5-1-1994

Selected Topics on Demand Side Management

S. Alyasin
Purdue University School of Electrical Engineering

L. Chung
Purdue University School of Electrical Engineering

D Gotham
Purdue University School of Electrical Engineering

D. Hu
Purdue University School of Electrical Engineering

B. Kwon
Purdue University School of Electrical Engineering

See next page for additional authors

Authors
S. Alyasin, L. Chung, D Gotham, D. Hu, B. Kwon, J. Lee, A. Mok, A. Risal, and R. Sasaki

SELECTED TOPICS ON DEMAND SIDE MANAGEMENT

S. ALYASIN
L. CHUNG
D. GOTHAM
D. HU
B. KWON
J. LEE
A. MOK
A. RISAL
R. SASAKI

TR-EE 94-14
MAY 1994

SCHOOL OF ELECTRICAL ENGINEERING
PURDUE UNIVERSITY
WEST LAFAYETTE, INDIANA 47907-1285

Selected Topics on Demand Side Management

S. Alyasin
L. Chung
D. Gotham
D. Hu
B. Kwon
J. Lee
A. Mok
A. Risal
R. Sasaki

Preface

Each year in the graduate course on "Economic Dispatch and Control of Integrated Power Systems," the students prepare a term project which is assembled into a report. This year, the assigned topic relates to demand side management. This topic appears to be especially timely and, because it relates to the revenue derived by the electric utility.

The term demand side management (DSM) refers to modification of power system demand by some means in order to obtain better load factor characteristics. The study of DSM has many unresolved issues - many stem from the fact that the electric utility industry is regulated, costs are often difficult to assign to the sector that causes those costs, and governmental regulations are not always consistent with physical laws. Most power engineers feel that DSM has the potential of substantial industry-wide savings. Hopefully some of these points come through in the student presentations.

G. T. Heydt
May, 1994

Table of Contents

Chapter I

Compact Fluorescent Lighting

Alan C. Mok

I.1 Introduction

Over the last decade, electric utilities have become more concerned with meeting increasing requirements for new generating capacity. However, environmental opposition has made expansion in generation and transmission capacities extremely difficult. As the utilities are trying to minimize the environmental impact and other indirect costs associated with electricity supply, measures to promote electricity end-use efficiency are advocated as a cost-effective means to reduce the growth of electricity demand. The term demand side management (DSM) is commonly used to refer to the programs employed by electric utilities that aim to reduce the energy demanded. Although this reduces the revenues for the utility, the utility saves more money because of the avoided additional generation and transmission requirements.

In 1991, more than 2,300 DSM programs were implemented in residential, commercial, and industrial sectors. DSM spending cut U.S. summer peak demand by 26,700 MW (4.8 percent) and cut annual electricity use by 23,300 GWh (0.9 percent of the retail sales) [6]. About one-third of DSM programs are related to the use of energy-efficient lighting. Utilities promote the use of compact fluorescent lamps (CFLs) to their customers because CFLs use one-third to one-forth of the energy needed to produce the same output as incandescent lamps. Also, CFLs last up to 10 times longer. [4].

CFL technology was first introduced in the early 1980s. By the mid-1980's the market had expanded primarily due to the increase in retrofit of the incandescent lamp sales. This is mainly due to the fact that consumers were more aware of the benefits of CF lamps because of promotion by utility companies. Between 1988 and 1990, the **U.S.** shipment of CFLs almost doubled. It is forecasted that the demand for CFLs will increase by 280% between 1991 and 1995 [6]. From these figures, CFL obviously plays a major role in DSM in the electric utility industry.

In this paper, the basic theory of CFLs, their classification scheme, and the types of ballast are first described. Next, the attributes and the applications of CFL are presented, followed by the lighting programs offered by utilities in residential, commercial, and industrial sectors. Finally, the CFL market in the **U.S.** is briefly discussed

1.2 Fluorescent lamps

I.2.1 Basic theory of light generation by fluorescent lamps

Fluorescent lamps are examples of low-pressure gaseous discharge lamps. Electrical current passes through the electrodes, which are wire-wound high-resistance coils, and heats up the electrodes. Electrons are emitted from the electrodes and bombarded with the mercury atoms inside the discharge tube. This collision results in generation of heat, which subsequently excites the electrons of the mercury atoms to a higher energy level state. Due to the electrostatic force generated by the mercury atom, the excited electrons return to their normal energy states. The energy gained by this returning electron will be released as a form of electromagnetic radiation. This form of energy is converted into visible light spectrum by means of the fluorescent powder coating inside of the discharge tube [7].

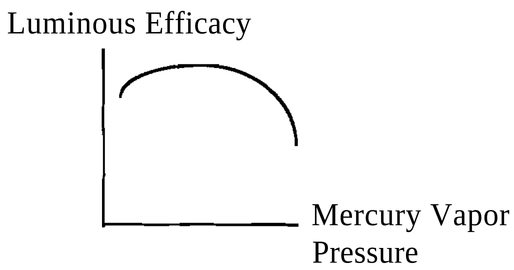
I.2.2 Critical factors determining the illumination

The critical factors that determine the light output of the fluorescent lamp are mercury vapor pressure, auxiliary gas, current density, and the discharge tube dimensions [7].

1.2.2.1 Mercury vapor pressure

Figure I.1 shows the luminous efficacy versus the mercury vapor pressure. The term luminous efficacy is defined as the light intensity in lumens per watt input. The gas pressure increases as the temperature rises by the gas pressure law. As the temperature increases, the probability that an electron will excite a mercury atom increases. The result is an increase in light illumination level. The higher is the temperature, the higher the probability the mercury atoms get excited. Therefore, the stronger the light intensity is . Above a certain vapor pressure, the light intensity decreases due to the self-absorption of the radiation [7].

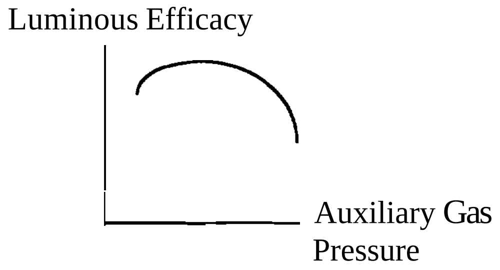
Figure I.1 Luminous Efficacy Versus Mercury Vapor Pressure



1.2.2.2 Auxiliary gas

Auxiliary gas is crucial in lamp starting. Figure 1.2 shows the luminous efficacy versus the auxiliary gas pressure. Without the presence of auxiliary gas, the mean free path (mean distance covered by free electrons after two collisions) of the free electrons is too great to excite the mercury vapor atom. The auxiliary gas, usually krypton, is added into the discharge tube to reduce the mean free path length. As auxiliary gas pressure increases, the elastic collisions between the free electrons and auxiliary gas increases. These collisions absorb some of the excitation energy of the mercury atom and thereby decrease the illumination [7].

Figure 1.2 Luminous Efficacy Versus Auxiliary Gas Pressure



I.2.2.3 Current density

As the current input to the electrodes increases, more free electrons are released from the electrodes. As a result, more mercury atoms get excited, the temperature goes up, and an increase in illumination level occurs. The term current density is used since the tube wall dimensions are fixed. Therefore, a higher current means higher current density [7].

I.2.2.4 Discharge tube dimensions

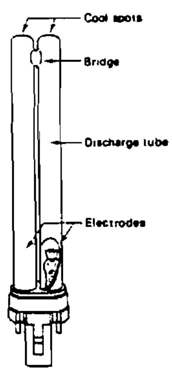
The length of the discharge tube dictates the lamp power. Lamp power is a function of lamp current and voltage. The lamp voltage consists of anode, cathode, and arc voltages. The arc voltage is the voltage across the discharge column between the electrodes. Since the anode and cathode voltages are constant, if the lamp current does not change there must be a proportionate increase in arc voltage with increasing tube length. Luminous efficacy also increases with lamp length because the electrode losses become lower in proportion to the total lamp power [7].

1.3 Compact fluorescent lamps

I.3.1 Classification scheme of CFLs

Figure 1.3 illustrates the compact fluorescent lamp. The lamp consists of two parallel discharge tubes connected by a narrow bridge near the end away from the electrodes. The overall lamp length is thus reduced by half. This design is called the "twin" configuration. For a 5 to 13 watt CFL, the approximate length is 4" to 6.5" as compared to 7" for an incandescent lamp.

Figure 1.3 Compact Fluorescent Lamp



Another design, known as the "quad" configuration, involves decreasing the tube length once more by "folding" each tube. This is more compact than the comparable twin tubes and delivers almost twice as much power.

As with the different configurations for CFLs, the diameter of the: tube size can be varied. The two common diameter sizes are T-4 and T-5. The "T" means tube configuration. The number stands for lamp diameter in eighths of an inch. For example, a T-4 twin-configured CFL has a tube diameter is 4/8 of an inch. Table I.1 summarize the classification scheme.

Table I.1 CFL classification scheme

Configuration	Classification	Lamp Wattage	Length
Twin	T4 /T5	5-13	4.5 - 7”
Quad	T4	9-26	4.5 - 8"

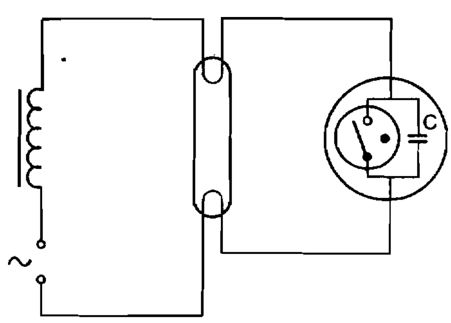
I.3.3 Ballast

The main function of the ballast is to create a high initial voltage *toionize the gas in the lamp and then to limit the current through the gas after the lamp has started. Ballasts are available in internal and external configuration. The internal configuration is known as integral ballast, meaning that all the components of the ballast are includecl in the lamp and are usually located in the base of the lamp. External configured ballast is called adapter ballast, and is separated from the lamp. Since the adapter ballast usually lasts longer than the lamp, replacement of the lamp will be cheaper than the CFL with integral ballast. There are two main kinds of ballast available for the lamps: electromagnetic and electronic.

I.3.3.1 Electromagnetic ballast

A schematic diagram of an electromagnetic ballast is presented in Figure 1.4.

Figure 1.4 Electromagnetic Ballast

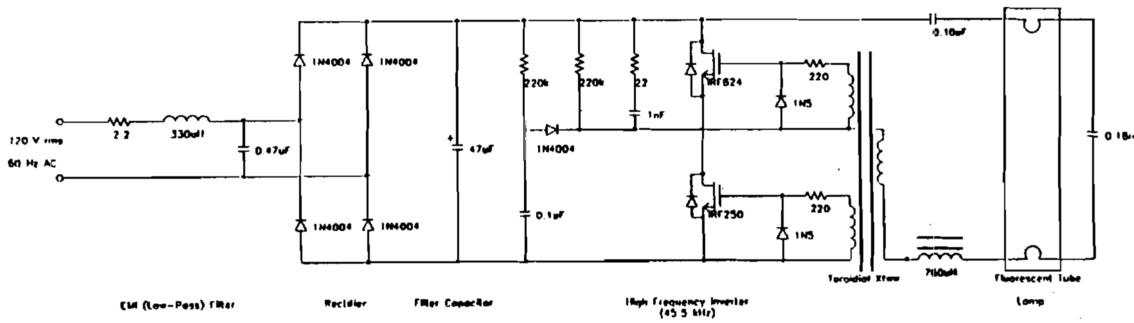


Electromagnetic ballast consist of a wire-wound high-resistance coil used to limit the current drawn by the lamp. When the CFL is connect to a voltage source, current flows through the electrodes and the switch. When the switch is open, the magnetic field built up in the ballast coil causes a voltage peak between the electrodes, sufficient to ionize the mercury atoms and start the lamp. Advantages in using this kind of ballast include low cost and a fast starting time for the lamp. Disadvantages are: (1) this type of ballast consumes 15-20% of rate lamp wattage due to the high-resistance coil, (2) it is bulky and very heavy, and (3) it is low in power factor.

1.3.3.2 Electronic ballast

Figure 1.5 shows a typical configuration of an electronic ballast.

Figure I.5 Typical Schematic Diagram of Electronic Ballast



The AC line voltage is first converted into a DC voltage using a full-wave bridge rectifier and a filter capacitor. An inverter then converts the DC voltage into the high-frequency (typically from 25 to 50kHz) AC voltage which supplies to the lamp. Advantages of this scheme include light weight, decreased hum, and increased efficacy and lamp life when compared to the use of an electromagnetic ballast. The main disadvantage of this type of ballast is that it creates high current harmonic distortion

I.4 Attributes of compact fluorescent and incandescent lamps

I.4.1 Characteristics

The characteristics of different kinds of CFLs are shown in Table 1.2 [4].

Table 1.2 Characteristics of different CFLs

Lamp Type	Ballast Type	Lamp Wattage	Efficacy	Lamp Life'	Overall Length
Incandescent	none	25-150	8-20	750-2,000	< 7”
T-4 Twin Tube	magnetic	5-13	25-50	10,000	4-7.5”
T-4 Quad Tube	magnetic	9-26	35-55	10,000	4.5 - 8"
T-5 Twin Tube	magnetic electronic	15[2] 7-27	45-50 55-65	9,000 9,000-10,000	6-9" 5-8”
Circline	magnetic electronic	20-40 22-30	35-60 80-85	12,000 9,000	6.5 -16"

1 Lamp life in hours, based on 3 hours per start
2 Includes ballast wattage

I.4.2 Advantages in using CFLs

The advantages of using these lights can be summarized as follows:

- They have efficacy 3-4 times higher than that of the incandescent lamp.
- They typically have 8-10 times longer rated life than the incandescent lamp.
- They produce light with excellent color rendering, similar to that of incandescent lamps
- Reduced Cooling Load -- CFLs reduce lighting load and thereby reduce air-conditioning load. Estimated savings from reduced cooling requirement is 10-30%.
- Cost Savings -- Although the initial investment for the lamp is higher than the incandescent lamp, the money saved through reduced energy use and fewer lamp replacements can quickly return the initial investment.

I.4.3 Disadvantages in using CFLs

The main disadvantages of using CFLs are as follows:

- Low power factor

Due to the inductive nature of the ballast, most CFLs have poor lagging power factor, which typically range from 0.45 to 0.65 [1].

- Dependency on ambient temperature

The efficacy of the CFL depends on the ambient temperature. When the ambient temperature is low, the mercury vapor pressure is low by the gas pressure law. This causes a decrease in light efficacy. Excessively low ambient temperature (below 0 Clelsius) can reduce the total output by 10-20 percent [4]. Also, this form of lighting may not be able to start when the ambient temperature drops below 2 C.

- High current harmonic distortion

CFLs with electronic ballasts have high current total harmonic distortion (THD) due to the inverter in the ballast. CFLs with magnetic ballasts does not have: as high a THD but has less efficacy and versatility than the CFLs with electronic ballasts [5].

Table 1.3 illustrates the power factor and current harmonic distortions of the CFLs and the incandescent lamps [2].

Table 1.3 Power Factor/Harmonic Distortions of CFL and Incandescent Lamps

	Incandescent	CFL (60Hz)			CFL (High Freq)		
Power (W)	100	7	15	20	11	15	20
Current (A)	0.85	0.16	0.40	0.33	0.13	0.18	0.23
Ballast	-	M	M	M	E	E	E
PF	1.00	0.47	0.41	0.51	0.67	0.65	0.64
Eff (LM/W)	17.20	34	28	51	57	65	59
Harmonics (%)							
3rd	2.9	8.1	17.8	12.4	79.4	81.3	64.5
5th	2.0	2.3	1.9	2.3	48.5	50.8	35.1
7th	1.1	1.1	1.3	2.2	18.4	20.6	40.8
9th	0.4	0.6	0.2	1.1	13.5	16.2	35.1
THD	3.7	8.1	18.0	12.5	100	106	98

E - Electronic Ballast
M - Electro-magnetic Ballast

1.5 Applications of CFL

Due to the poor luminous efficacy performance of CFL in cold temperatures, outdoor applications of CFLs are few. Also, They might not be suitable for ceilings higher than 12 feet. Table 1.4 summarizes applications of different kinds of CFLs [4].

Table 1.4 Applications of CFLs

	Down-lights	Surface Lights	Pendant Fixtures	2'x2' Fixtures	Sconces	Exit/ Step	Flood-lights
Incandescent	+	+	+	-	+	+	+
T-4 Twin Tube	+	+	-		+	+	+
T-4 Quad-Tube	+	+	+	-	+	-	-
T-5 Twin Tube	-	+	-	++	+		
Integral Ballast Lamp	+	-	+	-	-	-	-
Circline	-	+	+		+	-	-
Reflector Unit	++	-	+		-	-	+

++ **Uniquely superior lamp choice**
+ **Suitable lamp choice**
Unsuitable lamp choice

1.5 Residential, commercial, and industrial lighting program offered by utilities

Lighting programs in the U.S. for commercial and industrial customers used by utilities to promote CFLs can be grouped into 5 categories [3]:

- Information programs
  This involves mailing brochures that educate customers about the benefit of using energy-efficient lighting. Another approach is to provide a lighting audit in which a utility conducts a walk-through survey of a facility and provides a list of recommended lighting improvements to the customer [3].

- Rebate programs

  These programs offer CFLs to their customers free or at low cost. In addition, many utilities also try to encourage participation through personal contacts with lighting dealers and larger customers. The most common form of rebate is through direct mail offers [8].

- Direct installation programs

  In general, utilities will do a lighting audit to determine the lighting efficiency measures. Then, utilities pay for all or most of the cost of the lighting equipment and its installation. These programs are usually aimed at small commercial and industrial customers (peak demand of less that 50kW to 100kW), as they are less likely to participate in the rebate-type program [3].

- Loan and leasing programs

  A few utilities offer this type of program for commercial and industrial customers. In this program, utilities finance customer conservation investments at interest rate ranging from 0% up to the utility's cost of capital (12%) [9]. Some utilities, such as Florida Power and Light, offer customers a leasing program. In this scheme, utilities lease the energy efficient lighting to the customers. The incentive is that the customer needs to use a minimum amount of energy per day so that the savings from the lighting is greater than the lease payment [9].

- New construction programs

  In these programs, utilities usually offer comprehensive training and technical assistance, free computer simulations, financial incentives for additional design time undertaken by the project design team, and post-construction building services. Most of these programs offer rebates up to the full incremental cost of efficiency measures. Example of these programs include the Bonneville Power Adminstration's Energy Edge Program. This program reduces the energy use of participating office buildings by 33% compared to prevailing local construction practices. An estimated of 34% of these savings were due to lighting measures [9].

In the residential sector, utilities emphasize CFLs because of the large savings and their long life. General programs to promote energy efficient lighting programs are categorized as follows:

- Rebate and coupon programs

  'This program is widely used by utilities to promote CFL. In this program, customers receive rebates and coupons to offset the high cost of CFL. A representative example is PSI Energy giving away the light bulbs and rebate coupons to its residential customers. A total of more than 7,000 lamps have been given away [8] .

- Mail Order and Charity Sales

  Mail order programs bypass the traditional retailers and make CFL directly available to the customers at a lower cost. Usually, utilities buy the lights in bulk quantity at substantial discounts. Then, they offer the lights to the customers at the price they paid. One of the most successful programs of this type is run by Wisconsin Electric. In one year, 7% of the utility's residential customers purchased the bulb [8].

- Direct Installation Programs

  These programs provide customers with CFL plus assistance with installation. They are usually implemented in conjunction with other conservation programs. For example, free CFLs are given out to the customers during energy audits. Since the utility workers are at home sites, the incremental cost for these kind of program is relatively low [8].

- Leasing programs

  'These programs are currently offered by the cities of Taunton, MA and Burlington, 'VT. As with commercial and industrial customers, lighting is leased to residential customers. As long as the customers use the lamps at least 1.5 hours each day, the energy savings will offset the lease payment [9].

- New Construction Programs

  'These programs primarily target improvements to building lightings, heating, and cooling systems, and the installation of the fluorescent fixtures in homes. For example, utilities in Massachusetts offer $25 for hard-wire fluorescent fixtures [9].

Tables 1.5 and 1.6 show the participation level of each program, the general cost of the program in dollars per kWh, and the associated reduction in electric use for commercial, industrial sector, and residential sectors, respectively.

Table 1.5 Comparison of participation level, cost and reduction in energy used for commerical and industrial customers

Programs	Commercial /Industrial Customers		
	Participation Level	Cost ($/kWh)	Reduction in Electric Use (%)
Informational	Low (<3%)	NA	NA
Rebate	Medium (1-10%)	10.02	6-7
Direct Installation	High (> 15%)	0.012-0.048	10-23
Loan/Leasing	Low (1-2%)	0.029	7-9
New Construction	Low (2-3%)	0.027	34

Table 1.6 Comparison of participation level, cost and reduction in energy used by residential customers

Programs	Residential Customers		
	Participation Level	Cost ($/kWh)	Reduction in Electric Use (%)
Rebate/Coupons	Low (3-5%)	0.037	6-7
Mail Order	Medium (7%)	0.02	6-7
Direct Installation	High (40-60%)	0.04	7-10
Loan/Leasing	Low (5%)	0.025	3-5
New Construction	NA	NA	NA

1.6 The CFL market

The CFL market has been expanding exponentially since the 1980's due to the following reasons:

(1) The general public is more aware of the energy savings due to the promotional programs of utilities.

(2) Utilities are vigorously promoting energy efficient lighting such as CFLs to curb down the electricity demand.

(3) More CFLs are available in retail stores than in the past and the cost is $5-$10 less per bulb than in the past.

