CHAPTER
TWO

BACKGROUND

In the late 1980s, the Sacramento Municipal Utility District (SMUD) was faced with an energy purchasing crisis due to the early retirement of their 900 MW nuclear power plant, Rancho Seco. SMUD customers voted to close the nuclear plant and decided to invest instead in renewable energy sources including solar domestic hot water systems. As a summer peaking utility, SMUD was faced with very high demand on hot sunny days and was forced to purchase expensive peak power. By taking the initiative of investing in renewable energy sources, SMUD placed a value on the avoided cost of meeting those peaks. In 1993, the utility offered customers performance based rebates of up to $863 per certified solar system (costing less than $3000) (IRT, 1993). Through a financing program, customers pay the remainder of the SDHW system cost through their bills over the next 10 years. The savings from the SDHW system installment are typically more than the monthly payments for the system, yielding a positive monthly cash flow for the customer (Flavin, 1994). SMUD's goal is the installation of 12,500 systems by the year 2000 (Murley, 1994). With a predicted (Beckman, 1993) and observed (through monitoring) demand reduction of about 0.5 kW per installation, SMUD will have the equivalent of a 6 MW renewable power plant in terms of average peak reduction.

2.1 Utility Planning

Unfortunately, most state utilities are not municipally owned or as optimistic about solar energy as SMUD. Utilities are typically conservative (by necessity) and resistant to change, especially when fuel switching is involved. Public power utilities are in a unique situation. While the utility share-holders expect to make a profit, the rates that utilities charge fall under the jurisdiction of the Public Service Commission (PSC) or the Public Utilities Commission (PUC) for the state in which they reside. State commissions have a commitment to economic efficiency. The utility regulatory agencies are responsible for ensuring that the customers receive reliable service at reasonable prices. Without controls, utilities could feasibly charge exorbitant electricity rates in the absence of a free market; i.e., residential customers are not able to chose where they get they power from. At a higher level, the Federal Energy Regulatory Commission (FERC) also has jurisdiction over the utilities.

Since the rates that Wisconsin utilities charge are set by the Public Service Commission of Wisconsin (PSCW), they are driven by producing (or purchasing) energy at the least possible price at any given time. There is little motivation for investment in alternative energy sources, due to their perceived high costs. Thus, government mandates and market energy prices are the catalysts for change.

In the past, public power utilities operated (and were regulated) such that their profits were directly linked to electricity sales. Efficiency investments countered the economic interests of the shareholders to whom the utility executives were responsible. The National Association of Regulatory Utility Commissioners has pushed regulators to compensate the utilities in a variety of ways for lost profits (reduced electricity sales) by allowing utilities to earn equal or greater profits on saved power.

The idea that utilities should participate in energy conservation or fuel switching options seems counterintuitive, but public power utilities are not operating under normal market regulations. Their monopolies are still protected by governments. In addition, they have access to capital at lower interests rates than those available to the residential customer. Additionally, it is still true that it is less expensive to save electricity than to produce it. When utilities sell power to residential customers, almost a third of the costs are due to transmission and distribution of the power (Flavin, 1994). Reduced electric load does not necessarily mean reduced income. The Power Utilities Regulatory Policy Act (PURPA) of 1978 requires utilities to purchase renewably generated electricity at the "avoided cost" of power from conventional sources (See Chapter 2.3: Cost Analysis Schemes).

2.1.1 Utility Load Characteristics

Due to the incidence of customer electricity demands, utilities see varying loads throughout the day and throughout the year. The majority of utilities in the United States are termed "summer peaking utilities". Seasonal peaks formerly occurred in the winter, due to electric resistance space heating, but as more households switched to gas furnaces in the winter and electrically driven air conditioners in the summer, the air conditioning load on utilities has superseded the winter heating one.

The ideal load curve is flat, meaning that capacity requirements are constant. Baseload power plants could then run at full capacity (and at highest efficiency) for the duration of the day, or year, as it may be. Unfortunately, life is not so ideal. Most people work during daylight hours, causing a disparity between day and night loads (often referred to as “on- and off-peak loads”, accordingly). Since the load does vary, a utility needs to have extra capacity "on hand" even though it may only be needed for a short period of time. In order to meet these infrequent peaks, utilities often invest in gas combustion turbines. These are attractive from a utility standpoint due to their low initial costs, even though their operating costs are high. Utilities can rationalize the more expensive operating costs because the combustion turbines will seldom be needed. Even so, that high gas turbine operating cost is part of the reason for the on- and off-peak customer rates.

Table 2.1.1 shows how the annual energy and demands of each electricity customer sector are rationed. Since residential customers account for 30 % of the annual Wisconsin energy requirements and the highest peak summer demand, utilities often look to the residential customers for energy saving programs and demand-side measurement strategies.

