies Installed

3. In order to calculate the NC function in the last step **m**, the following components of NC should be determined **on an hourly basis**, and integrating for all the hours (from h = 1 to 8760).

$$\text{Electricity generated} = \sum_{h=1}^{8760} \sum_{i=1}^{m} \mathrm{r}_{ih}$$

$$\mathrm{C_p} = \text{Cost of purchases from grid} = \text{f (Residual Load, Tariff)}^{15}$$

$$\mathrm{C_g} = \text{Cost of self - generated electricity} = \sum_{h=1}^{8760} \sum_{i=1}^{m} \left(\mathrm{r}_{ih} \cdot \mathrm{LEC}_i \right)$$

$$\mathrm{R_s} = \text{Revenues from selling to grid} = \sum_{h=1}^{8760} \left(\sum_{i=1}^{m} \mathrm{r_{ih}} - \mathrm{Load}_h \right) \cdot \mathrm{PX}_h$$

[15] For details on how to calculate the cost of the electricity bought from the grid, please see Annex 2 on the tariffs from SCE (Southern California Edison). Part of the cost is due to the energy term and part due to the capacity term. The former depends on the kWh bought during a period of time, and the latter on the maximum demand for a given period of time. See the above algebraic expression of this variable.

R_s is calculated whenever: Electricity generated = Σr_i > Load. If not, R_s is equal to 0. For the expression of $\mathbf{C_p}$ to hold, Residual Load > 0.
Steps 2 and 3 will be repeated for i = 2 to **m**.

4. The process described in step 2 ends when the capacity of the last technology to be added does not lower the NC function with respect to the previous step.

2.3 Data

In this section, data sources and assumptions used in the model are explained. There are four main data types: customer load profiles, Power Exchange prices, electric utility tariffs and levelized energy costs.

2.3.1 Load Profiles

Characteristic load profiles of five commercial customers were studied. The California 1998 load profiles were extracted from the MAISY database.[16] Only those customers located in Southern California Edison (SCE) territory were considered because this utility's rates were used for the analysis.

Five types of commercial customers are analyzed: a grocery store, a restaurant, an office, a shopping mall, and a hospital. Maisy documentation describes them as follows:

- grocery: food-stores;
- restaurant: eating and drinking places;
- office: finance, insurance and real estate, business services, outpatient health care, legal services, school and educational services, general social services, associations and organizations, engineering and management services, miscellaneous services and public administration (whenever the buildings are not federally owned);
- mall: retail malls;
- hospital: hospitals.

The data are organized by day-types. Each customer type includes 24 hourly electricity loads (measured in kW) for each of 3 day-types in each of the 12 months. The day-types are: peak day, average weekday, and weekend. In order to match the 365 days in a year, the following distribution of day-types is applied:

- 20 weekdays per month for those months with 31 days, 19 weekdays for those months with 30 days and 17 weekdays for February;
- 3 peakdays per month for all of months;
- 8 weekend days per month for all months.

[16] MAISY (Market Analysis and Information System) is an energy industry source of commercial and residential energy and hourly load data. It includes information about building structure, building and end-use energy use, equipment and other variables for over 150,000 customers throughout the U.S. Detailed electricity, natural gas and oil consumption are also provided. The MAISY state-level energy marketing database for commercial sector hourly loads version 2.2. is the one used in this project.

Three different day-types enables a more accurate analysis of the real load profile of these customers because average prices of the Power Exchange for those day-types can be calculated and assigned to them.

2.3.2 Power Exchange Prices

The prices of the Day-Ahead market from the California Power Exchange (CalPX) were used as a lower bound estimate for the price that the analyzed customers would get for the electricity generated by them and sold to the grid.[17] The prices used were the ones for the zone IID-SCE or Southern California Edison territory. The Day-Ahead market establishes zonal prices and quantities used of electricity for delivery during each hour of the following day. The PX prices considered are from June 1998 to May 1999.
To match the real PX prices to the day-types of the load profiles, the average PX price was calculated in the following way:

- average weekday PX prices: for every month, the average price for every weekday hour was calculated. The average weekday PX prices calculated in this way were assigned to the weekday load profiles;
- peak day PX prices: for every month, the PX prices for the day with the highest peak in the price were selected as the prices to be matched with the peak day load profiles;
- average weekend PX prices: for every month, the average price for every hour of the weekends was calculated. The average weekend prices so determined were assigned to the weekend load profiles.

2.3.3 Electric Utility Tariffs

Because the analyzed customers are located in SCE territory, SCE's electric utility tariffs are used. Electricity bills are estimated for each customer, both with and without distributed generation installed. The tariffs, chosen because they are the ones relevant to the commercial customers in this sample, are Schedules TOU-GS-2 (Time of Use General Service Demand Metered) and TOU-8 (Time of Use General Service Large). TOU-GS-2 is applicable to single- and three-phase general service including lighting and power, except that the customer whose monthly Maximum Demand is expected to exceed or has exceeded 500 kW is ineligible for service under this schedule. TOU-8 is applicable to and mandatory for all customers whose monthly maximum demand is expected to exceed or has exceeded 500 kW.

In the cases analyzed, TOU-GS-2 applies to the grocery and the restaurant; for the mall, office and hospital TOU-8 is used. When applying TOU-8, the customers have been assumed to have service voltage below 2 kV.

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[17] This price will depend on the arranged contract between the customer with on-site generation and the electric distribution utility. However, the Power Exchange price should be a good approximation for a lower bound estimate of what the customer will be paid because, on average, the customer will probably be paid more than the PX price for the electricity sold to the grid.

Both tariffs distinguish between the energy charge and the demand charge. The energy charge is directly dependant on the energy consumed (kWh), however, different rates apply for different hours and months of the year (according to the classification of on-peak, off-peak or mid-peak). The demand charge depends on the maximum monthly demand and also makes the distinction between whether the maximum demand took place in an on-peak, off-peak or mid-peak period. Other applicable charges under these tariffs such as those related to power factor have been ignored, since the MAISY load profiles include no power information.

2.3.4 Levelized Energy Costs for the Different Distributed Generation Technologies

Electricity generation costs for the different technologies considered have been calculated using Levelized Energy Costs (LECs). The LECs include annual capital costs, operation and maintenance (O&M) costs and fuel costs. The LEC is a very useful measure to compare the different technologies on a dollar per kWh ($/kWh) basis.
The formula to compute the LEC of a technology is:

$$\mathrm{LEC} = \frac{\text{Capital Costs} + \mathrm{O\&M} + \text{Fuel}}{\text{Electricity generated in one year}} = \frac{\mathrm{CC} + \mathrm{O\&M} + \text{Fuel}}{\mathrm{P_r} \cdot \mathrm{CF} \cdot 8760} = \frac{\mathrm{ICC} \cdot \mathrm{CRF} + \mathrm{O\&M} + \text{Fuel}}{\mathrm{P_r} \cdot \mathrm{CF} \cdot 8760}$$

where:

CC = yearly contribution of the cost of capital to the cost of electricity ($),
ICC = total installed capital cost ($),
CRF = capital recovery factor, which is calculated as:

$$\mathrm{CRF} = \frac{\mathrm{r}}{1 - (1 + \mathrm{r})^{-n}}$$

r = interest rate,
n = assumed lifetime of the installation,
O&M = annual operation and maintenance costs ($), which includes fixed O&M costs ($/kW) and variable O&M costs ($/kWh), both terms calculated for a year,
Fuel = annual fuel cost ($), which depends on the number of kWh produced, the efficiency of the technology (kWh produced/ Joules of energy input), and the price of the fuel ($/Joule of energy),
$\mathbf{P_r}$ = rated capacity of the technology installed (kW),
CF = capacity factor, which is the ratio of the electricity produced to the maximum electrical output possible during a determined period of time,
8760 = number of hours in a year.

2.3.4.1 Data Sources

The sources for the different data used to calculate the LECs are the following:

- the fuel prices have been obtained from the Energy Information Agency's Natural Gas Monthly, as all the technologies considered are using natural gas. The California price in 1998 for commercial customers was \$5.82/GJ (\$6.14/MBtu), so a round price of \$5.7/GJ has been selected for the model (\$6/MBtu);

- the real interest rate chosen for the base case is 7%, which is an estimate based on (current prime rate (9%)[18] + small customer adder (e.g. 1%) – inflation rate (e.g. 3%))
- all the other technology-specific data have been obtained from various sources. For microturbines, data are from (Herman and O'Sullivan 1997) the EPRI report TR-10763 and from manufacturers (Capstone and AlliedSignal). For fuel cells, data are from (Rastler, et al. 1997). In addition, the fuel cell data were cross-checked with information from (Natural Resources Defense Council 1997) and (Gibson and Merten 1997).

A table containing a sample of the collected data can be found in the second appendix.

2.3.4.2 Base Case

The data used for the LECs of the different technologies in the base case follow (assuming Capacity Factor = 1):

	FC Solid Oxide SOFCo	*FC Solid Oxide TMI*	*FC PEM*	*Microturbine Parallon*	*FC Phosphoric Acid*	*Microturbine Capstone*
Source	SOFCo	TMI	Ballard	AlliedSignal	ONSI	Capstone
CF	1	1	1	1	1	1
Rated Power (kW)	50	100	250	75	200	28
Annual Production (kWh)	438000	876000	2190000	657000	1752000	245280
r, interest rate	0.07	0.07	0.07	0.07	0.07	0.07
n, lifetime	20	20	20	10	20	10
CRF	0.09	0.09	0.09	0.14	0.09	0.14
Capital Cost (\$/kW)	1200	1200	1800	650	3200	1240
ICC (\$)	60000	120000	450000	48750	640000	34720
O&M Fixed Cost (\$/kW/a)	0	0	10.8	0	0	0
O&M Variable Cost (\$/kWh)	0.015	0.015	0.002	0.007	0.015	0.01
Fuel Price (\$/GJ)	5.7	5.7	5.7	5.7	5.7	5.7
Efficiency (%)	45.05	45.03	37.30	28.50	35.99	26.00
Fuel Cost (\$/kWh)	0.045	0.045	0.055	0.072	0.057	0.079
LEC (¢/kWh)	**7.34**	**7.34**	**7.75**	**8.94**	**10.64**	**10.89**

[18] According to www.bloomberg.com, the current (as of November 1999) prime rate is 8.5%, so, being conservative, 9% has been chosen.

2.4 Analysis of the Results

This chapter discusses the various distributed generation operating scenarios, results from the analysis based on the customer adoption model from section 2.2, and the sensitivity of certain variables to different assumptions.

First, the base case for each of the different customers (i.e. load profiles) will be examined and then, the sensitivity analysis will be presented. In total, 25 cases were analyzed: one base case plus four sensitivities for each of the five types of customer.

2.4.1 Base Case Results

In all analyses, distributed generation technologies are used to produce all or almost all of a customer's electricity needs. Nevertheless, customers will typically still buy some electricity from the utility. Customers also have the option of selling electricity to the grid. In this analysis, sales to the grid were only considered when the Power Exchange price exceeded the marginal cost of generating. Actually, sales to the grid occurred in very few of the analyzed cases because the excess electricity would normally be produced during off-peak hours, when the Power Exchange prices are low. Only when the customer has a load profile shifted in relation to the system's peak is it typically profitable to sell intro the grid.

In the base case, as discussed above, the values of the fuel cost and of the real interest rate are, respectively, \$5.7/GJ and 7%.

Results that will be analyzed are the electricity bill for customers before and after adopting distributed generation, the average price of electricity, sales to the grid, which technologies are adopted, and their capacities.

2.4.1.1 Grocery

The first customer to be analyzed is a grocery.

2.4.1.1.1 Load Profile Analysis

Before implementing the customer adoption model it is useful to have a look at the load profile of the grocery and discuss some of its main characteristics.

The peakday load profiles of January and August were chosen as representative months.

The January load profile is very flat compared to August, with a ratio of minimum load to maximum load of 274 kW / 334 kW = 0.82. On the other hand, August has a noticeable peak in the central hours of the day (around 13:00) and the ratio of minimum load to maximum is 0.65. These trends can also be noticed in the other months, e.g. from April until October, the load profiles have a clear peak, not as high as in August, but still quite noticeable. On the other hand, months from November to March pose a much flatter load profile, like the one in January.

It is important to mention that Power Exchange prices in January also have a flat profile and never exceed the price of 4.1¢/kWh. Sales of electricity to the grid will therefore not take place during this month. Because the variable cost of all the different technologies considered exceeds the PX price, selling to the grid is never profitable in this case. In August, PX prices experience a peak reaching a price of 16.3¢/kWh, which allows the customer to sell back into the grid in the low fuel price scenarios. Because the peak in the load profile of the grocery happens before the PX peak, excess generation could be sold back.

Another important characteristic of the load profile is the load factor. The load factor is the ratio of the average to the maximum or peak demand during the entire year and gives a sense of the load profile (i.e., flatter load profiles will have a larger load factor, whereas load profiles with peaks have a smaller load factors). A high load factor means the load is at or near the peak a good portion of the time. In the case of the grocery, the load factor is 0.62, which indicates that the maximum demand is significantly bigger than the average one (the annual average demand is 283 kW, the maximum is 457 kW, and the minimum one is 167 kW).[24]

2.4.1.1.2 Results of the Adoption Model

Because the maximum load for the grocery, 457 kW, is less than 500 kW, the analysis was done assuming that the tariff TOU-GS-2 is applicable (see Section 2.3.3 for more details). Following are the results of the adoption model.

In this case, only capacity to meet the base load was selected. Any other capacity considered would increase customer costs.

The technology chosen was Fuel Cell Solid Oxide from SOFCo, which is the one with the lowest LEC for a Capacity Factor equal to 1. The installed capacity was 150 kW (slightly under the minimum load of this customer. The three installed Fuel Cells units (50 kW each) will be running 100% of the time as base load generation.

The benefits for the customer of installing distributed generation can be summarized as follows:

- the average price of electricity consumed is reduced from 8.76 ¢/kWh to 8.42 ¢/kWh,
- the savings in the electricity bill account for 3.93% of the original price paid. These reductions are not only due to less electricity being consumed but also due to the secondary effect, peak shaving, which has a positive effect on the demand charge.

[24] All the data and results for the different cases and load profiles are presented in Appendix 1

2.4.1.2 Restaurant

2.4.1.2.1 Load Profile Analysis

The load profile of the restaurant, for both cases, January and August, remains quite flat and without noticeable changes (except for the maximum and minimum loads that are, of course, higher in August). The ratio of minimum to maximum load is 0.62 for January and 0.68 for August, and both load profiles present a high level of sustained demand from around hour 12 to hour 22; for the rest of the time the load is stable at a low level.

No considerable sales to the grid happen in any month (only 29 kWh/year) because the PX prices are high when the restaurant's load demand is high. On the other hand, periods of low demand coincide with low system levels. It is, therefore, not profitable to sell because prices at the PX are not high enough to cover the variable cost of generating.

The load factor for the restaurant is 0.60, indicating that the maximum demand (328 kW) is well above the average (197 kW).

2.4.1.2.2 Results of the Adoption Model

The tariff applied to the restaurant is TOU-GS-2 because its maximum load of 328 kW is less than 500 kW.

In this case, capacity was installed beyond what was required to meet the base load. Units of different technologies were added in three steps, reaching a high ratio of installed capacity to maximum power (0.76). A total capacity of 250 kW was installed: two 50 kW Fuel Cell Solid Oxide units from SOFCo to cover the base load, one 100 kW Fuel Cell Solid Oxide unit from TMI (in the second step) and another 50 kW Fuel Cell Solid Oxide unit from SOFCo.

By installing that much distributed generation, the average price of electricity for the restaurant drops from 9.15 ¢/kWh to 8.17 ¢/kWh, and results in savings of 10.7% with respect to the base case in which no distributed generation was installed.

2.4.1.3 Office

2.4.1.3.1 Load Profile Analysis

The peak load profiles for January and August are quite different for this type of customer (office). In both cases, the ratio of minimum load to maximum load is quite low (0.41 in January, and 0.45 in August), however, the shape of the profile is different. Whereas in August, the peak takes place at around hour 15 (the hottest part of the day, so probably the result of the air conditioning working at full power), in January the peak happens at the beginning of the day, between hours 6 and 7.

The load factor for this customer is 0.42, quite low, which means that there is a big difference between the maximum load demanded (peak at 545 kW) and the average power (229 kW).

2.4.1.3.2 Results of the Adoption Model

For this customer, the maximum load (545 kW) exceeds 500 kW, so the electric tariff applied is TOU-8.

The adoption model for the office building results in 450 kW of capacity being installed, which is a large number compared to the average power. The ratio of installed capacity to maximum load is 0.83, the highest of any kind of customer analyzed.

Different distributed generation technologies were added to the customer's generation capacity in five steps. In the first step, to cover the base load, two 50 kW Fuel Cell Solid Oxide units from SOFCo were chosen. Then, in the next two steps, two 100 kW Fuel Cell Solid Oxide units from TMI were added. Finally, in steps 4 and 5, two 75 kW Parallon microturbines were chosen.

In this case, sales to the grid take place during the peak hours of August for a total of 142 kWh in the year considered. The sales happen at the end of the summer peak days, when PX prices are high enough to cover the running variable cost of the TMI technology.

The benefits for the customer after installing distributed generation are the following ones:

- the average price of electricity goes down from 9.7 ¢/kWh to 8.9 ¢/kWh,
- the savings in the electricity bill due to the reduction in the "price" of electricity are approximately 8.3%.

2.4.1.4 Mall

2.4.1.4.1 Load Profile Analysis

The load profile for a mall type of customer is quite interesting because it is possible to find big differences during the year. In this case, the ratio of minimum to maximum load is smaller in January than in August (0.31 in January, and 0.53 in August), which means that the difference between minimum load and the peak is more evident in January than in August (for the other customer types, so far, the opposite was true). Moreover, differences in the shape of the profiles for those months are worth mentioning.

January presents a sustained high level of load demand from approximately hour 10 to hour 22, and then the demand drops dramatically to a low level. The load is completely coincident with the hours of operation of a commercial mall.

On the other hand, August, with higher load levels, has a clear peak in the profile at around the hour 15 (again, as in the case of the office, during the central and hottest hour of the day), but before and after that time, the load goes to or from a low level that is maintained from around hour 22 to hour10.

The load factor for this customer is 0.36, pretty low, showing that the peaks are well above the average load demanded (686 kW).

2.4.1.4.2 Results of the Adoption Model

As the maximum load for the mall is well above 500 kW (1900 kW), the analysis was performed applying the tariff TOU-8 for this customer.

In this case, only capacity to meet the base load was selected. Any other capacity would not be economically profitable because costs would go up for the customer.

The technology chosen was Fuel Cell Solid Oxide from SOFCo, and the installed capacity selected was 250 kW (five 50 kW units), slightly under the minimum load for the mall (291 kW), which means that these units will be running 100% of the time (base load generation). The ratio of installed capacity to maximum power is 0.13. This value is quite low, probably due to peaks in the summer months preventing the technologies from having high capacity factors and, therefore, low LECs.

The benefits for the customer can be summarized as:

- reduction in the average price of electricity from 9.87 ¢/kWh to 9.66 ¢/kWh,
- savings in the electricity bill of 2.2%.

In this case, because there are no sales of electricity into the grid, the installed capacity never exceeded the customer’s load.

2.4.1.5 Hospital

2.4.1.5.1 Load Profile Analysis

The hospital presents a quite constant load profile throughout the year. January and August have a profile with some peaks in the central hours of the day (from around hour 10 to hour 21). The only difference between these two representative months, apart from having higher levels of demand in August than in January, is that in August the ratio of minimum load to maximum load is lower (0.41) than in January (0.57).

The load factor, 0.58, is not very high and shows that the average load (380 kW) is a little bit more than half the maximum load (654 kW) for this type of customer.

2.4.1.5.2 Results of the Adoption Model

Due to the maximum load for the hospital being larger than 500 kW, the electric tariff applied was TOU-8.

For this kind of load profile, only capacity to meet the base load (a little bit under the minimum load) was economical: 150 kW in three 50 kW Fuel Cell Solid Oxide units. Because the units are operating as base load, they will be running 100% of the time. The ratio of capacity installed to maximum power is 0.23.

The results of the adoption of these 150 kW for the customer are:

- reduction in the average price of the electricity: from 8.57 ¢/kWh to 8.42 ¢/kWh,
- savings of 1.7% (really low) as compared to not installing any distributed generation.

2.4.2 Sensitivity Analysis

Apart from analyzing the base case for every type of customer, sensitivities were performed to see how the results of the adoption model would change when modifying certain variables.

2.4.2.1 Variables to be Changed

The two variables selected for the sensitivity analysis are the fuel cost and the interest rate. These variables are interesting because, as the results show, the fuel cost has an important influence on how the adoption model functions (because it strongly influences the LECs of the different technologies), and the interest rate is the determinant for a customer deciding about capital investments.

The change in both variables is quite different. In the case of the fuel cost, the two cases considered for the sensitivity analysis are:

- low fuel cost scenario: $2.8/GJ, which actually corresponds to the average level of prices of Natural Gas for industrial customers in California;
- high fuel cost scenario: $7.6/GJ, which corresponds to the average level of prices of Natural Gas for residential customers in California.

In the case of the interest rate, the variation was not as high as for the fuel price, this was done on purpose, considering that the rates should not fluctuate beyond these limits:

- low interest rate scenario: 6%,
- high interest rate scenario: 8%.

When doing the sensitivity cases, only one variable was changed; the rest remained at constant values.

2.4.2.2 Sensitivity Results for the Different Customers

2.4.2.2.1 Grocery

In the low fuel cost scenario, results differ from the base case. More capacity is installed (350 kW) and different technologies are selected (one 250 kW Fuel Cell PEM unit, and one 100 kW Fuel Cell Solid Oxide unit from TMI). It is interesting to point out the fact that, under a low fuel cost scenario, the LEC distribution for the different technologies changes significantly enough (depending on their efficiencies) that Fuel Cell PEM is chosen as base load because it becomes the technology with the lowest LEC (in the base case this was Fuel Cell Solid Oxide from SOFCo).

Thus, in this scenario, the ratio of installed capacity to maximum power is very high: 0.77. Moreover, it is notable that sales into the grid occur during the summer peak days due to the fact that the grocery's peak is shifted, earlier with respect to the PX's peak (1745 kWh/year are sold to the grid). This shift allows this type of customer to profit from the high PX prices.

For this low fuel cost scenario, the savings are very important with respect to a scenario without any distributed generation installed: more than 34%. The average electricity price goes down dramatically from 8.76 ¢/kWh to 5.76 ¢/kWh.

In the high fuel cost scenario, due to the high LECs of all the technologies, adoption of none of the distributed generation technologies results in a cheaper electricity bill. In fact, it would actually increase the cost to the customer. Hence, no capacity is added and the customers purchase all their electricity from the distribution company.

For both the low and the high interest rate scenarios no significant changes were observed with respect to the base case. The same technologies and capacities were chosen and in the low interest rate scenario the savings increased slightly (4.5%). In the high interest rate scenario, the savings went down accordingly (3.3%).

2.4.2.2.2 Restaurant

This customer behaves very similar to the previous one when analyzing the sensitivities.

In the low fuel cost scenario, much more capacity is installed (325 kW), with a ratio of installed capacity to maximum power of 0.99, nearly enough power to cover all of the customer's needs at any point in time. The technologies chosen vary with respect to the base case: Fuel Cell PEM (250 kW) is chosen as base load, and in a second step, one 75 kW Parallon microturbine is added. The savings for the low fuel cost scenario are larger than in the base case: 25%, and the average price of electricity dropped from 9.15 ¢/kWh to 6.85 ¢/kWh. Furthermore, in this scenario, sales are made to the grid (about 1065 kWh/year).

For the high fuel cost scenario, no adoption resulted. The LECs of all the technologies are too high to result in adoption of any of them.

Both the low and high interest rate scenarios turned out to work as the base case: the same capacity and technologies were adopted. Bill savings were 12% for the low interest rate case, and 9% for the high interest rate case.

2.4.2.2.3 Office

This customer offers very different results for the sensitivity cases analyzed.

In the low fuel cost case, a total capacity of 500 kW is installed. The ratio of installed capacity to maximum load was 0.92, almost enough to completely cover the customer’s electricity needs. The base load technologies chosen differ from those of the base case scenario. As base load, a 250 kW Fuel Cell PEM unit was chosen instead of Fuel Cell Solid Oxide from SOFCo. The sales to the grid also increased to 690 kWh/year, as did the savings, to 20%. The average price of electricity dropped from 9.7 ¢/kWh to 7.77 ¢/kWh.

In the high fuel cost scenario, as for all the other customers considered, no adoption of any technology was the result.

For the case of low interest rate, adoption of one more 75 kW Parallon microturbine increased the total installed capacity to 525 kW. The ratio of installed capacity to maximum power was 0.96. Also, some sales are made into the grid in this scenario, around 141 kWh/year. The savings with respect to not adopting any technology are 10%.

In the high interest rate scenario, only adoption of capacity to meet the base load is profitable, so two 50 kW Fuel Cell Solid Oxide units from SOFCo were chosen. The ratio of installed capacity to maximum load drops to a value of 0.18, and the savings are considerably smaller than in the base case. In addition, for this scenario, no sales are made into the grid take place.

2.4.2.2.4 Mall

For the mall, in the low fuel cost scenario the total capacity installed increases with respect to the base case: 1100 kW, with different technologies: four 250 kW Fuel Cell PEM units and one 100 kW Fuel Cell Solid Oxide unit from TMI. This adoption of more technologies changes the ratio of installed capacity to maximum power demanded to 0.58 (in the base case it was really low: only 0.13). The savings in this case are 26%, and the average price of electricity drops from 9.87 ¢/kWh to 7.26 ¢/kWh. Furthermore, significant self-generated electricity is sold into the grid in this scenario (as opposed to the base case scenario), around 10640 kWh/year!

In the high fuel cost scenario, no adoption resulted from the model.

In both low and high interest rate cases, adoption of 250 kW of Fuel Cell Solid Oxide from SOFCo resulted, and no sales were made into the grid.

2.4.2.2.5 Hospital

This type of customer behaves similarly to the others with respect to the sensitivities, except that, for the low fuel cost case, more capacity is adopted than for the base case (575 kW, with a ratio of capacity installed to maximum power of 0.88). Again, the technology chosen to meet the base load changes to Fuel Cell PEM as a consequence of the low fuel price which makes this technology cheaper compared to the others. Sales are made to the grid (1549 kWh/year) and the savings increase to 19%. The average electricity price goes from 8.57 ¢/kWh to 6.94 ¢/kWh.

In the high fuel cost case, adoption of distributed generation is not economical for this type of customer.

In both the low and high interest rate scenarios, the same amount of installed capacity (150 kW) and the same technology (Fuel Cell Solid Oxide from SOFCo) were chosen as in the base case. No sales were made into the grid under these two scenarios, nor are there any in the base case.

2.4.3 Summary of Results

In this section a summary of the most important results of the analysis is shown in the form of tables. Variables considered are the installed capacity of distributed generation and the savings in the customer bill when adopting distributed generation.

2.4.3.1 Distributed Generation Capacity Installed

In Figure 5, the capacity installed for every type of customer in each scenario considered is plotted: base case, Fuel 3 (the low fuel price case), Fuel 8 (the high fuel price case), and the low and high interest rate scenarios.