Table 1.7 shows the estimated total number of CFLs sold in the **U.S** from 1988 to 1995 [6]. Please note that the figures for 1994 and 1995 are projections.

Table 1.7 Estimated total number of CFL sold each year in US

Year	1988	1989	1990	1991	1992	1993	1994	1995
# CFLs (mil)	9.8	11.6	16.7	25.2	35.6	47.0	58.8	71.8

Table 1.8 shows the shipment of power-factor corrected ballasts in thousands history and projection [6]. The figures for 1994 and 1995 are projections.

TableI.8 **US** Shipment of ballast from 1988 - 1995

Ballast Type	1988	1989	1990	1991	1992	1993	1994	1995
Magnetic	56,280	58,070	55,675	53,000	53,700	53,200	48,500	43,100
Electronic	1,220	1,550	3,070	6,390	9,100	13,900	19,100	27,980
Total	57,500	59,600	58,745	59,390	62,800	67,200	67,610	71,080

1.7 Conclusion

CFLs are available in a variety of shapes and sizes. T4 and T5 twin and quad tubes are among the most common lights available in the market. They have greater efficacy, longer life, better color rendering, and better cost savings than incandescent lamps. Because of these characteristics, utilities have been promoting the use: of CFLs as a lighting alternative in their DSM programs. Up to this date, there are more than 2300 DSM programs found in the US. About one-third promote energy-efficient lighting. US shipment of CFLs and ballasts has increased on the average of 10% each year since 1988.

Despite the attractive characteristics of CFLs, there are three main disadvantages of using them: (1) poor power factor, (2) high current harmonic distortions, and (3) ambient temperature dependency. The first two disadvantages have brought up some power quality issues in the distribution network. The last one makes CFLs unsuitable for outdoor use in cold temperatures. Nevertheless, the use of CFLs are expected continue to rise in the future.

LIST OF REFERENCES

W. R. Alling, O.C. Morse, and R. R. Verderber, "Harmonics from Compact Fluorescent Lamps," IEEE-IAS Conference, Sept. 28 - Oct. 4, 1991.

Rejean Arseneau, Micheal Ouellette, Steve Treado, and Micheal Simonovitch, "New Program for Investigating the Performance of Compact Fluorescent Lighting System," IEEE Trans on PAS, vol 3, pp. 1895-1897, May 1991.

Barbara A. Atkinson, James E. McMahon, and Srven M. Nadel, " A Review of U.S. and Canadian Lighting Programs for the Residential, Commercial, and Industrial Sectors," Energy, vol. 18, no. 2, pp. 145-158, 1993.

Electric Power Research Institute, "Compact Fluorescent Lamps," EPRI Technical Briefs, 1993.

E. E. Hammer, "Fluorescent System Interactions with Electronic Ballast," Journal of the Illuminating Engineering Society, Winter, 1991.

Kark Johnson, Erich Unterwurzacher, "Ensuring Market Supply and Penetration of Efficient Lighting Technologies," Energy, vol. 18, no. 2, pp. 163-170, 1993.

[7] Chr. Meyer, H. Nienhuis, Discharge Lamps, Scholium International, Inc., 1988.

[8] Bent Nielsen, "Load-Shape Data For Residential Lighting: Survey Results for Incandescent and Compact Fluorescent Lamps," Energy, vol. 18, no. 2, pp. 211-217, 1993.

Micheal Ouellette, "The Evaluation of Compact Fluorescent Lamps for Energy Conversion," National Research Council Institute for Research in Construction, September 9, 1993.

CHAPTER II

THERMAL STORAGE TECHNIQUES

LING CHUNG

II.1 Introduction

There are two kinds of thermal storage, one is heat storage and the other is cold (ice) storage. The main game here is to reduce the peak load despite the overall energy consumes may increases.

All thermal storage devices contain certain energy-abosrbing materials that are capable of producing some form of phase change, usually a freezing/melting or solid/liquid phase transformation. In these instances the energy is said to be store as latent heat, and the material itself is so called phase-change materials, or PCM. Since a thermal storage device may have its special application, selecting a proper PCM is the most important part in designing the device. The properties of some PCMs are discussed in the section 2.

Section 3 introduces some of heat batteries in the market. Section 4 discusses the usage of nature resources such as long term seasonal storage and geothermal energy. A summary is given in section 5.

IV.2 Phase-Change Materials

There are several hundreds of PCMs that are technically identified. They can be grouped into organic and inorganic. Paraffin wax is the only organic now used to an appreciable extent. Usually, inorganic PCMs are salt hydrates. Most commercial development has been on residential heating or cooling applications for salt hydrates. A perfect PCM should have the following properties:

* High heat capacity,
* Good heat transfer properties,
* Desirable fusion temperature point,
* Stable during heat cycling (would not decompose),
* No harmful to the environment,
* No corrosion to the piping,
* Low cost.

II.2.1 Organics

Organic PCMs suffer by comparison with inorganic salt hydrates by having poorer heat transfer properties, lower density, and greater fire hazard. In general, they are more costly than inorganics. Therefore, an inorganic PCM is usually selected for a given application, unless no suitable candidate is available. Paraffin wax is the most successful organic PCM used in commercial solar applications since no suitable salt hydrate PCMs that melt in the 35 to 50°C range.

Other oraganics have been suggested for PCM use, for instant, fatty acids. Like paraffin, fatty acids depend on the heat of crystalliization of linear, saturated hydrocarbon chain. Both fatty acids and paraffin wax are available commercially in bulk as mixtures of compounds. However, fatty acids have not found application in heat storage.

II.2.2 Salt Hydrates

The Salt hydrate PCMs now available commercially or as developmental products offer a selection of melting points from 7 to 117°C. It is possible to choose a material that matches well the desired operating temperatures of most heating or cooling systems. They offer good heats of fusion and heat transfer properties are generally good, though some suffer in this respect by being thickened and gelled to reduce segregation.

The best way to study a PCM is to look at its phase diagram. Figure II.2.2.1 and Table II.2.2.1 show the phase diagram and the thermalphysical properties of one of the most popular congruent-melting PCM, calcium chloride hexahydrate ($CaCl_2 \cdot 6H_2O$). This inexpensive PCM has been widely used in thermal storage applications.

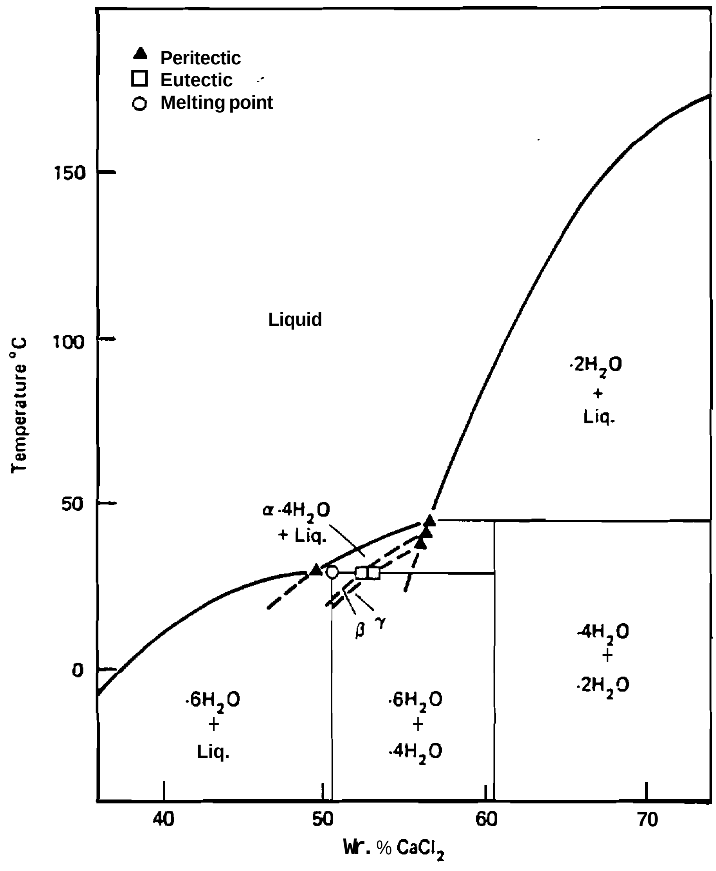


Figure II.2.2.1. Phase diagram of calcium chloride and water. [1]

Table II.2.2.1

Thermalphysical properties of commercial $CaCl_2 \cdot 6H_2O$ PCM

	Metric	SI	English
Melting point	29.6°C	302.8 K	85.3°F
Boiling point	132°C	405 K	270°F
Heat of fusion	45.6 cal/g	190.8 kJ/kg	82.1 BTU/lb
Heat of solution in water	17.2 cal/g	72.0 kJ/kg	31.0 BTU/lb
Heat of formation (25°C)	−623.0 kcal/mol	−2.6079 MJ/mol	−2472 BTU/mol
Specific heat			
Liquid. 48°C(118°F)	0.502 cal/g°C	2.10 kJ/kg K	0.502 BTU/lb°F
Solid, 16°C(61°F)	0.340 cal/g°C	1.42 kJ/kg K	0.340 BTU/lb°F
Thermal conductivity			
Liquid, 39°C(102°F)	1.29×10^{-3} cal/cm sec°C	0.540 W/m K	0.312 BTU/hr ft°F
Solid, 23°C(73°F)	2.60×10^{-3} cal/cm sec°C	1.088 Wlm K	0.629 BTU/hr ft°F
Density			
Liquid. 32°C(90°F)	1.562 g/cm³	1.562 x 10' kg/m³	97.5 lb/ft³
Solid, 24°C(75°F)	1.802 g/cm³	1.802×10^3 kg/m³	112.5 lb/ft³
Vapor pressure (29°C	7 mmHg	933 Pa	0.14 lb/in²
Surface tension (25°C)	103 dynefcm	0.103 Kg/sec²	7.02×10^{-5} lb/ft
Viscosity (50°C)	11.80 cps	0.0118 Kg/m/sec	28.6 lb/ft/hr
Molecular weight	219.0784 g/mol	219.0784 g/mol	0.4829852 lb/mol
Percent salt	50.66 wt%		
Percent waler	49.34 wt%		

The available salt hydrate PCMs display a vapor pressure, due to their water content, and higher the temperature, the greater the pressure. They all should be used in sealed containers which have low water vapor transmission rates. Besides, salt hydrates have high densities, but undergo a. volume change on freezing.

Supercooling is a problem for the salt hydrate PCMs, and nucleators are needed. Each PCM has its own favorable additive. Some of the additives may be toxic, but they are still acceptable due to the tiny amounts used.

Figure II.2.2.2 and Table II.2.2.2 give a list of some commercial available salt hydrate PCMs. In general, if a congruent-melting or eutectic PCM is available in the right temperature range, it should be chosen, rather than a semicongruent or incongurent material. There may be exceptions, however, due to cost or toxicity, for example. Lackiing a suitable nonsegregating PCM, a stabilized noncongurent candidate may be picked. There are three stabilization techniques appear to be proven so far: mechanical **agitation,** microencapsulation, and gellation. Not all these have proven out for every PCM, and the system designer should demand proof of stability in actual working devices.

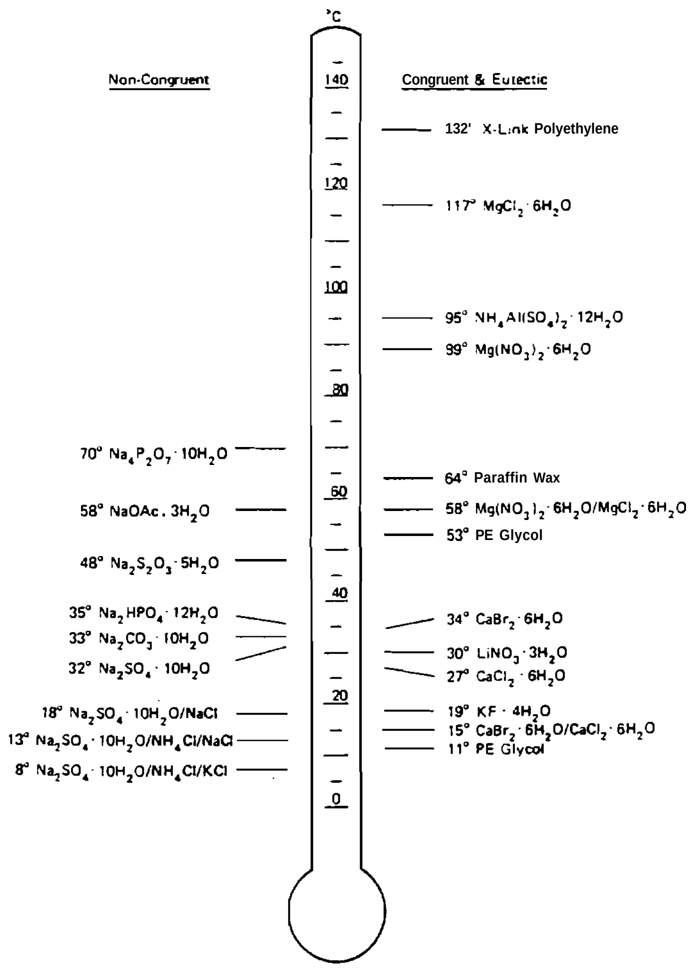


Figure II.2.2.2. Principal salt hydrate PCM candidates. [1]

Table II.2.2.2

Some commercial available salt hydrate PCMs

Phase change material	Type	Melting point (°C)	Source
$MgCl_2 \cdot 6H_2O$	Quasi-congruent	117	Dow*
$Mg(NO_3)_2 \cdot 6H_2O$	Congruent	89	Dow*
$Na_4P_2O_7 \cdot 10H_2O$	Incongruent	70	Calor
$NaOAc \cdot 3H_2O$	Incongruent	58	Calor*
$MgCl_2 \cdot 6H_2O/Mg(NO_3)_2 \cdot 6H_2O$	Eutectic	58	Dow*
Paraffin wax	Congruent	50	Various
$Na_2S_2O_3 \cdot 5H_2O$	Semicongruent	48	Allied. Calor*
Neopentyl glycol	Congruent	43	Eastman*
$CaBr_2 \cdot 6H_2O$	Congruent	34	Dow*
$Na_2SO_4 \cdot 10H_2O$	Incongruent	32	Calor.* various
$CaCl_2 \cdot 6H_2O$	Semicongruent	28	Solvay*
$CaCl_2 \cdot 6H_2O$	Congruent	27	Dow*
PE glycol	Congruent	23	Various
$Na_2SO_4 \cdot 10H_2O/NaCl$	Incongruent	18	Calor.* various
$CaBr_2 \cdot 6H_2O/CaCl_2 \cdot 6H_2O$	Isomorphous	15	Dow*
$Na_2SO_4 \cdot 10H_2O/KCl/NH_4Cl$	Incongruent	8	Calor*

* Marketed specifically for thermal energy storage

Each of the stabilization techniques carries with it a penalty. Thickening and gelling additives reduce the heat of fusion and add to the cost, as do encapsulant materials. Mechanical equipment adds to the expense complexity, and requires power to operate.

II.3 Storage Systems

A storage device usually contains a PCM container, pumps, controls, valves, a heat exchanger, a heater or a cooler. The PCM is charged during off-peak period or by some waste heat such as the ejected heat of a cloth dryer and then discharged during the peak period. Some of the devices work with the solar energy systems in order save more charging fee. 'The main issues concerned by a system designer are:

1. Size of the systems should be just big enough to fit the peak period, otherwise, it is waste of money.

2. Good insulation is required to improve the system efficiency and reduce energy losses.

3. Proper selection of material and design for the PCM container not only increase the system life-time, but also improve the its efficiency by reducing the water moisture transmission and corrosion inside.

4. Automatic fan speed and heat exchanging rate controls thur the temperature feedback by thermal couples is needed to make the system working in a better efficiency way.

There are too many heat storage devices in the market. Only some representative ones are introduced hear.

II.3.1 Calmac HeatBank™

Calmac Manufacturing Corp. of Englewood, N.J. has developed and put on the market a bulk thermal-storage system, the HeatBank™, a rotationally molded plastic storage tank which is 1.21 m (4 ft) in diameter and about 1.2m tall. The HeatBank™ contained a spirally wound Calortherm™ tube heat exchanger having a very large surface area. The heat exchanger consisted of 32: small parallel twin tubes spacing 3.8 cm on center. See Figure II.3.1. The supply and return headers at the top and the connections at the bottom caused the heat exchanger fluid to flow in the opposite directions within each pair of these tubes, effectively maintaining a uniform temperature radially and from top to bottom. Thus, melting and freezing were also uniform, eliminating damages to the tank and heat exchanger from thermal thrust

HeatBankTM systems can be ordered with any of the Calortherm™ tubes, and thus can store thermal energy at 7.5°C (45.5°F), 18°C (64°F), 31°C(88°F), 48°C(118°F), 58°C(136°F), and 70°C(158°F).

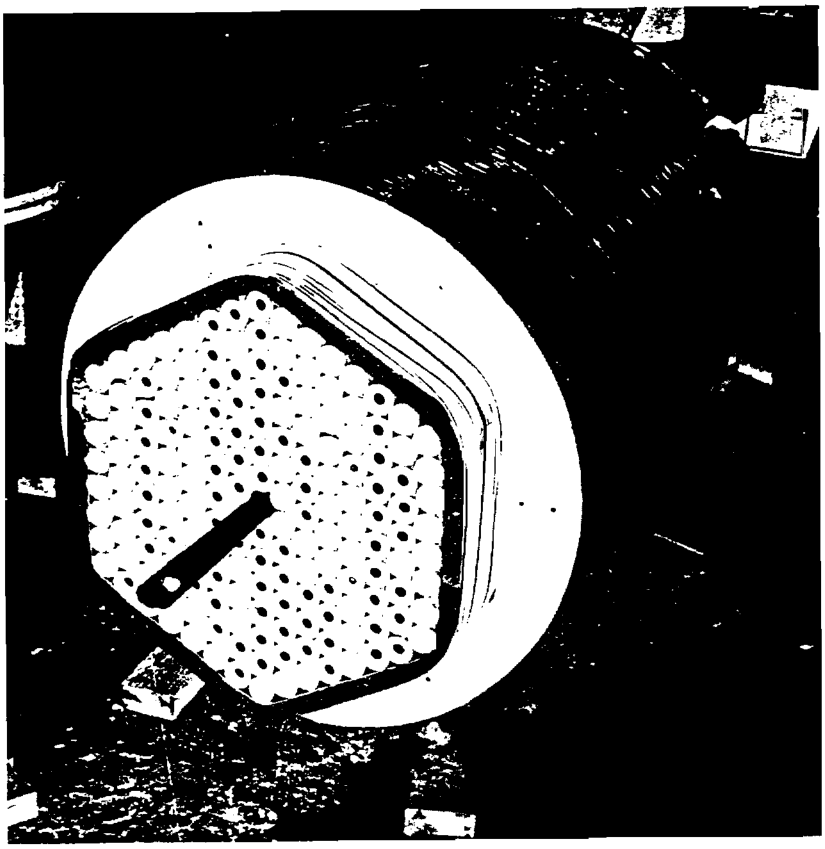


Figure II.3.1. Calmac HeatBank™ [1].

II.3.2 O.E.M. Heat Battery™

O.E.M. Products, Inc. in Dover, Fla. has developed and put on the market the Heat Battery™, a nonmetallic bulk heat storage tank filled with Glauber's salt ($Na_2SO_4 \cdot 10H_2O$). This tank utilizes direct contact by an immiscible fluid, a hydrocarbon oil, to charge or extract heat from the PCM, see Figure II.3.2.

During the heat extraction, the immiscible fluid is pumped to the bottom of the tank through a "Christmas tree" distribution system and bubble up through the PCM, collecting on top. As the PCM freezes, it sinks to the bottom of the tank, eventually plugging the outlet holes of the lowest oil distributor. The added system pressure causes the outlets of the next highest distributor to open. PCM freezing thus continues in an ascending manner, through five tiers of distributors, until the PCM is entirely frozen.

During the charging up step, the process is reversed, with the distributor ports opened in descending order. Heat-transfer. fluid through copper heat exchanger coils immersed in the immiscible fluid which collects at the top of the tank. This oil also serves to seal the PCM against: gain or loss of water of hydration.