Table 2.1.1: Wisconsin Energy and Demand by Sector (WCDSR, 1994)

Economic Sector	Annual Energy (GWh)	Summer Peak Demand (MW)
Agriculture	1,599	335
Commercial	14,975	3,206
Industrial	21,360	3,367
Residential	15,925	3,429

The contrast between the on- and off-peak periods has encouraged load shifting programs such as ice storage and demand side measures such as compact fluorescent light bulbs and appliance timers. It is through demand side management that utilities can justify paying people to not use energy at certain (peak) times of the day. There are demand side management advantages to SDHW systems, and it may be less expensive for the utility to invest in these solar systems than to operate their peak gas combustion turbines.

While the actual cost calculations are discussed in detail in Section 2.3, the general economic reasoning is simple. Evaluation of new generating or demand side options is based on least cost, but the types and definitions of the costs that are reviewed vary greatly. The most controversial of these costs today is the environmental, or societal, cost. Since it is difficult to assign monetary values, liability, or source to some environmental costs, most utilities do not even consider them, unless their inclusion is dictated by government.

2.1.2 Resource Mix

While Wisconsin is the focus of this study, its resource mix in comparison to the rest of the United States is shown in Table 2.1.2. This lends a national perspective to the Wisconsin analysis. In 1991, Wisconsin's total energy use per capita was about 93% of the national average (275 million Btu). Another important note: Wisconsin utilities show a heavy reliance on coal in comparison to the rest of the United States.

Table 2.1.2: 1991 WI and U.S. Energy Consumption by Resource (WI 1993-4 Blue Book)

Energy Resource	**Millions of Btu per Capita**	
Petroleum		
	U.S.	110
	WI	90
	WI % of U.S.	82%
Natural Gas		
	U.S.	79
	WI	66
	WI % of U.S.	84%
Coal		
	U.S.	60
	WI	80
	WI % of U.S.	134%
Wood		
	WI	10
Hydro-Electric		
	U.S.	5
	WI	2
	WI % of U.S.	31%
Nuclear		
	U.S.	26
	WI	24
	WI % of U.S.	93%
<u>Total Resource Use</u>		
	U.S.(excluding wood)	295
	WI (including wood)	275

WI % of U.S.	93%

Table 2.1.3: World Primary Energy Use by Source (Flavin, 1994)

Source	1970		1992	
	Use (exajoules)	Share (percent)	Use (exajoules)	Share (percent)
Crude Oil	92	36	123	31
Coal	65	26	91	23
Natural Gas	42	17	82	21
Biomass	39	15	50	13
Hydropower	13	5	24	6
Nuclear	1	0.3	22	6
Geothermal, Wind, Solar	<0.1	<0.05	0.4	0.1
Total	252	100	392	100

Table 2.1.4: World Electricity Production (Flavin, 1994)

Power Source	1971		1991	
	Use (Tera-Whr)	Share (percent)	Use (Tera-Whr)	Share (percent)
Coal	2,142	40	4,671	39
Renewables	1,241	23	2,290	19
Nuclear	111	2	2,106	17
Natural Gas	714	13	1,594	13
Oil	1,102	21	1,376	11
World	5,311	100	12,037	100

Conventional power plants are based on a Rankine cycle, in which efficiencies reach 30-35% (based on the energy content of the fuel). The only way in which to substantially improve efficiency is by using a combined cycle power plant, with cogeneration, but such facilities are limited by the proximity to the customers and their need for both electricity and steam. Power plant inefficiency creates the need for a cheap fuel, but even if they were 100% efficient, utilities (and consumers) would still want inexpensive electric power (and therefore cheap fuel). At the time most power plants were constructed, there was very little environmental control. Therefore, coal was the obvious fuel.

2.1.3 Integrated Resource Planning

Integrated resource planning gives a strategic opportunity to incorporate/internalize environmental externalities in a manner that is economically sensible. The Public Service Commission of Wisconsin states the purpose of integrated resource planning, the Advance Plan process, as follows:

> The Advance Plan is filed jointly by Wisconsin's electric utilities every two years, pursuant to 196.491 Wisconsin Statutes and Wisconsin Administrative Code Chapter PSC 111. The purpose of the Advance Plan is to inform the Public Service Commission of Wisconsin and the general public of the utilities' plans for the future.
>
> The objective of the integrated resource planning process is to assure that utility customers are provided with safe and reliable service while reasonably balancing the costs and benefits of providing that service. (PSCW-AP7, 1994).

Since the Public Service Commission of Wisconsin is concerned with system reliability and load forecasting, the capacity levels of utilities are an important part of integrated resource planning. Reserve generating capacity is considered the difference between the utility generating capacity and the customer's demand for energy. Reserve generating capacity is not to be confused with excess capacity, which is unused. Generating capacity may become unavailable due to (PSCW-AP7:D24, 1994):

- Planned maintenance.
- Breakdowns which force units out of service.
- Failure to meet scheduled start up dates for new generation units.
- Unavailability of fuel.
- Regulatory action.
- Limitations in or absence of the transmission system.

The Mid-America Interpool Network (MAIN organized in 1964) and the Mid-Continent Area Power Pool (MAPP) are networks of electric utilities, the idea being that there is safety in numbers from a reliability perspective. Each network has its own set of rules concerning the need for reserves and each member utility's responsibility. Each utility is responsible for its own load, yet provides a set reserve margin to ensure reasonable reliability and optimal economic operation. Without MAIN, Wisconsin utilities would need to have approximately 50 to 100 percent more reserve capacity to provide the same level of reliability that is achieved through the network (Arny, 1994). The planned reserve generation capacity margins for Wisconsin utilities are shown in Table 2.1.5.