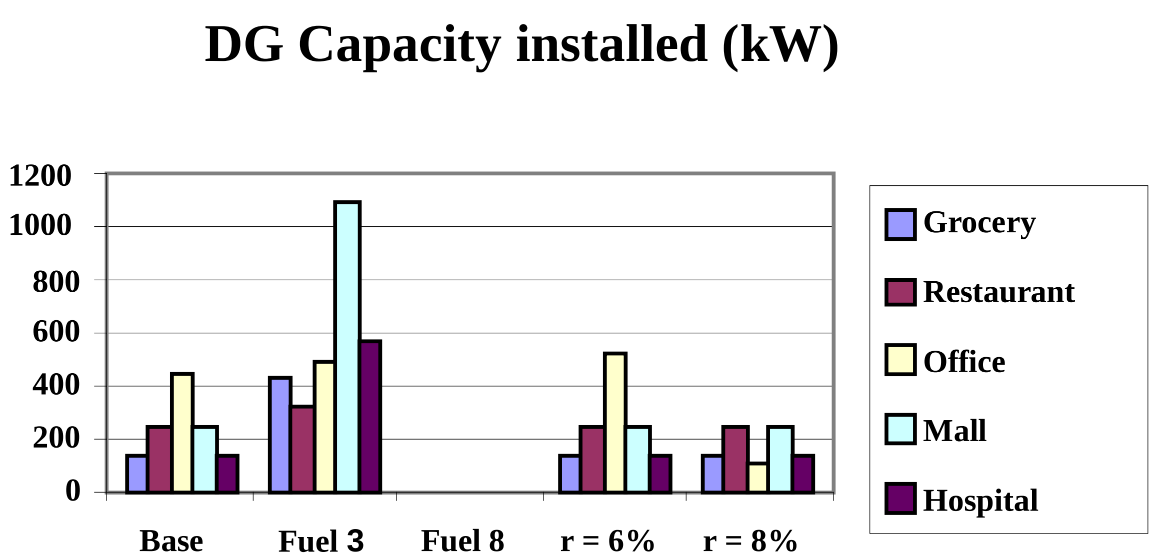

Figure 5: Distributed Generation Capacity Installed for Various Customers

From the graph, it is clear that distributed generation is adopted in all the scenarios with exception of the high fuel cost case. For the low fuel cost case, there is a considerable difference in the capacity installed with respect to the other cases. This difference is because the price of the fuel is a key factor in the Levelized Energy Cost of the technologies. As a result, a change in fuel cost can modify the results dramatically, making distributed generation technologies attractive or expensive. The change in the capacity adopted for this scenario is quite large, more than double that of the reference case.

Regarding the sensitivities on the interest rate, no noticeable change in the installed capacity can be noticed with respect to the base case. Only for the office building does the capacity drop considerably when the interest rate is 8%.

2.4.3.2 Savings in the Electricity Bill

The other variable examined are the electricity bill savings. Because this result determines whether the customer considers the installation of distributed generation for on-site power attractive, it merits special attention.

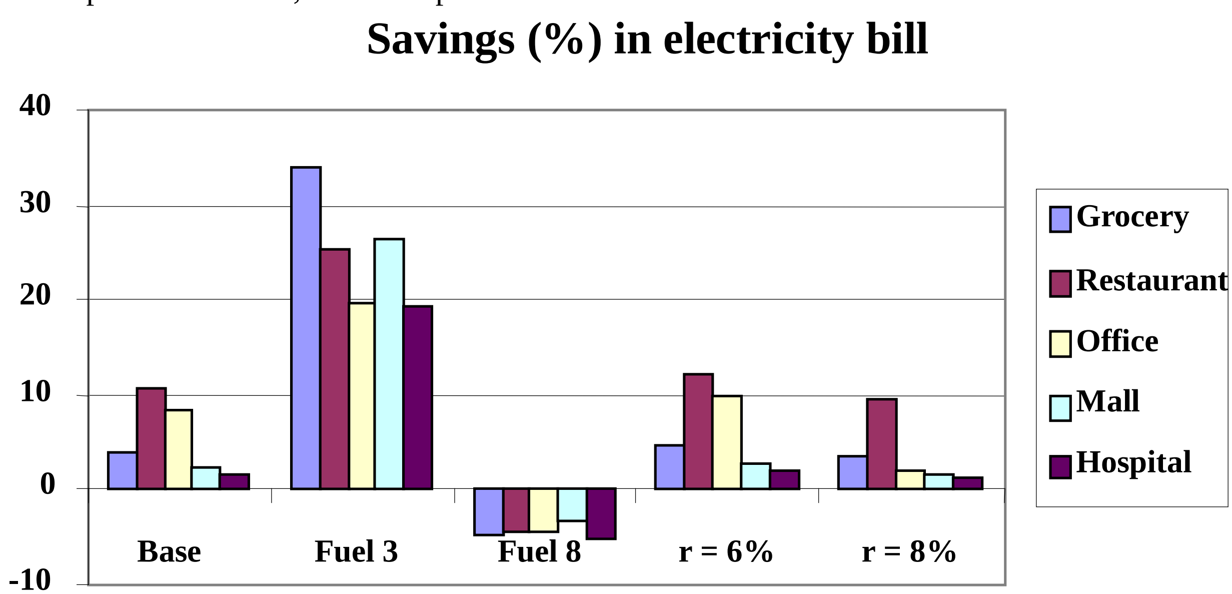

Figure 6: Customer's Savings in Electricity Bill

In general, the electricity bill savings are not very high, amounting to less than 10%, with the exception of the restaurant and the low fuel cost scenario. In the case of high fuel prices, the installation of the cheapest distributed generation technology would actually lead to an increase for all customers.

Under a low fuel cost scenario, savings are significantly higher, ranging from 19 to 34%, depending on the characteristics of the customer's load profile and on the possibility of selling into the grid. The case of the grocery is most surprising: the savings change dramatically from 4 to 34%. This change is due in part to importance of fuel cost and in part to the sales to the grid, to the reduction in the energy bought from the grid and to the reduction of the peak load which has also an important and direct influence on the demand charge of the electricity bill.

For the interest rate sensitivity cases that were analyzed, there is no significant change in the savings with respect to the base case. Although the results of the adoption model are not very sensitive to the interest rate as adjusted here, it should not be forgotten that the percent variation of the interest rate that was considered is much smaller than the change used for the sensitivity analysis with respect to the fuel price.

2.5 Conclusions and Proposals

2.5.1 Conclusions from Results

There are applications where distributed generation technologies offer an economic alternative to purchasing electricity from the grid. Although distributed generation will rarely be competitive enough to completely supply (as the only means) the power demand of the commercial customers studied, there is an important future for these technologies to supply at least a considerable part of the electricity needs of these types of customers.

According to the results obtained for electric power supply only, distributed generation turned out to be cost effective to cover the minimum load in all the cases except for the high fuel price scenario. This is because the capacity factor has a large influence in the economics of these technologies and, under normal conditions, these technologies are only economic when running almost 100% of the time.

For low fuel price scenarios, the future of distributed generation is promising: for four of the five customers considered (hospital, office, grocery and restaurant), the capacity installed is above 77% of the maximum load, and for the restaurant, it is 99%, almost meeting the peak load. In the case of the mall, the capacity to be installed is 58% of the maximum load, due to the high peak of the mall compared to its average power demanded which results in a load factor of 0.36, the lowest of all the customers studied.

In this scenario, there will be large sales of electricity to the grid during those periods of time when the Power Exchange price is above the variable cost of the technology installed because the fuel price is an important component of the total cost of the technologies. The ability to sell to the grid allows for the technology to be economic because the revenues obtained from sales will reduce the total net costs of the electricity for the customer. For high fuel price scenarios, it was not economical to install any capacity due to the high levelized costs of the different technologies.

In view of these facts, it can be stated that the results (capacities to be installed and electricity bill savings), are highly sensitive to fuel prices. The model is so sensitive to the fuel price because this variable determines the operation of the distributed generation units, alters variable costs considerably and therefore, allows the units to sell or not to sell into the grid.

For the low and high interest rate scenarios, no noticeable changes take place with respect to the base case. Thus, the sensitivity of the results to the interest rate is small. In only one case, the high interest rate office scenario, did the capacity to be installed drop considerably with respect to the base and low interest rate cases. It should not be forgotten, however, that the relative change in the interest rate when performing the sensitivity analysis was much smaller than the relative change in the fuel price.

According to the analysis performed of the load profiles, capacity installed and bill savings, the differences across the customers considered are due to several elements:

- load factor (the ratio of the average load to the maximum load demanded) and the height of the peak,
- the timing of the customer's load profile with respect to the system peak (the possibility of selling into the grid at good prices is higher when the customer's peak is not coincident with peak of Power Exchange prices, which normally reflect the system peak),
- the duration of the peak: peak shaving (or reductions in the demand charge) is optimized when the profile has low duration peaks, that way peaks can be eliminated and demand charges reduced; on the other hand, long duration peaks allow the capacity factor of the technology installed to be higher, which results in a lower levelized energy cost, so both characteristics can be beneficial for the economics of distributed generation,
- the shape of the load profile: flatter load profiles allow larger distributed generation units to operate at or near full capacity for a greater fraction of the time, which can make them more attractive from the economic point of view (in general, in this study, flatter profiles present a higher ratio of installed capacity to maximum power demanded).

Summarizing, the study performed suggests that distributed generation has a promising future and will be adopted by a large number of customers. However, in the near term, if the economics of these technologies does not improve significantly, distributed generation will not be profitable enough to cover the customer's load completely, hence, it is highly unlikely to see customers installing enough capacity to be able to economically disconnect from the grid. Regarding technical issues, customers will probably not disconnect from the grid due to reliability factors, even if it is economical to do so. Furthermore, it should not to be forgotten that it can be economical to install enough capacity to cover the customer's needs because of the revenues obtained from selling into the grid, which, of course, requires the customer to remain connected.

However, these results can be modified when considering other scenarios where thermal and electric needs are covered by distributed generation, such as cogeneration possibilities and other potential uses of the installed capacity apart from electric power production, which can make the installation of these technologies much more attractive in all cases. In fact, this issue should be devoted to further study.

2.5.2 Penetration of Distributed Generation

There is potential for the penetration of distributed generation especially taking into account the following facts:

- there are some areas with high electric rates, and probably those customers would be more willing to install their own generation and save money if the technologies are cheap enough,
- nowadays, natural gas prices are low; if prices remain low or go down, they may make on-site generation look more attractive due to the importance of this factor for the cost of the distributed generation technologies,
- other possible scenarios where not only electric applications are considered have not been taken into account. The possibility of using microturbines or/and fuel cells to satisfy the customer's thermal loads enhances the future of these technologies, making them much more economical. Scenarios like cogeneration, peak shaving and back-up power can change dramatically the economics of distributed generation. Hence, for customers with high thermal and electric load factors it can be very interesting to adopt distributed generation,
- these technologies are still being developed, so further improvements in performance and costs are foreseen which will make them more competitive in the future.

An interesting approach to determine the niche market for distributed generation is to analyze the price of electricity for different customers. In this case, improvements in the electricity bill due to reductions in the demand charges were left aside because only the average electricity price was examined. Some customers are more expensive to be supplied with electricity than others, and as functional unbundling of services (generation, transmission, distribution and ancillary services) will lead to costs varying widely among customers. Hence, it may be important to consider an electric industry after restructuring and with increased competition. A significant penetration potential for distributed resources will exist for those cases when the customer's average price of electricity exceeds the cost of the distributed resource.

In the next graph,[25] the potential market for distributed generation is easily determined. The number of customers (or locations) with different electricity prices (in ¢/kWh) is plotted. It is evident that most of the customers, according to the graph, would get an average price of 7.5 ¢/kWh. Considering a hypothetical cost for distributed generation of 8.75 ¢/kWh, all the customers with electricity prices higher than that would be potential "clients" for the adoption of distributed generation. (The area in black represents the potential market). By plotting the costs of distributed generation and the distribution of customer electricity prices, it is easy to determine how much distributed generation is likely to "penetrate" the market. (For the cases studied in this project the price of electricity ranged from 8.57 ¢/kWh for the hospital to 9.87 ¢/kWh for the mall).

[25] Source of the graph: "What's in the Cards for Distributed Resources?" Pfeifenberger, Hanser and Ammann. The Electricity Journal. Special Issue.

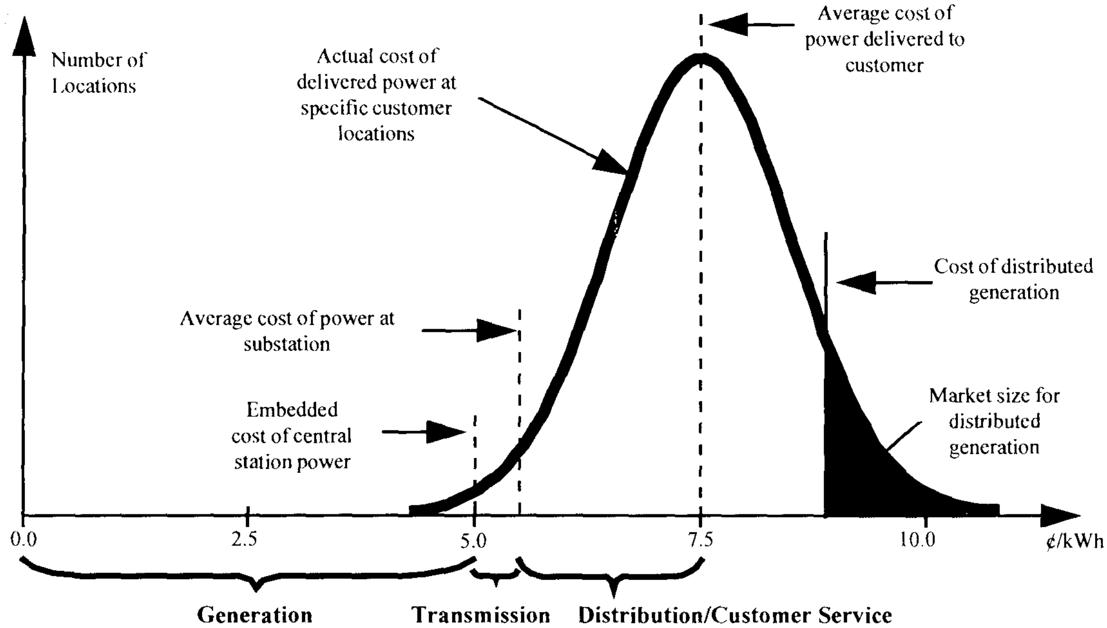

Figure 7: Potential Market for Distributed Generation

2.5.3 Other Issues about Distributed Generation

Nevertheless, the implementation of distributed generation is not only a question of economics. It depends also on other issues (entry barriers). The most important ones are:

- Stand-by charges and exit fees. Even if it is economical to install some generation, the charges to remain connected to the distribution network may preclude a customer from adopting on-site generation. The same applies for exit fees, for the case in which it is attractive to disconnect completely from the system.
- Interconnection standards. If these standards are too strict ("gold-plated standards"), distributed generation technologies may be not very competitive.
- Net Metering. The way the injection of power into the grid and the purchase of power from the grid is regulated and measured will be a determinant of the economic competiveness of these technologies. In California, only small scale solar and wind installations are subject to net metering, which permits the excess power that these technologies produce and inject into the grid to be valued at the tariff price.[26] This makes a very important difference. In this study it was assumed that the tariff price is much higher than the PX price, and therefore, the economics improve a lot for the distributed generation technologies.

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[26] However, with net metering the customer can not sell more electricity to the grid than he buys from it. The way net metering works is that the power sold to the distribution system is deducted from the power bought, but if the customer injects into the grid more power than he buys, then this excess power is granted to the utility; in other words, the customer doesn't get any money for it! Reference: CA Public Utilities Code/2827.

- Research and Development invested in distributed generation technologies. If a large effort is made to improve the technologies from an economic and technical point of view, their implementation will be more likely.
- Environmental benefits of distributed generation technologies. This is especially relevant for renewable technologies, like wind and solar for which emissions offsets are not recognized. If regulators credited the emissions avoided from displaced generation, again, the economics would look much more attractive.

2.5.4 Further Study

Because this project is, both, innovative and a first approximation, and also because the approach to distributed generation from the customer's side has not been treated in technical literature, further study is necessary.

The following issues should treated in future modeling efforts:

- other possible working scenarios like cogeneration or peak shaving possibilities,
- start-up costs of the different generation units,
- scale economies in Operation & Maintenance of generation units of the same technology,
- economic benefit of improved reliability due to installation of on-site generation,
- impact on losses of power injection directly in the distribution feeder.

Some of these issues, like other potential scenarios, scale economies in O&M costs, improved reliability, will make distributed generation more attractive, however, others, like start-up costs, may make it less so.

3. Distribution Company DER Adoption

3.1 Introduction

As has been previously stated in this report, and could be seen in the previous chapter, the focus is on the customer side. This means that the final goal is to have a clear picture of the future development of DER options by electricity consumers. However, it is obvious that consumers and discos form a dynamic interactive system, and as a result, decisions made on one side have an effect on the other. At present, this is true in only one direction. That is, changes in customer behavior along a specific feeder (for instance, changes in load shape) can change the Disco's planning. On the other hand, it seems to be true that a group of consumers along a certain feeder can be affected by changes in the Disco's policy or planning, principally by changing costs. In our view, this should affect customer DER deployment and has to be further studied, although, in this chapter, the issue is only briefly addressed.

Because of the reason just presented, it is necessary to address at this stage, at least in a simplified way, the Disco perspective on DER deployment. The effects that distributed generation could have on discos can be summarized in the following points:

- **Technical impact of customer driven installation**: The installation of generators inside distribution networks has a wide range of technical implications as several important studies have revealed (Dick, et al. 1998, Schweer A, et al. 1999). The deployment of generators in a feeder has to be studied by the disco that operates that feeder in order to assure proper feeder operation within voltage and other standards. These studies include steady-state (power flows), dynamic response, coordination protection, etc.
- **New opportunities**: For discos, distributed resources can be seen as a new tool for planning and operation[27]. Now, distributed generation has to be an option to add to such well known solutions as: network upgrades (wires and substations), capacitor placement, etc. DERs should be used as an additional weapon in the hunt to find the minimum cost of supply.
- **Economic signals impact**: As has been mentioned before, consumers and discos form a dynamic interactive system. Customer decisions (changes in consumption behavior, entry or exit) affect the disco's investment plans. A change in these investments can alter long term marginal costs of distribution. This means that the correct economic signals (distribution tariffs, in theory) also change.

Following this introduction a description of the main technical impacts that have been identified in the current literature is discussed. The important issues are currently being studied, in all of their aspects, in ongoing projects being carried out by the different CERTS teams. Below the latter section there is a brief description of all the different uses

[27] It is necessary to state here that distribution companies may be banned from owning distributed generation. However, this does not mean that Discos cannot find other ways to promote DER in their feeders if they see benefits by doing so.

that DER should offer to discos. The third section is devoted to a brief discussion of the economic interactions between customers and distribution companies.

Finally, at the end of this chapter is a description of various distribution software packages (load flow models) currently available on the market and some examples of their possible uses. The work described in this section was necessary because it was recognized that most of the analysis that would be performed by distribution companies involves load flows. For example, load flows are the main tool used for assessing planning and operating policies.

3.2 Technical Impacts

As the CERTS white paper on "Interconnection and Controls for Reliable, Large Scale Integration of Distributed Energy Resources" states, there is an important R&D effort to be done in analyzing and solving all the technical issues that a large scale integration of DER requires. Some studies have been published (Dick, et al. 1998, Cardell and Ilic 1998) that reveal a complete set of technical warnings to take into account before installing DER in a distribution network. The list is very extensive, but the more important aspects are mentioned in the following list:

3.2.1 Protection

- Protection coordination and selectivity: Connection of DER in a feeder alters the behavior of the overall system in fault conditions. Protective devices have to be modified to selectively trip the necessary feeder's sections. Also DER has to be adjust for avoiding disconnection in certain cases (faults in other feeders, for example)
- Operation safety: Installation of active systems in a feeder requires new procedures[28] and equipment to allow the safety of all maintenance workers.

3.2.2 Harmonics and Transients

- Type of inverters: The electronic devices that couple DER with the network produce several kinds of harmonics. In some cases (with line-commutated inverters) this can be an actual limit for DER penetration.
- Flicker: The level of flicker is altered mainly by PV and wind turbines systems.
- Fault levels: Generators increase fault currents and this can provide a penetration limit due to the rating of fuses and switchgear.

3.2.3 Voltage and Frequency Control

- Feeder voltage: The feeder voltage can be improved thanks to DER with VAr support.

[28] Currently utilities require DERs to disconnect from the feeder when a fault occurs. This prevents the DERs from feeding the fault and ensuring worker safety since most distribution systems are maintained deenergized.

- Transient voltage: There are standard limits for voltage dips occurring for sudden changes in the generator output. The generator's size has to be limited to a certain ratio between the generator's power ratio and the short circuit MVA at the point of connection.
- Stability: Instability can occur in some cases as the number of distributed generators in the distribution system increases.

This scientific evidence has been obtained through simple models or distribution test feeders and it cannot be easily generalized. There is a lack of procedures and methodologies that assess the deployment of DER in a straightforward way .

Also it should be mentioned that large scale installation of distributed generators not only has an impact at the distribution level, it can also have important consequences in other areas. Some of them include bulk transmission operation and planning, generation expansion and energy planning as well as operation issues such as ancillary services provision or load forecasting.

3.3 New Opportunities

The advent of most technologically advanced distributed generation provides a new degree of freedom in the Discos' equation of supply electricity at minimum cost. In most of the recent literatures these new opportunities are defined as new markets for Discos that involve distributed generation. These new interests of Discos in DER can be summarized as follows:

- **Energy services**: With self-owned distributed generation, utilities can offer new cogeneration services to customers with heat and electricity consumption needs.
- **Transmission and Distribution capital expansion deferral**: This is maybe the most promising market for utilities since DER can considerably augment the usage of distribution assets (reducing losses and augmenting the base load) and, consequently, can delay new investment needs. This application of DER is also known as "peak saving", because it is the peak condition that determines the need for further investment.
- **Uncertainty dealing**: Availability of economically effective (not only involving capital costs, but also operation reliability) small generation can help utilities to better deal with uncertainty.
- **Power Quality**: DERs can have, as mentioned in the latter section, an important role in improving power quality. Certain types of distributed generation can provide Voltage Support and then ameliorate the voltage profile and other quality factors regarding voltage.
- **Power Reliability**: Installation of DERs can be the best way to diminish power outages for certain kinds of customers or problematic feeders.

These new opportunities also represent a challenge for the traditional methods used by utilities in planning. That is, new procedures must be developed and adopted for taking the maximum advantage of these new possibilities, as can be seen in the recent literature (Ball 1997, Hoff 1997, Feinstein, et al. 1997).

3.4 Economic Signals Impact

The motivation of this section is to revisit the fact that the only way to achieve an "optimal" penetration of DER (including optimum decisions of customers and Discos) is to send proper economic signals to the customers. Only if distribution clients have access to these correct signals, the client-provider system will converge to the optimum solution.

Table 1: Distribution Software Comparison

Characteristics	Price	Demo
Powerworld 5.0 (Powerwold)		
• Intended for transmission level • Time-domain simulations, economic dispatch, area transaction analysis, animated one-line diagrams • Main limitation is the assumed balanced 3-phase, i.e. does not analyze each single phase circuit separately. Distribution system can be modeled as a balanced 3-phase system, although the voltage and power levels would be lower than typically used for transmission modeling. • Does not perform short-circuit/fault analysis or harmonic analysis	LBNL has a licensed version. was developed by PSERC Partner at U. of IL	N/A
Neplan (Busarello – Cott – Partner BCP)		
• Designed for distribution networks • European structure, asymmetrical topology, and unbalanced loads • Import/export of data to GIS- and SCADA systems • Modules for: short-circuit, load flow, harmonics, dynamic and reliability analysis	Graphical DB Editor: $6,500 Load Flow: $7,500 Short Circ.: $7,500 Dynamic: $20,000 Prices for 1yr trial cheaper	Yes

It is clear that current distribution tariffs do not have the ability to send the correct economic signals to customers. This is the reason for a "DERs markets created by inefficient pricing", as it is named in (Pfeifenberger 1997). That is, customers' distribution rates do not reflect the true cost of delivering power for a given customer (due to different network configurations, losses, type of terrain, etc.) because these tariffs are designed to recover the average cost of supply. As a result, different users with different load shapes (for example, one with constant consumption and other with a spiky load shape) may have the same motivations for installing DER.

The best solution to this problem should be to foster the design of spatially differentiated prices, as spot pricing does. Obviously, to capture the long term effects of DER deployment in a feeder, long term marginal prices should be used. If this is not the preferable solution for regulators, other schemes can be adopted. For example, a combination of “real time pricing” (Cardell and Tabors 1997) for selling DER electricity and economic incentives to customers with appropriate characteristics.

In any case, it seems to be obvious that there is a need for computing the right economic signals for customers in order to accurately determine the actual desirable DER penetration in distribution.

3.5 Distribution Software Information

Berkeley Lab personnel gathered product information from 13 different distribution load flow software vendors. The information included different aspects of electrical modeling capability (steady state and/or dynamic simulation, mono or three-phase analysis, harmonic analysis, etc.), GIS readiness, and price. The information obtained is summarized (main characteristics, price and demo availability) in Table 2.

Table 2: Distribution Software Comparison (cont.)

Characteristics	Price	Demo
CYMDIST Distribution Primary Analysis (Cyme)		
• Distribution system analysis of radial/looped systems • Per-phase voltage calculations (balanced/unbalanced) • Fault calculation, protective device coordination, optimal capacitor placement and sizing, load balancing and load allocation • Modules for: harmonic analysis, reliability assessment and service restoration (contingency analysis) • It can import data from AM/FM/GIS software	\$16,000 \$19,000 (with GIS mapping interface) \$21,000 (with switching optimization) \$24,000 (with both options)	Slide-show only

Characteristics	Price	Demo
DistriView V1998 (Aspen)		
• Distribution systems analysis of networked/radial feeders • Voltage profile, voltage drop, relay/fuse coordination, fault analysis studies (short-circuit), motor-start simulation • Single, 2-phase, & 3-phase line • Does not perform dynamic analysis, only steady-state	$1,200 (up to 10,000 buses) $6,000 (up to 100)	Yes. Also slide-show
Prof. Chiang's model (Cornell University)		
• Distriubtion system model of radial/looped systems • 3-, 2-, or single-phase, balanced/unbalanced • Short-circuit calculation • Load Voltage Profile • Fault identification/isolation, integrated Volt/VAR control, network reconfiguration for loss minimization/ service restoration • Sophisticated capacity expansion options available, e.g. optimal capacitor sizing and siting	N/A	No
PSS/ADEPT (Power Technologies Inc.)		
• Substitutes for PSS/U, which is widely used in the industry • Balanced or unbalanced, looped or radial systems (3-phase, 2-phase, or single-phase laterals) • Power flow, short circuit, motor starting, capacitor placement optimization, tie open point optimization, load scaling, machine scaling, predictive reliability analysis • PSS/ADEPT can exchange data with PSS/U to provide protective device coordination and harmonics	N/A	Slide-show

Characteristics	Price	Demo
Windmil (Milsoft)		
• Radial or network systems • Load flow (voltage drop), fault current, fault flow, load allocation, load balance, capacitor placement, sectionalizing, motor flicker analysis and feeder optimization studies • Unbalanced loading and unbalanced impedance • Can import data from AM/FM/GIS software, but only as a thematic layer; not suitable for analysis	$18,500 (first system) $5,000 (systems 2-6)	Slide-show
EDSA		
• Many different modules: power flow, short-circuit, distribution reliability (reliability, availability of electrical dist. networks)	N/A	Slide-show
Disco Suite (Electrotek)		
• Distribution system planning tool to ensure reliability, provide ancillary services and examine least-cost options • DSS (simulator) performs steady-state analyses following a load profile • Tool to calculate costs and the least-cost solutions for placing DER	N/A	No
Power Systems Analysis Software (GE Power Systems Energy Consulting)		
• Load Flow with relational database and graphics • Dynamic Simulation • Large-scale, short-circuit calculation	N/A	N/A
SynerGEE (Stoner Associates)		
• Balanced and unbalance load flow analyses (unbalanced loading, long single-phase laterals). Fault analyses, load modeling, capacitor placement, harmonic frequency, voltage conservation	$15,000 (single user license) $3,750 (additional license)	Yes

Characteristics	Price	Demo
TAG-DR (EPRI)		
• Evaluates small scale (25kW-25MW) distributed generation technologies comparative cost and performance • Evaluates the distribution ("wires") upgrade or new installation • Evaluates end-use technologies • Matches customer load profiles with distribution feeder profiles • Matches customer load profiles with rate programs • Evaluates and compares small scale generation and distribution options to serve the load requirements of a customer	N/A	No

All the technical characteristics were reviewed as well as the available demos. After this process, Berkeley Lab staff decided to select the Milsoft software named WinMil®, that stands for 'Windows version of Milsoft' and has no special capabilities for simulation of wind power. This decision was made taking into account this software's versatility and fitness to the required analysis, familiarity of CERTS partners with it, and its reasonable cost.