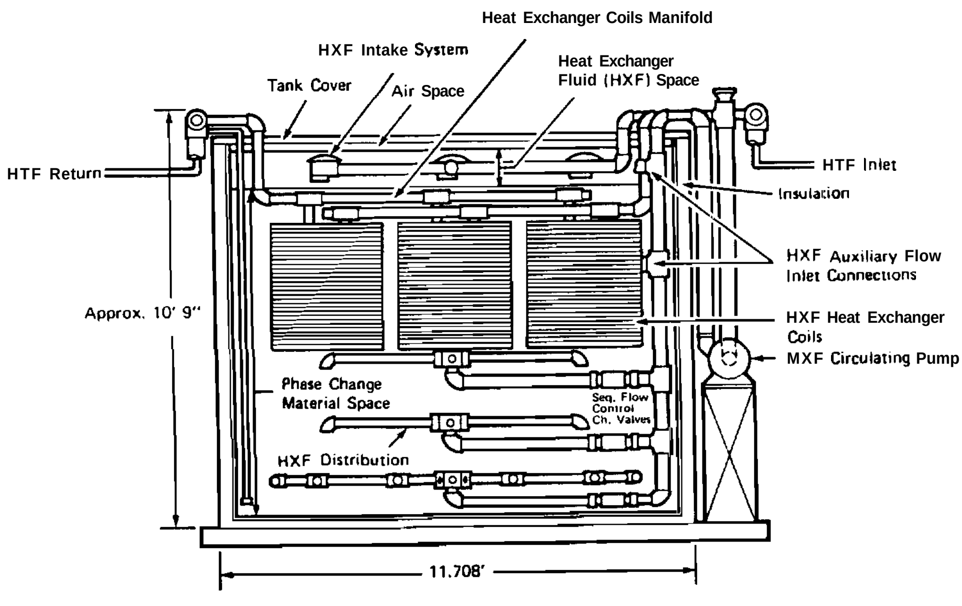


Figure II.3.2. O.E.M. Heat Battery^{TM} [1]

II.3.3 TESI Storage Tank

Thermal Energy Storage, Inc. (TESI) in San Diedo, Calif. developed and selling the TESI Heat Storage Tank, a tank/heat exchanger bulk storage device. See Figure II.3.3a-b. It consists of an insulated, rectangular tank, 1.21x0.73x1.61m high, with double wall, vented heat exchanger, consisting of a copper tube inside an extruded, finned aluminum tube. For the M250 model, the filled weight is 1812 kg (3987 lb) and it contains 843 1 (223 gal), or 1273 kg (2800 lb), of $Na_2S_2O_3 \cdot 5H_2O$, which melts at 48°C (118°F). Supercooling is prevented by a cold finger arrangement, which maintains a constant supply of nucleators to the PCM system. The manufacturer reports 44.4 cal/g (86 BTU/lb) heat of fusion for the PCM, or 59564 kcal (236,380 BTU) latent heat for the unit. Total heat stored between 100 and 140°F is 71500 kcal (283,700 BTU). TESI also offers other sized devices to meet the customers' requirement.

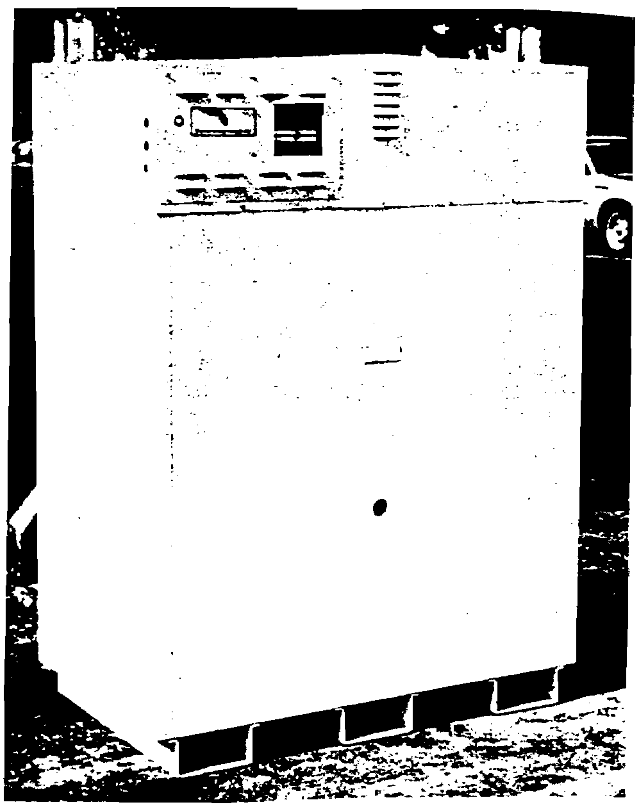


Figure II.3.3a. TESI Heat Storage Tank [1].

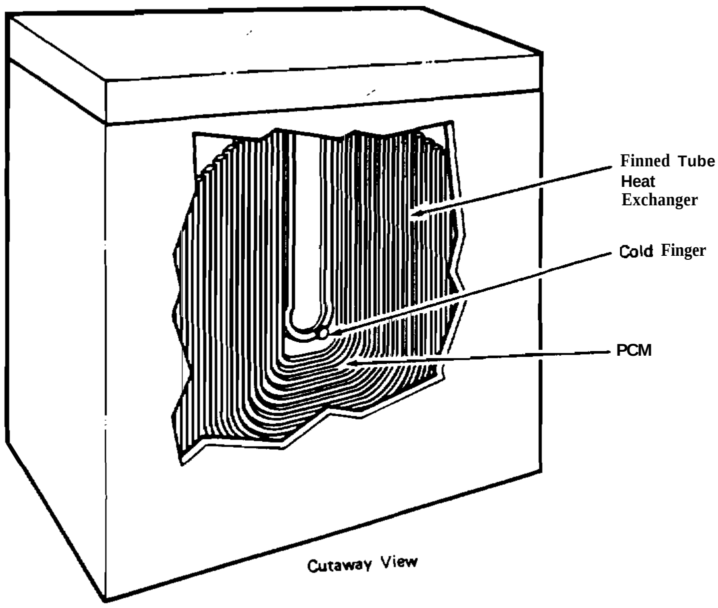


Figure II.3.3b. Cutaway view of TESI Heat Storage Tank [1]

TESI recommends that the storage tank be used for commercial water heating systems, or in an integrated active solar system, incorporating forced hot air and domestic hot water. This system would include water-cooling solar collectors; the TESI Hot Pak module, which contains the pumps, controls, valves, and wiring needed to install the system; a hot water tank; and a hot air heating system with fan coil heater unit. The TESI tank is finding application in condominiums, apartments, housing developments, commercial establishments, and public buildings. The market acceptance of TESI systems is good.

II.4 Natural Energy Resources Storage

Natural energy resources includes solar, wind, tide, geothermal, seasonal weather changes, etc. Thermal storage by using the natural energy resources are limited due to geographic locations. For example; it is impossible to use a seasonal ice storage in Florida or geothermal energy at a place where does not have this resource. In this section, only solar energy storage and seasonal ice storage are discussed.

II.4.1 Solar Hot Water Systems

Water heating is currently the most economic application of solar energy. The nation energy expenditure for water heating is approximately 4%. Solar water heating can reduce the peak elcctric demand in the late afternoon during summer months.

Figure II.4.1 shows a typical solar water heating systern. The collector fluid carries the solar energy to the heat exchanger and heating up the cold water. The main problem of this system is the water quality. The hardness of water cause scaling in the heat exchanger which not only decreases the thermal conductivity, but also reduces the system lift-time. therefore, scale prevention is the major concern for system designers.

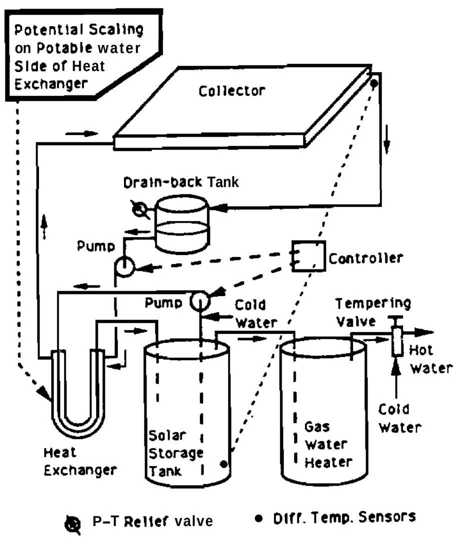


Figure II.4.1. A typical Solar Hot Water System [2].

II.4.2 Seasonal Long-Term Ice Storage

The cold air of winter is used for producing relative large amount of ice in long-term underground storage. The stored cooling capacity of ice is recovered during the following summer. Initial research indicates that in the regions where winter is sufficiently cold and of sufficient duration, this type of system could provide summer air conditioning, refrigeration, or process cooling. Thus the peak electric demand in summer is lowered.

The technique of interest involves using the natural coldness of winter air to produce enough ice to provide for the total annual cooling load. The Princceton system (Kirkpatrick et al 1981) uses a commercial snowing-making machine to produce a large pile of ice. This system has been successfully demonstrated. The Kansas State University system uses a stream of cold air blowing over a thin sheet of water, building up ice in layers, and a passive ice project of Argoone national Laboratory uses specially designed heat pipes to freeze water contained in a large insulated tank.

The relative heat losses from a storage volume can in principle be expressed as [4]:

$$HL = \frac{\lambda}{\rho c} \bullet \frac{\bar{T} - T_o}{\Delta T} \bullet \frac{f(t_p, G)}{V^{2/3}} \bullet t \qquad \text{(II.4.2)}$$

Where λ is the heat conductivity of the surrounding material, pc is the heat capacity of the storage medium. The second term is the mean temperature difference to the environment divided by the temperature amplitude in the storage. The third term is the geometric factor which depends on the time in use, t_p and shape, G divided by the 2/3 power of the total storage volume. The last term, t is the length of storage cycle. This suggests large storage volume and good thermal insulation can reduce the heat losses.

To improve the insulation, water-saturated earth is used as storage mass. The main costs of the system are the containment and. the insulation. Figures II.4.2a-b show a typical storage system with a total volume of 4000 ft^3 (113 m^3). The major components of the system include: (1) storage mass, (2) distributed storage mass heat exchanger, (3) blower for application, (4) diverter valves, (6) thermostat and control device, (7) heat exchanger fluid and a circulating pump.

According to the system shown in Figure II.4.2, it was found that 8,921,856 BTU (2613 kwh), 52% of the store energy was recovered during the summer, indicating about 48% loss to the surrounding earth [3].

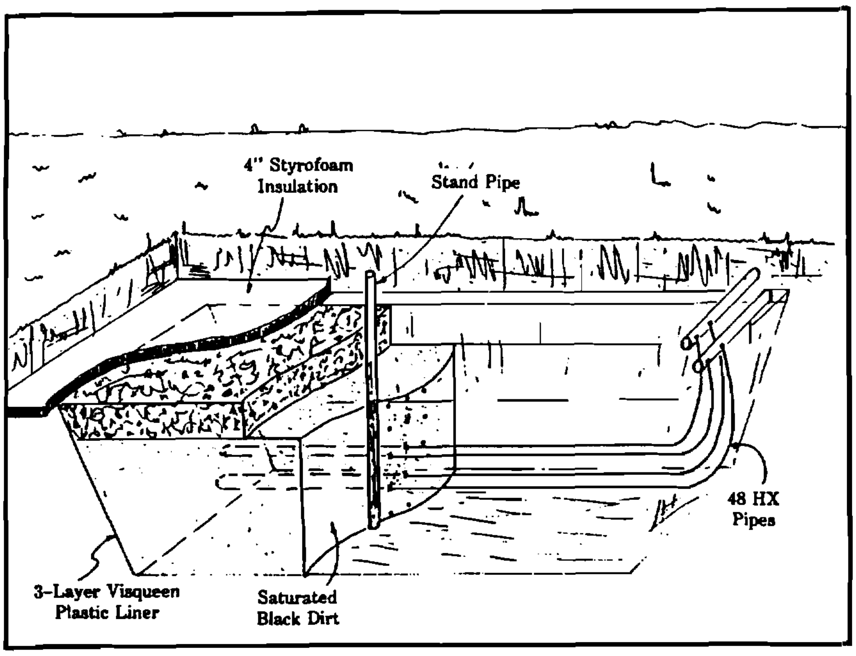


Figure II.4.2a. Arrangement of water saturated earth storage mass [3].

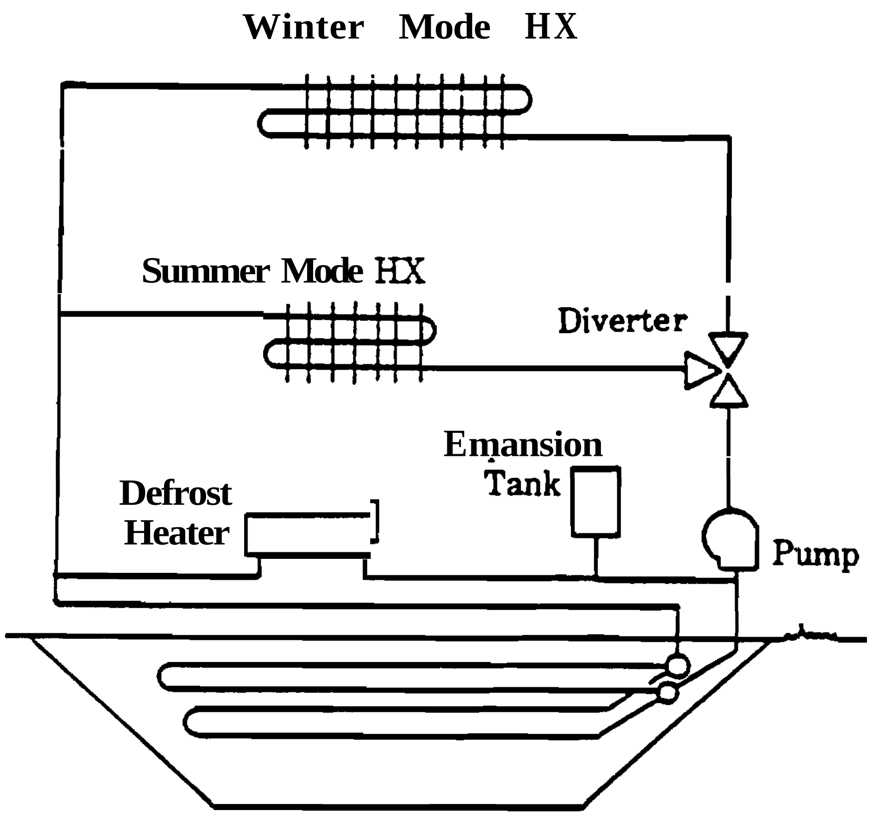


Figure II.4.2b. A typical ice storage system [3].

11.5 Summary

The general design and application of thermal storage systems have been introduced in this chapter. These include the selection of phase change materials, some system requirement and limitations. The major goal here is to reduce the peak electric load demand and as well as to save energy. Without losing our living standard, thermal storage is one of the best. way to do the job.

The future works in this area may concentrate on the better PCMs searching and the insulation technology, cause these lead thermal storage system more campact and efficiency.

11.6 References

1. George A. Lane, Solar Heat Storage: Latent Heat Materials, Vol. II: Technology, CRC Press, Inc. 1986

2. G. C. Vliet, Design of Solar Hot Water Systems for Scale Prevention/Remediation, Solar Engineering 1992, Vol. 1, pp201-206

3. C. E. Francis, The Production of Ice with Long-Term Storage, ASHRAE Technical Data Bulletin: Thermal Storage, 1985. pp139-145.

4. Gunnar Gustafson, Heat Storage in Caverns, Tanks and Pits, An Overview of Swedish Experiences. Thermal Energy Storage Technology in Sweden, 1987, pp51-62.

Chapter III

A Simple Procedure to Determine Real Time Prices

J. S. Lee

III.1. Introduction

Today, utility management is looking for more customer oriented strategies to respond to changes in the electric industry environment. A more customer oriented electric service is better suited for a more competitive generation market, for handling environmental concerns, and for satisfying regional development packages [7]. This paper will analyze general aspects a utility must consider to start using a 24 hr updated real time pricing (RTP) program. Real time pricing of electricity is a kind of demand side management (DSM) program that charges customers with prices that vary over time. RTP programs increase system efficiency and societal benefits, because they increase the level of information exchange between the utility and the customer. RTP may be seem as a load control device. However, RTP allows the utility to increase load control signals to a much broader base of customers and applications. These signals are not a hard control of the load, but a voluntary customer response to electricity prices. Price information conveyed to the customer reflects the net load-supply state of the system in any given period. Under certain conditions, this strategy can be proved to maximize economic societal gains[1][10].

According to the frequency the utility updates these prices, RTP can be classified and named differently. The most common RTP kind of program is the time of use (TOU) pricing. TOU programs update prices every month, in price schedules attached to the participant electricity bills. RTP programs that update prices more frequently can generate more system savings, however these programs may have more expensive implementation. If information update frequency increased to operational response of generation (usually 5 minutes or less), electricity could be traded like in a energy spot market. Spot pricing of electricity is a basic concept for RTP programs. Currently 24 hr price update programs are the most advanced, yet feasible RTP programs implemented by the industry. Because the previous existence of time indexed metering equipment and capability of price response, utilities targeted industrial and large commercials in RTP early stages. Today thanks to cost reduction in communication and micro-electronic technologies residential customers are also a main focus of RTP programs.

As a side effect from the savings RTP creates, utilities can learn more about each customer response to price and service quality. Learning more about customer needs and the economics of RTP allows the utility to offer other services that are based on spot pricing principles. RTP can be a learning process of new market strategies for the more liberal US electricity market. The next section of this paper will describe the economic principles RTP relies on. Section III. 3 presents what are the elements that program managers should consider when designing a RTP program. Section 111.4 analyze some aspects of determining RTP rates. Section III.5 presents a simple method to calculate real time prices using a procedure easy to establish in a typical utility. Finally, section 111.5 presents some RTP experiences already in place in US utilities.

III.2. A primer on spot price based strategies

Real Time Pricing (RTP) is a pricing strategy based on the concept of' spot price of electricity. Spot pricing of a commodity is a concept as old as trade. In the US, Vickrey [12] was a pioneer proposing an analogy between utility services and perishable goods. The objective of this analogy is to give an intuitive understanding of the communication protocol existent in a marketplace and of the benefits that follow flexible pricing. We use the simple trade model of a fish market to illustrate the transaction timing and the decision making order of each trade participant in a spot market. We assume fish as perishable good, that can not be stored from one day to the next. In the case of electricity this is mostly the case except for hydro pump-back strategies (these options are pretty much exhausted in US).

Imagine you are in a fish market. Boats just arrived from the sea with fresh fish. You have a vast number of options among different type of fishes and crustaceans (assuming you like seafood). You browse around. The fishermen display price and quality of their product. When you decide what you want, you tell the fisherman how many units you want. You pay cash and leave. If you came back the next day, unit prices for fresh fish may be completely different. Fish prices will be higher if the fishing was bad, or lower if there is too much merchandise and not enough customers.

Suppose the next day the fish was not close to shore. Only the fishermen with the largest boats could go far into the ocean to get fish in such a bad day. They only spent the extra fuel to go into open sea because they know scarcity will force prices to be higher than the previous day. Assume prices are set equal to marginal cost. I.E. the cost of fishing the last, most distant, stubborn fish. This cost is likely higher than the average cost of all fish in a boat.

Now, customers face two alternatives. Customers in extreme need of fish buy at high price. Customers that can postpone consumption will not buy today. Suppose the larger proportion of the customers are starving buyers, that will pay any price for fish. The fishermen that own big boats will not regret they had kept the boats with the capacity of going far into open sea. The fishermen operating smaller boats will have no revenue, today. If this situation repeats enough times small boat owners may consider investing in a larger boat. In the other hand, if most of the customers decide do not buy at the high. The fisherman must reduce his price to get rid of the fish, remember that if he does not sell the fish today it will spoil and have zero value. If fishermen have to reduce the price so much that the price is lower than the average cost, they will be facing a loss. The big boat owner may decide that the costs of having open sea capacity surpass its revenues. He may decide to reduce the size of his boat, and therefore reduce the industry productive capacity.

Over time consumer choice will be the driving the desired installed capacity. The spot prices of the perishable commodity carry information about the production capacity and consumer valuation of the commodity.

RTP is a pricing strategy that mimics the behavior of a free spot market. RTP use can improve utility and customers' savings, because capacity utilization of the utility increases. Utility can use price as signals to control demand. Customers can consume in lower price periods, if they can reschedule their consumption. RTP increases information exchange between utility and customer using a measurement of capacity use that is easy to understand and react, Dollars/KWh. In our simple trade model, spot prices are prices that fluctuate over time and location of delivery. In a competitive market, the equilibrium price is the price level that clears all supply and demand transaction. These prices are called spot prices if they serve immediate demand or cash transactions. For commodities that must be produced immediately, like electricity, the competitive producer perceives the spot price as the short run rnarginal cost of producing and delivering with short notice. The term marginal cost takes into account all the current conditions of the economic system (all opportunity costs the producer face). From the consumer's perspective, the spot price is the marginal cost that he must pay to obtain the next marginal profit amount (if the customer is a firm) or satisfaction (if customer is a household) provided by the commodity. The main advantage of this pricing strategy is to convey to consumers complete information about supply costs and to producers complete information about demand valuation of the commodity.

Market organization and product characteristics are very different in the fish market example and the electricity marketplace. Therefore some acclimatization must be done to make use of this ancient communication protocol in an electricity pricing program.

III.2.1 Regulated Monopoly x Free Market

Spot prices do not necessarily reflect a commodity's marginal production and delivery costs. Spot price is only equal to marginal costs in a competitive market, not the case of the electric utility market. Electric utilities are rate of return regulated monopolies. Electricity sales at a given price must recover revenue requirement imposed by regulation. Real time prices, however, are forced to behave as competitive market prices. Savings originated from reduction of revenue requirements will directly favor customers. Regulators allow the utility receive a perceptual of the savings as an incentive to promote DSM programs [6]. The simplifying assumption made in this paper, and most spot pricing based programs already in place, is that each rate determined by regulation must satisfy a revenue requirement. Rate cases will set the amount of revenue must collect from a customer's class in each rate[1]. The revenue requirements of a rate are equal to the total cost the utility incurs on serving all customers in that rate class. Traditional regulatory procedures fix price as the rate average cost given expected load profiles. Under spot pricing based programs prices are treated as a tool that shifts load from system peak to valleys among customers in a same rate. Therefore at any given time all customers in a same rate are charged with the same price. This assumption may be relaxed if marginal prices also include location costs.

III.2.2 Special characteristics of electricity and its uses

For our purpose, we must pay special attention to two characteristics of electricity as a product. First, utilities not only sell electric energy, but also the capacity to generate this energy. Second once capacity is assured, electricity energy supply must meet demand at all times.