Table 2.1.5: Reliability and Reserve Margins: Advance Plan 7

MAIN Members	% of Required Reserve Capacity
WEPCO	15% through 1993 16% in 1994 17% in 1995 18% in 1996 and beyond
WPL	15% through 1993 16% in 1994 17% in 1995 18% in 1996 and beyond
WPSC	15% through 1997 18% in 1998 and beyond
MGE	15% in all years
WPPI	15% in all years
MPU	15% in all years
MAPP Members	**% of Required Reserve Capacity**
WPPI	15% in all years
NSP	15% in all years
DPC	15% in all years

2.1.4 Contribution to Capacity

Electric utilities value new generation sources based on their ability to offset operating costs at other plants, but also for their capacity value. Capacity value is the ability for the particular plant to be available (to supply power) when it is most needed. While many methods exist for relating the reliability of different demand-side and supply-side options, the one chosen for this research is the "Capacity Contribution Index (CCI)" (Arny, 1994). The CCI method compares the relative capacity contributions to system reliability of both demand-side and supply-side resources on equal ground. The basis for comparison includes (Arny, 1994):

- Reliability distribution of an interconnected utility system versus an isolated system.
- Loss of Load Probability (LOLP) versus Expected Unserved Energy (EUE) as the system reliability indicator.

The CCI method replaces peak hour analyses that only provide credit for demand-side options at one system peak hour. Thus, the CCI method is advantageous from a utility planning perspective, especially when renewable options are being evaluated. The capacity value of a particular option is complicated, involving the value of having the equipment around and ready to use to meet demand on a peak day. Complicating it even more, capacity value is time of day dependent. An alternate explanation of the CCI method is that it compares the cost of the customer not being served to the cost of having the capacity to always meet the load. There is an added value to options that can dependably contribute energy or reduce load during peak periods. Calculation of the CCI for solar DHW systems is discussed in detail in Chapter 5, Section 4.

2.2 Environmental Externalities

Utilities use various forms of power generation to meet the system load, beginning with the plant with the lowest operating costs. Each of these plants incurs a certain cost to the utility and to the environment. Coal, oil, and natural gas plants release varying levels of carbon dioxide, sulfur dioxide, oxides of nitrogen, and particulates. The cost to the environment for these pollutants can be converted into $/ton produced. Using a marginal plant analysis based on a least cost production model, a utility's avoided emissions from the installation of SDHW systems can be evaluated and the impact of the solar systems on the utility can be quantified, as shown in Chapter 6.

2.2.1 Defining Externalities

Economists define externalities as the effects of actions by one party that provide costs or benefits to a third uninvolved party (Temple, 1990). These effects can be positive or negative. Externalities are generated by both producers and consumers. Environmental externalities can be defined as the changes in economic welfare that manifest themselves through changes in the physical-biological environment (NARUC, 1994). If the environmental costs are external to the production decisions of a utility, then the customer rates for electricity do not reflect the full cost to the consumer (society). Theoretically, all the external costs shown in Table 2.2.1 should be internalized. No environmental externalities would be ideal, but realistically, the external costs of electricity need to be reduced to an efficient level for four important reasons (NARUC, 1994):

• Risk management: Rate payers need to be protected from increases caused by future utility liability for environmental damage.

• Social equity: When one group benefits from low cost electricity at the expense of another group who experiences the accompanying environmental costs.

• Economic innovation: Renewables and conservation measures can be given a fair comparison to traditional supply-side resources.

• Utilities are franchised monopolies vested with a duty to serve the public interest, a responsibility that includes environmental protection (Pace, 1990).

Some public solutions to remediate the difference between marginal social costs and industry cost involve regulation, corrective taxes and tradable permits. Imposing a corrective tax (environmental adder or externality monetization in $/ton) provides some incentive for the pollution abatement at a somewhat "socially efficient" level.

Typically, no source of electrical generation is completely benign to the environment, but renewable energy sources do emit fewer pollutants than fossil fuel combustion (PSCW-AP-6, 1992). The environmental effects that are quantified in this thesis are only airborne pollutants. The emissions resulting from electric utility operations such as the burning of fossil fuels and the nuclear fuel cycle are listed below. Not only are their individuals effects significant, but their synergistic environmental effects (greater than the sum of their separate damages) may be a factor (Pace, 1990).