3.6 Software's Characteristics

WindMil® is a Windows application designed to analyze distribution systems that provides a graphical environment. This software allows analysis of the steady-state performance of a distribution network by feeder/substation, or for the entire system. WindMil® does not provide tools for dynamic analysis. The main features of WindMil® are summarized below:

- Second Generation Windows Application: Designed and written to take full advantage of Windows NT 4.0 and Windows 95.
- All voltage levels modeled and analyzed.
- No software limits on circuit elements or number of circuits.
- Both looped and radial solutions.
- Unbalanced loading, impedance and spacing.
- Charging current calculated for both overhead and underground.
- Generators modeled as voltage source or negative load.
- Different model types for loads: Constant power, constant current, constant impedance or a combination of the three.
- Flexible work environment: single circuit or entire system.
- Digitizing routine included.
- With the LandBase add-on (optional), WindMil® can import AM/FM or GIS file formats

WindMil® provides also a complete set of powerflow analysis tools:

- Load Allocation
- Voltage Drop
- Fault Current
- Fault Flow
- Sectionalizing
- Capacitor Placement
- Load Balance
- Motor Analysis
- Feeder Optimization
- Contingency analysis (optional)
- Feeder reduction (optional)

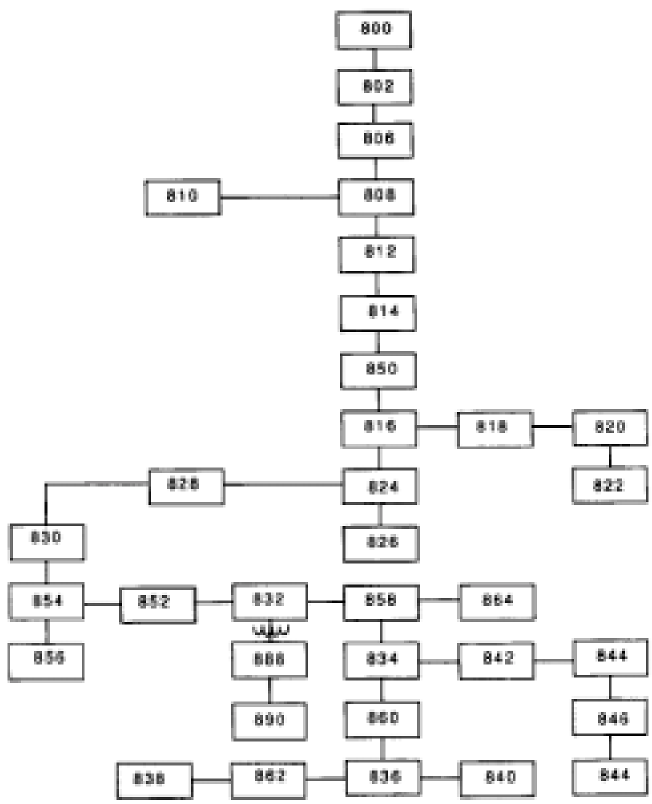


Figure 8: Circuit Diagram (borrowed from (Kersting 1992))

3.7 Software Validation

Once the software was chosen, a sample distribution network was used to validate the application. The IEEE 34 distribution test system was utilized in this project. The data set was taken from (Kersting 1992), which basically describes the same test system proposed by the (IEEE Distribution Planning Group 1991). However, there are slight differences in the distributed loads of both feeders. The distribution feeder of the first reference was selected because a solution is provided by the authors.

This feeder is not large (1.3 MW of peak power), making it not very realistic, but it is ideal for validation and for preliminary analysis of distributed generation. Figure 8 shows a feeder schematic.

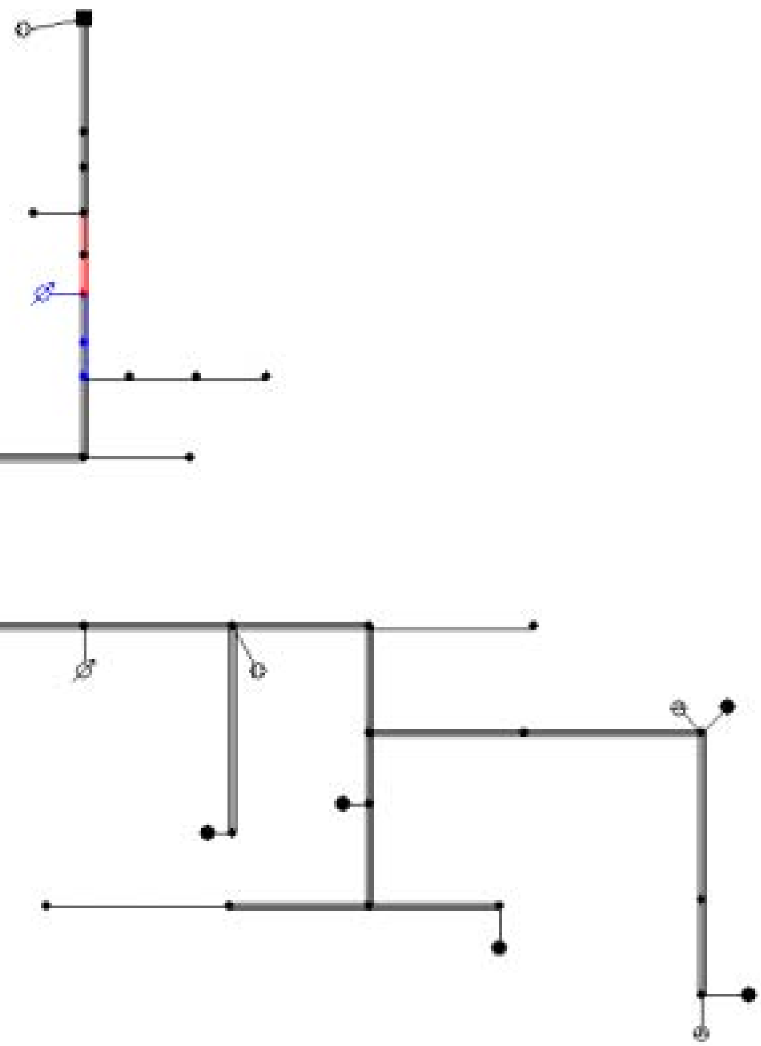


Figure 9: Test Feeder Modeled with WindMil®

The main feeder characteristics are described below:

- Substation: 2500 kVA transformer connected to a 345 kV bus.
- Load Types: Spot and distributed loads all "wye" connected. All the loads are modeled as constant kWh / kVAr.

- Line Types: Three-phase and single-phase overhead lines. 5 different configurations. The line's information includes the length and the type of conductor.
- Two single-phase voltage regulators.
- Two balanced three-phase capacitors capable to generate 250 kVAr per phase.
- In-line autotransformer converting feeder voltage from 24.9 kV to 4.16 kV.

All the technical data needed to simulate the distribution network can be found in the previously cited reference. The feeder modeled in WindMil® is shown in Figure 9.

Once the system was installed in WindMil®, it was simulated to find all the variables that electrically define the steady-state of the feeder (current, angles and voltages of every node in the system). The results that WindMil® produces contain a lot of detailed information. Only the main electrical magnitudes are included in Table 3.

Table 3: Feeder Results from WindMil®

Element Name	Phase	Base Voltage (V)	Accum. V. Drop (V)	Current (A)	Distance from Substation (km)
800	A	123.60	0.00	7.12	0.00
	B	123.60	0.00	6.91	
	C	123.60	0.00	7.16	
802	A	123.40	0.25	34.07	0.78
	B	123.40	0.21	32.13	
	C	123.40	0.21	31.63	
806	A	123.20	0.38	34.07	1.31
	B	123.30	0.31	32.13	
	C	123.30	0.33	31.63	
808	A	120.80	2.82	34.07	11.07
	B	121.40	2.19	30.04	
	C	121.20	2.39	29.89	
812	A	118.00	5.61	34.07	22.44
	B	119.40	4.21	28.98	
	C	118.80	4.81	29.89	
814	A	115.80	7.80	34.07	31.44
	B	117.80	5.80	28.98	
	C	116.90	6.72	29.89	
Regulator 1	A	125.20	1.61	34.07	31.44
	B	125.90	2.29	28.98	
	C	126.40	2.78	29.89	
850	A	125.20	1.61	31.51	31.45
	B	125.90	2.29	27.12	
	C	126.40	2.78	27.64	
816	A	125.20	1.59	31.51	31.54
	B	125.90	2.28	27.12	
	C	126.40	2.76	27.64	

Element Name	Phase	Base Voltage (V)	Accum. V. Drop (V)	Current (A)	Distance from Substation (km)
824	A	124.90	1.27	20.65	34.64
	B	125.30	1.66	27.12	
	C	125.80	2.21	27.64	
828	A	124.80	1.24	20.65	34.89
	B	125.20	1.61	24.42	
	C	125.80	2.16	27.64	
830	A	124.20	0.64	20.65	41.08
	B	124.20	0.56	24.42	
	C	124.60	1.01	27.46	
854	A	124.20	0.63	20.28	41.24
	B	124.10	0.53	24.42	
	C	124.60	0.98	27.46	
852	A	123.20	0.42	20.28	52.40
	B	122.30	1.34	24.19	
	C	122.50	1.07	27.46	
Regulator 2	A	124.70	1.12	20.28	52.40
	B	124.50	0.95	24.19	
	C	124.10	0.46	27.46	
832	A	124.70	1.12	20.03	52.40
	B	124.50	0.95	23.75	
	C	124.10	0.46	27.12	
Trafo 55	A	123.60	0.00	2.21	52.40
	B	123.40	0.18	2.22	
	C	122.90	0.67	2.22	
890	A	122.00	1.61	13.24	52.40
	B	121.80	1.79	13.26	
	C	121.30	2.28	13.32	
890	A	122.00	1.61	13.24	52.40
	B	121.80	1.79	13.26	
	C	121.30	2.28	13.32	
858	A	124.60	1.02	18.89	53.89
	B	124.30	0.73	22.40	
	C	123.80	0.23	25.64	
834	A	124.50	0.90	18.50	55.66
	B	124.10	0.48	22.33	
	C	123.60	0.04	25.31	
842	A	124.50	0.90	14.83	55.74
	B	124.10	0.48	16.32	
	C	123.60	0.05	15.25	
844	A	124.50	0.89	14.83	56.15
	B	124.10	0.45	16.32	
	C	123.50	0.06	15.25	
844	A	124.50	0.89	10.71	56.15

Element Name	Phase	Base Voltage (V)	Accum. V. Drop (V)	Current (A)	Distance from Substation (km)
	B	124.10	0.45	10.75	
	C	123.50	0.06	10.79	
Cap 2	A	124.50	0.89	-7.22	56.15
	B	124.10	0.45	-7.19	
	C	123.50	0.06	-7.16	
846	A	124.50	0.92	9.97	57.25
	B	124.10	0.46	10.08	
	C	123.60	0.02	9.82	
848	A	124.50	0.93	9.97	57.41
	B	124.10	0.47	9.86	
	C	123.60	0.02	9.88	
848	A	124.50	0.93	1.56	57.41
	B	124.10	0.47	1.57	
	C	123.60	0.02	1.57	
Cap 1	A	124.50	0.93	-10.83	57.41
	B	124.10	0.47	-10.79	
	C	123.60	0.02	-10.75	
860	A	124.50	0.87	6.43	56.27
	B	124.00	0.44	7.86	
	C	123.50	0.09	12.97	
860	A	124.50	0.87	1.60	56.27
	B	124.00	0.44	1.60	
	C	123.50	0.09	1.61	
836	A	124.50	0.85	3.80	57.08
	B	124.00	0.41	4.88	
	C	123.50	0.10	3.64	
862	A	124.50	0.85	0.00	57.17
	B	124.00	0.41	1.94	
	C	123.50	0.10	0.00	
838	B	124.00	0.39	1.94	58.64
840	A	124.40	0.85	1.90	57.34
	B	124.00	0.41	2.21	
	C	123.50	0.10	0.72	
840	A	124.40	0.85	0.71	57.34
	B	124.00	0.41	0.71	
	C	123.50	0.10	0.72	
864	A	124.60	1.02	0.04	54.38
856	B	124.10	0.52	0.26	48.31
826	B	125.20	1.64	2.93	35.56
818	A	125.10	1.50	12.01	32.06
820	A	122.80	0.77	12.01	46.65
822	A	122.50	1.06	9.62	50.81
810	B	121.40	2.20	1.14	12.84

As can be easily seen, there are some problems in this feeder. The "voltage profile" of the feeder (based on 120 V) shows that there are extremely low and unbalanced voltages at bus 814. An overvoltage appears in the other side of the voltage regulator (at elements numbers 850 and 816). These problems are graphically illustrated in Figure 9. The red color implies undervoltage and the blue color overvoltage. There are low voltages in the primary of the voltage regulator and higher voltages in the other side. The same effects were observed in the solution of (Kersting 1992), as can be seen in Table 4, is a copy of the corresponding table in the mentioned reference.

Table 4: Feeder Results According to (Kersting 1992)

P 1
VOLTAGE PROFILE ---- DATE: 9-17-1991 AT 11:28:19 HOURS
IEEE 34 BUS RADIAL SYSTEM

BUS	PHASE A-N		PHASE B-N		PHASE C-N		MILES FROM SUB
	MAG	ANGLE	MAG	ANGLE	MAG	ANGLE	
800	123.5958 AT	.00	123.6040 AT	-120.00	123.5937 AT	120.00	.000
802	123.3402 AT	-.07	123.4412 AT	-120.06	123.3717 AT	119.95	.489
806	123.1678 AT	-.11	123.3395 AT	-120.10	123.2271 AT	119.91	.816
808	119.9375 AT	-.98	121.5849 AT	-120.82	120.6897 AT	119.27	6.928
810			121.5684 AT	-120.82			8.027
812	116.1897 AT	-2.05	119.7080 AT	-121.64	117.5036 AT	118.52	14.023
814	113.2330 AT	-2.92	118.2148 AT	-122.29	115.0413 AT	117.92	19.653
850	124.5554 AT	-2.93	126.3416 AT	-122.29	126.5446 AT	117.91	19.655
816	124.5272 AT	-2.93	126.3269 AT	-122.30	126.5214 AT	117.91	19.714
818	124.4241 AT	-2.93					20.038
820	121.7848 AT	-3.02					29.157
822	121.4459 AT	-3.03					31.760
824	124.0518 AT	-3.13	125.7178 AT	-122.48	125.7867 AT	117.68	21.668
826			125.6953 AT	-122.48			22.222
828	124.0114 AT	-3.14	125.6789 AT	-122.50	125.7211 AT	117.67	21.807
830	123.0853 AT	-3.56	124.6769 AT	-122.84	124.2147 AT	117.22	25.679
854	123.0621 AT	-3.57	124.6512 AT	-122.85	124.1764 AT	117.21	25.777
856			124.6434 AT	-122.86			30.195
852	121.4229 AT	-4.32	122.9463 AT	-123.45	121.4433 AT	116.39	33.752
832	125.2168 AT	-4.32	123.6136 AT	-123.45	125.2377 AT	116.39	33.756
858	125.0189 AT	-4.43	123.4046 AT	-123.53	124.9239 AT	116.28	33.882
864	125.0187 AT	-4.42					33.989
834	124.8324 AT	-4.53	123.1650 AT	-123.63	124.5615 AT	116.15	34.786
860	124.7875 AT	-4.53	123.1378 AT	-123.62	124.4985 AT	116.16	35.169
836	124.7435 AT	-4.53	123.1236 AT	-123.63	124.4801 AT	116.16	35.677
840	124.7398 AT	-4.53	123.1198 AT	-123.63	124.4788 AT	116.16	35.839
862	124.7415 AT	-4.54	123.1241 AT	-123.63	124.4800 AT	116.16	35.730
838	124.7241 AT	-4.54					36.608
842	124.8281 AT	-4.54	123.1587 AT	-123.63	124.5571 AT	116.15	34.839
844	124.8100 AT	-4.56	123.1269 AT	-123.66	124.5364 AT	116.12	35.095
846	124.8447 AT	-4.61	123.1392 AT	-123.71	124.5690 AT	116.07	35.784
848	124.8496 AT	-4.61	123.1329 AT	-123.71	124.5756 AT	116.06	35.885
888	122.1523 AT	-5.09	120.5108 AT	-124.23	122.1484 AT	115.62	33.756
890	120.2592 AT	-5.05	118.4816 AT	-124.28	120.2490 AT	115.63	34.754

While the numeric results in WindMil® and in the above mentioned reference are very close, they are not exactly the same. This mismatch can be attributed to the different load allocation methods used in each analysis. The load data used in this feeder by Kersting et al, is in kWh and in order to run the simulation it is necessary to "translate" the consumed energy to kW. Kersting et al, used the REA method. WindMil® has an option under the same name, but it is not certain that the implementation is identical.

Although it is not in the previous table, WindMil® is able to calculate the fault current in every node of the distribution network. This electrical magnitude is very important in the study of DER deployment. The installation of a generator in a given bus automatically changes the fault current in almost every network's node. The alteration of this magnitude has important implications in the correct performance of all protective devices.

3.8 DER Study Example

Finally, as the last step of this part of the work, a simple example was completed with the same feeder. The goal of this example was to test the capabilities of WindMil® for DER studies.

Since the original feeder had some voltage problems, the appropriateness of using distributed generation to solve this problem was analyzed. Several options were evaluated, and one of the best results obtained involved installing two generators of 200 kW each. Figure 10 shows the location of each generator and that almost all the voltage problems disappear with these new two generators. Also the total power losses were reduced to 63 kW, which is a significant effect. The previous losses were 125 kW.

It is obvious that different generator's locations have different impacts in the distribution network. As can be seen in Figure 11, an alternative location was selected for one of the generators. The results are very clear: the voltage problem has become more serious and the power losses are higher (80 kW) than in the previous case. The site of the generator was set before the voltage regulator in order to make this example clearer. It is normally true that the best placement of DER is toward the end of the feeder. These examples presented here were done manually because the software does not have any generator-placement-tool (this feature is only available for capacitors).

It is clear that from the Disco standpoint, determining the best location for the DER is one more issue to take into account (Hadjsaid 1999) in the traditional planning process (Willis 1997). The criteria used to find the optimum sites are not unique. Several of them can be used: maximize reliability, power quality, loss minimization, etc. An example of the proposed method based on loss minimization can be found in (Kim, et al. 1998). At the same time it is also true that the optimum placement of generators only matters if it is carried out by the discos. Obviously, no placement-optimization is required for customers.

Regarding the software's testing, some experience was acquired in modeling generators inside WindMil®. There are two ways to do model generators: as "Swing kVAr" or "negative load". The first option allows the generator to produce or to consume reactive power in order to maintain the prefixed voltage level. This can be useful to simulate the generators as an ancillary service provider. However, in WindMil® there is no easy way to control various generators with this feature. The other option models the generator as a constant source of active power. This can be useful in most cases.

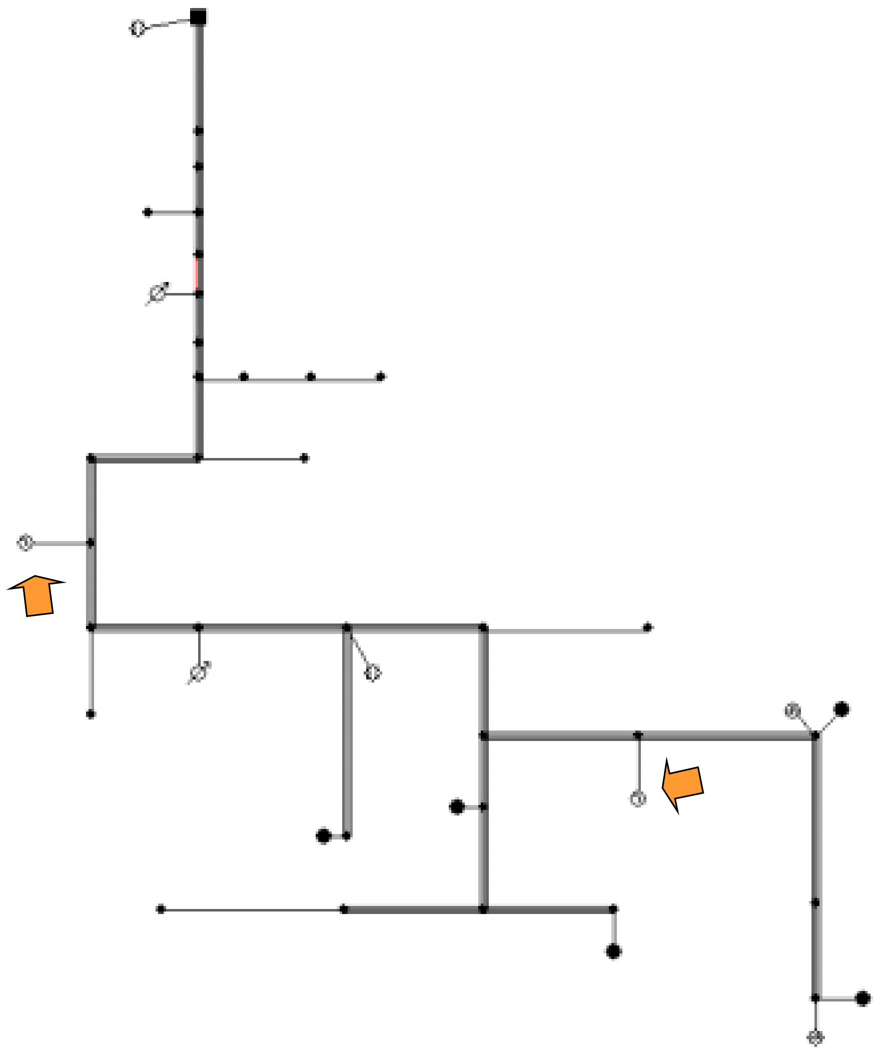


Figure 10: Test Feeder with Embedded Generation

3.9 Summary / Conclusion

Technical and commercial information about 13 different electrical distribution software was gathered and one,WindMil®, was selected. WindMil® can perform several kinds of analyses of a distribution network. The most interesting capabilities within the scope of this project are the following: steady-state analysis (voltages, currents, etc.), capacitor placement, and fault analysis. All of these features can be very useful in the current DER project because can help to evaluate the economic impact DER technologies can have from the Distco standpoint, one important perspective in this DER integrated approach.

However, this tool is not useful in other types of studies that have to be done in this project, that involve dynamic behavior of DER installed inside distribution networks. Other advantage of this software is that it can deal with unbalanced phases and import

GIS data. The latter can be very useful for advancing in the integrated approach that is being fostered in this report (see for example chapter 6 about GIS application on DER).

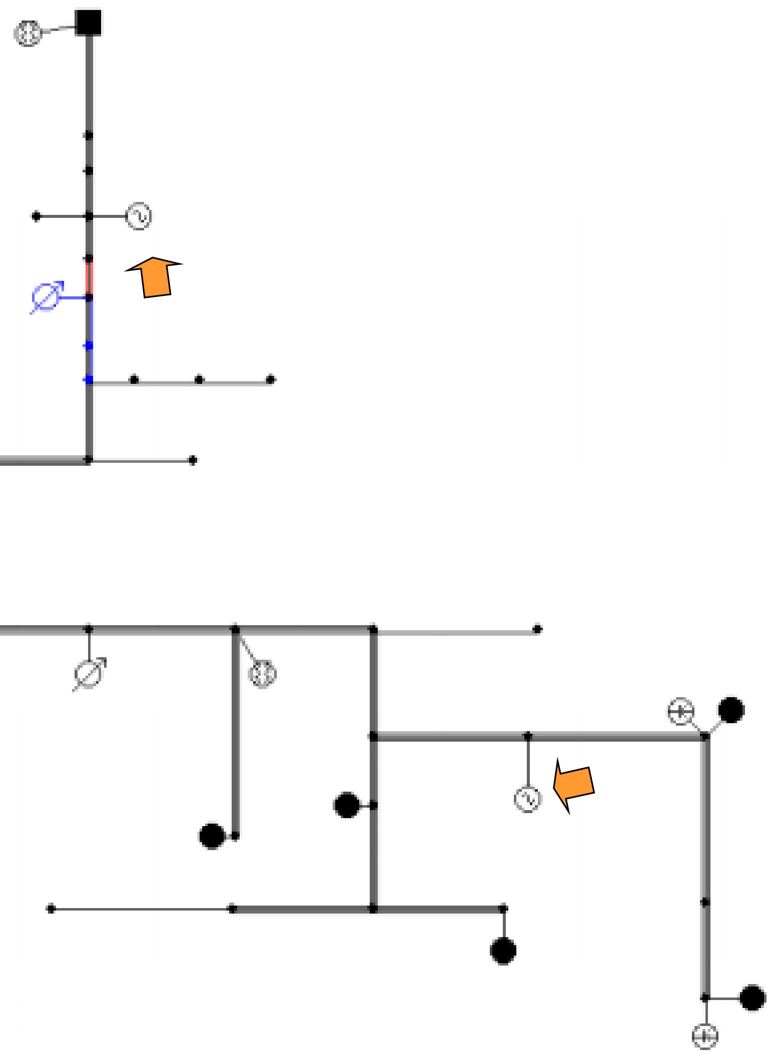


Figure 11: Test Feeder with Different Generator's Location

4. Regulatory Issues

4.1 Current Regulatory Situation

The ability under prevailing tariffs of customers to install small on-site generating equipment has been quite limited under prevailing public utility regulation. Under most tariffs, small on-site generation can technically only be used for emergency purposes when grid power is unavailable. The overriding concern of utilities has been safety. Customer siting of small-scale generation has been considered a reliability issue for the customer only, self-generation being generally considered unlikely to be attractive economically. That is, the potential system benefits of small-scale customer generation were never really addressed. However, current interest in DER is quickly changing this situation.

4.2 California Net Metering

Early pressure to ease restrictions on customer owned generation derived from the strong policy intent to simplify interconnection of small renewable sources, notably rooftop photovoltaic systems and small wind turbines. The goal of stimulating residential and small commercial adoption of these generating technologies has led firstly to limited weakening of interconnection requirements for them and, subsequently, to special tariff provisions such as net metering.

Approximately 30 other states, as summarized in Table 5, Germany, Japan, and Switzerland, have enacted net metering laws. California's law (AB 1755 and PU Code Section 2827) allows residential and small commercial customers with solar or wind generation of not more than 10 kW to connect in parallel and outlines the billing arrangements. SCE customers with net metering are served on the customer Net Energy Metering schedule, which came into effect at the beginning of 1999. Typically, a simple two-way meter is used, although SCE is authorized under the tariff to install other equipment, such as a time-of-use meter, and customers on residential time-of-use rates can participate. If the existing meter cannot run both ways it is upgraded at customer expense, whereas all other metering is done at SCE expense. Under the required customer agreement, the system must be inspected by SCE before connection, and SCE staff can enter the premises to inspect or disconnect equipment at any time. Customers are required to pay any customer charge due on their tariff, but bills are not due monthly. Rather, a monthly usage statement is sent to the customer which shows the net annual usage to date, but actual billing takes place after an end of year true up (often called *netting*) has been made. If, at the end of a full year, the customer has been a net electricity producer, no bill is owed the utility but nor is any payment made to the customer. In other words, the best the customer can do is break even on the energy part of his bill. If the customer has been a net electricity consumer, electricity delivered to the customer is charged at the average price for the year on the otherwise applicable tariff. In other words, the customer would receive no benefit for producing during high price periods and consuming during low price ones.