Compared to other capacity constrained industries, like airline and telephone companies, electric utilities have low price variation over time. The major objective of price variation is to increase capacity utilization, which reduce contribution to fix cost by unit sold. For instance, in airline industry price vary over different times of the year and over notice time before use for non-refundable tickets. For non-refundable tickets, capacity is assured ahead of time, therefore uncertainty costs are minimized. Electricity prices, however, are commonly divided in a capacity (or demand) charge and energy charge for large industrial and commercial electricity customers. Under RTP strategy capacity costs are included in the unit price of the service.

Real time pricing is a feasible implementation of the spot pricing principle (or marginal cost based pricing). The design of RTP strategy must allow a convenient customer's response time, and the costs incurred on implementing the program. Utility must keep electric equilibrium of supply and demand continuously, to assure system integrity. If utility relied exclusively in RTP to establish this equilibrium, prices would fluctuate continuously. However, price changes can not occur at faster rate than the time the customer needs to receive and react to spot prices.

---

[1] The criterion to form customer classes is electricity load profile. The cost of serving each different load profile is determined by the utility. Rates are usually designed to best serve a load profile, and reciprocally cover the costs of all customers in that rate.

Also interval between price updates and customer reaction must consider the costs of the program implementation, or transaction costs (metering equipment, software and hardware to respond to price changes). Transaction costs can not be higher than the program's benefits. Therefore electricity real-time prices will depend on different time dimensions of its implementation, that are included in the terms of the RTP contract. The next session presents the discussion of RTP time dimensions.

III.3. Characteristics or real time pricing

In 1982 Caramanis et al. [2] divide the implementation of spot prices in 3 levels, as an attempt to characterize possible RTP programs. Each successive level requires a less complex implementation, but also offer lower potential benefits (Table 1). The smaller interval between price schedule updates reflects more accurately the evolving states of the system and its marginal costs. The RTP price schedules may also differentiate according to customer location. Customers located over different transmission or distribution lines may be charged with different price according to the load (and consequent losses) in the line during the period considered. For customers enrolled in a RTP program electricity price will change to follow marginal prices as frequently as technical (utility ability to meter) and economical (customer ability to respond) constrains allow.

Level	Name	Information Media	Price Includes	Prices based on
I	5 minutes update RTP	Computer Link	Real and Reactive Power. T&D quality. Individual Losses	Real Time Operations
II	24 hour update RTP	Radio, fax, telephone or computer link	Real Power (opt. Reactive Power), adjusted to quality and losses.	Next 24 hr. Operation Forecast
III	Time-of-use prices (TOU).	Insert price schedule in electricity bill	Real Power. T&D differentiated by area.	Monthly Forecast

Table 1 -- Possible classification of RTP program implementation by complexity

In this paper we focus is in RTP programs of Level II. These programs represent the current equilibrium between cost of implementation and efficiency gains for most utility systems. They are what utilities around the country more commonly refer to as real time pricing programs. For this class of programs Tabors [1 I], suggested further categorization of RTP rates. Tabors used three divisions in the time domain and two divisions in the price domain In the time domain the most important characteristic is the same as pointed by Caramanis, the length of the update cycle. The second time domain characteristic is the smallest time interval a price is valid or the number of separated prices that are quoted in an update cycle. The third characteristic is the amount of time in advance the customer is notify before an emergency price enters in effect and/or before the regular price schedule update.

To illustrate this classification, Figure 1 presents a program that has prices update every **24** hr. Suppose prices for tomorrow enter in effect midnight today. The new price schedule is send today to the customer by **4** p.m.. The program in Figure 1 has **48** price intervals during the day. This is a common division, since for most utilities equipment used to record demand charges operate in 1/2 hr intervals. These equipment can be converted to be used in RTP programs.

In the pricing domain, the **2** most important characteristics are how RTP prices are calculated and how RTP prices are presented to customers. Tabor [11] divided calculation in four possible groups: Marginal cost based, operating cost, average cost and demand charge. The calculation method will depend on the program objectives and the potential savings being targeted. Prices can be brought to consumers in tiers with some descriptive names like "high",

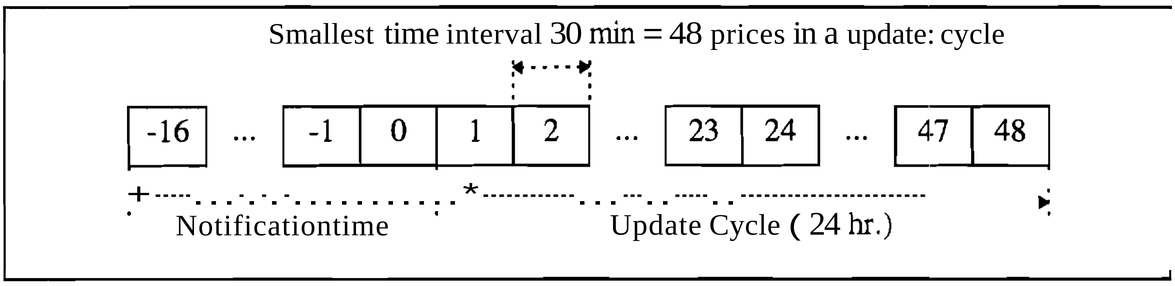


Figure 1. Example of an RTP program. Prices update every **24** hr, notification of new prices **8** hr ahead prices become in effect. Smallest time interval between price changes is 1/2 hr, hence it would be possible **48** price changes in each cycle.

"moderate", "low" or as a continuos price. The way prices are presented to the customer depends on the kind of customer and his decision making process.

III.4. Pricing. energy in real time

For the utility, the marginal cost of electricity is the cost of supply the next marginal increment of electricity demand given the current load demand and the current utility supply condition (units committed, tie line available capacity, supply contracts with other utilities, etc.) RTP in this paper is a surrogate to electricity marginal pricing of producing and delivering electricity in the short run ([9], 9). All other system conditions being the same, real time prices must increase during load peaks and decrease during load valley. Assuming customer consumption is responsive to price changes, the utility may use the real time pricing strategy for peak shaving or valley filling. As prices of electricity vary over time, customers will delay consumption during high price periods to periods of lower prices. RTP is efficient, if price variations optimally allocate resources across time and space.

Marginal pricing electricity may provide to the utility total revenues far above or far bellow the revenue requirements set by embedded capital cost based regulation. This difference must be reconciled by an adder or multiplier applied to the energy price and/or in form of a lump sum payment (from utility to customer or from customer to utility) at the end of billing period. The revenue reconciliation factor is calculated according to revenue requirements for each rate class.

Caramanis [3] divide the short run marginal (SRMC) cost of delivering 1 KWh at bus i at time t in two cost groups. The first kind of costs relate to generation activities. The second group of costs relate with transmission costs and therefore will vary depending the customer location in the grid. Costs in each one of these groups can be subdivided as:

Generation related marginal costs:

- $MCG_1(t)$ Cost of fuel, operation & maintenance caused by the last Kwh supplied during period t.

- $MCG_2(t)$ Cost of providing spinning reserve (1/2 hour) caused by last Kwh supplied during period t.
- $MCG_3(t)$ Cost of load following, maintaining frequency and voltage tolerances and other system security contingency planning related requirements, caused by last Kwh supplied during period t.
- $MCG_4(t)$ Cost of sustaining generation capacity shortage constraints caused by the last Kwh supplied in period t. This component reflects the costs such as emergency purchases, increased wear of equipment due to operation at emergency levels (above rate of operation), triggering interruptible contracts, brown outs, rotating blackouts and cost of unserved energy.

Transmission related marginal costs

- $MCT_1(i, t)$ Cost of transmission and distribution power losses caused by last Kwh supplied in bus i during period t.
- $MCT_2(i, t)$ Cost of transmission variable maintenance, cost of providing transmission loading related operating reserves and sustaining security controls, harmonics and other transmission related power quality tolerances, caused by last Kwh in bus i supplied during period t.
- $MCT_3(i, t)$ Cost of sustaining transmission and distribution capacity shortage constraints caused by last Kwh supplied in bus i during period t.

Not all elements of this calculation are included in the variable part of RTP rates. All these costs are always present, the question is if they are going to enter the final rate as variables over time or as part of adders and multipliers that recover revenue requirements. The next section proposes a model to determine appropriate rates a 24 hr update RTP program.

111.5. A simple real time price calculation model

In this paper, we assume there is no price differential among customers because of location. These price differentials can be included to the model using optimal power flow algorithm or as a penalty factor for each customer demand price. The formulation proposed aims mainly the unit commitment problem, but it explicitly solves the dispatching problem using forecast demands for each period. Merlin [8] and Zhuang [13] present good discussion of this formulation and solution method based on lagrangian relaxation.

$$\min \sum_{t\in T}\sum_{i\in I} F_{it}(P_{it}).u_{it} + ST_i(x_{it}, u_{it}) \quad (1)$$

St.

Demand constraint

$$\sum_{i\in I} P_{it} = PD_t(pe_t + Adder) + \overline{PD}_t \qquad \forall t \in T \quad (2)$$

Reserve constraint

$$\sum_{i\in I} u_{it}\overline{P_{it}} - PD_t(pe_t + Adder) - \overline{PD}_t - R_t = 0 \qquad \forall t \in T \quad (3)$$

$$x_{i(t+1)} = x_{it} + (1 - u_{it}) \qquad \forall t \in T,\ \forall i \in I \quad (4)$$

$$x_{it}.(-u_{it}) \geq 0 \qquad \forall t \in T,\ \forall i \in I \quad (5)$$

$$x_{it}. \geq 0,\ u_{it} = 0 \text{ or } 1 \qquad \forall t \in T,\ \forall i \in I \quad (6)$$

$$P_{it}. \geq 0,\ P_{it}. \leq \overline{P_i} \qquad \forall t \in T,\ \forall i \in I \quad (7)$$

$$pe_t \leq \overline{pe},\ pe_t \geq \underline{pe} \qquad \forall t \in T \quad (8)$$

Where:

$F_{jt}(P_{jt})$: Total fuel cost of generating unit i for time interval t. This function represents the input/output characteristics of generating plant i. However any functional form could be used, we assumed this function is linear, equation (9).

$$F_{jt}(P_{jt}) = a_i + b_i P_{it} \quad (9)$$

$ST_i(x_{it}, u_{it})$: Starting cost of generating unit *i* at time interval t. Starting costs are a function of the period throughout which the unit has been shut down. The longer this period, the colder the unit and the more expensive to warm-up. Equation (10) shows the functional form we used.

$$ST_i(x_{it},u_{it}) = \left[c_i.\left(1-e^{\frac{x_{it}}{d_i}}\right)+e_i\right].u_{it}.(1-u_{it}) \tag{10}$$

x_{it}: State of thermal unit i, denoting the number of hours that unit is has been off.

u_{it}: Discrete variable, indicates that unit i is on at time t if equal to 1, and off if equal 0.

P_{jt}: Power output of generating unit i for time interval t.

$\overline{P_i}$: Maximum power output of generating unit i.

$PD_t(pe_t)$: Forecast system power demand during time interval t, given electricity price for time interval t.

$\overline{PD_t}$: Forecast system power demand during time interval t, that is price independent.

pe_t Short run marginal cost portion of real time price of electricity at time t.

Adder: Fixed embedded cost portion of the real time price used to recover revenue requirements.

$\overline{pe}$: Pre-determined maximum short run cost of electricity.

$\underline{pe}$: Minimum price of electricity to recover revenue requirements.

i: Generating unit index.

I: Set of all generating units committed (available for generation).

This model is simple, computationally efficient and has good adherence to utility reality. It does not model reactive power or transmission losses. These cost elements are included in the revenue reconciliation adder or the rate. Assuming the revenue requirements (*RR*) are calculated annually, and Y is the set of all days in a year. Equation (11) presents the formulation that recovers revenue requirements.

$$RR = \sum_{T\in Y}\sum_{t\in 7}(pe_t + \text{Adder}) \tag{11}$$

The utility therefore desires to calculate de adder as presented in equation (12).

$$Adder = \frac{RR - \sum_{T\in Y}\sum_{t\in T} pe_t}{n_T \times n_Y} \tag{12}$$

or

$$Adder = \frac{RR}{n_T \times n_Y} - average(pe_t) \tag{13}$$

Where:

n_Y: Number of days in a year.

n_T: Number of price periods in **24** hr.

$average(pe_t)$ Average marginal short run portion of the RTP program price.

The operations and DSM department must work jointly to perform tht: daily routine on determining the real time pricing sent to customers. The mechanics of an RTP program using this kind of formulation could be as follows.

1. Forecast non sensitive price demand for next **24** or **48** hr.
2. set prices ***pe*** equal to inter utility market price plus any adder or multiplier.
3. Solve unit commitment/dispatching problem.
4. Increase or decrease prices ***pe*** to control strategic demand.
5. Solution is satisfactory go to 6. If not, go to step 3.
6. Communicate prices to customers

Note that ***pe*** can only be set as a variable of the problem if we change the objective function to a societal cost minimization. Where the objective functions of the customer and of the utility are incorporated in a single objective function. The solution proposed by the above fonmulation is subjective since, the operator must evaluate a satisfactory demand level. This procedure is not at all new for system operators. We assume that the utility is capable of importing power from a broad neighbor market or take power from a pool. The marginal cost part of the costs reflect the prices paid for the pool or neighbor utilities.

III.6. What is already real?

In the electric utility industry experiences with some kind of spot price based rates have been in used since 1952[2]. Besides the long service time RTP are still new for most of customers and utilities. They are included in DSM programs of most large utilities in some form or another. But the more aggressive 24 hr update are still seem with reserves. Experimental RTP programs are a good indication of utilities interest on learning how to provide electricity under a variable price arrangement. Some experiences are already in place for different customer classes. They show that customers tend to change consumption patterns in response to prices if they have appropriate hardware to analyze prices and preset their choice set. The most common applications among industrial users are related with interruptible power options, and large industrial capable of rescheduling production around the clock. Commercial applications are mostly related with heat or cold storage applications. Residential applications have became center of the attention recently with the introduction of the information high way concept.

Electric Power Research Institute (EPRI) and Georgia Power Co. (GPC) surveyed utilities using RTP in 1991 as retail market strategy. They determined 12 utilities that have programs already established. These programs have as few as 2 and as many as 176 customers, mostly large industrials. A modal number of customers are 15 (3 programs), only 2 programs have more than 100 customers, and 5 programs have 10 or fewer customers([4].)

Residential RTP programs are usually implemented with of proprietary systems like TranstexT® from Integrated Communication Systems and American Electric Power; PowerView™ from First Pacific Network and Entergy; and others. These systems, besides very different in terms of implementation one from another, are based in the same RTP principals. These systems are usually divided in two parts. A control center in the customer residence, that will receive utility prices and control water heater, room temperature and other devices,

---

[2] EPRI Innovative Rate Survey of 1990 reports a real-time pricing rate from Bangor Hydro-Electric Company that started in January of 1952 and is still in use today. Customer may request secondary power at any time. The service is subject to availability of power at the time of the request. The rate is computed monthly and is intended to pay the entire incremental cost of generating or purchasing the energy requested, plus not more than 2.5 mills per KWh.

according to customer preset preferences. The second part is a utility transmission system of information and feedback. The communication and feedback system in general include other functions besides implementation of RTP prices, such as, automated meter reading and systems check.

III.7. Conclusions

This paper presented theoretical and practical aspects to be considered when implement a real time pricing program. Some RTP price formation elements are described. Depending on the kind of RTP program and savings objective, not all cost elements will enter in the calculation of variable portion of prices. Elements that do not enter price calculation as variables being optimized will be added to the price as an adder or multiplier that will recover revenue requirements.

A simple model to determine 24 hr update RTP is proposed. This model ignores transmission and distribution cost per customer. These costs will be added to the adder or revenue requirement reconciliation mechanism after the main problem is solved. The model, however, allows the that some analysis in capacity displacement in the short run to be made. The proposed model include the most important controllable cost items on serving demand. Yet the model has simple formulation and low data requirement, what make RTP implementation easier to utilities.

III.8. References

[1] Baumol, William J.; Bradford, David F., "Optimal Departures From Marginal Cost Pricing," ***The American Economic Review,*** 69, 1970, p. 265-283.

[2] Caramanis, Michael C.; Bohn, Roger E; Schweppe, Fred C.; "Optimal Spot Pricing: Practice and Theory," ***IEEE Transactions on Power Apparatus and Systems,*** Vol. PAS-101, No. 9, September 1982, p 3234-3245.

[3] Caramanis, Michael C.; Tabors, Richard D.; Daryanian, Bahman; "Real Time Pricing as a Component of Least-Cost Power Strategies," Proceedings of American Power Conference, Vol. 52, Part 2, Pub. by Illinois Institute of Technology, 1991, p. 926-931.

[4] Electric Power Research Institute (EPRI), "Quick Starting a Retail Market Management Initiative -- Real Time Pricing: A Georgia Power Company/EPRI Collaborative Project," Technical Brief, RP2801-78, Integrated Energy Systems Division, April, 1993.

[5] EPRI, "EPRI Rate Survey 1990,"

[6] Gilbert, Richard J., Regulatory Choices--A perspective on Developments in Energy Policy, University of California Press, 1991.

[7] Hyman, Leonard S., America's Electric Utilities: Past, Present And *Future*, Fourth Edition, Public Utilities Reports, Inc., May, 1992.

[8] Merlin, A.; Sandrin, P.., "A New Method for unit commitment at Electricity de France," IEEE Transactions on Power Apparatus and Systems, Vol. 102, No. 5, May 1983, p. 1218-1225.

[9] Schweppe, Fred C.; Caramanis, Michael C.; Tabors, Richard D.; Bohn, Roger E.; Spot Pricing of Electricity, Kluwer Academic Publishers, 1988

[10] Sexton, Richard J.; Sexton, Terri A.; Wann, Joyce J.; Kilng, Catherine L..,"The Conservation and Welfare Effects of Information in a Time of Day Pricing Experiment," Land Economics, vol. 65, No. 3, August, 1989.

[11] Tabors, Richard D.; Schweppe, Fred C.; Caramanis, Michael C., "Utility Experience with Real Time Rates," IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, p. 463-471.

[12] Vickrey, William, "Responsive Pricing of Public Utility Services," The Bell Journal of Economics and Management Science, Bell Journal of Economics and Management Science, 2, spring, 1971, p. 337-346.

[13] Zhuang, Fulin; Galiana, F. D., "Towards a more rigorous and practical unit commitment by lagrangian relaxation," IEEE Transactions on Power Systems, Vol. 3, No. 2 May 1988, p. 763-773.

Chapter V

Shifting Energy And Demand Away From The System Peak

Atulya Risal

V.I Introduction

With limited energy resources, scarce capital and stringent safety and environmental regulations, utilities are forced to consider both supply and demand side options for optimal resource allocation. Least cost planning (LCP) or integrated resource planning (IRP) refers to the process where demand side options are compared with supply side opportunities to allocate resources to meet the future demand [1]. Until recently, utilities have focused more on the supply side to sustain load growth. These efforts focused on retrofitting existing plants with more efficient technologies, increasing generation capacity and using cleaner fuel to meet environmental regulations. However the nature of electricity as a consumer product has led utilities to consider the demand side a valuable management tool. In particular, electricity cannot be stored in most part and has to be supplied at the quantity demanded at the instant demanded. Furthermore, the reluctance of regulatory cornrnissions to grant investments in new plants rather than containing load growth has made utilities take a closer look at the demand side opportunities to make more efficient use of electricity.

Demand side management (DSM) gives utilities planners an extra degree of freedom in strategic charting of the course to meet anticipated demand. By effectively managing the loads towards optimal utilization of available resources, investments in new plants and equipment can be avoided or at least deferred. In addition, fuel consumption can be curtailed, leading to reduced environmental pollution. Current trends in energy efficiency through demand side management focus on implementing various technologies and programs that are categorized as either energy conservation or peak load management.

Energy conservation programs are geared towards creating a shift in load profile as shown in Figure 1. Conservation programs allow utilities to increase anti or **maintain** their spinning reserves, defer investment in new peaking plants and reduce transmission and distribution losses. Increased customer satisfaction and reduced emissions are also the outcomes of conservation programs.

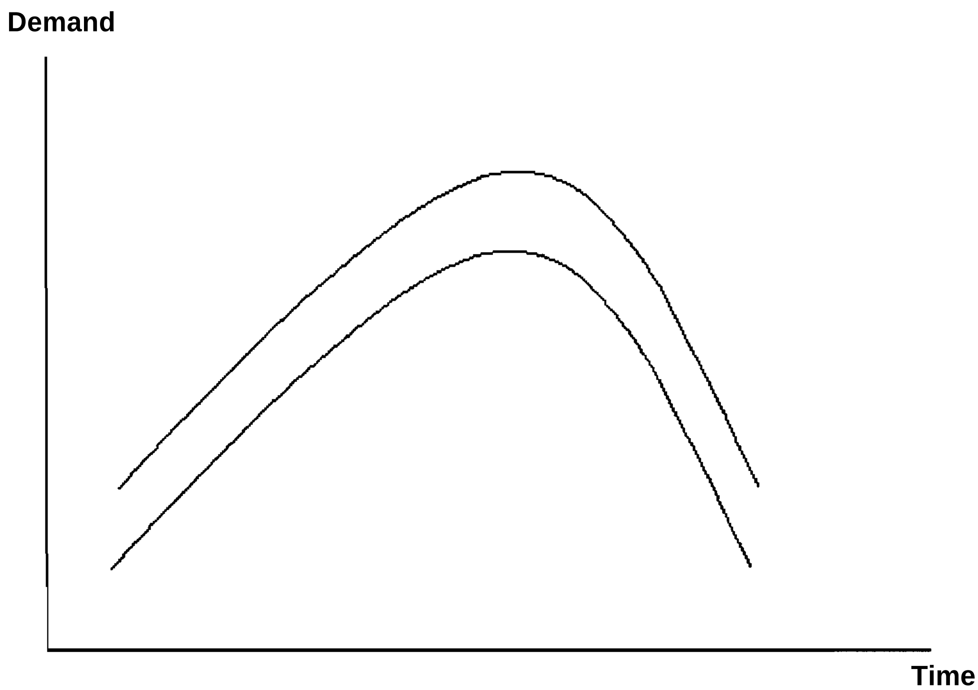


Figure 1 Demand shift

Peak management programs refer to efforts to shave peak (Figure 2), shift peaks (Figure 3) and fill valleys (Figure 4). The benefits include increase load factor, spinning reserves, deferred investment, and depending on base load plant types, reduced pollution emissions. The remainder of this report is going to focused on peak shifting and valley filling operation under demand side management. In order to fully appreciate the impact of peak load management, it is necessary to understand the operation characteristics of electric utility.