Table 2.2.1: Externality Checklist (Temple, 1990)

Health	Environmental
Particulate Emissions	Wetland Impacts
Toxic Emissions	Forestry Impacts
Carcinogenic Emissions	Agricultural Impacts
Formaldehyde	Recreation Area Impacts
Radon	Endangered Species Habitat
Hazardous Waste Discharges	Surface Water Quality
Impacts	
Waste Water Discharges	Ground Water Quality
Impacts	
Magnetic Field Effects	Water Flow/Distribution
Effect	
Ozone	Heat Pollution Effects
NO_X	Adverse Land Use Impacts
SO_X	Acid Deposition Impacts
Carbon Monoxide	Fish Impacts
Mercury	Wildlife Impacts
Selenium	Aesthetics
Chromium	Noise
Boron	Air Circulation Effects
Bromides	Effect on Lighting Conditions
PCBs	Effects on Visibility
CFCs	Runoff from Mines
Global Warming Gases	
Safety	Type of Fuel
Potential for Fire	Best Use of Fuel Resource
Potential for Explosion	Replenishability of Source
Potential for Electrocution	Effect on Fuel Dependencies
Potential for Other Accidents	
Economic	Social
Impact on Local Taxes	Jobs Created
Secondary Development Potential	Casual Proximity to Effect
Impact on Existing Businesses	Displacement of People
Local Work Force Used	Effect on Landowners
Effect on Property Values	Public Lands Encroachment
	Public Attitudes
	National Security Impact
Technical Innovation	Psychosocial Effects
Using New or Improved Methods of Generation	
Using New Designs for Transmission and Distribution	
Using New Technology for End Use Efficiency Improvement	

• Carbon dioxide (CO_2) - Global warming is the primary concern. Tree planting costs are sometimes the proxy for valuation of the greenhouse gas potential (Pace, 1990).

• Sulfur dioxide (SO_2) is primarily produced from artificial causes such as oil and coal combustion. SO_2 is a precursor of acid aerosols that result in acid rain. SO_2 also combines with particulates, entering the digestive system of animals (El-Wakil, 84).

• Oxides of Nitrogen (NO_X) cause damage to human health, agriculture, and animals. NO_2 attaches to hemoglobin, depriving the blood of oxygen, and also forms acid in the lungs (El-Wakil, 1984).

• Particulates (TSP) can be solids or liquids in sizes ranging from 1 micron to 100 microns or more. They result in both health effects by penetrating deep in the lungs and visibility effects by contributing to smog in urban areas.

Acid rain and greenhouse gas effects are the main motivations for the emissions focus. The greenhouse gas effect is similar (thus its namesake) to the effect that glass has in a greenhouse. Gases such as methane, water vapor, and carbon dioxide trap heat within the earth's atmosphere and cause temperatures to rise. The rising and falling level of carbon dioxide in the atmosphere correlate closely with rising and falling global temperatures. In 1896, the Swedish chemist Svante Arrhenius was the first to make the connection between increased coal combustion and increased global temperatures (Flavin, 1994)

Opponents of the pollution monetization argue that nature produces more airborne contaminants, through natural processes such as plant and animal decay, than any fossil fuel source. El-Wakil counters that argument:

> Contaminants are those materials, radiations, or thermal effects that are added to the environment beyond what nature itself puts into it. In the 1960's it was estimated that, globally, nature puts into the environment some 10 times the amount of contaminants that people put into it. The contribution of nature is, however, diffuse and thus largely harmless, whereas the contribution by human beings is more localized and

concentrated. It follows that pollutants are contaminants in concentrations high enough to adversely affect something that people value, such as their environment and health. (El-Wakil, 1984)

2.2.2 Clean Air Act Amendments

The air quality standards and emission requirements for burning fossil fuels are not new topics. The English King Edward I tried to reduce the heavy air pollution in London by banning the burning of coal within the city (Flavin, 1994). The year was 1306!

Acid Rain Deposition Legislation is not a new topic either. In 1990, the Environmental Protection Agency (E.P.A.) passed its farthest reaching legislation on air control yet. The principal goal of 1990 Clean Air Act Amendments (CAAA) is to achieve significant environmental benefits through reductions in sulfur oxide (SO_2) and nitrogen oxide (NO_X) emissions, the primary components of acid rain (E.P.A., 1991). The CAAA define guidelines through the New Source Performance Standards, National Ambient Air Quality Standards (NAAQS) and requirements for use of the "best available control technology" (BACT) for SO_2 and other criteria (Temple, 1990). Title IV of the CAAA sets standards for power utilities.

Power plant regulations are separated into three categories (E.P.A.,1991):

SIP: State Implementation Plans (which have variable emission limits)

NSPS I: New Source Performance Standards
(which mandate a 1.2 lbs SO_2/MBtu limit for compliance coal plants)

NSPS II: revised New Source Performance Standards
(which require a 70-90% reduction of SO_2 with flue gas desulfurization (scrubbers))

The primary goal of the legislation is the reduction of SO_2 by 10 million tons below 1980 levels (E.P.A., 1991). The CAAA takes a two step approach to control pollutants. A primary standard set for pollutants is designed to protect health. A secondary standard for pollutants is designed to protect welfare. The basic principles concerning utilities are (Heinz, 1991):

- Phase I: Utilities have to achieve an average system emission rate of 2.5 lbs of SO_2 per MBtu by 1995. 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states are affected.
- Phase II: Utilities are required to have an average system emission rate of 1.2 SO_2 lbs of per MBtu by 2000. All existing utility units with an output capacity of 25 MW or more and all new utility units will be affected.
- Post-2000: Any growth in emissions must be offset by an equal emission reduction from another source.