Table 5: Summary of Net Metering Laws

Summary of State Net Metering Programs (Current)

State	Eligible Fuel Type	Eligible Cust.	Limit on System Size	Limit on Overall Enrollment	Treatment of NEG*	Enacted	Citation / Reference
AZ	RE & cogen	All cust. classes	<=100 KW	None	NEG purchased at avoided cost	1981	Corp. Comm. Decision No. 52345
CA	Solar and Wind	Res. and small comm.	<=10 KW	0.1% of 1996 peak demand	Net Meter cust. billed annually; excess generation granted to utility	1998	Public Utilities Code § 2827
CO	All resources	All cust.	<=10 KW	None	NEG carried over month to month	1994	Advice Letter 1265; Decision C96-901
CT	Solar, wind, hydro, fuel cell, sustainable biomass	Res. only	No limit	None	Not Specified	1998	Pub. Act 98-28
DE	RE	All cust. classes	<=25 KW	None	Not specified	1999	Legis. S amend 1 to HB10
ID	RE & cogen	Idaho Power only Res. and small comm.	<=100 KW	None	NEG purchased at avoided cost	1980	ID PUC Orders No. 16025 (1980); 26750 (1997)
IL	Solar & wind	ComEd only, all cust. classes	<40 KW	.1% of annual peak demand	NEG purchased at avoided cost	1999	Special billing experiment (eff. 4/1/00)
IN	RE & cogen	All cust. classes	<=1,000 KWH/month	None	No purchase of NEG; excess is "granted" to the utility.	1985	170 IN Admin Code § 4-4.1-7

Summary of State Net Metering Programs (Current)							
State	**Eligible Fuel Type**	**Eligible Cust.**	**Limit on System Size**	**Limit on Overall Enrollment**	**Treatment of NEG***	**Enacted**	**Citation / Reference**
IA	RE	All cust. classes	No limit	None	NEG purchased at avoided cost	1983	IA Leg. & IA Util. Bd., Util. Div. Rules § 15.11(5)
ME	RE, fuel cells & recycled municipal solid waste	All cust. classes	<=100 KW	None	NEG carried over month-to-month; any residual NEG at end of 12-month period is eliminated w/o compensation	1998	Code Me. R. Ch. § 313 (1998); see also Order No. 98-621
MD	Solar only	Res. only	<=80 KW	.2% of 1998 peak demand	NEG carried over to following month; otherwise not specified	1997	Art. 78, Sec. 54M
MA	RE & cogen	All cust. classes	<=60 KW	None	NEG purchased at avoided cost	1997	Mass. Gen. L. ch. 164, § 1G(g); Dept. of Tel. & Energy 97-111
MN	RE & cogen	All cust. classes	<40 KW	None	NEG purchased at "average retail utility energy rate"	1983	Minn. Stat. § 261B.164(3)
MT	Solar, wind, hydro	All cust. classes	<=50 KW	None	NEG credited to following month; unused credit granted to utility at end of 12 month period	1999	SB 409
NV	Solar and wind	All cust. classes	<=10 KW	100 cust. for each utility	NEG purchased at avoided cost; annualization allowed	1997	Nev. Rev. S. Ch. 704
NH	Solar, wind & hydro	All cust. classes	<=25 KW	.05% of annual peak	PUC may require 'netting' over 12 month period; retailing wheeling allowed for up to 3 cust.	1998	H.B. 485

Summary of State Net Metering Programs (Current)

State	Eligible Fuel Type	Eligible Cust.	Limit on System Size	Limit on Overall Enrollment	Treatment of NEG*	Enacted	Citation / Reference
NM	RE, cogen	All cust. classes	<=10 KW	None	At utility's option, customer is credited on the next bill for (1) purchase of NEG at utility's avoided cost; or (2) kilowatt-hour credit for NEG that carries over from month to month.	1999	NM PUC Order 2847
NY	Solar only	Res. only	<=10 KW	.1% of 1996 peak	NEG credited to following month; unused credit is purchased at avoided cost	1997	Public Service Law § 66-j
ND	RE & cogen	All cust. classes	<=100 KW	None	NEG purchased at avoided cost	1991	ND Admin. Code § 69-09-07-09
OH	Solar, wind, biomass, landfill gas, hydro, microturbines, or fuel cells	All cust. classes	No limit	1% of peak demand for each retail electric provider	NEG purchased at unbundled generation rate, appears as credit on following bill	1999	SB 3
OK	RE & cogen	All cust. classes	<=100 KW and annual output <=25,000 KWH	None	No purchase of NEG; excess is granted to the utility.	1990	Schedule QF-2
OR	Solar, wind, fuel cell, & hydro	All cust. classes	<=25 KW	No less than .5% of utility's historic single hour peak load; beyond .5% eligibility can be limited by reg. authority	NEG purchased at avoided cost or credited to following month; at end of annual period unused credits shall be granted to low-income assistance programs, credited to customer, or "dedicated to other use" as determined by regulatory authority	1999	HB3219

Summary of State Net Metering Programs (Current)							
State	**Eligible Fuel Type**	**Eligible Cust.**	**Limit on System Size**	**Limit on Overall Enrollment**	**Treatment of NEG***	**Enacted**	**Citation / Reference**
PA	RE only (incl. fuel cells)	All cust. classes	<=10 KW	None	NEG granted to utility at end of month	1998	PA PUC, Miscellaneous Individual Utility Tariffs
RI	RE & fuel cells	All cust. classes	<=25 KW	1 MW for Narrangansett Electric	NEG credited to following month: unused credit granted to utility at end of annual period	1998	PUC order, Docket #2710
TX	RE only	All cust. classes	<=50 KW	None	NEG purchased at avoided cost	1986	PUC of Texas, Substantive Rules, § 23.66(f)(4)
VT	Solar, wind, fuel cells using renewable fuel, anaerobic digestion	Res., comm., and ag. cust.	<=15 KW, except <=100 KW for anaerobic digesters	1% of 1996 peak	NEG carried over month to month; any residual NEG at end of year is "granted' to the utility	1998	H. 605
VA	Solar, wind, hydro	Res. & comm.	<=10 KW res.; <=25 KW comm.	.1% of annual peak demand	Net metering cust. are billed annually; excess generation is granted to utility	1999	SB1269 (effective by 7/1/2000)
WA	Solar, wind and hydropower	All cust. classes	<=25 KW	.1% 1996 peak	NEG credited to following month; unused credit is granted to utility at end of annual month period	1998	House Bill 2773
WI	All Resource	All retail cust.	<=20 KW	None	NEG purchased at retail rate for RE, avoided cost for non RE	1993	Schedule PG-4

Summary of State Net Metering Programs (Current)							
State	**Eligible Fuel Type**	**Eligible Cust.**	**Limit on System Size**	**Limit on Overall Enrollment**	**Treatment of NEG***	**Enacted**	**Citation / Reference**
GA pend.	Solar, wind, hydro, biomass, fuel cells	All customer classes	<=100 KW	None	Net metering customers are billed annually; excess generation is granted to the utility	Pending	Senate Bill 433
IL pend.	Solar or wind	All customer classes	<=40 kW	None	NEG credited to following month; unused credit is purchased at avoided cost	Pending	House Bill 2615, Senate Bill 0534 (companion bills)
NC pend.	Solar, wind, hydro, and biomass	All customer classes	<=10 kW (res.); <=100 kW (non-res.)	1% of annual peak demand	NEG credited to following month; unused credit is eliminated at end of annual billing period (residential customers only)	Pending	NC Util. Comm., Docket No. E-100, Sub 83 (Nov. 18, 1998)
SD tabled	Solar, wind, geothermal, biomass, hydro	All customer classes	<=100 kW (as amended)	None	NEG credited to following month; unused credit is purchased at avoided cost	Pending	House Bill 1232

* "NEG" refers to the "net excess generation" which occurs only when total generation exceeds total consumption over the entire billing period, i.e. the customer has more than offset his/her total electricity use and has a negative meter reading.

source: Kelso Starrs & Associates LLC

4.3 Other Small Scale Generation

In general, use of small scale generation by customers has been considered only for emergency back up purposes, to be used when grid power is unavailable. This is not to say that utilities discouraged the installation of back-up equipment. In fact, its availability clearly lowers the liability of the utility to outage costs. Self-generation by customer generation operating in parallel, however, has not been warmly accepted by utilities. In the case of SCE, connecting a small generator requires the customer to agree to the complex terms of Rule 21, originally intended to govern the interconnection of qualifying facility equipment under the terms of the Public Utilities Regulatory Policies Act. One of the requirements of Rule 21 was formerly that any customer connecting under it became subject to a standby tariff known as Schedule S. Under this tariff, the customer must pay a standby charge on the lesser of the nameplate rating of its generating capacity or its estimated peak demand. For a small customer the monthly charge is 6.77 \$/kW·month.

A broad Order Instituting Ratemaking (OIR) was begun in December 1998 as a joint process of the three major California regulatory authorities, the California Public Utilities Commission (CPUC) , the California Energy Commission (CEC) , and the Electricity Oversight Board (EOB) . The OIR decision issued in September, 1999, proposed a dual track approach to further review of regulatory review of distributed generation issues. (CPUC, 1999)

First, a proceeding docket (California Public Utilities Commission 1999) was opened to discuss interconnection issues. Rules for the interconnection of other small generators are under review in many states. Texas has made the most progress towards establishing a simple interconnection procedure. The TX agreement is attached as Appendix 3. In general, the regulatory process in California seems to heading the direction of a standardized agreement similar to Texas's being adopted. Two initial workshops have been held so far.

Second, the OIR decision instructed CPUC staff to prepare a report on distribution competition, which is due for release on 21 April 2000. The report should cover both the issues surrounding possible utility distribution company (UDC) ownership of generation, and the viability of distribution network competition.

In the meantime, existing interconnection rules for DER are also getting established by other regulatory activity. For example, on 3 February 2000, the CPUC in Resolution E-3652 approved a proposed revision to SCE's Rule 21 that expands the applicability of customer interconnection rules to smaller generators that are not qualifying facilities. Under the revision, customer-owned generating equipment can be connected and operated in parallel with utility service without the customer becoming subject to Schedule S charges, although SCE is expected to propose alternative standby charges in the ongoing CPUC DER proceeding.

4.4 Building Codes

In addition to CPUC regulation, the viability of DER installations are likely to be determined in part by the amenability of building codes to DER.

4.5 Conclusion

The regulatory situation is in a period of rapid change. Historically, regulation has not allowed customers to install small scale generation intended to operate in parallel with the distribution network. However, a liberalization process that began with the interconnection of qualifying facility generation and continued with interconnection rules for PV and other renewable generation is now dramatically accelerating. It seems quite likely that, at least in California, a basic interconnection agreement along the lines of the Texas one will be in place in a matter of months.

5. Environmental Issues

5.1 Introduction

The prospect of minimizing costs and increasing reliability in a decentralized electricity utility market raise a multitude of environmental issues where implementing DER in California is concerned. As utility distribution companies are presented with the possibility of using DER to provide power generation to local communities without need for extensive transmission lines, it is important to assess the environmental impacts such alternatives could cause. With the serious air quality issues plaguing California, analysis of the environmental affects due to enhanced DER are essential in deeming it a beneficial alternative. This section serves as an example of what environmental issues should be taken into account when considering installation of a microturbine in the southern San Joaquin Valley. Located in the heart of California's valley climate, installation of a 25-30 kW microturbine involves consideration of the various air quality issues currently plaguing this region of the state.

An environmental assessment serves as a key factor in the deployment of DER. In developing an integrated and comprehensive framework for DER adoption, the various chapters in this deliverable have addressed the technical, economic, and regulatory issues and factors associated with DER adoption. A focus on the current environmental status of potential DER sites completes the framework for assessing DER deployment. Focusing on the southern SJV of California as attractive for DER installation, an environmental assessment of the region is key in identifying potential barriers to DER deployment. The sensitive nature of this region's current air quality situation further emphasizes how critical it is to address the possible affects DER could cause. With the current and prospective environmental regulations facing the potential DER site, assessment of the environmental effects due to DER deployment are imperative.

This environmental analysis of the San Joaquin Valley Air Basin (SJVAB) is divided into the following subsections. Section 5.2 provides a brief introduction to the geographic setting of California and the meteorological influences that affect the southern portions of central California. Section 5.3 then discusses the significance of air pollutant transport into the SJV. Section 5.4 presents the air quality issues facing the SJV, with detailed descriptions of ozone, particulate matter, and other pertinent emissions and pollutants. Also in this subsection, a brief overview of current legislative rules and regulations affecting emissions levels in the SJV are presented. Section 5.5 then discusses the current status of road noise issues in this region and how installation of a microturbine could impact current noise regulations. Emissions calculations are then presented in section 5.6 as rough estimators of environmental impacts that result from installation of a small-scale microturbine. Concluding remarks are then provided in section 5.7.

5.2 California and the Central Valley

California is characterized by a variety of climates. The coastal region possesses a mild climate, with the northern coastal region somewhat cooler than the central and southern portions of this region. The Sierra Nevada to the east marks an area of higher elevation where summers are mild and winters snowy. A warmer valley climate is situated in the middle of the state, separating the coastal region to the west and the Sierras to the east. Also known as the Central Valley, this region covers 70,000 km^2, extending 720 km northwest to southeast and more than 80 km west to east. The Central Valley represents the Sacramento Valley to the north and the San Joaquin Valley to the south. Much of the state is characterized by two distinct seasons: a rainy season, which extends from approximately October to April, and a dry season, which characterizes the remainder of the year. The climate of the Central Valley makes it one of the most desirable places to harvest certain crops (Network 2000).

California's diverse and mild climate promotes an area rich in agriculture. Fed by a network of lakes, reservoirs, and rivers, the state leads the country in agricultural revenue, making over $26 billion in 1997. Virtually all of the land used for agricultural purposes is irrigated flat lands. Leading the state in farm income, Fresno County represents the nation's leading county in agricultural production. Benefiting from ideal soil and water conditions, the Central Valley allows farmers to grow over 300 different crops. Milk is the state's leading agricultural commodity, making it the nation's number one dairy state with cotton production in California ranked second in the country. Almonds, artichokes, dates, and figs are just a few of the crops that help contribute to the nearly 39 million tons of fruits, nuts and vegetables produced in 1997 (California Department of Food and Agriculture 1997). Specifically, the SJV is known for its almonds, apricots, cantaloupes, grapes, kiwi fruit, nectarines, olives, and oranges, just to name a few (Network 2000).

Enclosed by the coastal range to the west and the Sierras to the east, the SJV has become subject to serious air quality problems. This, along with significant upwind influences from the San Francisco Bay Area, contributes to enhanced pollutant and emission concentrations in the SJV. Occupying the lower two-thirds of the Central Valley, the region, also known as the SJVAB, consists of eight counties: Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus, and Tulare. The population in the SJV is estimated to have increased by nearly 50% from 1980 to 1997 (California Air Resources Board Technical Support Division 1999). According to the 1990 Census poll, the population in the SJV exceeded three million and is regarded as one of the fastest growing regions in the state (Austin-Joy, et al. 1998). This rapid population growth coupled with the hot climate has resulted in enhanced electricity development growth.

5.3 Transport into the San Joaquin Valley

The current air quality status in the Central Valley raises the importance of analyzing the effect of air transport from one region to another. Specifically, the nature and severity of air flowing into the SJV from points elsewhere is assessed.

5.3.1 Characteristic Flow Patterns in the Central Valley

The air quality issues facing the SJVAB largely stem from conditions that exist during the summer season. Typically, a moderate pressure gradient, or difference, is present between the Sacramento Valley and the SJVAB (California Air Resources Board

Technical Support Division 1996). The orientation and strength of the various pressure systems that characterize California's weather are a major factor in determining the strength of flow patterns. Cooler air residing over the ocean is prevented from entering the Central Valley by the Coastal mountain range. This permits the Valley to heat up. Two characteristic wind flow patterns that originate in the Carquinez Strait and Altamont Pass, typically split upon entering the Central Valley. This produces a dominant northwesterly wind flow into the SJVAB. Although these two flow patterns are capable of producing a variety of flow patterns, close to 90% of summer flows come from the northwest. Furthermore, about 70% of these summer winds are channeled into the SJVAB from the San Francisco Bay Area (California Air Resources Board Technical Support Division 1996).

One aspect of the San Joaquin Valley atmospheric influences is a 30 km gap where the coastal mountain ranges break at the Carquinez Strait. Located where the San Joaquin River flows into the San Francisco Bay, this important break serves as a passageway of marine layer flow into the valley. Typically, the coastal range acts as a barrier of flow into the valley regions, but with this gap situated at 500 m above mean sea level, the marine layer (typically 400-700 m thick) is able to penetrate further inland (California Air Resources Board Technical Support Division 1996).

The Santa Clara Valley is another important pathway from the San Francisco Bay Area Air Basin (SFBAAB) to the SJVAB. Here, a gap in the coastal barrier to the east of the Santa Clara Valley serves as another passageway in the SJVAB. This break is better known as Pacheco Pass, and is a very favorable wind site as a result (California Air Resources Board Technical Support Division 1996).

5.3.2 Pollutant Transport into the SJV

Numerous studies have shown the downwind transport of air pollutants in certain regions of California. In the SJV, studies partially attribute poor air quality conditions to upwind sources in the San Francisco Bay Area and the broader Sacramento Valley (California Air Resources Board Technical Support Division 1996). Both have been suggested as contributing to high levels of ozone, the main constituent of smog.

The SJV Unified Air Pollution Control District (SJVAPCD) estimates that approximately 27% of the total air pollution in the northern part of the SJV originates from the Bay Area. In the central SJVAB, this coupling of airflow drops to 11% with less than 10% influencing the southern SJVAB. The southern SJV, therefore, is predominantly exposed to locally produced smog (SJVAPCD 2000).

A 1990 study performed by the California Air Resources Board (ARB) investigated ozone and ozone precursor transport to the SJV. Looking at a specific time period from 1983-1986 results indicated a significant influence from transport patterns. This 3-year assessment concluded that approximately 43% of ozone exceedance days were significantly impacted by upstream wind flow patterns, 11% were not, with the remaining 46% inconclusively classified as neither. Days with significant upstream transport influences are believed to be a combination of airflow transport from external sources as well as inconsequential or influences not related to transport (California Air Resources Board Technical Support Division 1996).

A second study conducted in the same year called the *San Joaquin Valley Air Quality Study* was able to analyze both surface and upper level flow data to conclude a strong occurrence of transport. By assessing a 2-day period in August of 1984, this analysis revealed that high levels of ozone were horizontally transported southward from the cities of Tracy and Crow's Landing situated in the SFBAAB into the SJVAB. Although the degree of transport could not be statistically quantified, the study was important in raising such concerns (California Air Resources Board Technical Support Division 1996).

A more recent study by the ARB was then conducted in 1996, analyzing data from 1994-1995 from the SFBAAB and SJVAB. The findings revealed 2-4 exceedance days in 1995 where air was transported from the Bay Area down to the SJVAB. However, the morning ozone levels were so high in these days, speculation revolves around the possibility of other sources of contribution to the SJVAB ozone levels. One possibility is the vertical fumigation of ozone from aloft or perhaps the ozone contributors were just anomalously high in the area or areas just upwind. With increased sunlight as the day progresses, more ozone is able to form. This study also used the SARMAP modeling system to further verify their findings. For the period August 3-6, 1990, model results indicated that high ozone concentrations were due to varying combinations of local and transported emissions. The greatest impacts were apparent in the northern portion of the Central Valley, where ozone levels were reduced by one-third when SFBAAB and Sacramento Valley emissions were turned off. Central and southern SJV results from the model indicate that emissions were primarily locally derived (California Air Resources Board Technical Support Division 1996).

5.4 Air Quality in the San Joaquin Valley

Despite the rich soils and scenic landscapes, the Valley is categorized as one of the most highly polluted areas in the country. Interestingly enough, the long and warm summers that make the Valley ideal for agriculture are also a key contributor to the serious smog problem. Air quality in much of California, however, has improved in recent years with smog-producing emissions continuing to decline (California Environmental Protection Agency 1998). In contrast to other California areas, air quality in the SJVAB is not dominated by emissions from one central urban source. Rather, a series of moderately sized urban settings characterize the air quality issues in the SJVAB.

The state of California is under some of the nation's strictest air quality standards, making it difficult to achieve attainment and giving the state its sub-standard air quality rating. California uses numerous monitoring stations throughout the state to determine whether a region's air quality is at or below the State standard. Ratings of attainment, nonattainment, transitional, and unclassified assignments are used to classify each region of the state and help identify areas that need more consideration and planning.

An attainment ranking indicates that the region's emissions are within mandated levels and are considered acceptable to environmental air quality well being. Nonattainment indicates that an area's air quality is in violation of the standard. An unclassified rating indicates that there is insufficient data to categorize the area as either attainment or nonattainment. Transitional means that the area is still in nonattainment, but is near attainment (California Air Resources Board Technical Support Division 1999).

It's important to note that classification of nonattainment in one area is not the same as the same classification in another area. As an example, one area could have a maximum ozone concentration of 0.13 ppm, while another area has a similar nonattainment rating with a maximum concentration of 0.23 ppm. Clearly, the second area has a more serious problem than the first and will likely require stricter control measures (California Air Resources Board Technical Support Division 1999).

Seriously high levels of ozone, particulate matter, and carbon monoxide are the largest contributors to the air quality problem in California (California Air Resources Board Technical Support Division 1999). The SJVAB is currently in violation of both State and federal standards for ozone and particulate matter, not able to currently meet health-based standards set by the United States Environmental Protection Agency (EPA). Because of the potentially harmful affects of high concentrations of air pollutants, the primary purpose of California's air quality programs is to ensure the safety and health of the exposed public (California Air Resources Board 1999). With both health and agriculture risks evident under smoggy conditions, the SJVAPCD was created to improve the air quality and help maintain a safe living environment.

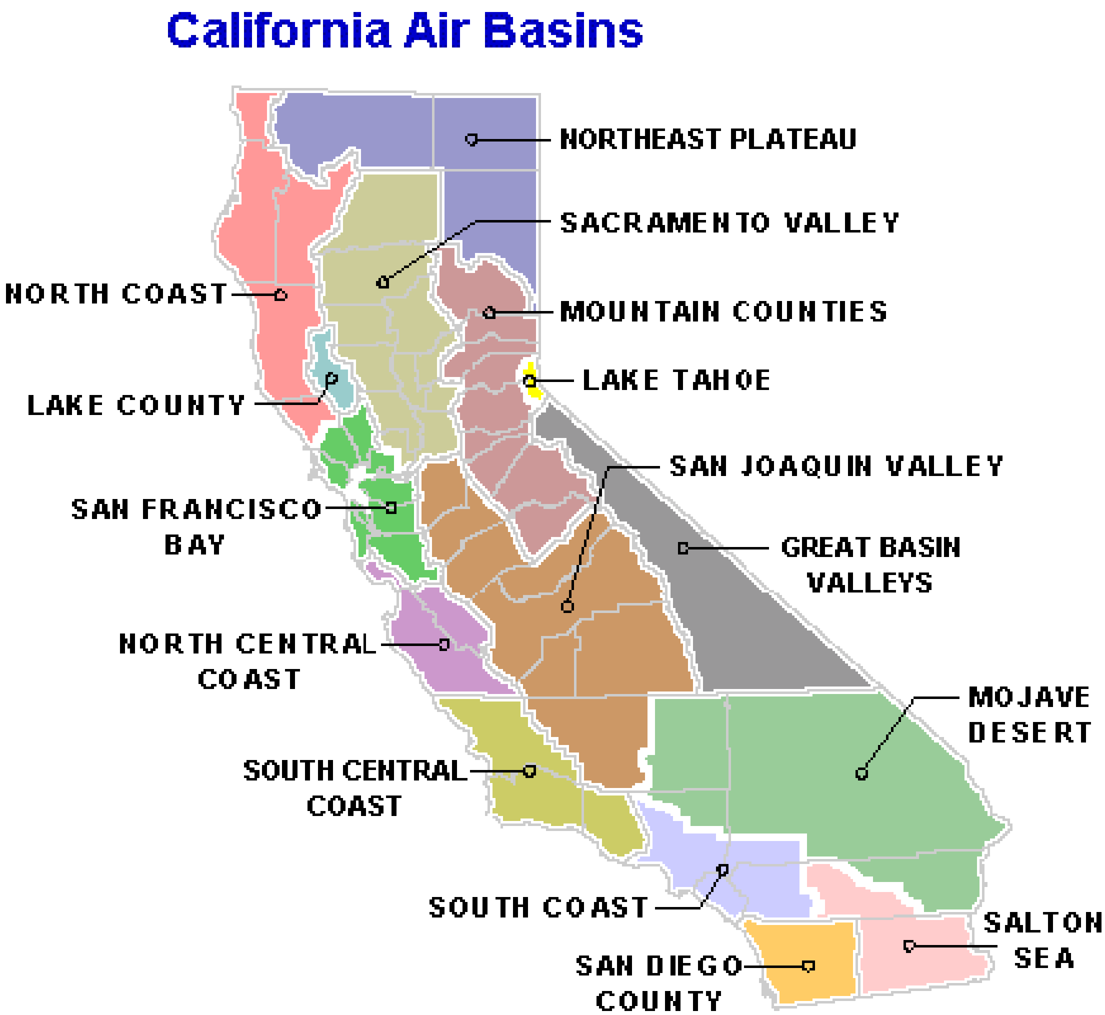
With California's diverse climates, improving the state's air quality is difficult with each region's air quality needs requiring different treatment. To alleviate this, 15 separate air basins were established as seen in Figure 12 to group areas with similar meteorological and geographic conditions with air basin boundaries designated to incorporate both source and receptor areas to the best extent possible. Cases of inter-basin transport are still evident, however (California Air Resources Board Technical Support Division 1999).

Over 250 air quality monitoring stations exist in California as seen in Figure 13. Most are operated by the ARB, but some are from individual air districts, other public agencies, and private contractors. More than ten million measurements are taken each year and stored into a database maintained by the ARB, who routinely calibrates the instruments to ensure its integrity (California Air Resources Board Technical Support Division 1999).

Overall, the emissions levels in the SJVAB have been decreasing since 1985 with the exception of emissions from PM-10. This decrease is largely due to enhanced motor vehicle controls, which are the largest contributors to CO and NOx emissions in the SJV.

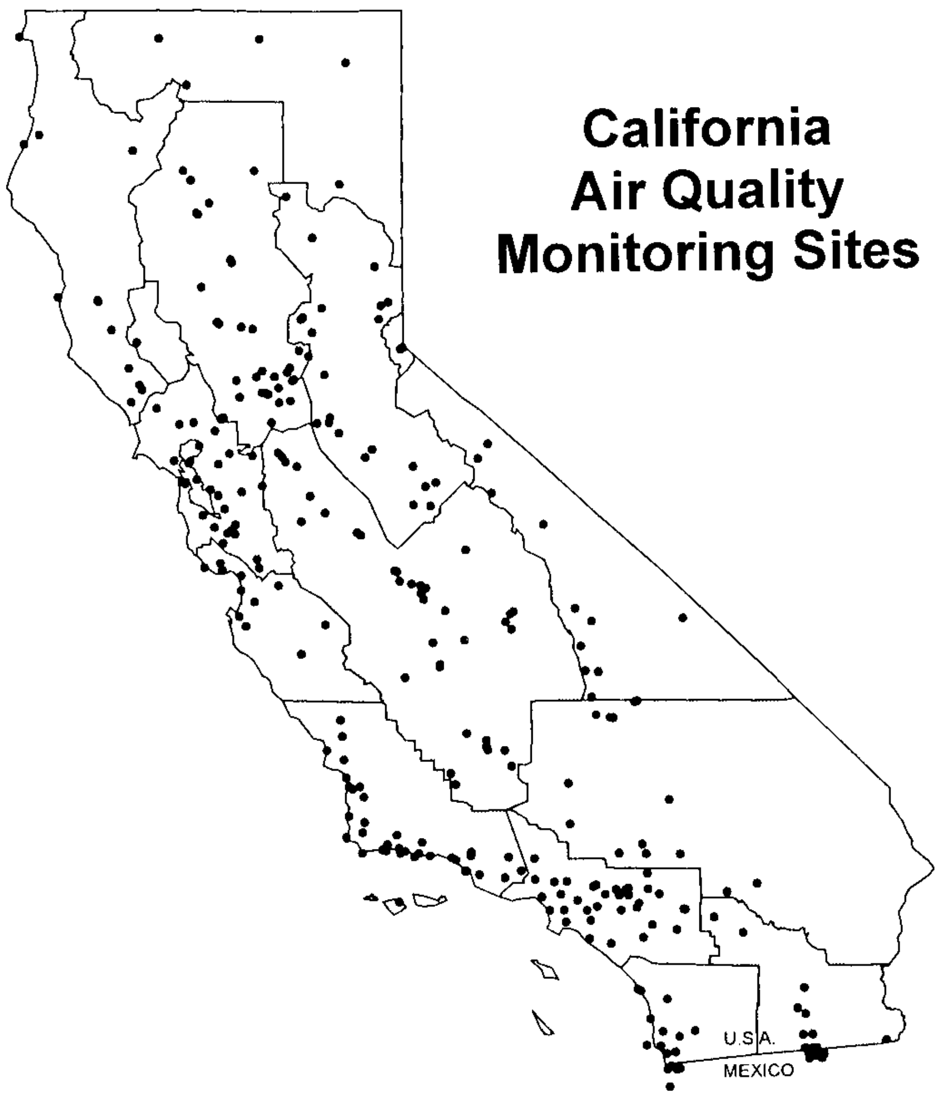
5.4.1 Ozone

Commonly referred to as smog, ground level ozone is a serious concern in the Central Valley. As the chief constituent of smog, ozone is a colorless gas, which possesses a characteristically pungent odor. Unlike other criteria air pollutants, ozone is not directly



source: California ARB website

Figure 12: Air Basin Map of California



source: California ARB website

Figure 13: California Air Quality Monitoring Sites

emitted into the air. Rather, it forms when sunlight reacts with emissions of nitrogen oxides (NOx) and reactive organic gases (ROG), which are volatile organic compounds (VOC) that are photochemically reactive and contribute to the formation of ozone (California Air Resources Board Technical Support Division 1999). Ultraviolet radiation from the sun plays a key role in activating the process of ozone formation. NOx and ROG measurements, therefore, serve as good indicators of ozone levels.