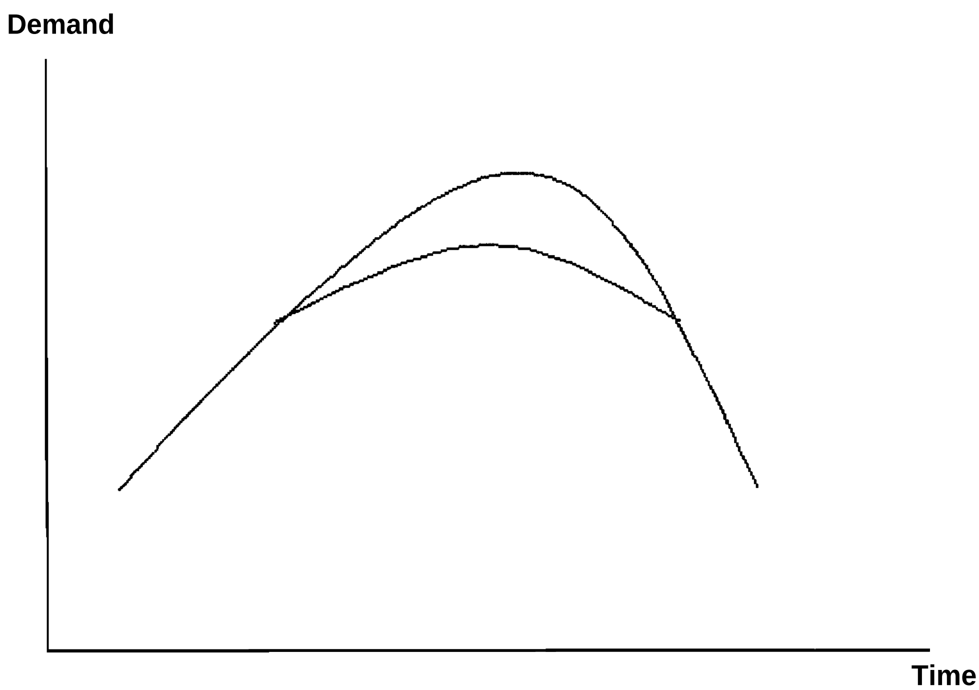


Figure 2 Peak shaving

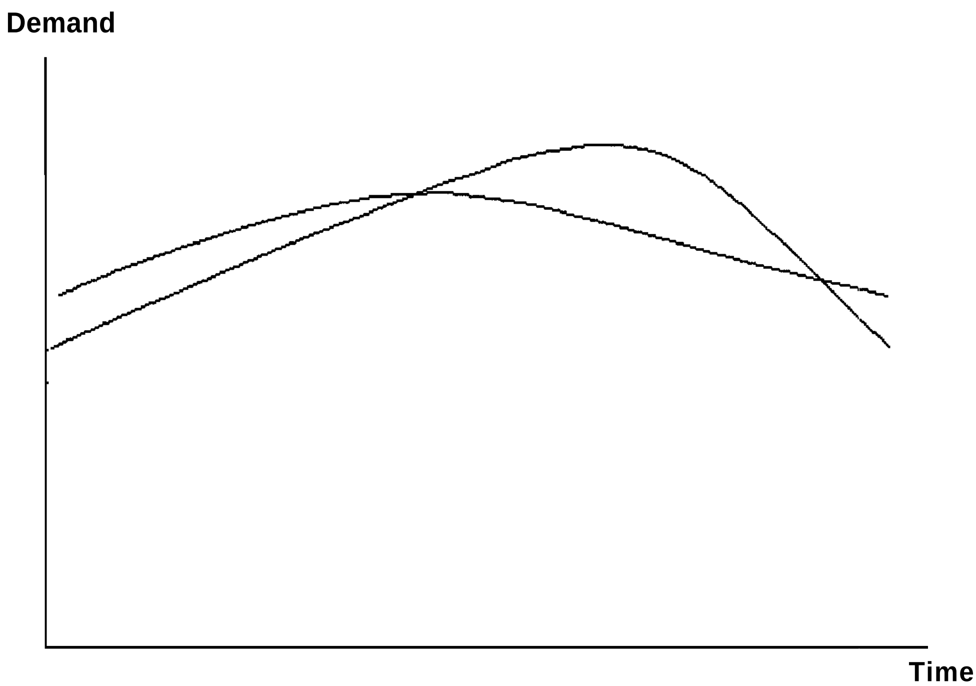


Figure 3 Peak shift

V.II Utility operation characteristics

Unlike regular consumer goods, electric utility has its own set of characteristics.

- It must be made available to all requests within a service area.
- It must be provided in quantity and at time demanded at the customers' site of use.
- It cannot be stored. In most part it has to be produced and served at the demand of the consumer

Utilities have to constantly upgrade their facilities to be able to meet the maximum probable demand at any period. This maximum rate of use or "peak coincident demand" is a major factor in determining the amount of investment required to maintain a reliable supply of energy. A typical daily load demand of a utility is shown in Figure 5.

Figure 6 and 7 show the seasonal load profile of a summer peaking and winter peaking service area respectively. In order to serve such load profiles, utilities rely on a various type of generating plants. A load duration curve (LDC) shows the amount of time that a certain generation level needs to be maintained to serve the load demand curve [9]. It also helps determine generation capacity mix necessary to meet various load

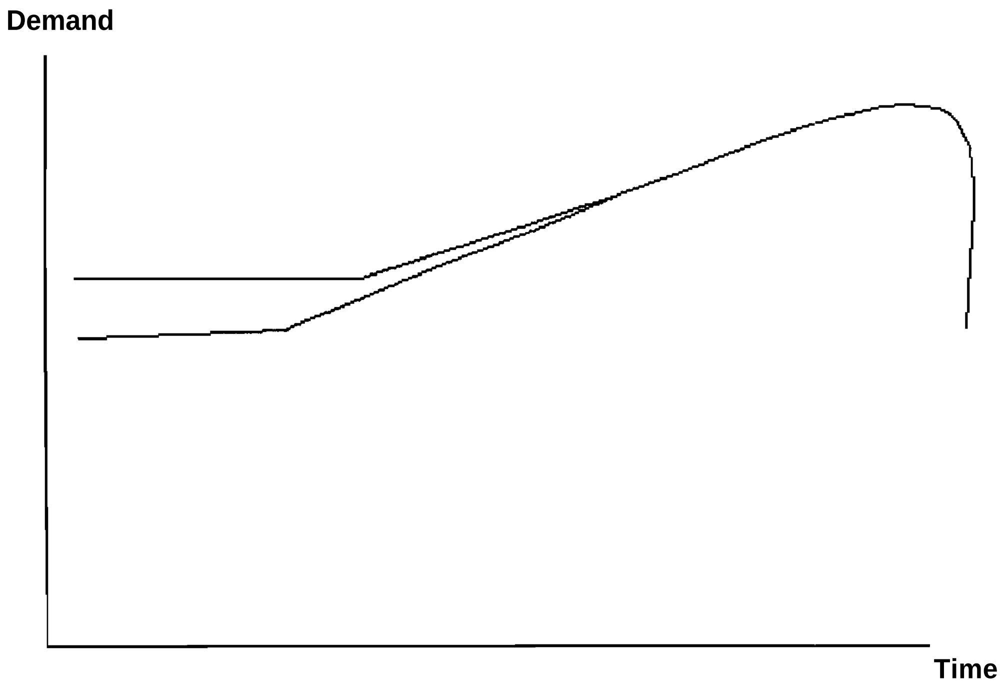


Figure 4 Valley filling

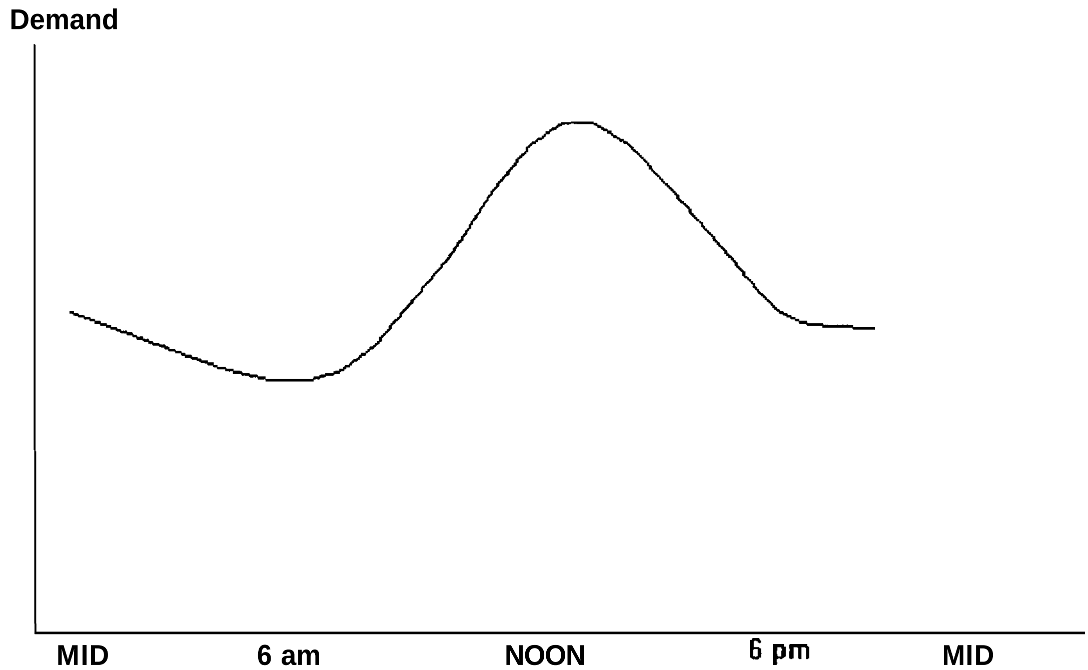


Figure 5 Daily peak load

maintenance, and outage requirements. Figure 8 shows an example. .A utility typically implements various generating technologies of varying cost characteristics to serve the loads. As shown in Figure 8, there is an annual minimum load under which the demand seldom falls This load that needs to be served at all times is called the base load. At the other extreme, the maximum load or "peak load" occurs for a relatively short duration. Regulations require utilities to have the internal capacity to meet this demand level [10]. Plants that operate only to meet the peak demand are known as peaking units. Intermediate or cycling units are plants designed to operate under varying load demands between base and peak loads.

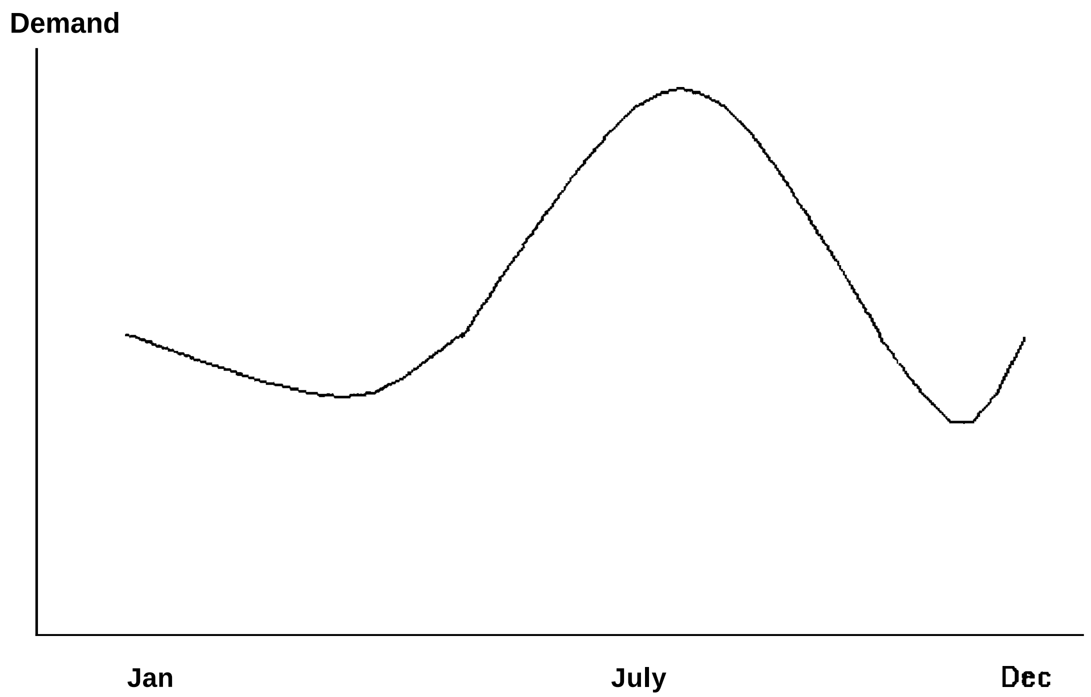


Figure 6 Seasonal load curve (summer peak)

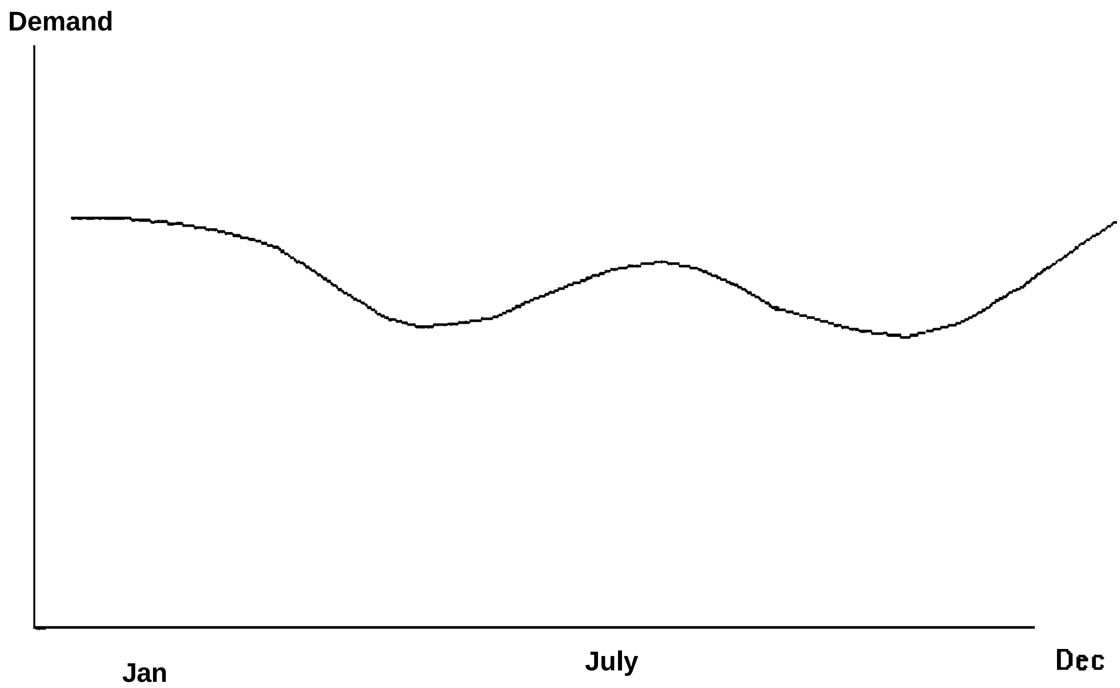


Figure 7 Seasonal load curve (winter peak)

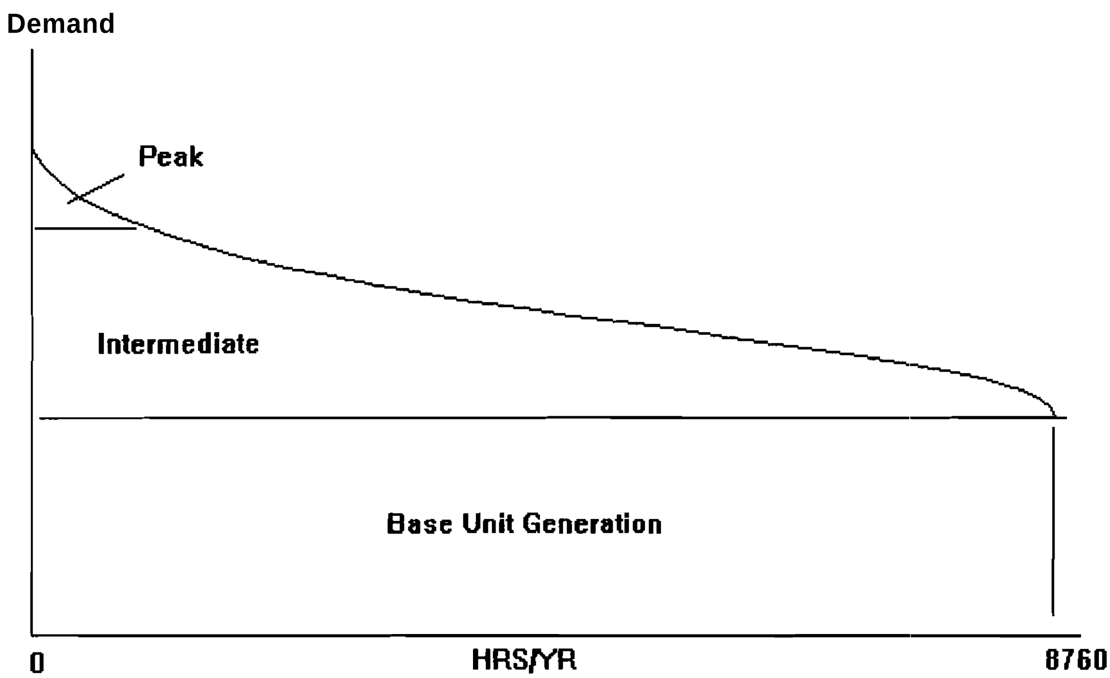


Figure 8 Typical load duration curve

Understandably, base load units need to have low generation cost. Planners choose capital intensive yet fuel efficient units for this purpose. Most of the base load units in the US are either coal or nuclear with 500 + MW capacity. Peaking units on the other hand have very low operation period or "on time." Hence the variable cost of generation is not as important. Older inefficient units tend to serve as peaking units. Units with low fixed cost but high generating cost such as combustion turbines are designated as peak load units in the range of 25-100 MW. Cycling units are mostly in the range of 200 - 500 MW. They are primarily coal, oil or gas fired units. The various mix costs of generating technologies, combined with transmission and distribution losses, shape the cost curve for utilities. In particular, as the load demand increases the cost of next unit of power generation rises. This effect in incremental cost can be attributed to various factors. Fuel efficiency of a generation unit is always lower at its maximum capacity than at lower operating points. Lower fuel efficiency is directly translated into higher operation cost for each additional unit of power generated. As explained earlier, cycling units and specially peaking units tend to have higher generating cost than base load units. As more and more units are brought on line, adding to the start up and shut down costs, the cost of producing an extra unit of power rises. Lastly, since power loss in transmission and distribution systems are directly related to the amount of power delivered to customers, the net cost to supply side is higher for higher demand level. Figure 9 shows a typical incremental cost curve that accounts for the aforementioned factors.

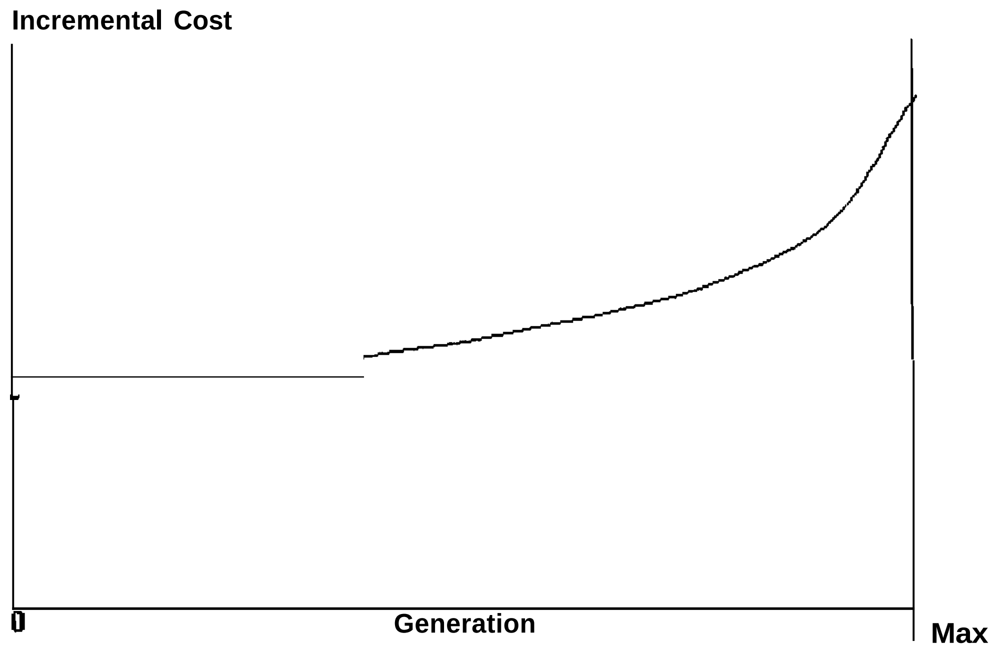


Figure 9 System incremental cost

V.III DSM impacts

Considering the operation characteristics of a utility, the economic impact of demand side management technologies and programs that are geared towards peak shifting and valley filling of load profile cannot be overlooked. Peak shifting refers to the effort to modify consumption pattern such that demand is shifted in time. Valley filling on the other hand is the attempt to introduce new loads at off-peak periods in order to increase system load factor. Whereas peak shifting may lead to valley filling, valley filling does not reduce peak demand. The economic advantages of peak shifting program can be identified by considering it to be an equivalent "peak load unit." Namely, by shifting a certain percentage of the peak load to off peak period, the need for a peaking unit to supply the percentage of original peak is averted. The economic analysis of such deferment will vary among different utility structures and operations. Furthermore, the decrease in peak will lead to a more economic dispatch of base and intermediate units as they operate under lower power output. Increased load factor due to valley filling and peak (shiftingprograms also decrease the partial loading conditions during off-peak period. The decrease in start up and shut down frequency is reflected in increased savings. Transmission and distribution losses are also lowered.