Options Available for meeting Acid Rain Legislation include (Gillen, 1991):

- Installation of Scrubbers
- Emission Reduction Technologies
- Fuel Switching
- Allowance Trading
- Unit Retirements
- Repowering

One of the most prominent results of the Clean Air Act Amendments is its effect on the coal industry. To meet the sulfur dioxide limits, utilities pushed industry for lower sulfur coal. Wisconsin utility coal information is shown in Table 2.2.2. The delivered cost in \$/MBtu vary from 1.09 to 1.94 \$/MBtu, while the sulfur contents, mining costs, and transportation costs for coal span an even broader range of values. It is sometimes advantageous to pay more for transportation to receive lower sulfur coal, and thus lower the costs of sulfur emissions.

Table 2.2.2: Wisconsin Coal Costs (PSCW-AP7: D24, 1994)

State of Origin	Coal 1000 tons	Heat Btu/lb	Sulfur % by wgt	Ash % by wgt	Mine-Mouth $/ton	Trans. Cost $/ton	Dlvd. Cost $/ton	Dlvd. Cost $/MBtu
CO	10	12731	0.46	11.40	$17.98	$17.98	$35.95	$1.41
IL	823	11834	1.48	6.89	$27.38	$6.85	$34.23	$1.45
IN	1411	11197	2.09	9.00	$34.66	$8.66	$43.32	$1.94
KT	446	12591	1.15	8.37	$25.82	$11.06	$36.88	$1.47
MT	1858	8794	0.67	8.08	$6.31	$20.43	$27.24	$1.55
NM	578	12394	0.55	12.49	$18.68	$18.68	$37.36	$1.51
PA	1534	13254	1.59	6.19	$29.16	$12.50	$41.65	$1.57
VA	62	14122	0.68	4.20	$30.56	$13.10	$43.65	$1.55
WV	282	12981	0.67	8.01	$30.14	$12.92	$43.05	$1.66
WY	10585	8635	0.34	4.94	$4.70	$14.09	$18.78	$1.09
Total	17589	9725	0.71	6.18	$12.02	$13.90	$25.92	$1.30

Notes: (1) The Delivered costs represent the average cost of coals delivered to Wisconsin for 1/92-12/92.
(2) Transportation and Mine to Mouth costs represent approximate average estimates.
(3) Figures do not include the NSP system or the WEPCO Presque Isle, Michigan Plant.
Sources: (A) All figures from "cost and Quality of Fuels for Electric Utility Plants 1992", DOE/EIA, August 1993, Table 22, p. 40, except for mine-mouth and transportation costs which represent approximate average estimates.
(B) FERC Form 423, "Monthly Report of Cost and Quality of Fuel for Electric Plants."

Another important result of the Clean Air Act Amendments of 1990 is that emission allowances can be traded. There is an SO_2 cap for the United States and utilities can buy and sell SO_2 allowances on the Chicago Board of Trade. If compliance with Title IV legislation is not achieved, the owners or operators of delinquent units must pay $2000 per excess ton of emissions (E.P.A., 1991). Violating units must also offset the excess SO_2 emissions with allowances in an amount equivalent to the excess. Even with these regulations, there are still local emission limits.

The economic incentive to reduce emissions, and the incentive to find less expensive way to control emissions is then left to the utility. If one utility puts scrubbers on their stacks, or invests more in renewables, thus producing less SO_2 emissions, they can sell their allowances to another utility which might be exceeding its allowable limits. The value of each emission can be thought of as the conservation cost versus the cost of buying more allowances. A New York Times article described an agreement between two utilities (Niagara Mohawk (NM of New York) and Arizona Public Service (APS)) in which Niagara Mohawk's sulfur dioxide allowances (obtained from APS in exchange for carbon dioxide reductions) were "donated" to an ecology group (Passell, 1994). The tax benefits that NM received for the SO_2 allowance retirements are then being invested in conservation programs. There was even one study about the profitability of one utility investing in another utility's DSM measures to save money, if they purchase electricity from that utility (Orans, 1993)!

> Take, for example, a decision about whether to build a new oil refinery or a coal fired plant that is projected to cost $1 billion and last 40 years. Air laws already require that such a facility have extensive pollution control equipment, but long before such an investment were amortized, the climate problem could have reached a point where the government requires the plant to be substantially modified or closed. Some electric utilities in the United States have begun to consider this issue of "regulatory risk", and there is early evidence that it has begun to shape their investment decisions. (Flavin, 1994)

2.2.3 Evaluation and Monetization of Externalities

Complexity and potential for debate are the most notable characteristics of environmental externality valuation. Which valuation method should be considered when setting a price on externalities: health effects, cost of defending world (U.S.) oil reserves in Kuwait, land and water use, aesthetics? If only airborne pollutants are to be considered, which ones? Should the level of emission be quantified or should a dollar value be placed on the net costs? Which method should be used; damage approach, cost/avoidance approach, risk assessment?