The variability in ozone concentration levels greatly depends on meteorological conditions. Temperature, solar radiation, and minimum surface winds are important factors in determining the likelihood of significant ozone events. The presence of an inversion layer, where temperatures increase with height above the ground, characterizes stable and minimal vertical mixing. Accumulation of ozone is commonly associated with synoptic-scale subsidence of air in the troposphere, which tends to result in the development of strong inversion layers. Minimal surface wind speeds resulting from a weak horizontal pressure gradient around the surface high pressure system, along with clear sky days, and high temperatures are all ideal conditions for smog accumulation (NCEA 1996).

With ozone levels directly linked to ROG and NOx levels, sources of ozone formation are those that emit high levels of ROG and NOx. Nationally, the two largest source categories of VOC emissions are industrial processes and transportation (NCEA 1996). According to a nationwide statistic, VOC's from highway vehicles accounted for almost 75% of transportation-related emissions, with a majority of this percentage originating from only 20% of the automobiles in service. This implies that most of the transportation emissions are a result of older cars that are poorly maintained (NCEA 1996).

Emissions of NOx are largely related to combustion processes. Under high combustion temperatures, NOx is formed from nitrogen and oxygen in the air and from nitrogen in the combustion fuel. Both nationally and in the SJV, the two dominant sources of NOx are electric power generating plants and highway vehicles (California Air Resources Board 1997). Also, making a significant contribution to NOx emissions levels are lightning events and emissions from ground level soil. Nationally, NOx emissions from natural sources contribute about 2.2 Tg of NOx with a U.S. total of 21.4 Tg of NOx in 1991.

In terms of seasonal variability, ozone tends to peak in the late spring and into summer as temperatures warm. However, due to a lengthy reaction time, peak ozone concentrations frequently occur significantly downwind of the source area. With the tendency for concentrations of ozone to develop in urban areas, levels can occur at considerable distances downwind of urban centers (NCEA 1996).

Many areas in the northern and some central portions of California of the state are designated as attainment, with much of the central and southern areas of the State designated as nonattainment (Figure 14). Most of the state is, therefore, in violation of the current state ozone standard. Highly populated urban areas definitely show a strong influence on ozone status. Few areas have made enough changes to transition themselves

source: California ARB website

Figure 14: 1999 California Area Designation for Ozone

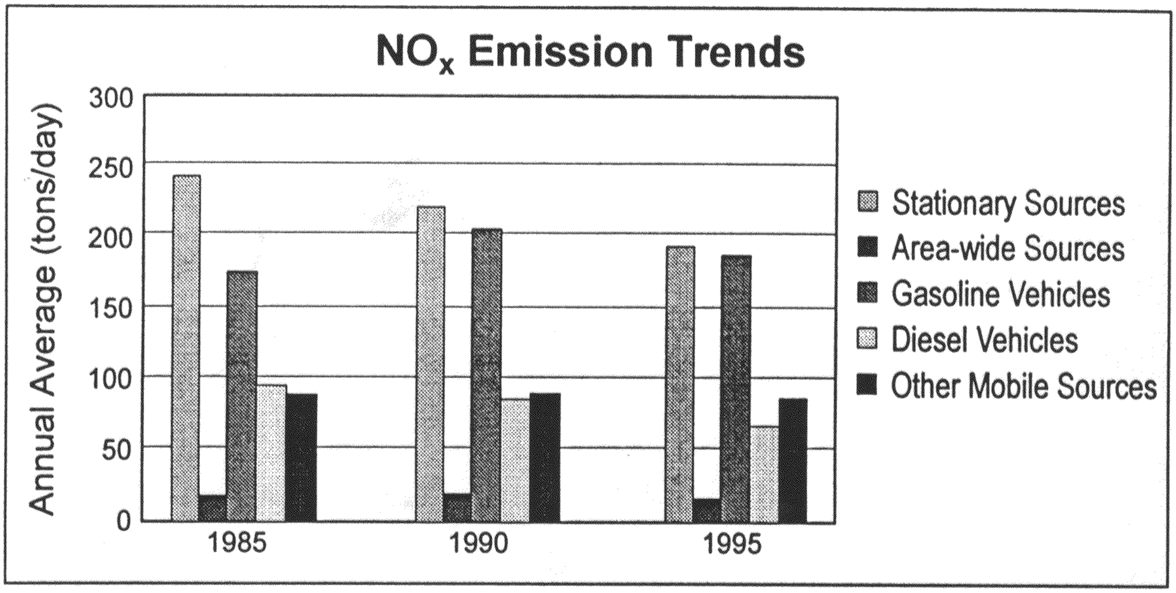
into attainment status despite accelerated efforts to enforce more stringent standards (California Air Resources Board Technical Support Division 1999).

Ozone standards were developed to reflect the fact that concentrations of air pollutants in air temporally vary. Measurements of ozone are based on a daily maximum arithmetic average concentration calculated over a specified time period of either 1-hour or 8-hours. Concentrations are expressed in parts per million (ppm) and are made by a continuous ambient air monitor. One drop of water in a full bathtub is analogous to one ppm (EPA 1997).

For more than twenty years, the standard for ozone was based on 1-hour averages. The nationwide ozone standard was established in 1979 as a 1-hour average of 0.12 ppm, not to be exceeded. The EPA then updated its national standard in 1997 to an 8-hour standard average of 0.08 ppm, not to be exceeded. The previous standard was believed to still pose a risk to public health, so a revised standard based on an 8-hour average was developed for those that spend a significant amount of time outdoors. To attain this standard under federal jurisdiction, the 3-year average of the fourth-highest daily maximum 8-hour average must not exceed 0.08 ppm (EPA 1997). The statewide 1-hour standard for ozone is 0.09 ppm not to be exceeded. Under State regulations, if the ozone level exceeds 0.08 ppm for an averaged period of 8 hours during any given day, an exceedance occurs (California Air Resources Board Technical Support Division 1999).

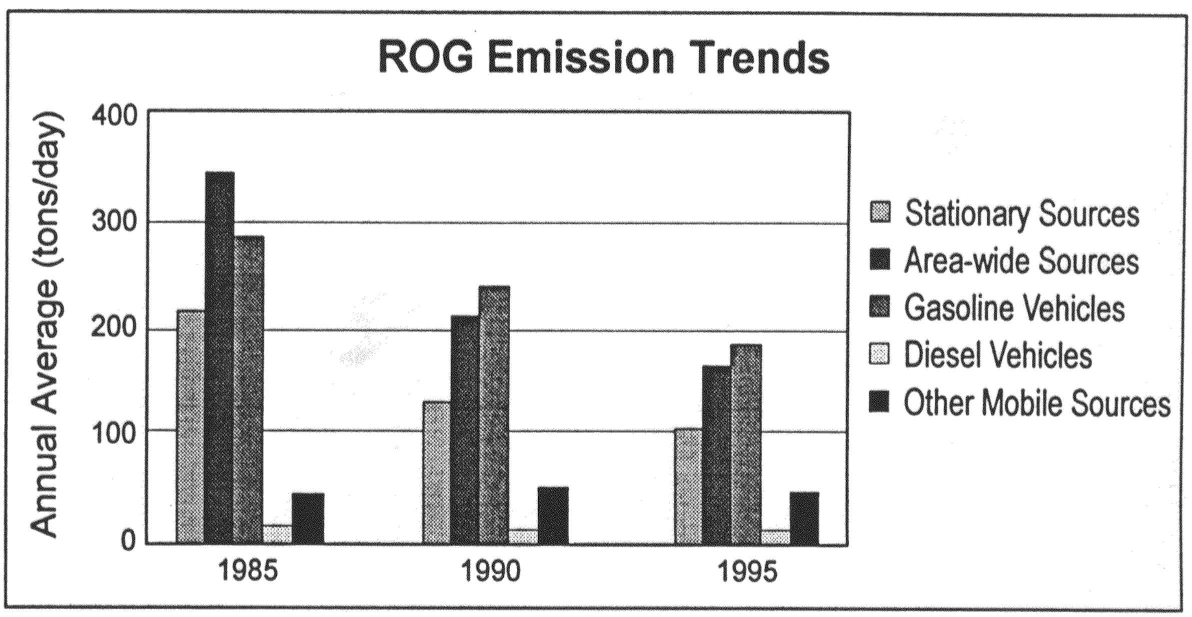
The SJVAB has the second most severe ozone problem in California. The ozone precursors of NOx and ROG, however, have shown a decreasing trend in emissions since 1985 as shown in Figure 15 and Figure 16, respectively. Stationary and area-wide sources of ROG have decreased due to stricter standards lowering emissions from petroleum production operations and solvent use. As well, declining oil prices have reduced oil production and the associated ROG fugitive emissions. Both NOx and ROG emissions have dropped considerably due to recent enforcement of strict motor vehicle standards, despite the increase in vehicle miles traveled through this area.

Since 1980, the 1-hour ozone air quality measure has decreased by approximately 10% as seen in Figure 17. The number of exceedance days from both the federal and State standard have also declined. Under the State standard, the number of days California exceeded the allowable cap decreased from 124 in 1980 to 110 in 1997 as seen in Figure 18. This is just over a 10% reduction in the number of exceedance days under the California State standard. The lowest number of exceedance days occurs under the 1979 federal 1-hour mandate, with the highest number of exceedance days seen with respect to the State 1-hour standard. However, according to the California Air Resources Board, the decreasing trend in ozone air quality status is unimpressive relative to most areas of the State. Reasons for this lack of progress include the SJV’s focus on hydrocarbon controls, rather than both hydrocarbon and NOx measures as well as the physical geographic influences. With the coastal range serving to trap airflow in the SJV, stagnant airflow conditions tend to accumulate higher levels of pollutants and emissions (California Air Resources Board 1999). The rapid population growth in the SJVAB has also



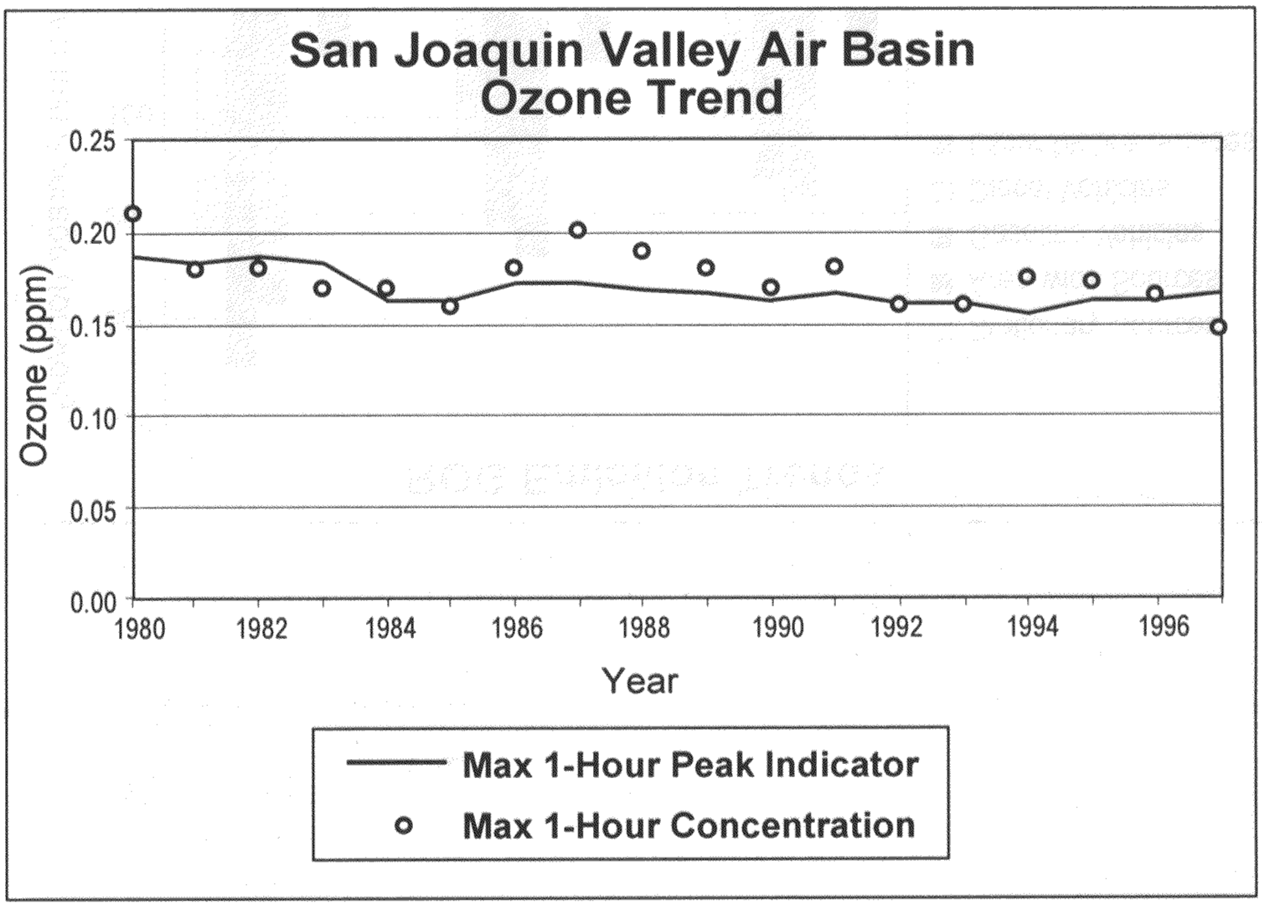
source: California ARB website

Figure 15: NOx Emissions Trends



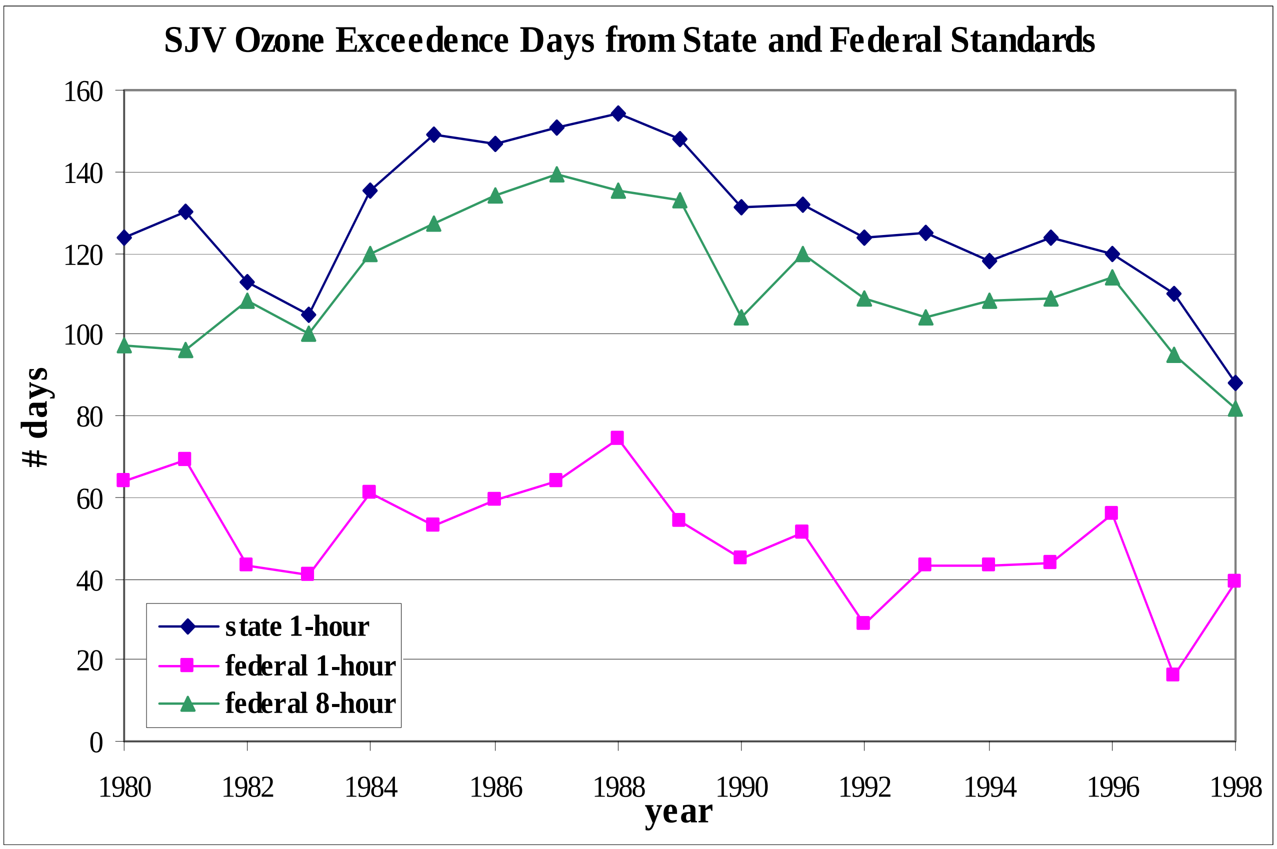
source: California ARB website

Figure 16: ROG Emissions Trends



source: California ARB website

Figure 17: Air Quality Ozone Trend for San Joaquin Valley



source: adapted from California ARB website

Figure 18: Ozone Exceedance Days for the San Joaquin Valley

unfortunately made air quality improvements less notable than the coastal regions (California Air Resources Board Technical Support Division 1999).

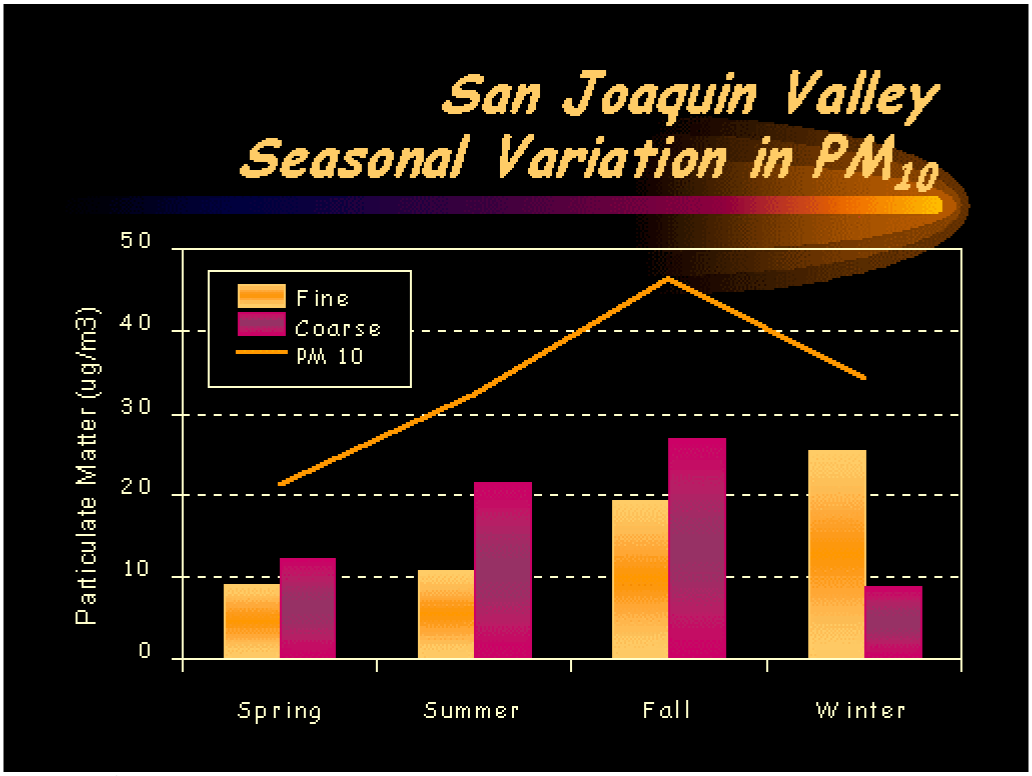
5.4.2 Particulate Matter (PM-10 and PM-2.5)

PM-10 is defined as particulate matter possessing an aerodynamic diameter of 10 μm or less. At most, this amounts to only 10-20% of the diameter of a human strand of hair. This classification of pollutant is comprised of many elements, including carbon, lead, and nickel, compounds such as nitrates, organic compounds, and sulfates, and also diesel exhaust and even soil. PM-10 is seen in either solid or liquid form, consisting primarily of soot, dust, smoke, fumes, or mists. Major sources of PM-10 include motor vehicles, wood-burning stoves and fireplaces, dust from construction, landfills, and agriculture, wind fires, windblown dust, and industrial sources. Measurements of PM-10 are taken over a 24-hour period using an 8-inch by 10-inch quartz fiber filter with a high volume sample and size selective inlet. The sampler operates at 36-44 ft^3 per minute and is collected approximately every sixth day and weighed in micrograms (μm).

The EPA and ARB have adopted air quality standards to control the potential adverse affects from air pollution. These standards establish acceptable levels of pollutants that can reside in the ambient air. Under federal legislation passed by the EPA, the 24-hour PM-10 standard is a maximum concentration of 150 $\mu g/m^3$ with the national annual standard in exceedance when the annual arithmetic mean of all 24-hour concentrations at a site is greater than or equal to 50 $\mu g/m^3$. In July of 1997, the PM-10 24-hour federal standard was updated by changing the form of the standard. The previous exceedance characterization was replaced by the 99^{th} percentile of 24-hour concentrations at each monitoring site within an area averaged over 3 years (California Air Resources Board 1997).

The state PM-10 standard is currently a geometric mean of 50 $\mu m/m^3$ for a 24-hour period with a 30 $\mu m/m^3$ annual geometric mean, neither to be exceeded (California Air Resources Board Technical Support Division 1999). California established a 24-hour as well as an annual standard in order to protect the public from both the harmful short-term affects as well as the long-term impacts from elevated pollutant levels. PM-10 measurements presented in this research is based on data obtained from the California ARB. Concentrations are estimated as the weight of particles in micrograms per one cubic meter of air, or $\mu g/m^3$. Contrary to the State standard concentration, the federal standard is based on both geometric and arithmetic means as opposed to just geometric ones (EPA 1997).

PM-2.5 are a relatively new issue in California, so mention here is limited (California Air Resources Board Technical Support Division 1999). As a more recent addition to the PM family, PM-2.5 represents a smaller-scale classification, identifying those particles less than or equal to 2.5 μm. Because they are finer in nature, PM-2.5 poses a much greater health risk to humans as it can penetrate further into the respiratory system and result in more serious lung problems. The national PM-2.5 standard was enacted in 1997 by the EPA, establishing a cap of 65 $\mu g/m^3$ for a 24-hour period. Figure 19 is provided to



source: California ARB website

Figure 19: San Joaquin Valley Seasonal Variation in PM-10 and PM-2.5

source: California ARB website

Figure 20: State Area Designation for PM-10

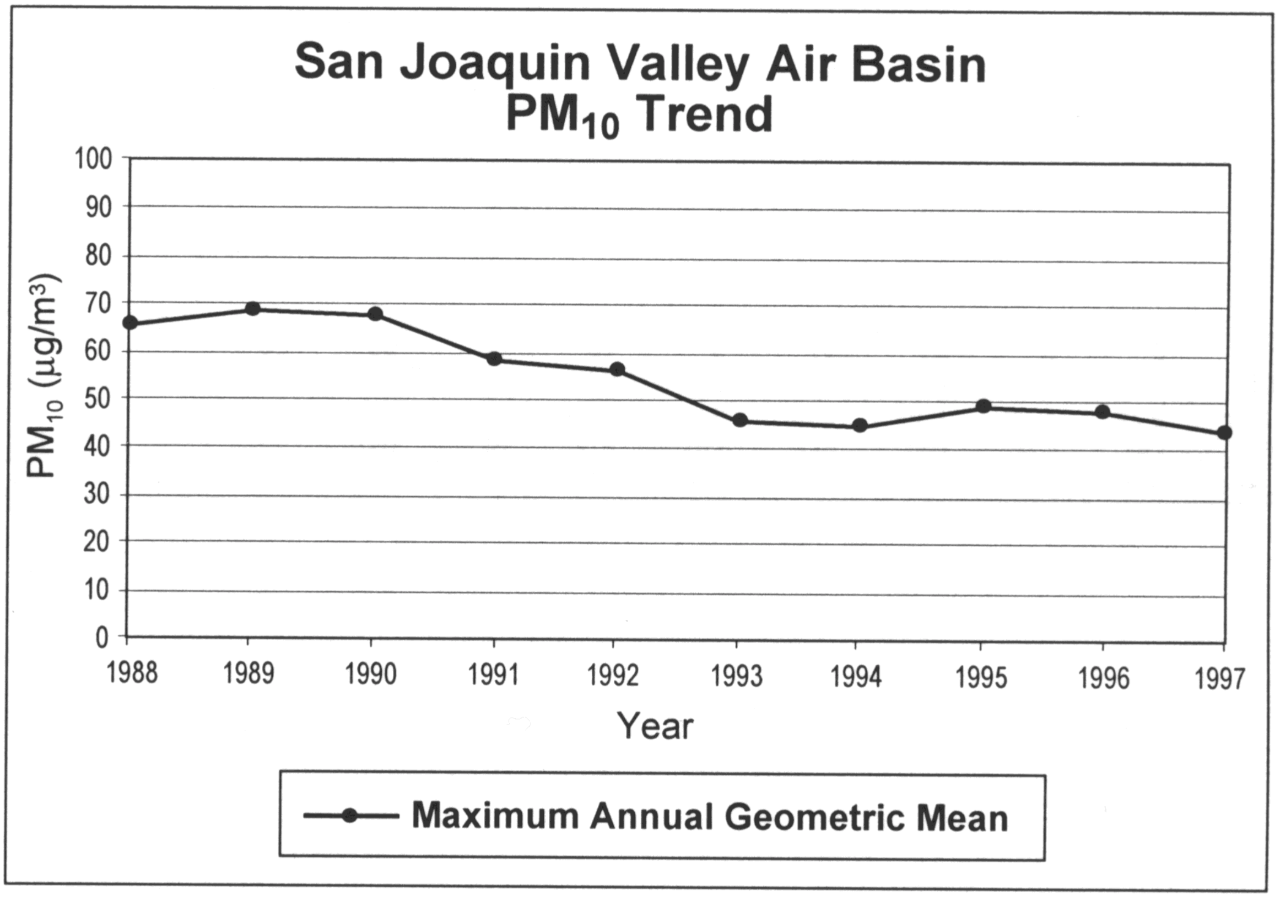
illustrate the seasonal variation in both PM-10 and PM-2.5 (California Air Resources Board 1999). The fine PM-2.5 measurements show a strong peak in the fall and winter, when wood-stoves, motor vehicles, and stationary sources contribute to the rising problem. In contrast, the coarser PM-10 type particles dominate in summer and fall as a result of arid soils that become easily picked up by winds and agricultural activity into the ambient air.

Even worse than ozone designation, PM-10 status in California is virtually all classified as nonattainment (Figure 20). Only one county in the entire state, the Lake County Air Basin, received an attainment status with three counties in northern California unclassified. Because of the diverse causes of PM-10 concentration, problems can vary from one location to another. The composition of PM-10 is highly variable, with differences in the make up of particle size and chemistry. The difficulty in treating PM-10 is therefore in the nature of having to assess each region separately (California Air Resources Board Technical Support Division 1999).

Data of PM-10 air quality levels in the SJVAB indicate that trends have decreased slightly over the past ten years. The maximum annual mean, which is shown in Figure 21, illustrates concentrations have decreased by nearly 35% from 1988 to 1997. A reduction in the number of exceedance days for PM-10 State standards is also evident over this same time period. Shown in Figure 22, the percentage of exceedance days in the SJV has dropped from 71 to 33 over the same 10-year period for the 24-hour State standard. The State exceedances are significantly higher than those based on the federal standard. For example, the SJV experienced only one federal exceedance in 1997. This is due to the more stringent regulations set in California. Emissions of PM-10 (Figure 23), on the other hand, have increased slightly from 1985-1995 despite the decrease in air quality conditions. Although emissions appear to be rising from area-wide sources, the overall quality of the air is showing an improvement in concentration. This trend has been largely associated with fugitive dust sources such as automobile travel as well as agricultural operations. Considering only emissions from motor vehicles, PM-10 levels have decreased between 1985 and 1995. Although ambient PM-10 levels appear to be lowering, ARB warns that it will take a number of years before the SJVAB is able to reach attainment status (California Air Resources Board Technical Support Division 1999).