Although DSM programs intended to shift peaks appear to move generation away frorn oil and gas to coal with higher emissions, the environmental impact is not necessarily negative under all operating conditions [15]. In areas with generation mix emphasis on hydro, oil and gas rather than coal, the reduction in emission due to the non-use of inefficient coal fired peaking units is clear. Similarly in areas where coal based plants are sustaining both the base and peak loads, reduction of the operation period of the inefficient peaking units leads to reduced emissions as well. Utilities with generation mix containing gas or oil units for peaking but coal for base and cycling load have the potential to increase pollution due to peak shifting. However, if the environmental concerns are incorporated into the dispatch schedule, then the slight increase in coal emissions can be corripensated and even reduced without making a significant economic impact. The assessment of environmental impact of valley filling operations have to include emissions from previous end use fuel.

The economic advantages of peak shifting programs are not limited to the supply side. Advanced technologies that implement more efficient trajectory for heating, cooling cycles in commercial and residential buildings offer smaller operation bill [4]. Energy storage technologies allow equipment with lower capacity to serve the original same volume for heating and cooling. This will result in lower capital investment cost for consumers. For an effective implementation of DSM programs, customers have to be aware of the potential savings [2].

Sufficient incentives on the behalf of utilities are required to implement available technologies in peak shifting programs. Even though non-financial incentives such as publicity campaigns do shift energy consumption in the short run, long run results are seldom satisfactory. Consumers tend to fall back into the "old habit." Spot pricing or dynamic pricing incorporate the true cost of supply, transmission arid distribution of electricity to optimize the use of scarce resources [5,6,9]. Since the cost of electricity tends to vary by the minute as demand level changes, dynamic pricing structures are difficult to implement and costly to meter. Time-of-use (TOU) pricing or peak load pricing is one of most effective incentive, closest to spot pricing, to modify consumption pattern [3]. Time-of-use pricing typically contains two different rate periods: peak and off-peak. The higher cost of generation, transmission and distribution during pealk load demand is reflected by the higher rate during the peak period. Similarly off-peak period rate is lower than the regular usage based tariff. Peak load pricing has been in practice in numerous high volume consumer services. Airlines and telephone rates are some of the: examples where peak pricing are introduced in an effort to shift demand from one period to another. The effectiveness of time-of-use pricing is based on the long and short run elasticity of demand for electricity. It is also influenced by the availability of alternate fuel sources [5]. Full economic analysis is beyond the scope of this report but practical experiences have demonstrated TOU rates as an effective tool in shifting demand. However, a possible scenario of needle peaking by increased demand just prior to rate switching have to be examined before applying TOU rates [7].

Other financial incentives like rebates or subsidies are also effective to a lesser degree in changing consumption pattern. Rebate programs offer consumers billing credits for utilizing technologies that will lead to peak reduction and or shifting. Some utilities provide rebates to retrofit current equipment to a more efficient level. Heat pumps, adjustable speed drives are some of the technologies that are currently being offered by utilities across the nation. Under subsidy option, utilities distribute energy efficient products at a lower cost. Compact fluorescent lamp distribution is a good example of such programs.

V.IV DSM technologies

For DSM programs to be successful, proven technologies are a necessity. Presently available demand side technologies for peak shifting are

- thermal, heat/cool storage
- direct load control
- battery storage
- superconducting coils.

Energy storage programs of many utilities fall under three different options: cool storage, space heating storage and water heating storage [13]. Almost a third of electricity consumption in commercial sector is accounted for by space cooling. That makes it the single largest contributor to utility summer peaks and hence, the obvious target for load management programs. Cool storage technology uses conventional HVAC system with water, ice or eutectic salt storage tank. The storage medium is chilled during off-peak period and used for peak load cooling. In addition to the savings from demand charges, consumers can realize savings from down-sizing the chillers since the off-peak charges are used to support peak loads. Storage space heating systems utilize off-peak period to charge a heat reservoir and discharge as required during the full period. There are four systems currently available: control forced air, room-size, hydronic and under floor. Some utilities combine space heating with heat pumps to yield higher efficiency. Residential space and water heating are two of the major contributors to winter peaks. Storage water heating, commonly used in the 1940s and abandoned in the 1950s, is becoming a popular choice in DSM programs. Storage water heating supplies daily hot water requirement by heating only during off-peak period and storing the water. Again combining such storage systems with heat pump produces much more efficient implementation for storage water heating. In sites without time-of-use rates, utilities may opt for direct control of such loads.

Interruptible loads are classified as loads that are under direct control of the utilities. The ability to turn loads such as air conditioners and water heaters off during the short peak periods acts as a peak shifting mechanism. Traditionaaly utilities offer lower rates as an incentive to customers who allow such interruptions.

Although present manufacturing and operation costs have kept battery storage and superconducting coils to the supply side of load management [1], the possibility of their implementation in the demand side cannot be overlooked. Both of the technologies store electricity directly, making them more efficient and versatile in applications. Direct storage technologies allow the customer to purchase electricity at cheaper rates during off-peak period and utilize during peak period.

V.V DSM implementation results

Results from different utilities show that various DSM technologies are effective in shifting peak electric demand. Experiences have also shown that the best results are obtained through careful selection of demand side management programs and not just technologies. Table 1 lists some of the publicized results of DSM programs [14, 16,171.

Table 1 Load shifting impacts of various utilities

Utility	Year	Reduction	Comments
Ontario Hydro			
	1989	62 MW	Miscellaneous small residential commercial and industrial programs
	1990	59 MW	
United Power Assoc.			
	1990	5% Summer peak	Direct load control and other thermal storage based technologies.
	1990-91	12% Winter peak	
Dutch Electricity			
Peak clipping	2000	917 Gwh	Anticipated annual savings based on current experience.
Peak shifting		5242 Gwh	

Under DSM program selection, several factors need to be considered. Time-of-use rates induce the desired shift in peak only when customers with loads that can be switched to different period are targeted. For example, washing and drying can be switched to off-peak period easily but lighting loads are not as easy. in the effort to gain customer support of DSM programs, long term commitment by the utility is required. Furthermore, customers need to be assured that they will not have to pay higher amount for the same usage pattern after enrolling in DSM program. Also, utilities have to periodically provide support such that customers do not fall back to the old consumption habit. This is a distinct possibility when the electricity expense accounts for only a small percentage of total expenditure. It is difficult to generalize ideal selection processes and evaluation methods of DSM programs under different regulatory constraints faced by utilities.

However, utility-customer cooperation, long term commitment, and appropriate technologies are fundamental to a successful demand side management program implementation.

V.VI Conclusion

It is clear that when properly implemented, DSM programs yield benefits to both the customer and the utility. Load shifting programs are specially attractive to utilities for their proven effectiveness. Since load shifting programs do not decrease the total load requirement they are more likely to be adapted by utilities. In addition to financial benefits, load shifting offers environmental benefits as well. With the present trend in demand side management, load shifting programs are bound to play a vital role in reducing new generation requirements, transmission and distribution losses, increasing energy efficiency, load factor and containing environmental pollution.

REFERENCES

[1] G. Paula, "Load Management," Electrical World, August 1990, pp 41-49

[2] L. J. Hill, E. Hirst, M. Schweitzer, "From DSM Technologies to DSM Programs: Issues in Demand-side Planning for Electric Utilities," Energy,. Vol. 17, No. 2, 1992, pp. 151-160

[3] K. L. Lo, J. R. McDonald and T. Q. Le, "Time-of-day Electricity Pricing Incorporating Elasticity for Load Management Purposes," Electrical Power & Energy Systems, Vol. 13, No. 4, August 1991, pp 230-239

[4] J. E. Braun, "Reducing Energy Costs and Peak Electrical Demand Through Optimal Control of Building Thermal Storage," ASHRAE Transactions, Part 2,pp 876-888

[5] T. Bergstrom, K. MacKie-Mason, "Some Simple Analytics of Peak-load Pricing," RAND Journal of Economics, Vol. 22, No. 2, Summer 1991, pp 241-249

[6] B. Daryanian, R. E. Bohn, R. D. Tabors, "An Experiment in Real Time Pricing for Control of Electric Thermal Storage Systems," IEEE Transactions on Power Systems, Vol. 6, No. 4, November 1991, pp 1356-1365.

[7] F. Wirl, "Needle Peaking Caused by Time of Day Tarrifs," Electrical Power & Energy Systems, Vol. 13, No. 3, June 1991, pp175-181.

[8] M. Munasinghe, Energy Economics, Demand Management and Conservation Policy, Van Nostrand Reinhold, New York, 1983.

[9] F. S. Walters, Analysis of Various Pricing Approaches: Topic 1, Electric Utility Rate Design Study, 1977, Palo Alto California.

[10] J. Plumrner, T. Ferrar, W. Hughes, Electric Power Strategic Issues, Public Utilities Reports Inc.VA, and QED Research, Inc. CA, 1983.

[11] A. D. Little, Inc., Topic 8: Utilization of Off-peak Electricity, Electric Utility Rate Design Study, 1977, Palo Alto California.

[12] J. Skeer, "Highlights of the International Energy Agency Conference on Advanced Technologies for Electric Demand-Side Management," Advanced Technologies for Electric Demand-Side Management, Vol. 1, Sorrento Italy, April 1991, pp 3-10.

[13] V. A. Rabl, "Status of Energy Storage Technologies," Advanced. Technologies for Electric Demand-Side Management, Vol. 1, Italy, April 1991, pp 93-102.

[14] T. Van. Biert, "Prospects for Demand Side Management: Dutch Case," Advanced Technologies for Electric Demand Side-Management, Vol. 3 Italy, April 1991, pp 5-71 - 5-83.

[15] T. Yau, V. A. Rabl, "Load Management and the Environment," Advanced Technologies for Electric Demand-Side Management, Vol. 3 Italy, April 1991, pp 4-121 - 4-134.

[16] V. Zehriger, "Demand-Side Management with Off-Peak," Advanced Technologies for Electric Demand Side Management, Vol. 3 Italy, April 1991, pp 5-161 - 5-174.

[17] D. B. MacCarthy, "Programme Approaches for Implementing Demand-Side Management Technology," Advanced Technologies for Electric Demand-Side Management, Vol. 1, Italy, April 1991, pp 131-142.

[18] A. J. Wood, B. F. Wollenberg, Power Generation. Operation And Control, John Wiley & Sons, New York, 1984.

Chapter VI

The Effectiveness of Various Peak Reduction Techniques

S. Alyasin

VI.1 Introduction and scope

The high costs of expanding generation, transmission, and distribution capacities forces today's electric utilities to exhaust their installed facilities before considering expansion. Postponing system expansion in this way necessitates the ability to control peak demand of the system as well as total energy use by the consumers. ***Demand Side*** Management ***(DSM)*** programs involve direct control of the loads by the utility, enabling them to shift loads during peak demand hours, as well as achieve other economic goals through conservation, improved efficiency, and peak reduction. This report identifies the effectiveness of various methods considered in DSM programs to reduce electric peak demand. Before analyzing these peak reduction techniques, a brief summary of the importance of peak loads and a statistical view of urban electricity consumption is needed.

The generating units of any utility are composed of base load units which are the most economical to use for loads present throughout the year, intermediate cycling units which are more economical for satisfying short term peak loads, and peak-load units meant to handle loads that occur during few hours of the year. Fluctuations in demand during peak days of the year are the most expensive for utilities to satisfy, therefore the daily peak load rather than the average load over the season dictates important financial, operational, and regulatory decisions. This is the reason for the involvement of DSM technologies in reducing the peak load.

Although the focus of this paper is to introduce various peak reduction methodologies and to realize their effectiveness, it is beneficial to gain an understanding of how electricity consumption is quantified. Load management studies require data on time-sequencing of loads as well as the time series behavior in the occurrence of loads throughout the day. [5] Since the actual parameters which influence electricity use vary from resident behavior to specific appliance type, to climatic parameters as well as to socio-economic factors, some studies rely on electricity use patterns over a certain number of days as random variables and then try to describe their stochastic behavior in statistical terms as load forecasting measures. Thus, a set of data is taken over the peak days of the year (only a few times over the year) and the statistical variation in this set of data is used to evaluate the need for peak reduction and to plan the specific method for achieving lowest peaks. The following means of peak reduction are discussed in this paper.

- Peak demand reduction due to solar water heaters
- Summer peak load reduction from the operation of photovoltaic (PV) systems
- Application of conservation voltage reduction (CVR) for residential, commercial, agricultural irrigation, and industrial consumer classes
- Use of electricity pricing as a signal to communicate messages to consumers

Concluding remarks as to the effectiveness of each method are also provided.

VI.2 Peak demand reduction due to solar water heaters

One peak demand reduction scheme is the use of solar water heaters. This section provides a study of the effectiveness of using solar water heaters in the residential and cotnmercial sector in reducing peak demand. Note that hot water use profiles are quite different for residential and commercial consumers. The residential peak hot water use occurs between 7:30-8:30 am. Four studies performed by the Florida Power and Light ('78-'80), University of Texas at Austin ('82-'83), Florida Solar Energy Ctr. ('82-'83), and the North Carolina Alternate Energy Corp. ('84-'85) aimed at determining coincident demand reduction in each system due to solar water heater penetration. The term coincident refers to demand reduction during the utility's peak (usually 5-6 pm) as opposed to noncoincidental peak demand reduction referring to reduction in demand during the water heater's peak. [3] For the Florida Power and Light system involving 21 solar systems, an electric demand of 0.33kw is replaced by a "negligible" solar water heater, resulting in a coincidental demand reduction of 0.33kw. The University of Texas experiment involving 14 solar systems, an electric demand of 0.399kw was replaced with a 0.01kw solar water heater. This lead to a coincidental demand reduction of 0.39kw. The Florida Solar Energy Ctr. replaced their electric demand of 0.72kw with 20 solar systems consuming 0.08kw, thus resulting in a coincidental demand reduction of 0.64kw. Finally, the North Carolina Alternate Energy Corp. satisfied their electric demand of 0.3kw with 24 solar systems consuming only 0.2kw, corresponding to 0.1kw of coincident demand reduction.

A more recent study performed by the city of Austin utility in 1991 focused on the utility savings in the commercial sector. The Rosewood Multi-Purpose Center, Firestation 21, and the South Austin Red-Center (SARC) are the three city owned buildings identified as good sites for solar water heating systems based on their potential to save the most energy and money for the city. The Rosewood center's: hot water profile has a sharp peak at midday due to the use of a large dish washer after lunch (average daily water use is 150 gallons). An active drain-back solar water heating system consisting of three 4ft x 8ft flat-plate solar collectors and two 82 gallon solar storage tubes is installed. Average summer reduction for this system is shown in Figure VI.1.

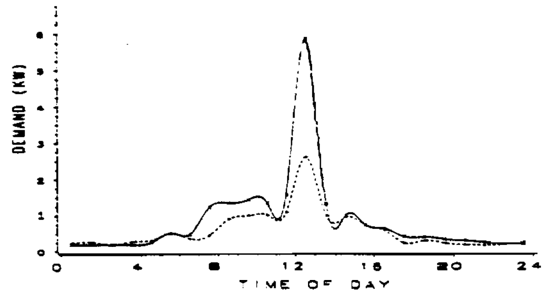


Figure VI.1 - Average summer day electric demand for the Rosewood System

Observe that the peak demand at midday is considerably lower "with solar." Note that the "with solar" curve is based on the metered electric demand with the solar system on plus an estimate of the parasitic power used by the pumps and controller. The "without solar" curve is from a model which uses measured hot water energy use and estimated tank heat loss to predict what electric demand would have been without a solar system. The area between the two curves represents the demand reduction for the utility.

The average summer day diagram for peak reduction in the Firestation system is shown in Figure VI.2.

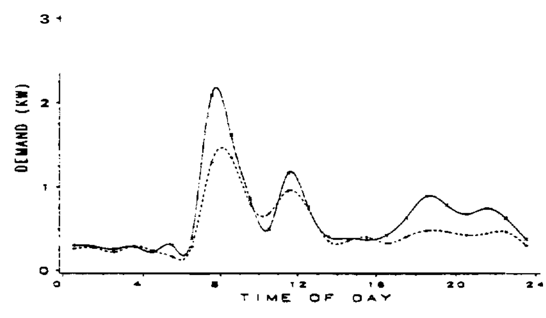


Figure VI.2 - Average summer day peak demand for the Firestation system

Hot water is used in the Firestation for showering, dish washing, and cleaning with an approximate daily use of 60 gallons. One peak is seen in Figure VI.2 during the morning hours. The utility's demand reduction is easily seen in the figure.

The average summer day electric peak demand for the SARC is seen in Figure VI.3.

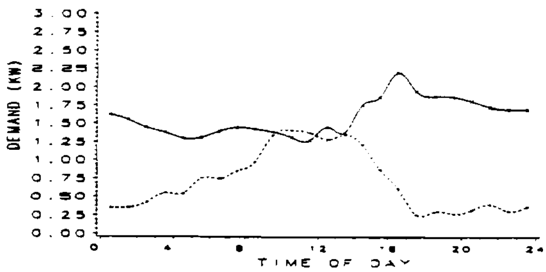


Figure VI.3 - Average summer day peak demand for the SARC system

SARC houses a gymnasium, game room, locker room, and offices. The main hot water use is from showering. The use varies from day of the week to season to events scheduled. Approximate average daily hot water use is 100 gallons.

The utility savings due to demand reduction for the three systems shown is evaluated by the following rate. A 1kw coincident peak demand reduction is $350 to the utility (note that the coincident peak interval in this study is 5-6pm). At this rate, and based on average peak demand reduction values, a saving of $175 due to the Rosewood solar heaters, $105 due to those of the Firestation system, and $280 due to those at the SARC is seen by the utility. Furthermore, if any of the three system's hot water use peak demand coincided with the peak demand of the utility, a saving of about $2000 is likely for any of the systems. This justifies the utilities one-time rebate policy of providing $150-350 depending on the size of the installation. Realize that the above numbers suite an average summer day, since a winter day may be either sunny or completely overcast, and determining average peak is not feasible without several years of testing.

VI.3 Summer peak load reduction from the operation of photovoltaic (PV) systems

This section discusses the capability of grid-connected photovoltaic systems serving commercial buildings in upstate New York, a study supported by the Niagara Mohawk Power Corp.

The PV system involved is composed of an installed, roof-fitted 15.4kw system. Generally, PV systems are well-suited to DSM technologies since the available isolation coincides well with the typical daily electrical demand curve of commercial customers. The minimum system specs are:

- 15kw dc output @ 100W/m^2@25 degrees celsius
- total system efficiency near full load > %90
- PCU pf > 0.95 under rated output condition and > 0.85 at %25 of rated output
- ITHD < %5 - individual harmonic distortion <%3; VTHD < %3 - single frequency distortion < %1.

The PV installation managed to comply with all original specs mentioned above and provide the average demand reduction (July-August 1990) similar in form to that illustrated in Figure VI.4. The actual system installed had a peak reduction of about 10kw over the 2 month period while the study was carried out.

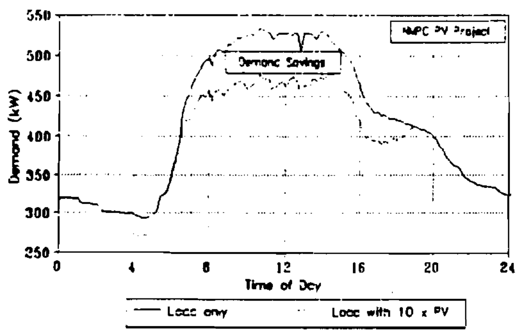


Figure VI.4 - Average (NMPC) bldg. demand reduction for July-August 1990 due to the addition of a PV system with 10 times the capacity of the existing system

The upper curve in Figure V1.4 defines building demand on the utility grid without the PV' system. The lower curve defines the building demand with the PV system. The difference in area is the demand savings. Note that the results depicted in this figure are the.expected savings for a PV system with 10 times the capacity of that installed in the experiment.

Again following the guideline of $350/kw in coincident demand reduction during the. utility's corresponding interval, the PV system installed has effectively saved the utility $3500. Furthermore, a PV system with the capacity of the systern depicted in Figure VI.4 results in much lower demand. Unfortunately, installation costs are not quoted in the study. Assuming these costs are low in comparison to savings seen in

Figure VI.4, the grid-connected PV system has successfully provided a considerable reduction in peak demand.