Another question is at what stage of the fuel cycle should these pollutants be quantified? In a study by the Thermal Storage Applications Research Center at the University of Wisconsin, source to site analyses were performed for different commercial cooling strategies. These included all aspects of transportation and processing. The environmental impacts of a specific end-use can be evaluated by tracing the electrical and gas demands back to their source where the fuel is extracted from the ground (Reindl, 1994). The reasoning for incorporation of environmental externality costs in utility resource decisions is best stated by F. Paul Bland:

> While it is difficult to quantify externalized costs, one cannot escape setting some value. A decision not to consider external costs in itself quantifies them by setting their value at zero. This is unreasonable, given both the strong evidence that the costs are massive, and the significant difference between externalized costs of traditional central station plants and alternative energy facilities. A crude approximation, made as exact as possible and changed over time to reflect new information, would be preferable to the manifestly unjust approximation caused by ignoring these costs. (Pace, 1990)

Valuation of pollution abatement is another manner in which the benefits of SDHW system investment can be quantified or monetized. By not considering the environmental cost of airborne pollutants, utilities monetize them, as $0/ton. There is much debate over what price to put on which pollutants. The actual amount of pollutant avoided through solar DHW systems remains the same, while the price that regulators or society place on it is extremely uncertain. The only security that utilities have where emissions are involved is that their value will increase. Thus, today's actual cost/ton becomes irrelevant in comparison to the actual amounts of each pollutant. But, as we (society) place a greater value on emissions reduction, more expensive systems with better emission reductions become more economical. In the Public Service Commission of Wisconsin analysis, the cost of emissions is not decided. A sliding scale is provided to plan for changes by asking what would it cost to achieve the same level of emission reduction and what is the best strategy to achieve that level.

Table 2.2.3: Monetization of Airborne Pollutants

Costs Per Ton of Airborne Emissions			
Pollutant	**PSCW**	**Mid-Range**	**High**
Carbon		$26	*
CO_2	$15.64	$15-$18	$26.45
SO_2	$250	$170 -$2000	$4006
N_2O	$2814.7	$2700	*
NO_X		$400-$1640	$7934
CH_4	$156.38	$150	*
Particulates		$2380	*

* Unavailable
CO_2: $26.45 Maine (Flavin, 1994)
SO_2: $2000 =EPA fine, ME=$1873/ton for SO_2 (Flavin, 1994) $4006/ton (Pace, 1990)
NO_2: $2700 (NARUC, 1994)
NO_X: $400/ton (WI DNR), $7934 Maine (Flavin, 1994)
Particulates: $2380 (Pace, 1990)

While the values shown in Table 2.2.3 are a range (Wisconsin PSC, mid-range, and high) from various published sources, the means by which those numbers were produced are varied. A schematic for the one valuation method is shown in Figure 2.2.1. The legal, moral and economic details associated with the valuation issue are beyond the scope of this thesis.

Although nuclear power plants are not being analyzed in this thesis, some interesting effects of their eminent retirements are given (Crowley, 1994):

> Only fifteen percent of the volume of materials at a nuclear site actually is affected by radiation during operations: However, the Office of Technical Assessment (OTA) says that the Decontamination and Decommissioning (D & D) for a large commercial power plant can generate more low-level waste than the plant itself generated during its operating life. To put that

into perspective, consider that the Nuclear Regulatory Commission (NRC) estimates a 1,100 MW light water reactor operated for its full 40 year license life will have generated 18,000 cubic meters (636,000 ft^3) of low-level waste, much of it contaminated metals and concrete. (Crowley, 1994)