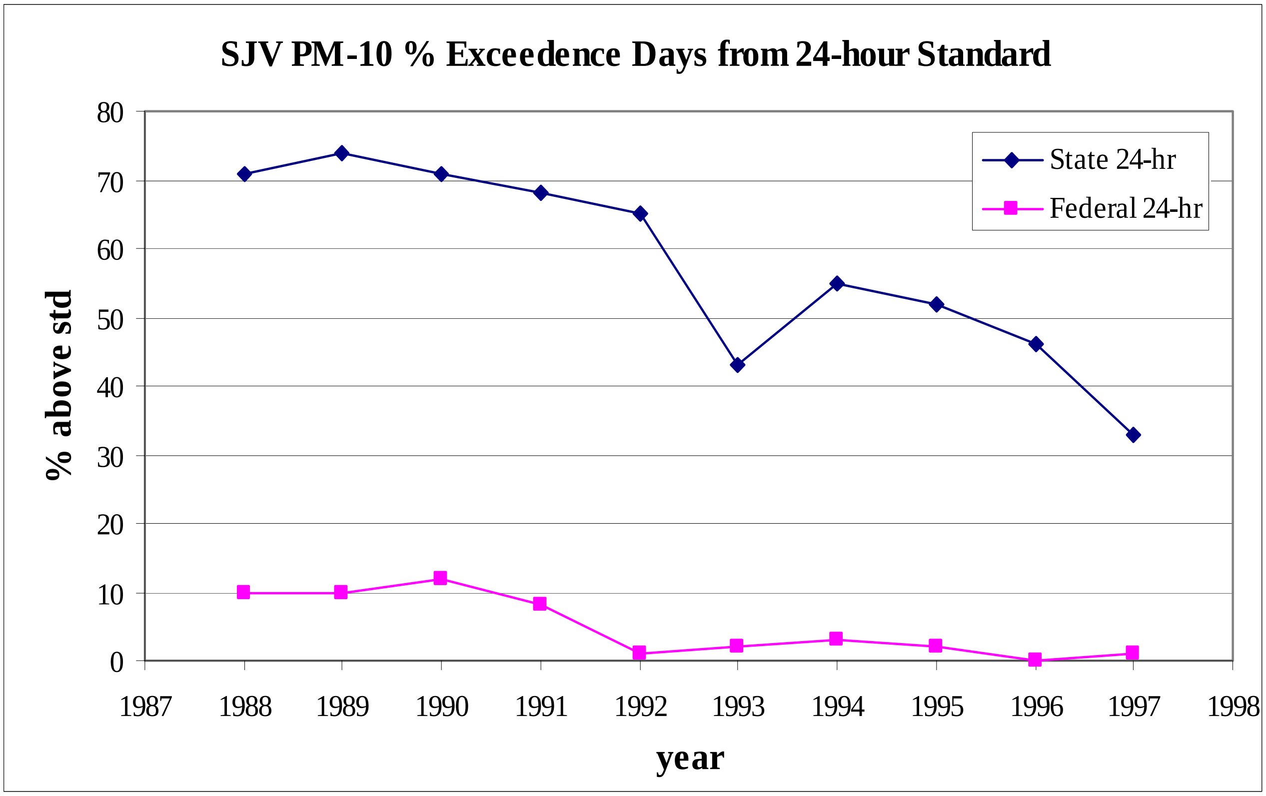
5.4.3 Carbon Monoxide

Carbon monoxide is a colorless and odorless gas whose emission is the result of fuel combustion. It is a byproduct of motor vehicle exhaust, contributing to more than two-thirds of all CO emissions in the nation. In more densely populated cities, automobile exhaust can cause as much as 95% of all CO emissions. Unlike ozone, concentrations of CO tend to peak during cold and stagnant winter events and also tend to be more localized than smog. Currently, the state CO standard is 20 ppm over a 1-hour period with a 9.0 ppm standard over an 8-hour averaged period, not to be exceeded. The cap is stricter in the Lake Tahoe Air Basin with an average cap at 6 ppm over 8 hours because



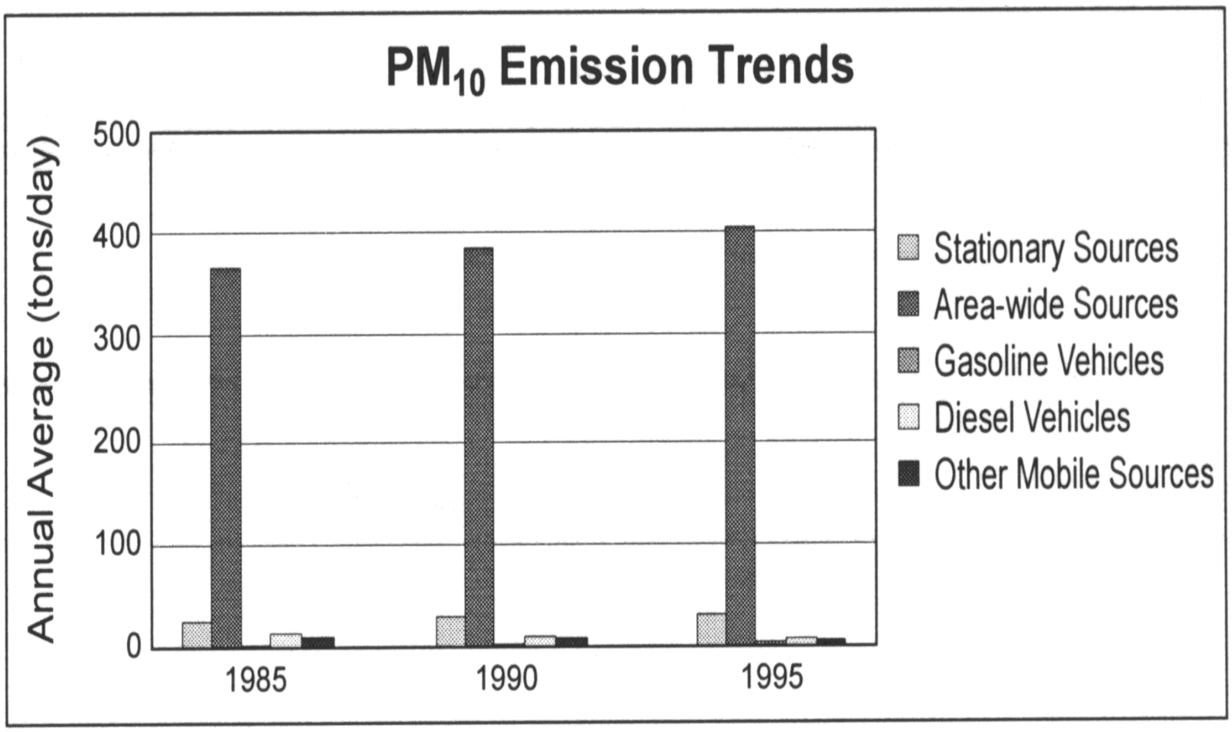
source: California ARB website

Figure 21: San Joaquin Valley Air Basin PM-10 Air Quality Trend



source: adapted from California ARB website

Figure 22: Percentage of Exceedance Days from 24-hour State Standard in SJV



source: California ARB website

Figure 23: Emissions Trends of PM-10

source: California ARB website

Figure 24: 1999 State Designation for Carbon Monoxide

of the increased CO health risk at higher elevations (California Air Resources Board Technical Support Division 1999).

Measurements of CO are represented as concentrations in parts per million (ppm). The State standards refer to maximum measurements taken over a period of either 1 hour or 8 hours, depending on the standard.

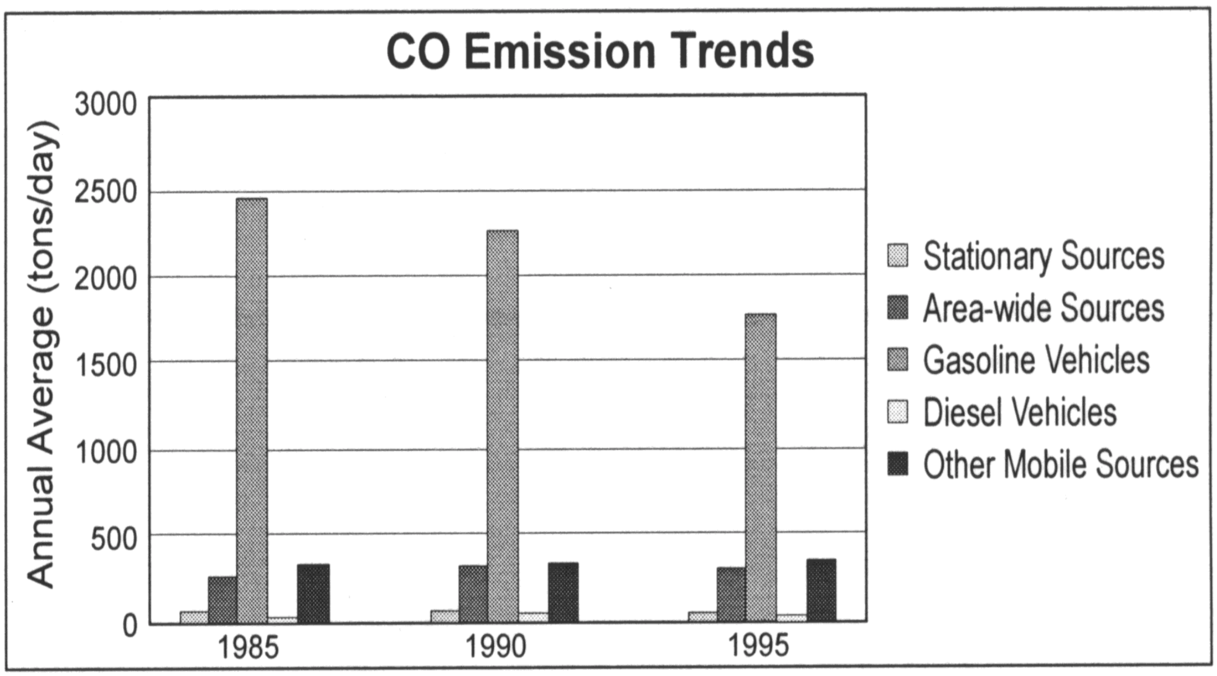
High levels of CO are very toxic and can be life threatening. Characteristically, CO easily penetrates into the lungs and blood, depriving the ability of blood to carry oxygen. Overexposure to CO is especially critical for those with heart- or lung-related difficulties; however, even healthy people have shown signs of headaches, fatigue, and dizziness (California Air Resources Board Technical Support Division 1999).

In California, the designations of CO are considerably less severe than for ozone or PM and according to the ARB, is considered largely a resolved issue. There are currently only two areas of nonattainment as shown in Figure 24, both in the southern portion of California, in Los Angeles County and the city of Calexico in Imperial County. In the past decade, the State has been able to redesignate 13 areas as attainable of CO standards. The significant reduction in CO over the state has been due to strict motor vehicle laws and the transition toward cleaner-burning fuels. Continued improvement in Los Angeles County is promising, with continued reductions in emissions forecasted. In Calexico, the CO levels are higher than allowable due to impacts from Mexico (California Air Resources Board Technical Support Division 1999).

In the SJVAB, CO emissions have decreased since 1985, as shown in Figure 25. Clearly, the major contributor to this emission is motor vehicles. As with the NOx emissions trends, these reductions are largely due to the adoption of more stringent standards from automotive vehicles. CO has also shown signs of decrease since 1980 as in Figure 26. The maximum 8-hour concentration is only about half the value it was in 1980 (California Air Resources Board Technical Support Division 1999).

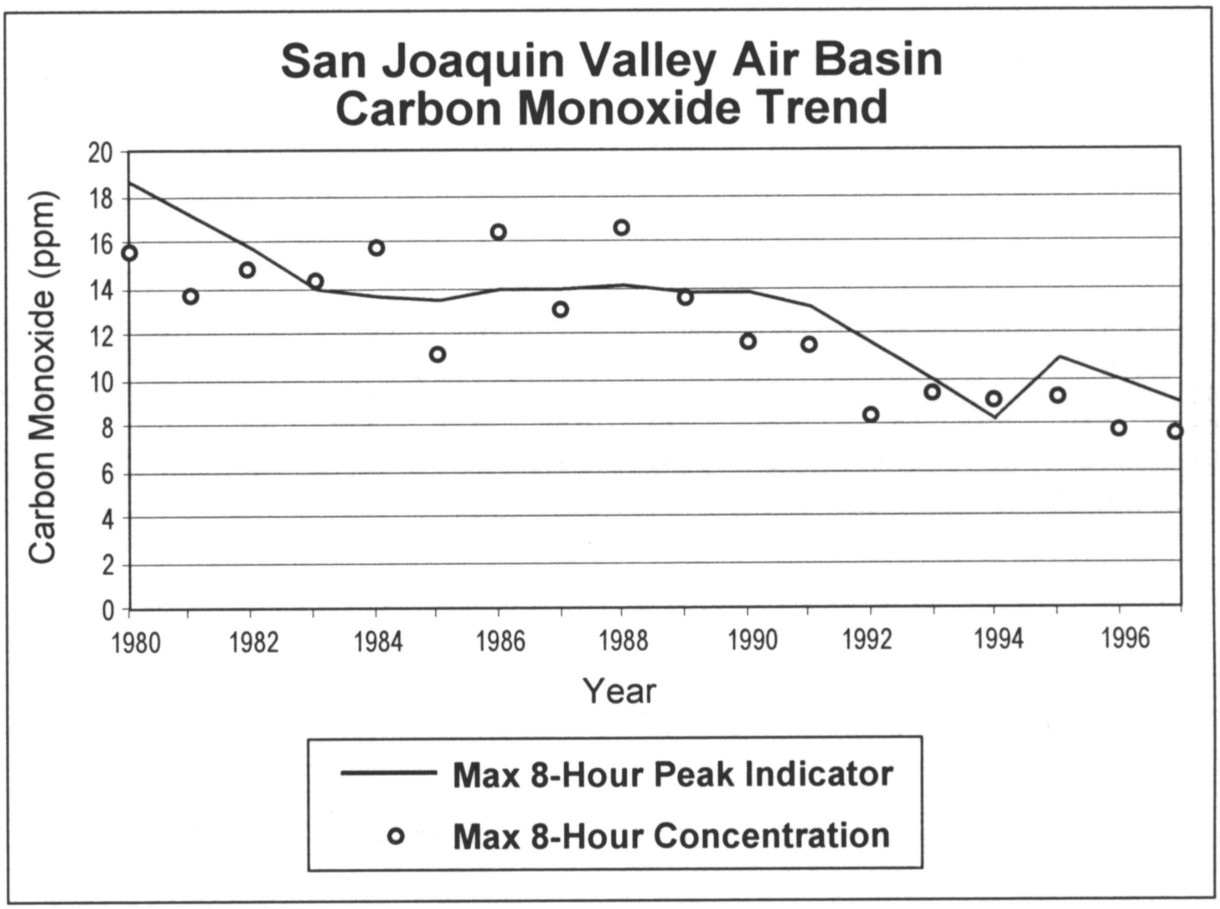
An additional concern that results in CO emissions is related to the hotly debated topic of methyl-tertiary-butyl ether (MTBE) as an additive to oxygenate California Phase II Reformulated Gasoline (CaRFG2). Although the use of CaRFG2 has shown significant improvements in reducing motor vehicle exhaust emissions relative to conventional gasoline, the federal law requiring the gasoline to be oxygenated has created controversy. Implemented to promote a more complete combustion of hydrocarbons and further reduce the amount of air pollutants such as VOC's, NOx, and CO released from motor vehicles, MTBE is currently under a lot of scrutiny regarding the potential environmental and human health hazards it poses. In 1998, over 90% of California gasoline contained 11% by volume MTBE, amounting to approximately 100,000 barrels of MTBE per day (Koshland, et al. 1999).

One major concern is groundwater contamination from leaking underground storage tanks and pipelines. Continued use of MTBE threatens the quality of water resources, especially groundwater basins, with a heightened severity of water shortages during



source: California ARB website

Figure 25: CO Emissions Trends



source: California ARB website

Figure 26: Carbon Monoxide Air Quality Trend for San Joaquin Valley

drought years. At high enough concentrations, MTBE can also threaten aquatic life. Current concentrations of MTBE found in California's surface waters, however, do not pose a toxic threat to aquatic organisms yet, but increased concentrations with continued use of MTBE is sure to threaten the lives of the aquatic ecosystem (Werner and Hinton 1999). Studies have also linked the presence of MTBE to occurrences of headaches, dizziness, nausea, and even increased potential of developing cancer in both animals and humans. The combustion of MTBE is also speculated to be related to an increase in asthma related problems, although no studies have currently addressed this issue (Keller, et al. 1999).

In a recent UC report on the health and environmental effects of MTBE, results indicated that no significant effects in exhaust emissions between the oxygenated and non-oxygenated CaRFG2 were apparent. This implies that there is no statistically significant air quality benefit in using MTBE in reformulated gasoline relative to alternative CaRFG2 non-oxygenated formulas (Keller, et al. 1999). These, along with numerous other studies led to Governor Gray Davis' order to gradually eliminate the use of MTBE in California gasoline. On March 25, 1999 Governor Davis declared that MTBE poses an environmental risk to California, demanding that MTBE use in California be discontinued by December 31, 2002.

5.4.4 Rules and Regulations

The SJVAPCD is responsible for a number of emission and pollutant standards from both state and federal legislation. The federal government, through the EPA, sets standards and oversees state and local behavior, enforcing programs to reduce motor vehicle emissions, fuels, and smog checks.

The SJVAPCD is responsible for developing and implementing local control measures that primarily concern stationary sources such as factories and plants. Regulations for generator sources focus mainly on larger scale operations with heat rates greater than 5 MBtu/hr and emitting more than 25 tons/yr of NOx or ROG. A 25-30 kW MT only runs at approximately 13,000 Btu/hr with an emissions rate of 0.065 tons/yr, far lower than the threshold of regulation adherence.

The prospect of regulating distributed generation technologies raises an added complication to implementing DER. The regulatory agencies that control emissions within each air district are concerned with improving air quality by lowering emissions within their own region. Displacing larger generators from the grid and replacing them with microturbines locally to the area of required power will influence the air quality, possibly in that jurisdiction. This could deter agencies from supporting DER because the potential increased emissions resulting from a nearby DER source are important to the district, while reduced emissions outside it are not. This makes assessing the environmental impacts from DER crucial in determining how likely customers will be allowed to adopt DER under local regulations.

Aside from regulating large-scale stationary sources, the SJVAPCD is also active in public education as well as other programs like the District's *Spare the Air*, *Please Don't Light Tonight*, and *Smoking Vehicle* voluntary programs. *Spare the Air* is a voluntary effort to notify local residents to try and reduce air pollution levels, primarily ground-level ozone, during the summertime when conditions are most serious. The *Please Don't Light Tonight* program is a complementary wintertime effort to reduce air pollution by asking volunteers to refrain from wood-burning fires during poor air quality nights. To help reduce visible exhaust from motor vehicles traveling in the area, the *Smoking Vehicle* program was developed to motivate drivers to report vehicles emitting significant amounts of exhaust smoke to the SJVAPCD.

5.4.5 Agricultural Burning

Agricultural burning is another potential air pollution contributor. This type of burning is defined as any open outdoor fire composed of material solely produced from agricultural operations. California permits commercial agricultural operations to burn specific types of crop debris in an effort to eliminate waste and minimize the threat of pests. This activity, however, is regulated in the SJV to protect public health by scheduling agricultural burn days when air quality is sufficient to adequately disperse the smoke. The SJVAPCD issues permits, which allow farmers to burn only on specified burn days (SJVAPCD 2000).

As a threat to air quality, the combustion processes that take place during agricultural burning result in the formation of PM. Smoke from these fires can potentially result in short-term (several hours) elevated PM levels, from both PM-10 and PM-2.5. For the most part, however, the impacts from agricultural burns are short-lived, lasting only a few hours. This prevents such burnings from contributing to the violation of 24-hour PM standards. The important impacts on public health and safety are still a concern during these events. The California EPA is currently in the process of revising the agricultural burn guidelines to further minimize the threats to public health and promoting the possibility of alternative methods for disposing of agricultural waste.

5.4.6 Health Concerns

Over-exposure to high levels of ozone can result in shortness of breath and related respiratory problems, including aggravated asthma symptoms, chest pain, coughing, and even the potential for chronic lung damage. Enhanced levels of particulate matter can bring on asthma attacks and bronchitis, even posing the risk of premature death in people with cardiac or respiratory disease. High levels of carbon monoxide exposure are believed to effect the central and nervous system, depriving the body of oxygen and potentially contributing to cardiovascular disease (California Air Resources Board 1999).

In addition to health concerns, increased smog is also known to harm agricultural harvests. The presence of smog is also believed to contribute to crop damage in the Central Valley. According to research studies, the smoggy conditions characteristic of the Central Valley can result in lower crop yields, slower growth rates, and deformities in tissue growth. Ozone is believed to be the biggest concern for SJV growers, as citrus fruits, tomatoes, cotton, potatoes, beans, and lettuce have all shown signs of stunted growth under high ozone conditions (California Air Resources Board 1999).

5.5 Noise Pollution

In California, noise pollution is primarily an issue in situations involving road or highway construction, building construction or renovation, airplane noise, and vehicle noise in heavily traveled areas.

Sound is a physical disturbance of mechanical energy in the air, produced by a vibrating or moving source transmitted by pressure waves through a medium (like air) to human ears. In order for sound to exist there must be an identifiable sound source, path for the sound to travel through, and a receiver or hearing sensor to detect it. The common unit of measuring sound is the decibel (dB), a unit of sound pressure level. The sound pressure level is the ratio of actual logarithmic sound pressure to reference pressure level squared. Sound is composed of various frequencies, some of which can be heard by the human ear in the range from 20 Hz to 20,000 Hz. Sound level is dependent on the distance from the source; noise increases the closer one gets to the source. Since zero dB is defined as an extreme value that only a select few with highly sensitive ears can detect, it is possible to refer to negative dB values (CalTrans 1998).

For this reason, a weighting system of measuring sound was developed to adjust measured sounds by a sound level meter. The most common scale, known as the A-weighting, estimates the frequency response of the average young ear when listening to most ordinary sounds. The scale was developed by averaging the statistics of many psycho-acoustic tests involving large groups of people with normal hearing of ages ranging from 18-35 years old. This scale is the standard measure for traffic noise and is the preferred scale for environmental noise studies (CalTrans 1998). Use of this weighting is noted by dBA.

Noise is defined as a sound that is loud, unpleasant, unexpected or undesired. The perception of sound and noise, therefore, are highly subjective. Noise levels approaching 140 dBA are nearing the threshold of human pain, with higher levels raising the potential for physical damage (CalTrans 1998). Typical noise levels include 50 dBA for quiet urban daytime, 25 dBA for a quiet rural nighttime, with 60 dBA for heavy traffic at a distance of 90 m, and close to 100 dBA for a gas lawn mover at 1m.

The Noise Pollution Clearinghouse, a non-profit organization with extensive online resources on noise, provides information on background literature, latest issues, and current federal and state regulations. Some states with regulations on noise levels from industrial type operations include Oregon, Hawaii, Delaware, and Maryland. In Oregon, the maximum allowable noise level for industrial sources is 60 dBA. Hawaii, Minnesota, and Maryland all have a maximum permissible sound level of 70 dBA for industrial-type purposes with New and Jersey and Delaware capped at 65 dBA.

In California, the Traffic Noise Analysis Protocol contains both federal and State regulations that restrict the amount of noise from highways, heavily traveled roads, and construction. The National Environmental Policy Act requires that impacts and measures to mitigate adverse noise impacts be taken. The Federal Highway Administration Regulations constitute the Federal Noise Standard. It states that noise abatement measures must be taken when noise levels for highway construction approach or exceed the Noise Abatement Criteria (NAC). The NAC for residences, motels, hotels, schools, churches, hospitals, and libraries is a maximum interior noise level of 52 dBA. For comparable exterior situations the NAC is 67 dBA. For quiet lands whose serenity and low noise level are essential for the area's purpose, the NAC level is 57 dBA (CalTrans 1998).

Under the California Environmental Quality Act (CEQA), a substantial increase in noise could potentially result in a significant adverse environmental effect, resulting in the need for mitigation or control measures. The state currently has in place a *Streets and Highways Code, Section 216*, which states that if during freeway construction noise level exceeds 52 dBA, noise abatement tactics are required to reduce noise in elementary or secondary public or private schools (CalTrans 1998). Without the presence of schools nearby, freeway construction noise should not exceed 86 dBA at a distance of 15 m (CalTrans 1998). Permits are required for airport noise standards, which are based on human perception of acceptable noise levels in the vicinity of the airport.

One advantage to installing a microturbine versus other types of generating technologies is the fact that most microturbines are low to moderate in noise level. Under consideration of a 25-30 kW microturbine installation in the southern SJV, an approximate noise level of 65 dBA at 10 m is used to estimate the impact such an installation would result. As a rough estimator, noise level increases/decreases by approximately 6 dBA for each halving/doubling of distance away from the sound source. This means that a properly functioning microturbine can be theoretically heard up to a distance of over 10 km. More realistically, however, this noise level is heard at a far lower distance under outdoor ambient conditions. Under this approximate rule of thumb, sound levels are about 53 dBA 40 m away from the source and only 35 dBA 320 m away. This 35 dBA is almost comparable to the noise level in a quiet nighttime rural location, virtually unnoticeable for outdoor conditions. Thus, the low-noise engineering characteristic of a microturbine does not pose a threat to noise regulations in the SJV.

5.6 Estimating Environmental Impacts from Microturbine Installation

Some rough estimates are presented here to provide the impacts from emissions that installation of a small microturbine could cause. As representative of the installed microturbine, calculations are based on the characteristics from a 28 kW maximum output Capstone Gas Microturbine. With the serious air quality issues facing the Central Valley, there is a clear concern about how an installed microturbine will affect environmental emissions. Some simple calculations are provided as a coarse indication of the expected impacts this area should experience as a result of a newly installed microturbine.

Emissions from NOx are estimated to be approximately 6.7 g/hr or 58.7 kg/yr if the generator is running year round and at full capacity, according to the technical specifications from a Capstone microturbine. This corresponds to a concentration of less than 9 ppmv. In general, this magnitude of emissions is significantly lower than most generating operations and as stated before, far lower than the regulated level of 22,680 kg/yr (or 25 tons/yr) for large-scale generating units.

Next, an effort is made to try and estimate how the magnitude of these microturbine NOx emissions relates to current vehicle emissions. Emissions from mobile on-road vehicles were obtained from the California ARB's *On-Road Motor Vehicle Emission Inventory Model*. A predicted on-road motor vehicle emissions rate for the year 2000 is 1,366,538 kg/day (or 1506.35 tons/day) from NOx and 7,554,563 kg/day (or 8327.48 tons/day) for CO. Using these forecasted emissions rates and a population estimate from the same model of 26,277,613 vehicles in California for the year 2000 provides the resources needed to estimate the amount of emissions from a microturbine in terms of pollutant-emitting cars on the road. From this information, the annual NOx emissions from an installed 28 kW Capstone microturbine running at full capacity and throughout the year is comparable to just over 3 cars in the state of California in 2000. This is the result of generating a maximum 245 MWh in one year.

The amount of CO emitted from a microturbine is very low and considered to be equivalent to only a fraction of one car's average emissions for one year.

So both NOx and CO emissions from a microturbine are relatively small contributions to the overall state of emissions in California. With less than 60 kg/yr of NOx and just over 100 kg/yr of CO, these levels only amount to 3 NOx-emitting cars less than 1 CO-emitting car in California.