VI.4 Application of CVR for residential, commercial, agricultural irrigation, and industrial consumer classes as means of reducing peak load

The ANSI standard C84.1-82 defines the distribution end voltage levels in the United States. This regulation is needed to protect consumer equipment. The regulation of distribution system voltage to narrower ranges than those permitted by the ANSI standard has been studied, debated, and practiced. This practice is known as conservation voltage reduction (CVR) and has been applied by many utilities in the US with the aim to reduce peak load demand and end-use energy consumption. This section provides a description of this practice and points out a case study made by the Pacific Northwest Laboratory to indicate the savings in the Bonneville Power Administration service area (BPA) due to a region-wide implementation of CVR.

The CVR practice of utilities and the expected energy savings depend on feeder length and consumer class (residential, industrial, commercial, and agricultural). The implementation costs of CVR are typically low for short, high-density urban feeders and quite high for low density suburban and rural lines. [6]

Two CVR implementation strategies often considered are line-drop compensation regulation (LDC) and Voltage speed reduction (VSR).

- ***Line-drop compensation (LDC) regulation***

This involves regulation that keeps the most distant portion of the circuit at some minimum acceptable voltage level (about 114 volts), while the rest of the circuit voltage is left to vary with load conditions. During peak demand hours, the substation voltage can rise to maximum allowable service voltage (126 volts), but at all other times it would be somewhat less. During off-peak hours, the entire circuit would operate near the minimum controlled voltage. Thus, energy consumption of end-use load is reduced because the average circuit voltage is less than it would be under conventional voltage regulation.

- ***Voltage Spread Reduction (VSR)***

This involves the compression of the voltage range on a feeder. For circuits with an adequate voltage margin, VSR is implemented by setting regulation voltage-level controls to a narrower than normal range while maintaining required minimum voltage at the most distant load. For example, by using VSR to set the voltage on a feeder to the lower half of the $\pm$%5 band allowed by the ANSI standard, an average voltage reduction of %2.5 is achieved on the feeder. When used in conjunction with LDC regulation, it is often possible to implement voltage reductions in excess of %5 while maintaining an **adequate** voltage at the most distant load. The %2.5 reduction in the **CVR** implementation resulted from a contribution of %55by the residential, %29by the commercial, %14 by the industrial, and %2 by the industrial sectors. The implementation costs for the CVR applying to Table VI.1 are broken down into the following categories:

Feeders < 3 miles -- Table VI.1 (a)
3-12 miles -- Table VI.1 (b)
> 12 miles -- Table VI.1 (c)

(a)

	Circuits	Voltage Reduction (%)	Cost/circuit
1 Reregulation 5% Lower and LDC	12.8	5.7	$150
2 Reregulation 5% Lower	14.0	5 0	$150
3 LDC	31.3	2.4	$150
4 Reregulation 1.2% Lower	17.e	1.2	$150
5 Balance Feeders, LDC, and 5% Reduction	0.8	5.7	$390
8 Balence Faders and 5% Reduction	0.7	5.0	$390
7 Balance Feeders and LDC	1.9	2.4	$390
8 Balance Feeders end 1.2% Reduction	1.1	1 2	$390
9 Capacitor Addition	9.0	2.5	$24,800
10 Regulator Addition	8.0	3.2	$8,000
11 Capacitor and Regulator Addition	1.9	3.2	$32,800

(b)

Option	Circuits (%)	Voltage Reduction (%)	Cost/circuit
12 Reregulation	8.0	2.0	$150
13 Capacitor Addition	13.1	2 0	$27,800
14 Regulator Addition	14.1	2 0	$8,000
15 Regulator and Capacitor Addition	11.1	2.0	$47,800
16 Reinsulate	3.2	2 0	$155,000
17 Reconductor	5.0	2 0	$180,000
18 Combination	12.7	2.4	$126,000
19 Reregulation and LDC	4.0	4.4	8150
20 Capacitor Addition	6.4	4.4	$27,800
21 Regulator Addition Voltage Reduction	8.9	4.4	$8,000
22 Regulator and Capacitor Addition	5.4	4.4	$47,800
23 Reinsulete	1.6	4.4	$155,000
24 Reconductor	2.4	4.4	$180,000
25 Combination	6.3	4.6	$126,000

(c)

Option	Circuits (%)	Voltage Reduction (%)	Cost/circuit
26 Reinsulate	43.5	2.5	$486,000
27 Combination	56.5	2.5	$703,000

Table **III.1** - Costs involved in the implementation of **CVR**

A CVR resource in the range of 170 to **268** avg. **MW** was estimated to cost **5 cents/kwh** as established by the Northwest Planning Council. For the BPA system under study, for up to **1 cent/kwh, 142** to **230** avg. is calculated which is very competitive with **other** conservation approaches. In fact, the BPA study has recognized CVR as the foremost plan for a ten year period. For larger periods of time, the **Model** Conservation Statndards (MCA) plans are deemed more optimal. The effectiveness as far as the BPA system is considered translates to energy conservation of 270 avg. MW at a cost of 5 cents/kwh which meets the Northwest Planning Council standards.

VI.5 Use of electricity pricing as a signal to communicate messages to consumers

The aim of utility load management schemes is to encourage mutual cooperation between consumers and the supply authorities in optimizing the process of generation, distribution, and end use of elecmcal energy. [4] This section emphasizes on utility indirect control over electrical demand. By issuing relevant tariffs to each class of customers (residential, commercial, and industrial), the consumers can be driven to alter their energy use and demand into a more energy efficient plan. In general, the tariff is cheap during off-peak periods and expensive during on-peak periods. Two methods of achieving this are identified below.

- ***LP Method***

This method involves a two component cost during on-peak hours and a one component cost during off-peak hours. The on-peak calculation involves capacity costs as well as energy costs. During off-peak hours, the price is only the relevant energy costs. The required revenue is maintained by attracting more energy consumption during the: off-peak periods. This is accomplished, for example by employing cheaper prices for water and space heating during off-peak hours.

- ***Total Surplus Method***

This method involves a surcharge per kwh during the peak period. This surcharge is to maintain peak capacity demand. Again, as with the LP method, there is a higher unit price during the peak hours and a lower unit price during the off-peak hours.

The effectiveness of these methods is difficult to identify since the success of this plan is largely dependent on the socio-economic characteristics of the consumer. Consumers with better financial means may not see the price reductions as enough motivation to alter their practices. Nevertheless, in general this method may have positive effects and lead to savings. The study used as reference did not apply this to a particular case so an example of the application of this idea is not presented in this report.

VI.6 General conclusions

Peak load is very expensive for a utility to satisfy ; thus, the load's characteristics dictate many of the important financial and operational decisions made by a utility. Many DSM technologies are aimed at reducing fluctuations in demand during peak days of the year. This report analyzes the application of the following methods of peak reduction.

- Peak demand reduction due to solar water heaters
- Summer peak load reduction from the operation of photovoltaic (PV) systems
- Application of conservation voltage reduction (CVR) for residential, commercial, agricultural inigation, and industrial consumer classes
- Use of electricity pricing as a signal to communicate messages to consumers

Use of solar water heaters is effective as a peak reduction scheme for commercial as well as residential (not to the same extent as commercial) use. The study made by the city of Austin utility shows that a one-time rebate cost of $100-350 to encourage the use of :solar water heaters is easily redeemed by the savings expected from the operation of the system, especially if the unit's peak coincides with the peak of the utility.

Large photovoltaic systems can function to significantly reduce peak demand. The 15kw NMPC PV project discussed in this paper shows a large reduction in peak dernand due to the operation of the PV system. This translates to considerable monetary savings to the utility, assuming the customary rebates for the installation of the system are low compared to the savings expected (a point not addressed in the study).

Line-drop compensation regulation and Voltage spread reduction are discussed as two CVR measures. Combined use of these techniques can result in up to about %5 reduction in voltage. The study for the Bonneville Power Administration estimates savings of 270 average MW at a cost of 5 cents/kwh for the implementation of CVR on this system. Electricity pricing may be an effective technique in peak reduction if the consumer group under consideration is well aware of the message being sent and sees the tariff as enough motivation to change their practices for more economical rates. Notice that the success of this method clearly lies in how well the message is communicated by the utility as well as the type and characteristics of the consumer involved.

Works Cited

[1] Q. Ahsan, 'Load management: impacts on the reliability and productive costs of interconnected systems,' Electrical Power and Energy Systems, Vol. 12, No. 4, pp. 257-262, October 1990.

[2] B. Baily, 'Early experiences of the 15kw NMPC demand-side management photovoltaic project,' Solar Cells, Vol. 30, pp. 529-533, 1991.

[3] M. Ewert, J. Hoffman, and D. Panico, 'A case study of electric utility demand reduction with commercial solar water heaters,' Journal of Solar Energy Engineering, Vol. 113, pp. 94-101, May 1991.

[4] K. L. Lo, J. R. McDonald, T. Q. Le, 'Time-of-day electricity pricing incorporating elasticity for load management purposes,' Electrical Power and Energy Systems, Vol. 13, No. 4, pp. 230-239, August 1991.

[5] T. A. Reddy, 'Statistical analyses of electricity use during the hottest and coolest days of summer for groups of residences with and without air-conditioning,' Energy, Vol. 15, No. 1, pp. 45-61, 1990.

[6] J. G. Steese, J. E. Englin, and R. D. Sands, ' Conservation voltage reduction potential in the Pacific Northwest,' Proceedings of the 25th *Intersociety* Energy Conversion Engineering Conference, Vol. 4, pp. 43-48, August 12-17 1990.

Chapter VII
Cost to Benefit Ratio of Demand-Side Management Programs

Reid I. Sasaki

VII.1 Introduction

With an increased concern in the nation's environment and natural resources, many electric utilities are involved in integrated resource planning (IRP) to cope with future load growth. Integrated resource planning involves the comparison of demand-side and supply-side resource options to obtain the most cost-effective resource combination to satisfy load requirements [1]. These demand-side resource options are the focus of demand-side management (DSM) programs implemented by electric utilities.

There are various types of DSM programs, most of which focus on the reduction and timing of power consumption by the utility customer. Some examples of DSM programs include peak-shifting, energy conservation, and the promotion of energy-efficient devices. The development, promotion, and implementation of any type of DSM program have benefits and costs associated with it. These benefits and costs, which are seen by both the utility and the customer, are the determining factors to assess the cost effectiveness of a DSM program. These factors include

- program participation,
- participant adoption of recommended actions,
- electricity savings caused by these actions, and
- utility and customer costs of the program.

The value of a DSM program is determined by the product of the first three factors divided by the fourth. Each of these factors is described in detail in the following sections.

VII.2 DSM program participation

The value of a DSM program implemented by a utility is highly dependent on the participation of the program by its customers. Program participation is defined as a customer's use of any of the services or technologies promoted by a DSM program. Various DSM programs must be tailored to cater to the individual needs of the commercial, industrial, and residential sectors so that program participation may be maximized. Some of the barriers facing the utility when developing a DSM program include a potential participants lack of infonnation of DSM programs, confidence in DSM technologies, and capital to invest in DSM technologies. By removing these barriers and achieving a high penetration of DSM programs, utilities will be able to increase program participation rates. The program participation rate is defined as the ratio of the number of participating units to the number of eligible units for the program for a specified unit of time. The terms used in calculating program participation rates, namely participating units, eligible units, and time period, will be discussed in detail below. The various types of eligible markets will also be discussed below.

- Participating units. The definition of a participating unit is dependent on the type of DSM program initiated by the utility. For informative energy conservation DSM programs that inform the customer of ways to reduce power consumption without the use of energy-efficient devices, an appropriate participating unit may be a building, a business, a meter, or an account. In this case, the participating unit selected is dependent on the customer sector that the program is focused. For instance, the number of households may be used as the participating unit for a conservation program intended for the residential sector. DSM programs that promote the use of DSM technologies through rebates (e.g., high-efficiency heat pumps, refrigerators, and lamps), the number of devices may be used as the participating unit. This may be more appropriate due to the fact that a building may contain a number of these devices.

- Eligible units. The eligible unit used for calculating the participation rate is identical to the participation unit. Compared to the participation unit, determining the number of eligible units is a much more difficult task due to the vast number of customers who could adopt DSM actions. Some examples of methods used to determine the number of eligible units are rnarket surveys, appliance saturation surveys, building inspections, and sales data. Note the participation rate, which is defined as the ratio of number of participating units to the number of eligible units, is sensitive to the number of eligible units used. In many cases, the number of eligible units is defined as all of the utility's customers in a certain sector. When this is done for audit programs, the participation rate may be conservative due to the fact that the number of customers who could actually adopt the action is actually smaller than the number of eligible units used. Conversely, the participation rate may be artificially high for DSM programs aimed only at the utility's largest customers due to the fact that the number of eligible units defined is very small..

- Time periods. The time period used when calculating a participation rate is identical for both the number of participating units and the number of eligible units. A one-:yeartime period is used to calculate an annual participation rate starting from the program's starting date. A time period starting from the program's starting date to the present is used to calculate a cumulative participation rate. Cumulative participation rates are invaluable for determining overall market penetration of DSM programs.

- Types of eligible markets. The types of eligible markets for DSM programs include retrofit, replacement, new construction markets, or a combination of the three. Alternate definitions for annual and cumulative participation rates for the retrofit market and the replacement and new construction market are shown below in Table (VII.l).

	Numerator	Denominator
RETROFIT		
Annual	Number of participating units in year i	Number of eligible units in year i
Cumulative	Number of participating units since program inception	Number of eligible units from program inception that are still eligible
or	Number of participating units since program inception	Number of eligible units in the base year
REPLACEMENT (Appliances, equipment, or new construction)		
Annual	Number of participating units in year i	Number of appliances purchased (or new units constructed) in year i
Cumulative	Number of participating units since program inception	Number of appliances purchased (or new units constructed) from year program started through year i
or	Number of units participating since program inception	Number of eligible units currently in service

Table (VII.l) Alternative Definitions of Program Participation Rates [2]

When determining the cumulative program participation rate for retrofit programs, two methods are used. The first involves the use of the number of eligible units from the initiation of the program that are still eligible as the denominator in calculating the program participation rate.

This shows the cumulative percentage of units that were initially eligible (from the initial year) have participated in the program. The second involves the use of the number of eligible units in the base year as the denominator in calculating the program participation rate. This shows the cumulative percentage of units that are currently eligible (in the base year) have participated in the program.

When determining the cumulative program participation rate for replacement or new construction programs, two methods are also used. The first involves the use of the number of appliances purchased (or new units constructed), from the year the program started through year i, as the denominator in calculating the program participation rate. This shows the cumulative percentage of appliance buyers (or the percentage of new buildings constructed) that have participated in the program. The second involves the use of the number of eligible units currently in service as the denominator in calculating the program participation rate. This shows the cumulative percentage of high-efficiency units in the current stock.

Note that the eligible population for replacement or new construction programs changes each year,,unlike the eligible population for retrofit programs that remain relatively constant (neglecting attrition, or customers dropping out of ongoing DSM programs). This is due to the fact that the eligible equipment in replacement or new construction programs must first depreciate to the point of replacement. Thus, high cumulative participation rates are obtainable sooner for retrofit programs than replacement or new construction programs.

VII.3 DSM program participant adoption of recommended actions

The adoption of actions recommended by DSM programs is another factor that affects the value of a DSM program. Measure adoption includes secondary measure adoption, interactions of measure adoption, free drivers, and participant takeback [3,4]. These will be discussed in detail below.

- Secondary measure adoption. Secondary measure adoption refers to any measures adopted by the participating customer outside of the program as a direct result of the promotion and incentives. For example, a participating customer may purchase more units of a promoted high-efficiency device at retail cost than the maximum number offered through a utility rebate program at reduced cost.

• Interactions of measure adoption. Interaction of measures adoption is defined as the propensity of customers to purchase and install certain combinations of related measures promoted by a DSM program. Some examples include the purchase and installation of high-efficiency electronic ballast and lamps and the purchase and installation of high-efficiency water heaters and insulation. As compared to the adoption of a single DSM measure, the adoption of two or more related measures will lead to an increase in the value of a DSM program.

• Free drivers. Free drivers may be defined as participating customers who take the initiative to adopt measures that are not promoted as a part of the DSM program. This is a result of the programs effect on the awareness of energy conservation and energy-efficient devices. For example, a customer participating in a high-efficiency heat pump rebate program may also decide to install high-efficiency refrigerators not covered under the rebate program. Another definition of free drivers includes non-participating customers who adopt DSM recommendation. For example, a retail store unaffected by the any DSM may decide to stock a large number of high-efficiency devices to sell to the consumer. In both cases, free drivers contribute to the value of a DSM program without contributing to its cost.

• Participant takeback. Participant takeback, sometimes referred to as rebound or snapback, is defined as the change of the customers energy use due to the energy savings obtained by implementing DSM actions. For example, a residential customer that reduces their energy consumption by purchasing a high-efficiency air conditioner may decide to run it longer due to the increase in savings obtained from the unit. Although this may lead to an increase in comfort to the customer, participant takeback reduces the energy savings measured when determining the overall value of a DSM program.

VII.4 DSM Program Electricity Savings

There are a variety of ways of evaluating the electricity savings obtained from a DSM program. These include a number ways of defining and measuring changes in electricity use, load shape, and peak demand by the customer. The three main factors in determining the electricity savings obtained from a DSM program include the determination of net versus total savings, the comparison group, and the measurement method used to calculate the electricity savings. These will be discussed below.

• Net versus gross savings. When determining the electricity savings obtained from a DSM program, a distinction must be made between the net and gross savings. The gross savings obtained may be defined as the electricity savings incurred by all customers participating in utility-sponsored DSM programs. The sampling of participants that adopt methods prescribed by DSM programs includes a number of customers that would have adopted these: methods even in the absence of any utility-sponsored DSM programs. The savings obtained by these customers, referred to as free riders, VII.6 must be subtracted from the gross savings to obtain the net savings. When there is a difference between the gross and net savings, the utility will be paying for some DSM action that would have been installed even if the DSM program, did not exist.

• Comparison groups. Comparison groups are used to determine the net electricity savings due to a DSM program and the extent to which customers modify their energy-use behaviors after participation in a DSM program. The comparison group may either be a non-participating group that resembles the participating group in the DSM program or the participating group itself. When the participating group is used as the comparison group, a time-series data analysis (i.e., before and after the implementation of a DSM action) is sometimes made. This is often done when a similar comparison group can not be found, due to the fact that most, if not all, customers are participants of the program under evaluation.

• Measurement methods. There are a number of methods to determine electricity use and savings of a DSM program participant, all of which vary in cost and complexity. The explanation, advantages, and disadvantages for these measurement methods are described in Table (VII.2) shown on the following page. The most common measurement methods are the use of engineering calculations, short-term metering, customer monthly electricity bills, and end-use load monitoring, all of which will be described in detail below.

Engineering calculations, sometimes referred to as the technical savings potential, is the simplest method of measurement when determining electricity savings. It involves the calculation of expected changes in energy and loads based on the specifications of the energy efficient device, the operating patterns of the customer, and the operating conditions. Although engineering calculations require no metering by the utility to determine electricity savings, they typically produce results that are higher than actually achieved and are usually the least accurate of the measurement methods.

Approach	Explanation	Advantages	Disadvantages
DSM-action-specific factors	Standard factors for certain actions are determined beforehand, which form the basis for estimation.	Very simple, no ambiguity, very low administrative cost.	Valid for only some devices:,could yield estimates of savings not realized if factors are incorrect or if devices fail to perform as expected.
Engineering calculations	Calculations of expected electricity savings are performed for each device in each building, may (involvesimple formulas or computer models.	Simple, no ambiguity, low administrative cost.	Could yield estimates of savings: not realized if calculations are incorrect or it equipment fails to perform as expected.
Periodic measurements of electricity use	Monitor electricity use before and after participation for short times (e.g., a few days), also measure other relevant factors (e.g., operating hours for equipment, heating degree days) for a longer time (e.g., a year).	Measures electricity savings (both kWh and kW) for well-defined, short time periods. Modest cost.	Could yield estimates of savings not realized if measurements taken incorrectly or at atypical times, or if building use change:;. Difficult to apply to devices that are season- or weather-dependent.
Analysis of monthly electricity bills	Obtain electricity bills for a year before and a year after participation. adjust annual electricity use for weather and other factors, compute difference between pre- and post-participation rate.	Measures actual changes in electricity use, permits adjustment for changes in weather and other factors, (requires little primary data collection.	Provides no estimate of demand (kW) reductions. Analysis of billing data can yield ambiguous results if kWh use affected by changes in facility use unrelated to devices installed.
End-use, bad-research monitoring	Monitor specific circuits affected by new systems to record kW-demand before and after participation.	Measures actual changes in electricity use and demand (kWh and kW) for specific end uses affected by program. Combine kW information with other data to adjust for changes in weather and other factors.	Most expensive and time consuming method. Large amounts of data require sophisticated computer programs and analyst to interpret. Results may be affected by changes in facility use unrelated to equipment installed.

Table (VII.2) Methods Used to Measure Electricity Savings Obtained from DSM Programs [2]

The periodic measurement of electricity use determines the before and after energy consumption of the participating customer to calculate the savings obtained from a DSM action. This method requires the metering of the affected circuit at least twice, once before the implementation of a DSM action and once after. The savings are then determined by calculating the difference between the two values, which are adjusted for the number of hours per year that the system is in operation. This method is best suited for customers that have regular operating schedules and use electricity for many different purposes, such as large commercial buildings and industrial facilities.