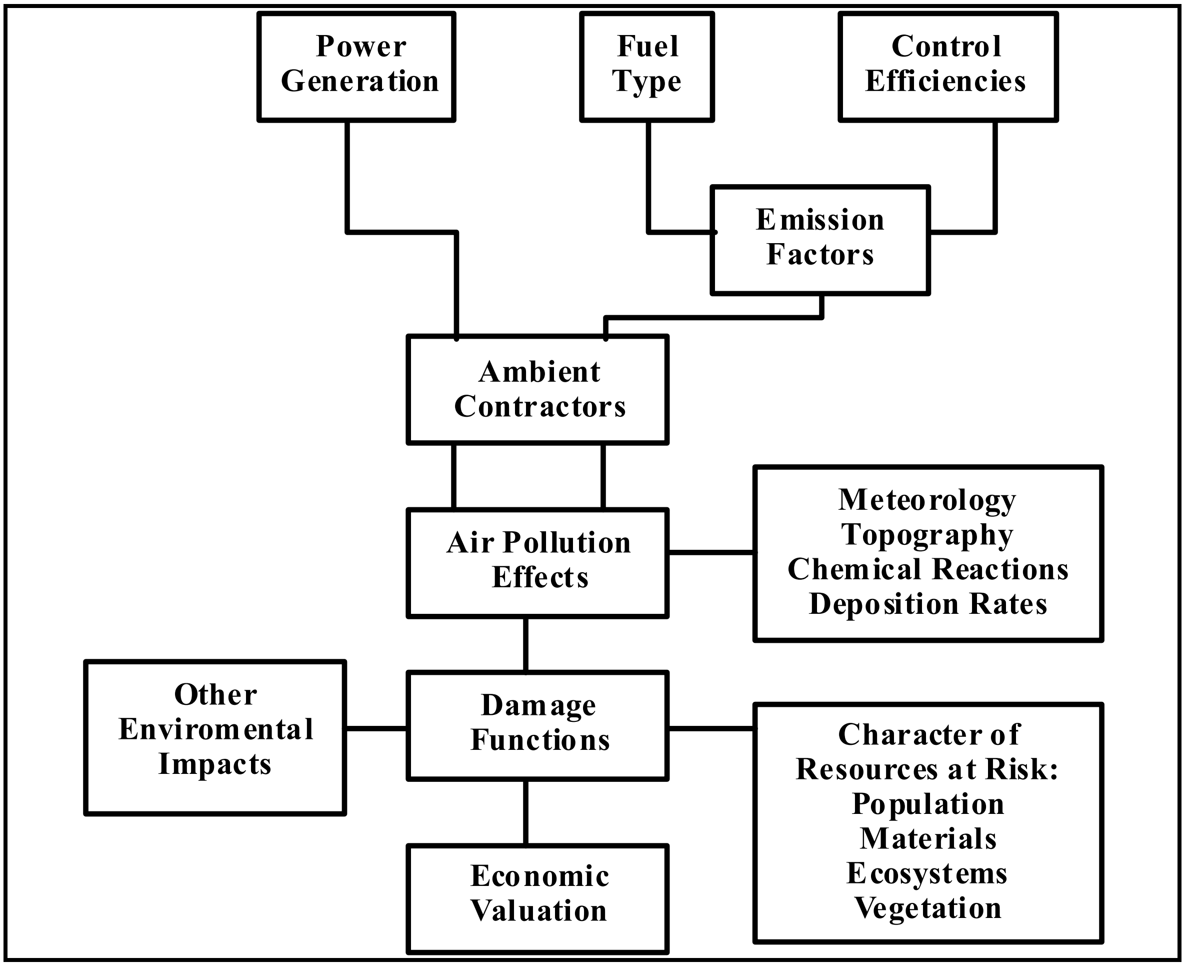

Figure 2.2.1: Schematic of Overall Methodology to Assess Air Pollution Externality Costs Associated with Electricity Generation (Pace, 1990)

Some public power utilities argue that the supposed cost of these externalities have already been internalized through their plant production, pollution, safety and control strategies. In addition, electric utilities resent the additional scrutiny that power producers receive in comparison to industry and other private sources, which are also responsible for many pollutants. Although electric utilities feel singled out, inclusion of environmental externalities from a utility planning perspective is not without merit. Integration of externalities into resource planning is already here. Utilities need to decide whether to take a pro-active or reactive stance towards their valuation.

In Advance Plan 6, Order Point 12.6 (PSCW, 1992):

> Utilities shall include the monetized values established in the Findings of Fact, regarding the risk of future greenhouse gas regulations, when determining the economic cost of a generating plant...Utilities shall include these values when comparing resource options in planning, when designing demand-side management (DSM) programs, and when implementing DSM programs. Utilities should also keep these values in mind when considering how to pass through the renewable resources to non-utility generators. ...Utilities are responsible for insuring that the monetized greenhouse costs are incorporated into the analysis consistently across utilities. (PSCW, 1992)

2.3 Cost Analysis Schemes

The benefits of solar DHW systems are savings from avoided generating capacity costs, avoided energy costs, avoided transmission and distribution cost (neglected here due to the variance) and avoided emissions. The term "avoided cost", as used throughout the Wisconsin Advance Plan documents refers to the definition determined by the PSCW in its AP6 Order, Appendix C (1992):

> The costs that the utility can avoid incurring if it is able to procure capacity and energy from a source other than conventional utility-owned and operated facilities, or if the utility does not have to meet an electric demand at all.

A classical approach to political economy is to achieve an efficient allocation of society's resources. As many costs as possible, including environmental, need to be integrated into the price of each good (unit of electricity) so that producers and consumers perceive the correct price that reflects the total cost their actions (NARUC, 1994). "The socially efficient solution equates the marginal cost of pollution abatement with the marginal social cost of pollution (Temple, 1990)". The last power plant unit dispatched ("turned on") is considered to be the marginal unit. Determining the type of generating equipment being dispatched to meet the electrical demand is the key to marginal emission analysis. The marginal plant varies as a function of time of day and time of year.

For DSM options, participation rates, program costs, free-riders, and naturally occurring conservation need to be analyzed. The real levelized revenue requirement of each option must be performed, including the MW and annual MWh saved at both the customer and generator level (PSCW-AP-7, 1994). The various types of cost analysis schemes that utilities use to screen DSM programs are shown in Table 2.3.1. For example, a Technical Cost screening of a DSM option would only include to costs and benefits marked with an "x" in the table. In Table 2.3.1, "non-electric" refers to natural gas utilities and customers. For a DSM program to be enacted, a positive benefit to cost ratio (greater than one) must be evaluated for more than one cost perspective; e.g., Total Resource Cost and Participant Cost. Thus, a DSM program's total benefits must be sufficient to overcome any program costs in order to be cost effective (Sim, 1991).