5.7 Conclusion

Numerous environmental issues need to be addressed when considering the possible impacts that could result from a 25-30 kW microturbine installation. Especially in the SJV, where air quality is such a crucial issue, analysis of pollutants like ozone, PM-10, and CO is necessary to avoid further endangerment of an already unstable environment. Despite aggressive efforts to reduce ozone concentrations in California, levels of the harmful contributor to smog still remain unhealthy in the SJV and other portions of the State. Under stricter standards, the SJV has reduced its ozone levels significantly, particularly from stationary sources and motor vehicles over the past 20 years. PM-10 remains the biggest challenge in California and the SJV, with almost the entire state designated as unattainment. PM-10 air quality has improved slightly and the number of exceedance days have fallen by over 50% from 1988 to 1997, however, emissions in the SJV have increased somewhat over the same period. The State fortunately appears to have conquered the problem of CO with enforcement of strict motor vehicle standards, the primary source of hazardous CO accumulations.

Based on this assessment of the southern SJV, impacts from installation of a 25-30 kW microturbine are far below any regulated standards. With predicted NOx emissions amounting to only 3 emitting cars over the course of one year and CO equivalent to less than 1 car, the levels of emissions from a microturbine in the southern SJV will not significantly influence the air quality status. Despite the serious environmental air quality concerns facing this area, installation of a microturbine will not produce emissions large enough to affect the status of air quality in the area. The low emissions levels and noise operation levels make use of microturbines in DER operations environmentally favorable to the southern SJV.

In order for these smaller scale technologies to become attractive for adoption, environmental issues need to be addressed. Some DER technologies are more environmentally benign than others. Environmental regulations need to be created. With local air pollution control districts focused primarily on the air quality conditions within their jurisdiction, adoption of DER to more localized neighborhoods could result in a conflict of interest. Emissions that result from implementing a cleaner DER technology reduce emissions at the central station. However, increased emissions from a new source that was previously outside the monitoring zone could result in opposition to implementation. Although overall emissions as a result of the DER installation would be reduced, this shift in emissions' source could complicate its adoption. Also, the effects of smog are local or regional, so the total human exposure could be worse with DER in place, even if total emissions are lowered.

With the increased interest in distributed generation resources, the current regulatory status for DER deployment is changing quickly and the need to address the environmental issues is becoming more critical in establishing a context of a controlled DER environment. With this deliverable helping to identify the various potential barriers to DER deployment, assessments of environmental influences will have a profound affect on DER installation.

6. Integrating Geographic Analysis and Site Selection

The previous chapters have dealt with some key factors relevant to the siting of DER, covering the technical, economic, regulatory and environmental considerations for implementation. Each of these factors can form a potential barrier to deployment and so must be integrated into a comprehensive evaluation of possible DER projects and their implications. While these issues affecting deployment can be discussed generally for DER options, the specifics vary greatly depending on the actual location of the installation. Ideally, an optimal technology choice and siting, considering each of the variables discussed in the preceding chapters, would be the most cost-effective, environmentally benign solution for ensuring an adequate and reliable power system. In practice, this solution is difficult to arrive upon without explicitly incorporating geography into the equation. Geographic information systems (GIS) offer a method by which to integrate these factors and visualize potential DER options. As discussed in the next section, local issues will become critically important for DER deployment. Relevant noise and air quality regulations, cost of fuel delivery, impact on the grid, and even the technology chosen are all influenced by the physical location of the sites under selection. The power of GIS is that large quantities of this type of spatial information can be stored and processed efficiently, allowing local constraints to DER deployment to be considered at high levels of detail. This chapter offers examples of how these systems can be used for this purpose.

6.1 Overview of Geographic Information Systems (GIS)

GIS are spatially integrated databases that can link disparate data sources and enable planners to leverage local resources based on their geographic relationship. Through GIS, it is possible to store and analyze information from various sources related to the local deployment of DER, such as technical, regulatory, environmental, economic and demographic factors. For example, maps of distribution networks, zoning laws, emissions targets, customer demand, and housing developments can be overlayed within the GIS environment. This information can then be queried so that, beyond just functioning as a central repository, GIS serve as a powerful, analytical tool to enable more informed decision-making. Geographic analysis can be applied to all phases of the planning process, from the initial decision to elect DER, to selecting the appropriate technology, complying with relevant regulation and determining the optimal size and location for DER.

In this chapter, the relevance of local issues to reliability in the electricity sector and the role of GIS in selecting the most appropriate, cost-effective generation option for both customers and discos is described. Examples are provided of current applications of GIS that illustrate its potential as a siting tool for DER.

6.2 A New Focus on Local Issues

As alternatives to centralized generation and disco-supplied electricity proliferate that are typically of smaller scale (less than 1 MW) and more tailored to specific conditions, local issues will become increasingly important for power system expansion. For these applications, GIS can not only significantly reduce the time spent analyzing data as compared to conventional methods, but the geographic component enables spatial analysis not practical with attribute databases alone.

Increasingly, discos are moving toward enterprise-wide geographical information system (GIS) solutions for managing their operations and systems data (Black 1997, Lewis 1997). According to surveys conducted by Environmental Systems Research Institute (ESRI 1998), utilities indicate that 80 percent of their work requires knowledge of the physical location of customers and equipment. With deregulation, this relationship will become even more important. These efforts, however, are heavily weighted towards static automated mapping/facilities management (AM/FM) applications, such as outage management and tree-trimming programs, and towards the use of GIS as a convenient data repository. While these concerns are important contributors to reliability problems, and GIS can assist in reducing operational costs and improving customer service, these applications do not leverage the full analytical power of GIS.

An initial assessment of GIS analysis activities at some of the main discos in California was made in the summer of 1999. The level of sophistication of the GIS systems at the individual companies and municipalities was found to be quite varied, with most of the larger entities (500,000 or more customers served) currently using or in the process of developing a comprehensive AM/FM application. All of the operators also conducted some sort of powerflow analysis for capacity planning. In no instances, however, was it found that the distribution planning software was being integrated with the GIS system, although several entities were in the process of implementing such capabilities. A wide variety of both GIS and powerflow software packages were found to be used. For GIS, the software included Intergraph, SmallWorld, ESRI, as well as some systems developed in-house. For powerflow analysis, PragmaLine, PowerOn, WindMil, PSS/U and SynerGee were among the software applications currently being used or to which systems were being converted. Site selection for DER technologies was not indicated to be an application of their GIS.

In the next sections, the potential of GIS as a site selection tool for both customers and discos that can improve the economics, reliability, capacity expansion, loss minimization, emissions compliance, land acquisition and other factors relating to DER siting decisions is explored. These functions have not yet been fully developed in most applications but the data conversion process for AM/FM and municipal resource mapping has already, in many cases, created geoprocessed data ideally suited for deriving optimal DER deployment scenarios. The first step in this process is to identify areas potentially suitable for DER deployment. This short list of potential sites can then be more rigorously analyzed to optimize the factors relevant to individual requirements and rank the potential sites according to their suitability.

In addition to assisting customers and discos in their site identification and selection optimization, GIS can also be used as a market assessment tool to forecast the potential penetration of DER on a regional or national level. The last section in this chapter provides examples of assessments conducted with GIS for other energy-related markets.

6.3 Potential Site Identification

Site selection for DER, whether by a customer or a disco, involves the consideration of a host of economic, technical and regulatory factors. While traditionally treated as separate issues, the reality is that these factors are integrally related. What might be an optimal site for a microturbine in terms of its proximity to a natural gas line under the appropriate compression, may be the least favorable spot to site a small generator according to zoning laws. A basic factor that relates all of these issues is the physical location of the site. GIS can be used to help visualize these factors and determine potential areas for deployment, as well as eliminate areas that are not suitable for one reason or another. Figure 27 shows a GIS-generated map of a neighborhood in California with electric service territories, natural gas and electric transmission lines, substations, and urban boundaries delineated. Such maps can be customized to illustrate any features relevant to DER siting.

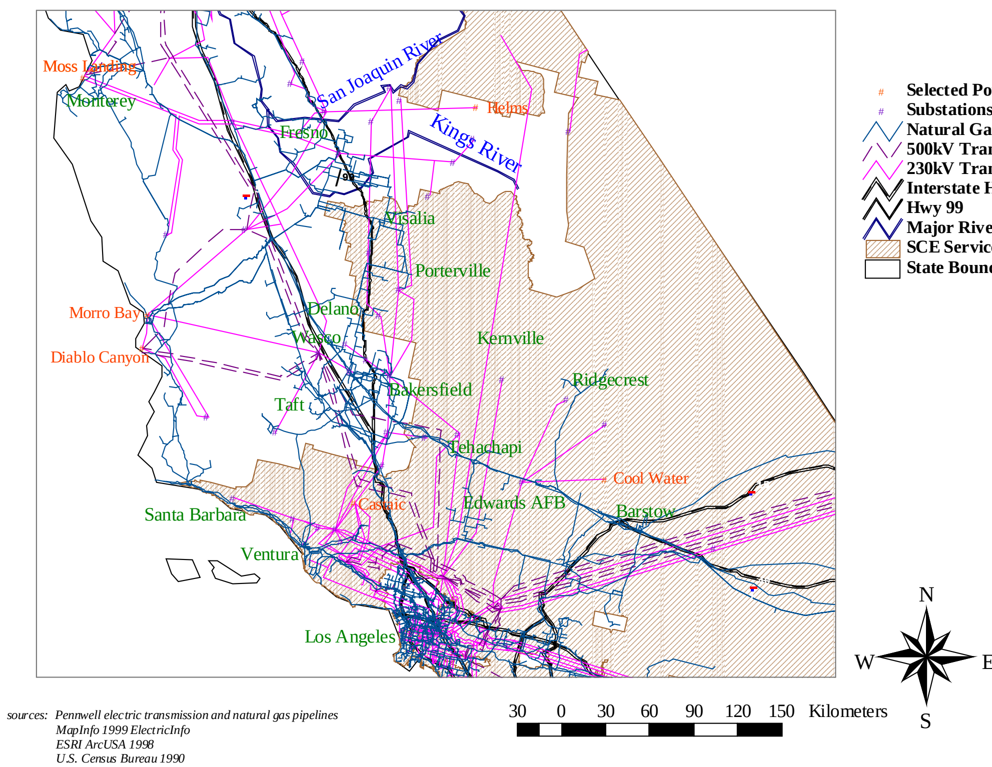


Figure 27: Electric and Gas Transmission Lines in a Sample California Neighborhood. Electric Transmission Lines 230 kV and Greater are Shown.

GIS is used as a common site selection tool in many fields, but it has only recently been to be adopted by the electric supply industry. Currently, the focus of GIS for electric utilities is on AM/FM applications. AM/FM takes advantage of the more traditional capabilities of GIS as a data repository. It serves as an enterprise-wise forum for editing, maintaining, modeling and managing utility information. In this function, information on the distribution network and customer base is combined with maps of road networks, real estate and topography to improve operations and maintenance, emergency response and customer service.

Taking these already compiled files and applying them to GIS siting analysis is especially relevant for electric generation planning. By its nature, electricity is especially tied to geography in several respects. Both the cost and complexity of a system increases with the distance between the load served and generation. In addition, what happens at one site has direct implications to those connected downstream. GIS offers both modularity and integration of this geographical relationship when selecting potential sites, from large-scale, centralized power plants to the more decentralized, renewable projects, as illustrated in the following examples.

6.3.1 Power Plant Research Program

In Maryland, Versar's Power Plant Research Program (PPRP) "Smart Siting" project has compiled statewide data in GIS format to highlight potential regional areas for development (Brown 1998). The PPRP was established under the Power Plant Siting and Research Act of 1971, which has subsequently served as a model adopted by several other states for addressing power plant licensing issues. Funding for the program is provided through an environmental surcharge on all electricity used in the state, which adds between 10¢ and 20¢ per month to the average residential customer's electric bill.

The PPRP strives to meet the State's electricity demands at reasonable costs while protecting the region's natural resources. In keeping with that goal, it provides a continuing program for evaluating electric generation issues and recommending responsible, long-term solutions. An integral part of this program is the geographic database that has been assembled by Versar. The need for the Smart Siting project is underscored by competition in the electric industry, which expected to augment demand for dispersed "greenfield" sites around the state (Versar 1998).

Thus far, the PPRP does not use their GIS to select specific sites for development; that process is left up to local developers. In the near term, its objective is to conduct a statewide assessment identifying regions of the state more favorable for power plant development, while promoting economic development opportunities in a balanced framework. Potential regional areas for development are highlighted, rather than selecting or eliminating specific candidate sites. To complete the evaluation, more detailed, localized information would have to be collected for the individual sites. The layers incorporated into this database include:

- Transmission lines
- Gas pipelines
- Industrial areas
- Wastewater treatment plants
- Existing power plants

- Water availability
- Property tax assessment and land value
- Incentive areas
- Protected lands
- Railroads
- Ozone non-attainment areas
- Major roads

This database includes the 21 utility power plants currently operating in Maryland, 15 of which have a generating capacity greater than 100 MW. In addition, two generating plants are owned and operated by non-utility generators. The combined generating capacity of all 23 of these plants is 11,276 MW. Figure 28 illustrates the location of these plants in relation to the 500 kV transmission lines.

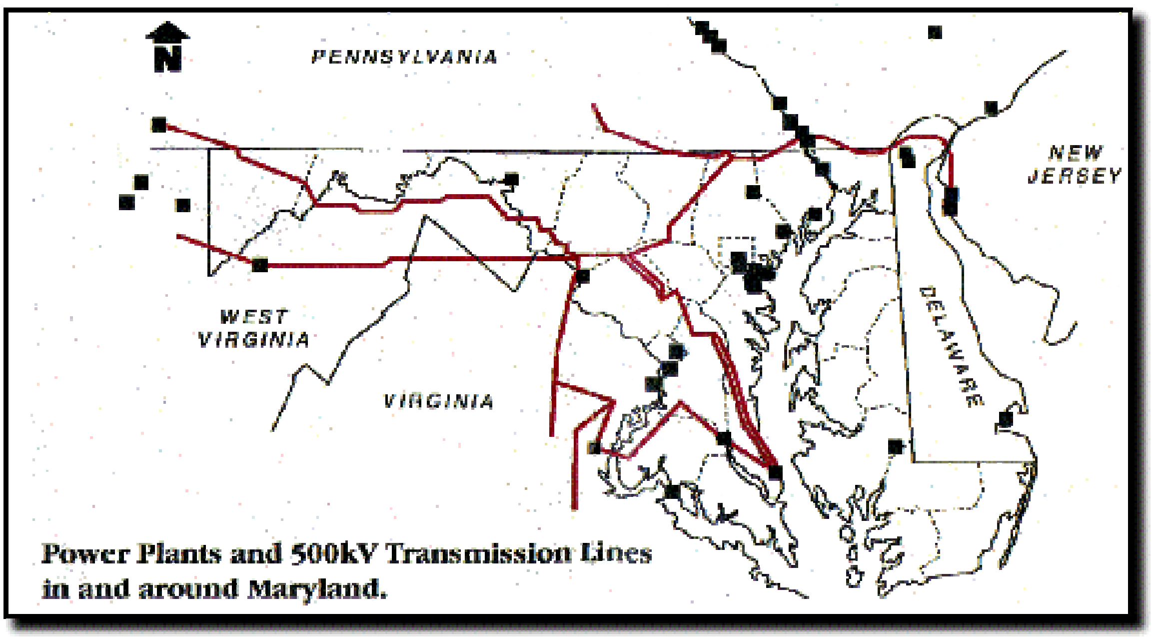
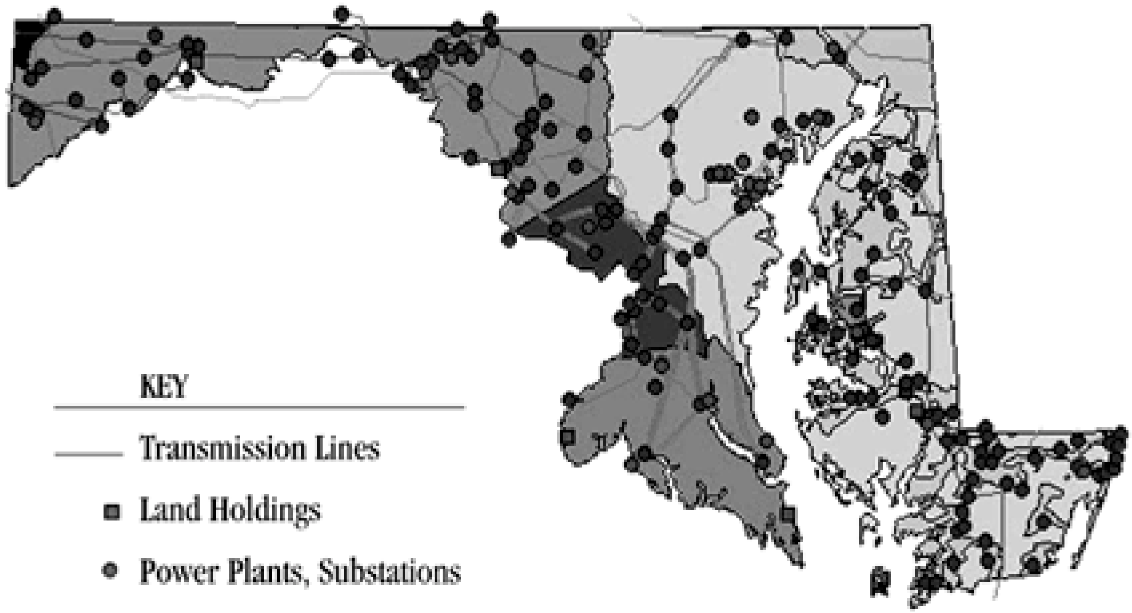


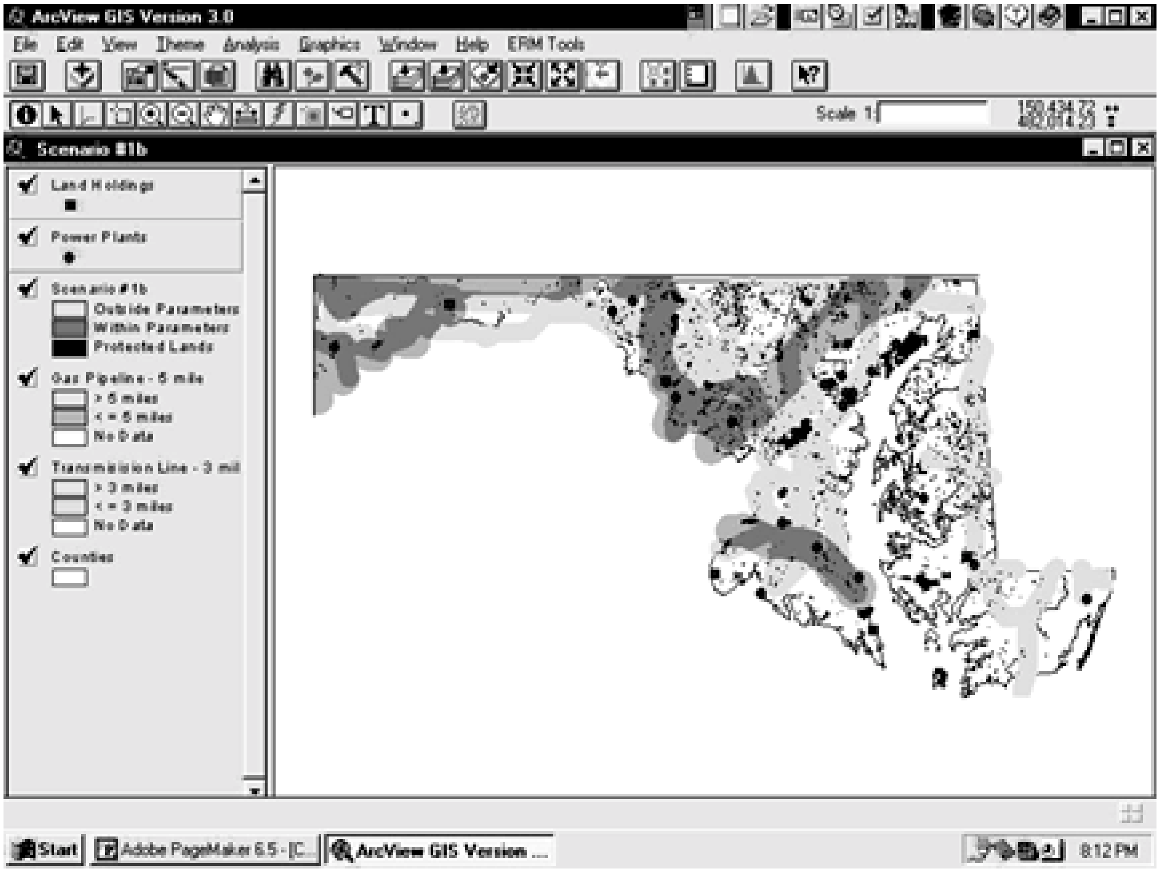
Figure 28: GIS-generated Map of Maryland's Major Power Plants and Transmission Lines.



source: Maryland State Department of Natural Resources, "Power Plant Update" Volume 5, Number 2, Winter 1998.

Figure 29: Sample Database Layer from the "Smart Siting" GIS. Power plants, Substations and Major Transmission Lines are Noted. Shading Indicates Service Territories of Various Utilities, Munis and Cooperatives.

Figure 29 shows a subsample of the data layers, including major transmission lines, power plants, substations, and service territories for utilities, municipals, and cooperatives. These data can then be queried according to a pre-determined list of criteria and composite maps can be generated that illustrate areas that comply with all the requirements of a given query. For example, a query could consist of all industrial zoned areas located within a specified distance of transmission lines, gas pipelines and water supply. Maps have been generated for a set of eight pre-designed scenarios, one of which is shown in Figure 30, or these queries can also be customized. This project will improve the efficiency and minimize the environmental impact of power plant development within Maryland, and is particularly relevant for DER.



source: Maryland State Department of Natural Resources, "Power Plant Update" Volume 5, Number 2, Winter 1998.

Figure 30: Sample "Smart Siting" GIS-generated Composite Map. Shading Corresponds to the Suitability for Siting a New Simple-Cycle Combustion Turbine Facility. Darkest areas Indicate Infrastructure is Most Suited, Lightest areas are Least Suited.

6.3.2 Environmental and Regulatory Considerations

Beyond the basic technical and economic factors that influence site selection decisions such as those included in the Smart Siting database, environmental and regulatory considerations also are important in determining appropriate sites. Of particular concern for DER are zoning, building codes, emissions, noise and viewshed issues.

6.3.2.1 Planning for Community Energy, Economic and Environmental Sustainability (PLACE^{3}S)

In some instances, regulatory agencies have already begun assembling basic planning and demographic information into GIS format, a process that can otherwise be a laborious and costly endeavor. For example, the Center of Excellence for Sustainable Development and the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy are promoting an energy-based approach to urban planning, called PLACE^{3}S, that hinges on GIS. Several communities in Washington, Oregon and California, including Ft. Lewis, Washington, Beaverton and Portland, Oregon, and San Jose and San Diego, California, have implemented this PLACE^{3}S method for land use and urban design.

The PLACE^{3}S method incorporates public participation, planning/design and measurement into its determination of the costs, benefits and impacts of various development alternatives. The energy sectors that PLACE^{3}S measures are transportation, residential/commercial/industrial, infrastructure (such as street lights, traffic signals and water and sewer systems) and energy production. The energy production category measures energy output for local renewable energy resources such as solar, wind, and geothermal and high-efficiency technologies such as cogeneration and district heating and cooling. Energy units are converted to a common unit (in this case, million Btu) for comparison and air pollutant and CO_2 emissions are used to quantify the environmental implications of alternatives.

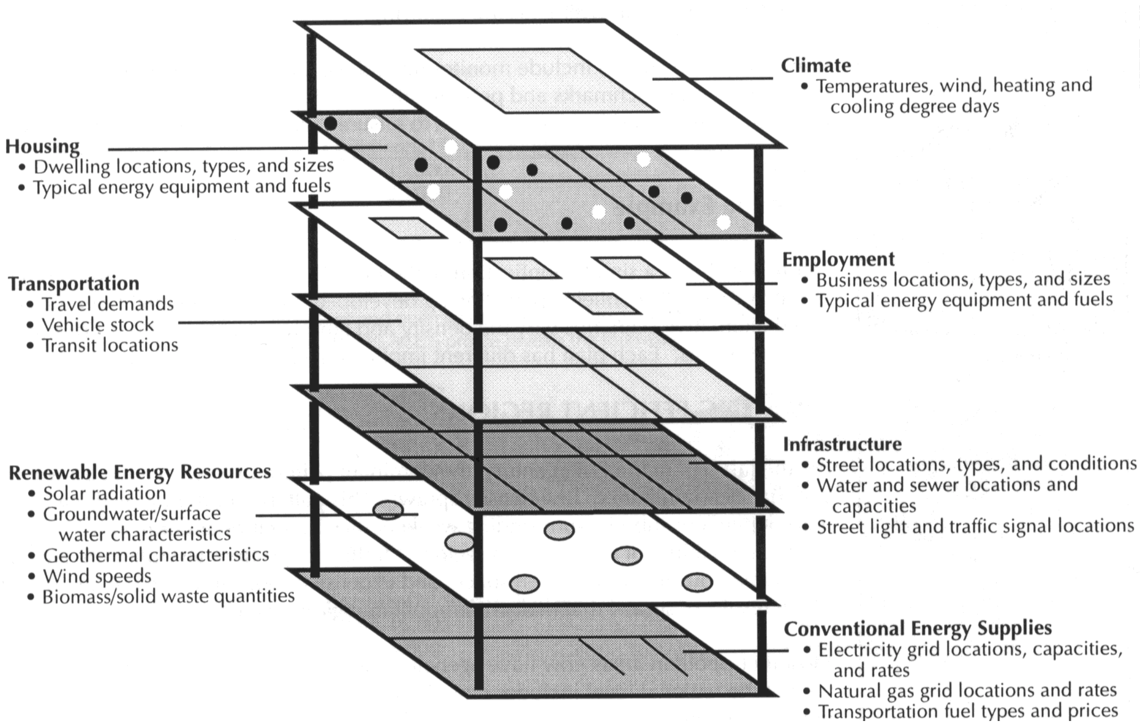
One of the goals of PLACE^{3}S is to leverage pre-existing data sources. Generally, participants have found that local data sets exist for many key energy-related factors. Table 6 lists sources of basic energy data that can often be mined to extract localized information.

Table 6: Sources of Basic Local Energy Data. These are National Databases with Multi-State Regional Distinctions, Periodically Updated by U.S. DOE.

Data Source	**Description**
Annual Energy Outlook with Projections	Existing conditions and 20-year forecasts of energy supplies and demands by fuel type and end-use.
Household Energy Consumption and Expenditures	Survey of consumption and expenditure patterns for all residential energy use, except household transportation.
Household Vehicles Energy Consumption	A companion residential survey devoted to household transportation, including vehicle types, miles traveled, and fuel efficiency.
Commercial Buildings Energy Consumption and Expenditures	Survey of commercial building energy consumption by building type, energy end-use, and fuel type nationally.

source: The EnergyYardstick: Using PLACE^{3}S to Create More Sustainable Communities

Figure 31 summaries the layers of the GIS database needed for the PLACE^{3}S approach. These layers cover climate, housing, employment, transportation, infrastructure, renewable energy resources and conventional energy supplies. In conducting its energy efficiency analysis, PLACE^{3}S evaluates two basic linkages between energy and regional development. First, PLACE^{3}S quantifies the energy demands created by the arrangement of land-uses throughout the region. In addition, PLACE^{3}S matches energy production and distribution systems to the land-uses and transportation systems they will serve. The data infrastructure created through this process could easily be applied to evaluating DER options as well.



source: The EnergyYardstick: Using PLACE^{3}S to Create More Sustainable Communities

Figure 31: Database Layers for PLACE^{3}S Analysis.

6.3.2.2 Zoning and Codes

Building codes and zoning restrictions are both important factors to consider when determining candidate sites for DER. These factors can easily be incorporated into a PLACE^{3}S type database structure and are often accessible as digital files through municipal agencies. What might initially appear to be a prime location for a generator based on ancillary services to the grid or gas transmission access, might be impossible to develop because of codes. As illustratedin the PPRP's composite maps, GIS provides a means for easily idenifying these conflicts in a cost effective, timely manner.

6.3.2.3 Emissions

As discussed in the preceeding chapter, Environmental Issues, regional air quality and emission regulations can have an overriding effect on what generation options are acceptable. Because air quality is influenced by an entire region's activities, individual businesses must account for their regional impacts when considering choice of generators. The cost of migitating emissions from DER must be included into the economic evaluation for both customers and discos.