For this thesis utility cost analysis, costs are considered from only the Technical Cost perspective, excluding the program implementation expenses. The customer cost perspective is then performed using the Participant Cost perspective.

Table 2.3.1: Utility Cost Perspectives (EPRI, 1991)

Integrated Resource Planning Benefit/Cost Matrix

Perspective Components	Tech -nical Cost	Electric Revenue Require -ment	Total Resourc e Cost	Partici -pant	Electric Non-Partici -pant	Non-Electric Non-Partici -pant	Non-Electric Revenue Require -ment
COST							
Elec. Program		X	X		X		
Elec. Utility Equipment	X	X	X		X		
Elec. Utility Rebates		X			X		
Electric Utility Lost Revenue			X		X		
Non-elec. Supplier Equipment	X		X			X	X
Non-elec. Supplier Rebates						X	X
Non-elec. Supplier Increased Costs	X		X			X	X
Consumer Non-elec. Bill Increase						X	X
Customer Capitol & O&M	X		X	X			
BENEFIT							
Elec. Utility Fuel Savings & GHGs	X	X	X		X		
Elec. T&D Capacity Savings	X	X	X		X		
Non-elec. Supplier Revenue Increase							
Non-elec. Supplier Cost Reduction	X		X			X	X
Customer Elec. Bill Reduction				X			
Customer Elec. Rebates				X			
Customer Non-elec. Bill Reduction				X			
Customer non-elec. Rebates				X			
Total	*			*			
Total Costs	*			*			
Total Benefits	*			*			
Net Benefits	*			*			
Benefit/Cost Ratio	*			*			

2.4 Literature Review

Research has shown that the number of samples needed to characterize a diversified load is between one hundred and one thousand. Grater (1992) estimated that a sample size of five hundred hot water profiles was needed to achieve a diversified sampling pool. Warren (1993) showed that agreement between simulated and measured average use and demand of an ensemble of systems (<100) is adequate to provide confidence in the results of a larger number of simulated systems. In a Florida Solar Energy Center study, only eight different solar DHW systems were metered to estimate the demand reduction (from a utility perspective) of an ensemble of solar DHW systems (Merrigan, 1994). The diversified hot water demand from a sample size of ten is significantly higher than the average demand of three hundred (see Chapter 3.2.2 Diversified Demand Sample Size).

Sample size itself is not the only problem. Randomizing a wide range of average hot water draws to achieve a diversified hot water demand (Grater, 1992) does not work. Grater's random profiles were not individual water draws. His "individual" profiles were either average loads, or unrealistic limiting cases. The Wisconsin Energy Bureau (Draft, 1993) extracted an average Wisconsin household daily hot water use estimate, absent of any timing information, from an annual hot water usage statistic (by dividing by the number of days in a year and the number of households in the sample). Extrapolating a daily hot water usage total from an annual total is inaccurate for demand reduction analysis since the incidence of the individual profiles is as important as the amount of the water draw. Average daily use statistics can only be used for average energy analyses. An Advance Plan 7 Solar Task force used the same method with F-Chart and daily gallon estimates to reach the following decision about solar DHW impact on Wisconsin:

> <u>AP-7 Solar Task Force Conclusions (1993):</u>
>
> "Therefor(e), under current assumptions and analysis methodology, no significant penetrations of solar water heating or PV systems are expected to become cost effective in the foreseeable future...."

The previous Wisconsin Energy Bureau and PSCW studies were performed without giving any credit for demand reduction. Yet in 1991, a research team predicted that SDHW systems could reliably displace 1.3 kW of capacity and allow for $1500 utility rebates (Carpenter et al., 1991). This study was performed in Canada, which has a much harsher climate than Wisconsin.

Some studies compare the electric demands in different geographical locations. The peak electric demand reductions during different seasons and the peak electric demands in much warmer climates, such as Florida, are distorted comparisons. In a study of commercial solar water heating, demand reductions of three different locations were compared (Florida, Texas, and North Carolina) yielding significantly different results (with similar sample sizes (20 sites)) (Ewart, 1991). Such differences in electric water heating demand (from a utility perspective) are evident for a few reasons. Comparison studies of solar and electric DHW demands in different utility service territories are constrained by water mains temperature differences, DHW system placement, and ambient temperatures. Most northern climate DHW systems are inside the home (e.g. a basement with relatively constant ambient temperatures), so the losses throughout the year are relatively constant. Therefore, the seasonal load follows the mains temperature variation (see Chapter 4.4: Mains Water Temperatures). In Florida, most DHW systems are outside in a garage so their losses vary throughout the year, following outside ambient temperatures. Depending on the water mains source (lake, ground well etc.) the temperatures can range from 40 to 90 °F, so the seasonal electric demand variance of southern DHW systems can be much greater than that in Wisconsin.