GIS database layers can include regional estimates of current emissions, emissions targets and predicted emissions levels based on different DER options. As in the alternative analsysis decribed in the PLACE^{3}S section of this chapter, the effects of different DER deployment alternatives on regional emissions levels can be modeled and visualized with the aid of GIS.

6.3.2.4 Noise Modeling

Noise modeling for many different purposes, from highway development to airport expansion, is a newly evolving application of GIS. Characteristics of sound and its propagation can be modeled using the relief characteristics in a three-dimensional database. Topographic relief of the terrain and physical structures can be included to determine the effect of generator noise on surrounding areas. Because some generator options may produce noise inappropriate for residential neighborhoods, GIS could also be used to target specific sites when noise is less of an issue, such as near airports.

6.3.2.5 Three-dimensional Viewshed Analysis

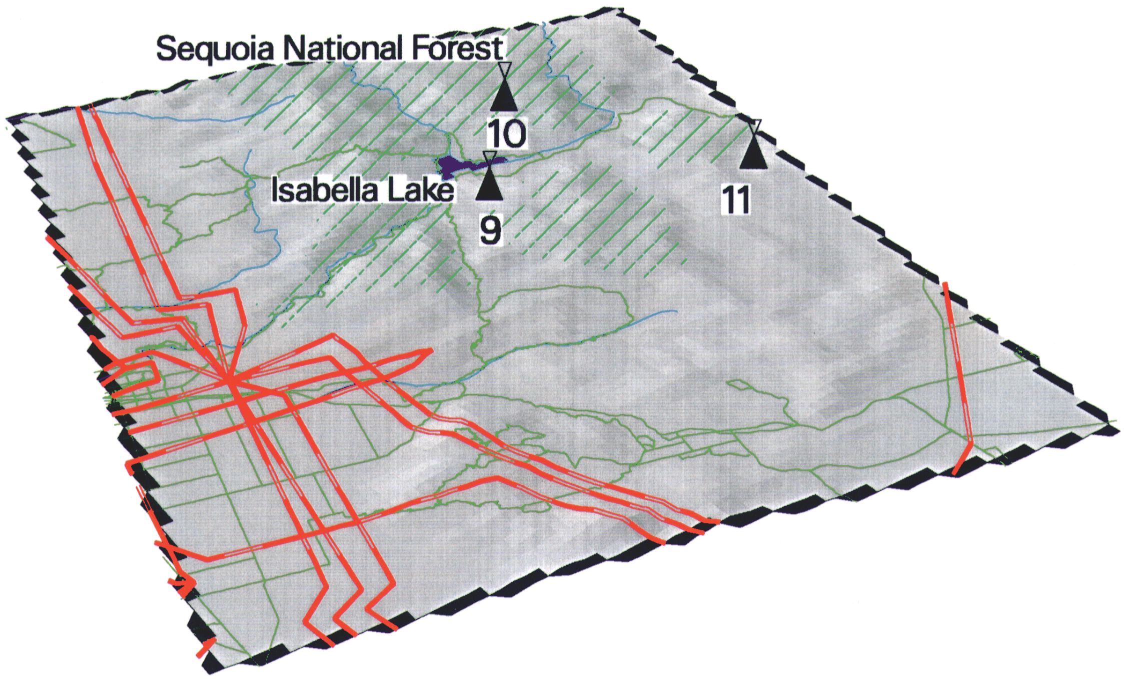
Viewshed (also called intervisibility) analysis is another feature than can be incorporated into GIS-based site selection. For some technologies, particularly wind power, visual impact is often cited as a potential concern. The area visible from a point (e.g., the top of a wind turbine) can be modeled by three-dimensional GIS analysis. The terrain is represented by a Digital Elevation Model (DEM), and the area visible along a horizon line is modeled by radiating a set of rays outward from that point. The basic line of sight geometry can actually be represented two-dimensionally (distance versus elevation). For a given line of sight, an object is visible if a more distant object is at a higher vertical angle than nearby objects; otherwise, they are eliminated from view (Chrisman 1997).

6.4 Site Suitability Analysis

Once areas of potentially viable DER deployment have been identified, the next step is to rank the suitability of the sites based on a number of criteria. This process is a more sophisticated application of GIS that requires integration with economic and powerflow simulation. Two examples follow that demonstrate this approach.

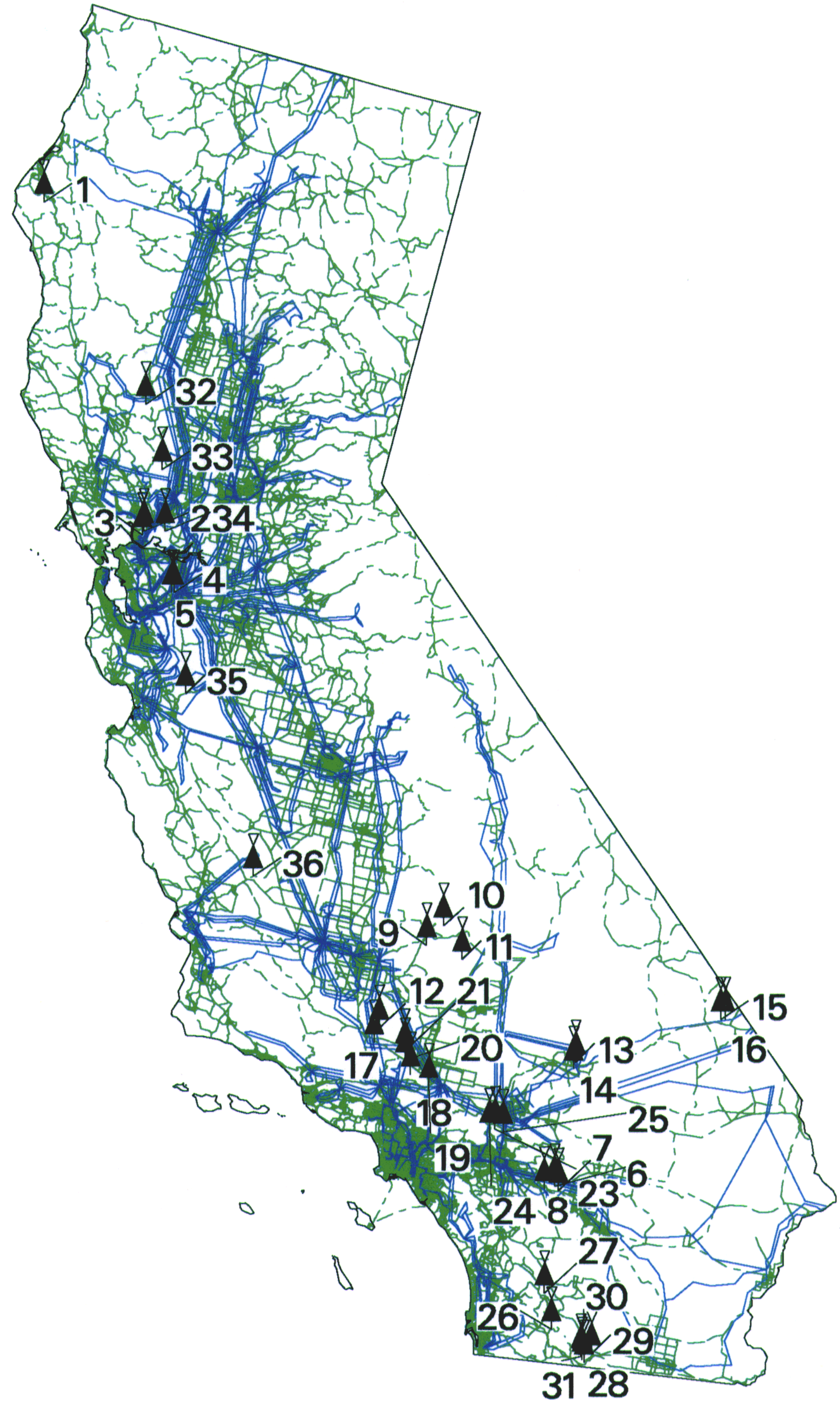
6.4.1 California Wind Resource Assessment

At Lawrence Berkeley National Laboratory (LBNL), Sezgen, et al (Sezgen 1998) conducted an assessment of the potential wind resource in California using GIS and an economic model developed by the Environmental Defense Fund, called Elfin. In this study, GIS was used to determine the cost of development for a limited number (36) of wind sites. These sites, which had been identified as favorable for wind development by the California Energy Commission, were placed on DEMs following ridgelines as appropriate for strings of turbines. The total potential wind resource at a given site was then calculated based on the number of turbines that could be located according to pre-determined spacing specifications and the topographical characteristics of the terrain. The sites were also overlaid with maps of transmission lines (obtained from FEMA) and major roads (from ESRI). An example DEM with transmission lines, roads, major population centers, water bodies and potential wind plants is shown in Figure 32. After determining the total potential resource, development costs at individual sites were calculated by incorporating distances to roads and transmission lines in the cost assessment (Figure 33). For wind and other remote generators, distance to roads and transmission lines can represent a significant construction cost for site development.



source: adapted from Sezgen et al (1998).

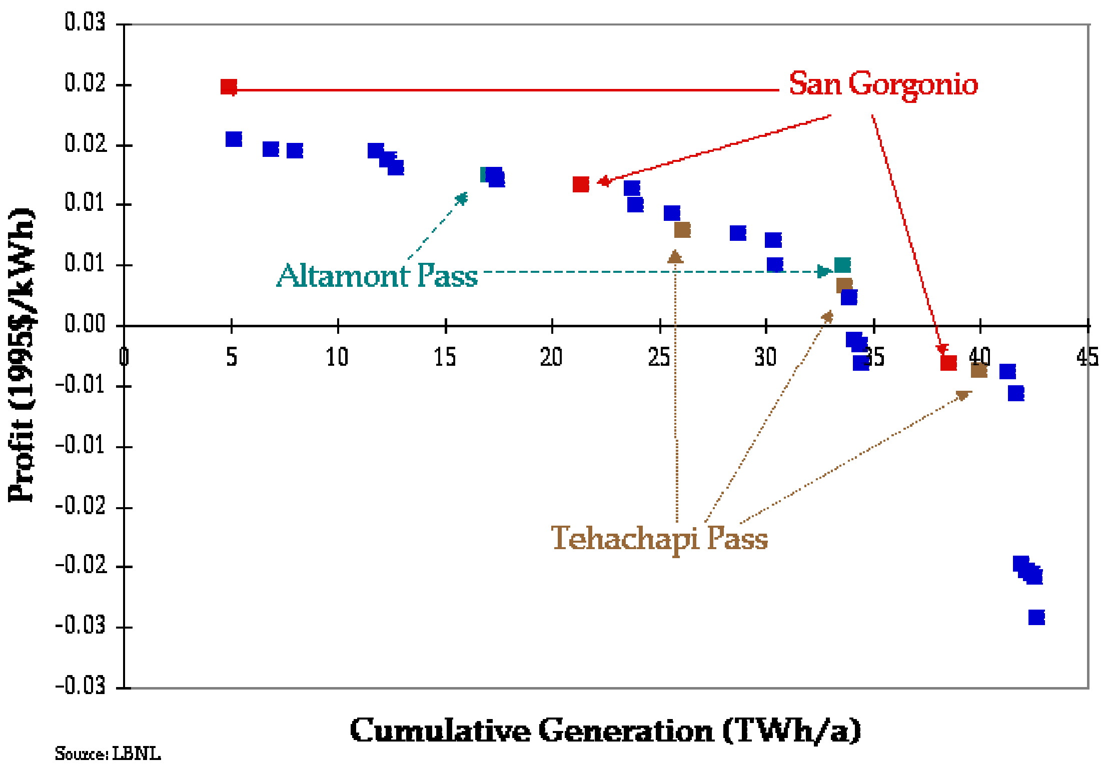
Figure 32: Digital Elevation Model of One of 36 Potential Wind Plants Studied by the California Energy Commission.



source: adapted from Sezgen et al (1998).

Figure 33: Transmission Lines and Roads used for Calculating Costs of Wind Plant Construction.

Once the potential capacity and cost of development at each site was calculated with GIS, the Elfin model was used to gauge the economic viability of the wind farms. Forecasts of profitable development levels at each site and the effects of the development on the electricity system as a whole were generated. Under best guess assumptions, including prohibition of new nuclear and coal capacity, moderate increase in gas prices and some decline in renewable capital costs, about 7.36 GW of the 10 GW potential capacity at the 36 specific sites is profitability developed by 2030, as shown in Figure 34. Most of the development happens during the earlier years of the forecast. Importantly, it was found that a simple levelized profitability calculation approach did not sufficiently capture the implications of time varying prices in a competitive market.



source: adapted from Sezgen et al (1998).

Figure 34: Profitability in the Year 2030 of 36 Potential Wind Plants Identified by the California Energy Commission.

6.4.2 Project SOLARGIS

The integration of renewable energy technologies for decentralized electricity production is being explored using GIS for regions within Europe and in some developing countries by the Institute of Systems and Computer Engineering (INESC 2000). Seven laboratories are establishing a common methodology for energy planning studies in Sicily, Andalucia, Crete, Cabo Verde, Tunisia and India. The goal is to incorporate base maps (from digital and paper maps, aerial and satellite images) with geographic data (meteorological, electric grid and demographic) in a single GIS. In each region, the studies are being conducted in close collaboration with electric utilities or regional authorities responsible for energy planning. Special emphasis is being placed on remote, off-grid sites and small-scale generators.

The data being gathered for this siting exercise include vector (line-based) datasets of line coverages such as roads, electric grid and hydrology, polygon coverages such as land use and administrative boundaries, and point coverages such as meteorological stations. Raster (pixel-based) datasets include wind and solar resource maps, digital elevation models, electricity demand and distance to the electric grid.

For the resource maps, simulation programs will be used and integrated with the GIS data to generate layers that will be used in later steps of the analysis. Wind resource assessment models that are being considered include NOABL (a mass consistent model development by Traci and Phillips, 1977), AIOLOS (a mass consistent model developed by Lalas, 1988) and WASP (a dynamic model developed by Risoe National Laboratory, 1987). Solar resources can be estimated using meteorological data, which are interpolated based on hill shading that considers the terrain as modeled in the GIS. Using GIS, incident radiation can be modeled for each hour of the day. Solar radiation data as estimated from remotely sensed satellite images can also be incorporated.

These databases can then be used to evaluate wind and solar resources in relation to demand to identify areas of "high potential." Each pixel of the GIS will be coded according to a favorability index that considers both technical and economic factors, including levelized cost, land availability and electricity demand. For this exercise, grid-connected, stand-alone and hybrid systems will all be considered. For grid-connected systems, high potential areas will be those in which the cost of electricity generated by the renewable resource is less than the cost to purchase the electricity from and ESP. For off-grid sites, high potential areas will be ranked relative to each other, with levelized cost of energy as the determinant. The options will be compared to the cost of energy as supplied by the grid, including the cost of grid connection. Hybrid systems will be considered for island communities and remote, village power-type situations.

The final step in the analysis includes the local integration studies that will be conducted to estimate total number of units that can be installed in the high potential sites and their production and costs, as well as to rank these sites by quality, location and size.

6.5 Market Assessment

Aside from improving the site selection process, GIS can also be applied to forecast the potential penetration of DER nationally. Two studies assessing the potential market for PV that integrate GIS and economic modeling illustrate the benefit of incorporating local factors through GIS into this assessment.

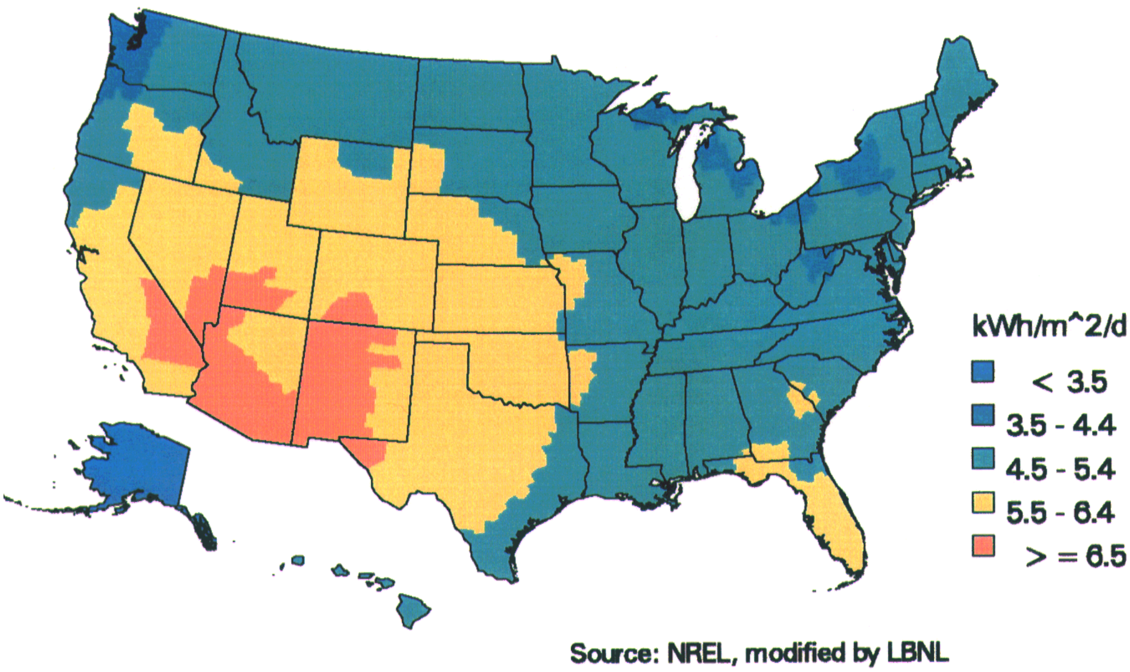
6.5.1 Solar Thermal Water Heating

Voivontas, et al (Voivontas 1998), have used GIS to estimate the market potential for solar thermal water heating systems in the residential sector in Greece. The broad goal of their research is to estimate solar potential and energy demand for specific end-use activities to determine the best policies for facilitating large-scale deployment of solar energy application. They capitalized on extensive research into the correlation of spatial and temporal factors in calculating solar radiation and integrated this information with economic analysis to conduct the overall market assessment.

Researchers gathered demographic data (population, number of households, average household water heating demand) to estimate energy demand, meteorological data to calculate regional solar radiation, and economic indices to estimate financial profits. Each of these attributes was overlayed within the GIS and this spatial relationship was fundamental to their calculation of the profitability of solar thermal water heating systems. The economic evaluation was conducted by comparing the energy production cost and the net present value of the investment in the solar technology. In addition to providing an estimation of the potential market, the spatial component revealed new information regarding the patterns of hot water and energy consumption of interest to policy makers that would not have been possible through conventional analysis.

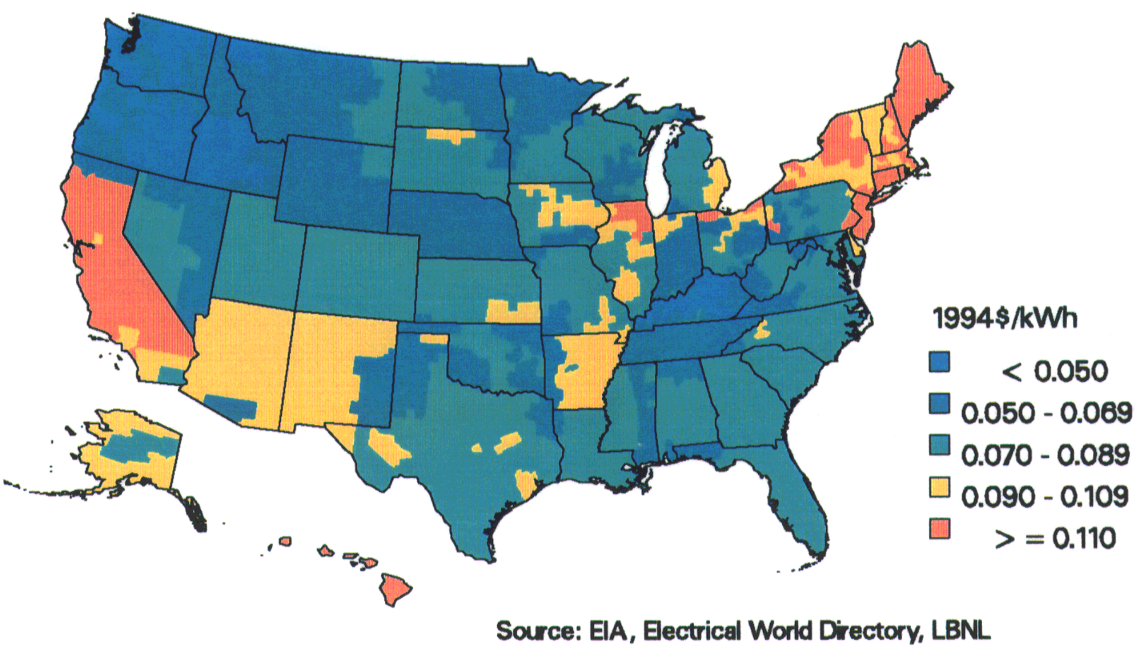
6.5.2 Rooftop PV

Another study examining market potential through GIS was completed at LBNL for residential rooftop PV systems (Marnay 1997). For this study, databases for solar insolation (from NREL, Figure 35), electric utility rates (from the Electrical World Directory of Electric Utilities and the Energy Information Administration, Figure 36) and population (from the U.S. Census Bureau, Figure 37) were spatially linked at county-level resolution. To identify areas where adoption of rooftop PV would be economical, the hypothetical levelized cost of a system for a single-family detached home under various scenarios was compared to the prevailing retail electricity price in a county. Adoption of rooftop PV was assumed to occur if the levelized cost of the PV system was less than the local (county-level) average retail electricity rate. Potential PV generation was then calculated for these homes using insolation data, as shown in Figure 38. Based on a levelized energy cost of $3/W, rooftop PV systems were found to be cost effective in 16% of detached single-family households.



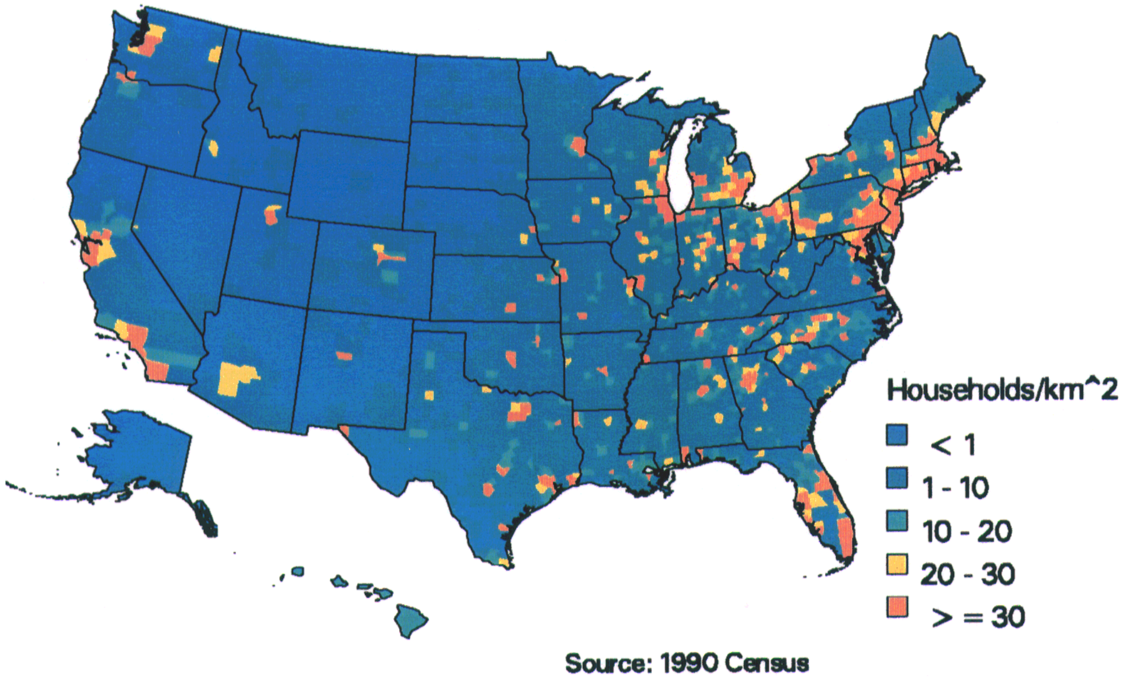
source: adapted from Marnay, et al (1997).

Figure 35: Daily Average Output for Flat-pate Collectors with a Fixed Tilt



source: adapted from Marnay, et al (1997).

Figure 36: 1993 Residential Electricity Prices



source: adapted from Marnay, et al (1997).

Figure 37: Residenial Population Density - Single Family Detached Homes

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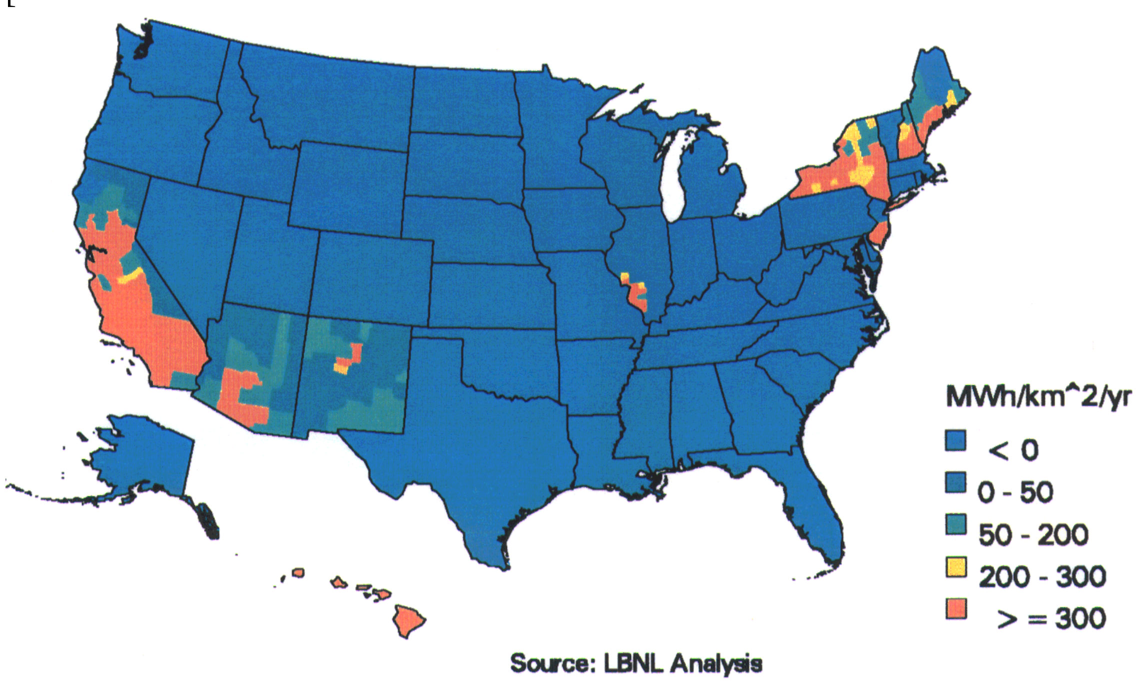

source: adapted from Marnay, et al (1997).

Figure 38: Adoption Forecast for Residential PV Electricity Generation

6.6 Conclusion

As electric utilities are decentralized and competition selects least-cost power generating options by new rules outside of traditional centralized utility planing methods, local issues will play an increasing role in determining power system expansion, especially for DER. Both discos and consumers will have influence on the other’s strategic planning and will require powerful decisionmaking tools for this process. The ability of GIS to store and analyze spatial data enable it to respect many of the local constraints on deployment of DER, including technical, environmental, regulatory and economic concerns, that traditional centralized optimization cannot. Therefore, GIS can provide a powerful tool to customers and discos seeking to simulate the development of the future power systems.

7. Conclusion

This work covers the first year's effort in a multi-year project intended to develop the tools necessary to perform an integrated assessment of the likely patterns of DER adoption. The purpose and relevance of this work to the wider CERTS goal of enhancing power system reliability in the age of competitive electricity markets derives from its ability to guide. In this first year, initial efforts have been made in five component analysis areas relevant to this broad objective. A simple model of customer DER adoption has been designed, built, and applied to some sample customer types, load flow analysis tools have been surveyed and a simple example analysis completed using one of them, the status of environmental and electric utility regulation has been examined, the environmental consequences of microturbine installation estimated, and the potential of GIS to provide an analysis framework has been explored.

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