Similar to the periodic measurement of electricity demand, the analysis of monthly electric bills of a customer determines the electricity savings obtained from a DSM action by analyzing the before and after energy consumption by the customer. In the case of analyzing monthly electric bills, records are collected for at least one year before the DSM action is implemented and one year after. The savings are then determined by analyzing the cumulative difference between the before and after consumption, adjusted for seasonal variations in energy consumption. This method is best suited for customers whose energy use is dependent on the effects of outdoor temperature, such as residential and small commercial buildings.

The most complex of the methods requires the end-use metering of the specific loads or circuits which are impacted by the DSM action. Similar to the other metering methods, electricity savings are determined by end-use metering by analyzing the before and after consumption by the customer. Although more costly than other metering methods, end-use metering is the most accurate of all methods because it is specific to the DSM action implemented and records the time-of-use. This method is best suited for large buildings where the DSM action implemented affects a small percentage of the overall building energy consumption, such as a large office building which is retrofitted with high-efficiency water heaters.

VII.5 DSM program costs

The development and implementation of any DSM program involve a cost to the utility, the participating customer, or a combination of the two. Similar to program savings, DSM program costs are often incomplete to accurately access program performance,. These costs are usually divided into direct costs, or the costs associated with the measure implemented by the DSM program, and indirect cost, or the administrative costs required to develop, market, and implement the DSM program [4]. These direct and indirect costs will be discussed in detail below.

- Direct costs. The direct costs associated with the measure implemented by a DSM program, C_d include financial incentives given to participating customers by the utility and costs for the purchase, installation, and maintenance of DSM equipment and systems, which are footed by the utility, participating customer, or a combination of the two. Note that rebates offered by utilities often account for the majority of DSM program costs. For example, customer rebates offered by Central Maine Power Company as a part of a commercial lighting program in 1989 accounted for 85% of the total program costs.

- Indirect costs. The indirect or administrative costs of a DSM program, C_{admin}, include development, marketing, implementation, and evaluation costs, all of which are borne by the utility. Development costs include the costs for market evaluation, load research, creation of the program concept, and staff development and training associated with preparing: a new program. Marketing costs, which may be either fixed or variable, include the costs to prepare and implement the promotion of the program. Implementation costs, which also may be fixed or variable, include the costs for labor, equipment, and material required to implement the program. Evaluation costs include the costs for program monitoring and data collection and analysis.

The division of the cost between the utility and the participating customer depends on the type of DSM program involved. The cost to the utility, C[illegible] is the administrative costs, C_{admin}, plus a fraction of the measure costs, $f \times C_{meas}$, where f is the fraction of the measure costs that the utility pays. The cost to the participating customer, C[illegible] is the remainder of the measure costs, $(1 - f) \times C_{meas}$. This is summarized in Figure (VII.1). Note that there is a relation between the administrative and the measure costs that are borne by the utility. As the fraction of the measure costs that the utility pays increases, the administrative costs to the utility often [decrease. Thus a DSM program may be designed where the total costs to the utility may be minimized by determining the optimal mix of administrative and measure costs.

The cost of conserved energy (CCE) is defined as the ratio of the total cost of a DSM program to the total energy conserved by the DSM actions implemented. This figure is often stated in terms of dollars invested in the DSM action per kilowatt hour conserved due to the implementation of the DSM action. For example, an analysis of 46 high-efficiency lighting rebate programs aimed at the commercial and industrial sectors determined the CCE to be less than $0.02/kWh [5].

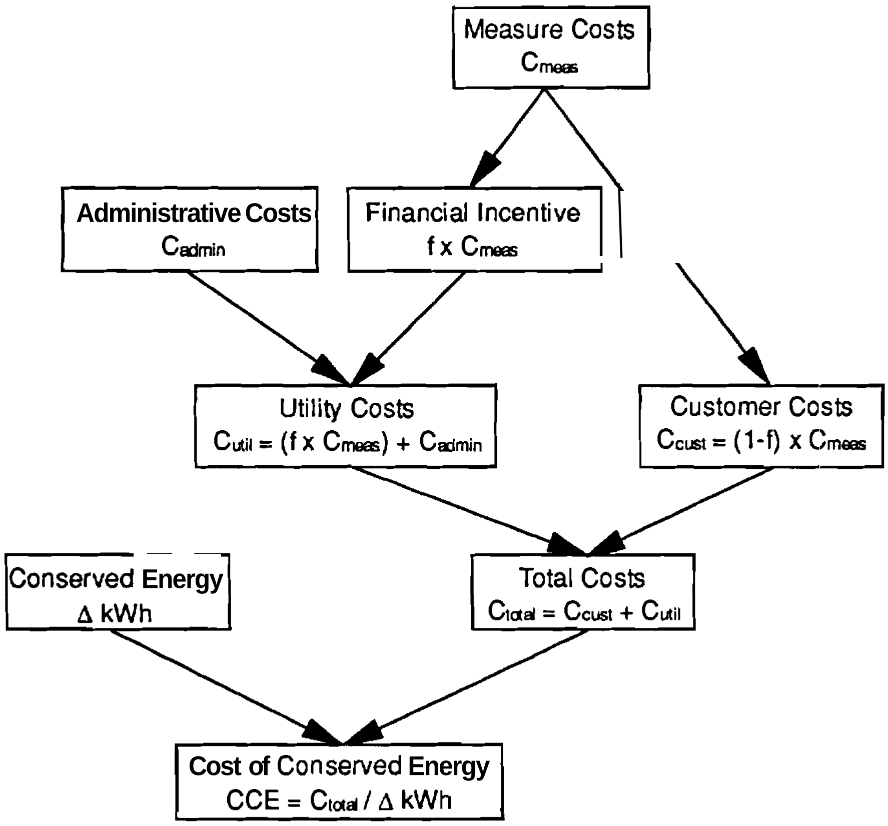


Figure (VII.1) Cost of Conserved Energy Obtained from a DSM Program [2]

VII.6 Conclusion: The value of DSM programs

The cost to benefit ratio for DSM programs implemented by utilities is difficult to accurately access because of the wide range of programs implemented and the vast number of variables involved with determining the value of a program. The aspect of accurate data collection and analysis also adds to the difficulty of accurately accessing a program's worth. Nonetheless, DSM programs have proved themselves rewarding in terms of overall dollar figures. The utility investment and net benefit to both ratepayers and shareholders for various DSM. programs are shown below in Table (VII.3).

Utility (State)	Size of DSM Program (Year)	Net Benefit to Ratepayers	Net Benefit to Utility Shareholders
Massachusetts Electric (Massachusetts)	$37 million (1990)	$55 million	$5 million
Pacific Gas & Electric (California)	$94 million (1990)	$156 million	$30 million
Orange & Rockland (New York)	$9.4 million (1990)	$12.7 million	$2.7 million
PSI Energy (Indiana)	$34 million (1991, 5 year estimate)	$80-90 million	$8-18 million

Table (VII.3) DSM Program Investments and Net Benefits [3]

As shown in the table above, the implementation of a successful DSM program leads to financial benefits to both ratepayers and shareholders. These financial benefits reflect an overall reduction in consumption of energy, which is the main goal of DSM programs.. Future DSM programs should focus on the needs of the ratepayer (participating and non-participating), utility, and society as a whole to achieve successful results.

VII.7 References

[1] L.J. Hill, E. Hirst, and M. Schweitzer, "From DSM Technologies to DSM Programs: Issues in Demand-Side Planning for Electric Utilities," Energy, Vol. 17, No. 2, 1992, pp. 151-160.

[2] E. Hirst, "A Rose by Any Other Name: Defining Key Terms on Utility DSM Programs," Energy Systems and Policy, Vol. 14, 1990, pp. 305-318.

[3] J. Clinton (presentor), "Demand Side Management, 101," short course presented to Public Service Indiana, Inc., June 25-26, 1991.

[4] E. Hirst and C. Sabo, "Defining and Reporting Data on Utility DSM Programs," Energy, Vol. 17, No. 7, 1992, pp. 635-637.

[5] S. Nadel, B. Atkinson, and J. McMahon, "A Review of U.S. and Canadian Lighting Programs for the Residential, Commercial, and Industrial Sectors," Energy, Vol. 18, No. 2, 1993, pp. 145-158.

Chapter VIII

Tests of Effectiveness of DSM

D. J. Gotham

VIII.1 Introduction

When considering a demand-side management program, it is necessary to consider the cost-effectiveness of participation. Since a DSM program can have vastly different effects on various individuals or companies, many tests have been designed to analyze the effectiveness of DSM programs. These tests can be performed from different perspectives, such as from the viewpoint of the participating customer, the utility, the general ratepayer, or society as a whole. Most of these tests compare the costs accrued to benefits gained. These tests include the participant test, the utility cost test, the total resource cost test, the ratepayer impact test, the societal test, and the value test 11-31.

A DSM program could easily be beneficial to both the utility and the participant but could result in higher rate levels for those who do not participate. Another scenario that could occur is a DSM program that is not cost-effective for the participant, thereby resulting in low participation levels. An example of this would be a rebate for a high efficiency product, such as a motor or a lighting system, where the combined rebate and energy savings do not offset the higher cost of the product. Therefore, when considering a potential DSM program, it is necessary to consider the various tests to determine which is appropriate for the situation. It may be necessary to perform more than one type of effectiveness test. Another aspect that could be considered is the effect of free riders, which are customers that would participate even without the incentive of the program. These customers receive benefits from the program, such as rebates, even though they would have participated anyway. Also, non-financial effects may be considered. These externalities may include environmental concerns, worker safety, and quality of life issues.

This chapter presents several cost-effectiveness tests for **DSM** programs. These tests are explained and strengths and weaknesses are explored. All tests included here compare benefits to costs to determine feasibility.

VIII.2 Participant test

As the name implies, the participant test is used as a measure of the net benefit to the customer taking part in a particular **DSM** program. The participant test includes only the costs and benefits that can be quantified. Externalities, such as environmental impacts and comfort level, are ignored. This test provides an indication of the impact on an average or typical customer and can be used by the utility to gain insight into potential participation levels.

The benefits considered in the participant test include reduction in the customer's utility bill, incentives provided by the utility, and tax credits provided by the federal, state, or local government. It could also include any avoided costs from equipment or technology that is not used. This is typical of fuel-switching **DSM** programs.

The costs used in this test are any equipment purchased by the customer in order to participate, any increases in the customer's utility bill, as well as installation, operation, and maintenance expenses that the participant might have to pay. Charges associated with the removal of existing equipment also must be considered.

One point in favor of the participant test is that it can be used to determine the lowest level of utility-sponsored incentive necessary to induce customer participation. This test can also be used to indicate the desirability of the program. It can be used by the potential participant to determine whether it is economically advantageous to take part in the program.

A major weakness of the participant test is its failure to model the complex process that the customer uses in deciding whether to participate. Customer's often take into account various externalities when choosing equipment. Comfort level and reliability are just two of many non-financial aspects that play a large part in the decision-making process. Since externalities are ignored, a certain amount of error is included in the test. Also, the possibility of free riders is not considered.

VIII.3 Utility cost test

The utility cost test is used to determine the effect of a DSM program on the overall utility costs. The test ignores the effects on customers. Therefore, it is used to evaluate a program from the perspective of the utility costs and benefits.

The benefits used in the utility cost test include capacity additions that could be avoided if the program is used. For instance, a DSM program that reduces the peak load might save the utility the expense of purchasing and installing a new peaking unit. Additionally, the costs associated with supplying that load is now avoided. These costs include fuel costs, operation and maintenance costs, potential wear and tear on machinery, and transmission and distribution costs.

The costs that must be considered in the utility cost test include all expenses that are incurred by the utility if the program is used. These could include administrative costs, any additional costs associated with increased energy use (for example, valley filling), and any rebates or incentives supplied to the customer to entice participation. Additionally, any costs associated with the installation, operation, and maintenance of utility equipment used in the DSM program are included.

A major point in favor of the utility cost test is the ability to determine the long term effects on average customer bills. The utility revenues, which are primarily derived from customer billing, are strongly associated with utility costs. Also, the utility cost test is similar to many supply-side tests and some other demand-side tests. This allows for easier comparison of various supply-side and demand-side options.

The major weakness associated with the utility cost test is the exclusion of non-utility costs. A **DSM** program that passes the utility cost test will not have much of an impact if it is cost prohibitive to the participant. Furthermore, externalities are neglected when using this test.

VIII.4 Total resource cost test

The total resource cost (TRC) test is used to evaluate a **DSM** program from the perspective of the costs associated with both the utility and the participants. This test is also referred to as the all ratepayers test. By combining the utility antl participants, any payments associated with the **DSM** program that pass between the utility and the participants can be ignored. The TRC test can be considered to be a combination of the participant test and the ratepayer impact test. Free riders and externalities are not taken into account when using the TRC test.

The benefits accounted for in the TRC test include avoided costs associated with load that no longer needs to be served, such as energy costs and new capacity construction. Avoided costs of equipment not used are an additional benefit. Any tax credits received are included.

The costs associated with the TRC test include any cost paid by the utility or the participant that is not paid to the other. Possible costs to consider are atlministrative costs and all equipment costs. For load building programs, increased supply costs must be included.

The major strength of the TRC test is the ability to include the costs and benefits of both the utility and the participants in a single test. It is similar to other **DSM** tests and supply-side tests. Therefore, it can be useful in comparing demand-sitle and supply-side options for integrated resource planning.

The TRC test does not include any information about the effect on non-participants. It is quite possible that a test can pass the TRC test while having a negative impact on rate levels. The TRC test also ignores the effect of free riders and externalities.

VIII.5 Ratepayer impact measure test

Also known as the non-participant test or the no losers test, the ratepayer impact measure test (RIM) compares the change in revenues for a utility to the change in costs for that utility. It indicates the effect of the DSM program on the rate levels. A program with an increase in revenues that is larger than the increase in cost should result in lower rates. Likewise, if the revenue increase is lower than the cost increase, rates will increase.

The benefits of the RIM test are the avoided costs of supplied energy and capacity, as well as any increased revenue from load-building.

The costs of this test include additional energy costs for load-building, lost revenue from load reduction, operational and administrative costs, and any rebates or incentives paid to participants.

The major strength of the RIM test is that it protects the non-participant from subsidizing a DSM program in which the non-participant is not involved. Additionally, this test is valid for all types of DSM programs, which is not true for other tests.

Since rates are usually higher than marginal costs, many DSM programs fail the RIM test. The test also gives no indication of the feasibility of the test from the participants point of view. Externalities are neglected in this test.

VIII.6 Societal test

The societal test is an attempt to determine the benefit to society as a whole by including externalities. It is similar to the total resource cost test.

The benefits used in calculating the societal test are the sarne as in the total resource cost test with two exceptions. First, benefits associated with externalities, such as reduced pollution levels, are included. Second, tax credits are not included since they are a transfer within society.

The costs are identical to the costs associated with the total resource cost test with any costs associated with externalities included.

The strengths associated with the societal test are similar to those of the total resource cost test. By including externalities, the net benefit to society as a whole is determined.

However, it is difficult, if not impossible, to put exact values on externalities. Even if one could place a value on such things as comfort and security, it is quite likely that not all externalities would be apparent. Furthermore, just because a DSM program is found to be good for society as a whole does not necessarily indicate that it is good for each member. A program could pass the societal test but fail another test, such as the participant test or ratepayer impact test.

VIII.7 **Value** test

The value test is a relatively new approach that attempts to measure the effect on efficiency of a DSM program. It is similar to the total resource cost test in that it measures the effect on all ratepayers. It differs from the total resource cost test in that it attempts to include changes in quality. It also includes the likelihood that a consumer with a lower electric bill may respond by increasing demand. For instance, the participant may use a high efficiency product more often than its standard efficiency counterpart. Aclditionally, the value test includes market barriers, such as unavailability in some areas, as a cost. Finally, the value test includes the impact of rate changes caused by the program.

VIII.8 **Example**

Consider a proposed DSM program. The utility offers a \$1000 rebate to industrial customers who purchase a high efficiency motor costing \$8000. The cost of an equivalent standard efficiency motor is \$5000. The calculated amount of energy saved over the life of the program is 50000 kwhlparticipant at a rate level of' 0.07 \$/kwh and a marginal cost of supply equal to 0.05 \$/kwh. The estimated value of the emission gasses that would not be released is estimated to be \$500. The utility cost to administer the program is 500 \$/participant. The reduction in the utility's energy production cost per participant is

(50000 kwhlparticipant) X (0.05 \$/kwh) = 2500 \$/participant.

The reduction in each participant's energy cost is

(50000 kwhlparticipant) X (0.07 \$/kwh) = 3500 \$/participant.

It is assumed that the reduction in load will not be sufficient to reduce any new capacity costs. The results of five of the tests are shown in Table VIII.1. While this particular program passes the participant and utility cost tests, it fails the rest of the tests.

Table VIII.l Cost–effectiveness of example DSM program

Participant		
	Benefits	3500 + 5000 + 1000 = 9500
	Costs	8000
	Net benefit	1500
Utility cost		
	Benefits	2500
	Costs	1000 + 500
	Net benefit	1000
Total resource cost		
	Benefits	5000 + 2500 = 7500
	Costs	8000 + 500 = 8500
	Net cost	1000
Ratepayer impact measure		
	Benefits	2500
	Costs	3500 + 1000 + 500 = 5000
	Net cost	2500
Societal		
	Benefits	5000 + 2500 + 500 = 8000
	Costs	8000 + 500 = 8500
	Net cost	500

VIII.9 Summary

Several tests exist to help determine the cost-effectiveness of DSM programs from various perspectives. All of the tests described here have some strong arguments in favor of them. However, these strengths come with a price. Each test neglects some potentially affected segment of society. When evaluating a potential DSM program, one must determine which test or combination of tests is appropriate for that particular situation.

VIII.10 References

[1] California Public Utilities Commission and California Energy Commission, "Economic Analysis of Demand-Side Management Programs," Dec. 1987.

[2] Electric Power Research Institute, "Principles and Practices of Demand-Side Management," Aug. 1993.

[3] J. Chamberlin, P. Herman, M. Maudlin, "The Value Test: Economic Efficiency and Demand-Side Management," Barakat & Charnberlin, Inc. Mar. 1993.

CHAPTER IX
THE ROLE OF DSM PROGRAMS IN A REGULATED INDUSTRY

Brian H. Kwon

IX.l Introduction

The electric utility planning process has originally consisted of estimating the future demand for electricity, then finding the supply-side options to meet the demand. However, since 1.970's when there was energy disruptions, this process became very difficult. The predictable demand and flexible low-cost supply was simply hard to accomplish. As a result, people have looked upon managing demand side. This revolution in utility planning is called "demand-side management" (DSM).

Presently, nearly 50 % of the United State's utilities are into some kind of demand-side management. And this management applies in general such as large or small, city-owned or investor-owned across the nation. [1] Demand-side management activities are those which involve actions on the customer-side of the electric meter, either directly caused or indirectly stimulated by the utility maintain a balance of electricity supply and demand in today's uncertain planning climate. Demand-side management programs includes the activities such as load management, conservation and strategic load growth.

Forecating the effects of demand-side program is difficult, however, because we are uncertain about the engineering characteristics of the hardware and behavioral characteristics of consumers.

IX.2 General description of DSM.

DSM is relatively new concept in utility planning that can be defined as a strategy of modifying the pattern and level of customer loads for the mutual benefit of the utility and its customers. DSM does not include the changes in the load shape that occurs as a normal consequence of the market mechanism changes in income levels, industrial production, weather conditions.

DSM includes programs for achieving a wide range of load shape objectives: [2]

(1) peak clipping

(2) valley filling

(3) load shifting

(4) strategic conservation

(5) strategic load growth

(6) flexible load shape

The first three objectives are classic forms of load management programs that seek to improve the system load factor. Peak clipping, or the reduction of system peak loads, is often achieved by direct control of customer loads by utility-directed signals to customer's appliances. In most application, this direct control manipulates the appliance load by de-energizing the appliance and returning it to service in a predetermined duty pattern. Utilities most often use direct control to reduce peak capacity or the need for peak capacity purchases, but direct control can also reduce operating costs and dependence on expensive fuels through use in an economic dispatch program.[2]

Valley filling is a another kind of load management in that it builds loads in off-peak periods. This may be useful when incremental cost are less than the average cost of electricity. Adding load at the proper price can reduce the average cost of electricity to customers and can improve system load factors. Thermal storage is one of the method that displaces loads served by fossil fuels with electricity.[3]

Strategic conservation affects end-use consumption so that overall electricity sales are reduced by altering specific patterns options as what reduction would occur or if the price increases then what degree of additional stimulation is needed from utility programs. Appliance efficiency improvement and insulation programs are some examples of strategic conservation.

Strategic load growth produces a general increase in sales beyond any increase from valley filling. This is accomplished by increasing market share of loads that are served by other fuels, as well as general economic development. [2]

Another major load objective is flexible load shape, which describes adjusting the load shape to match supply within system reliability constraints. Load shape can be flexible enough to conform to system reliability needs if customers are presented with options in the level of service that are willing to accept in exchange for programs.[3]

IX.3 Electric utility regulation

Although, the roots of public utility regulation are buried in the political economy of the struggle for control of power, a main economic benefits of regulation has been, until recently, to provide a stable environment for investment in large-scale facilities. The regulation has the characteristic of an implicit contract between the regulated firm and its ratepayers. The terms of this contract has provided insurance for the regulated firm against changes in factor costs and demand. The firm has the obligation to build new facilities to meet demand; in return for this obligation, ratepayers implicitly agreed to gurantee the firm a reasonable rate of profit.

Recently, there was a new report listing the state commisions that provide incentives for electric-utility investments in DSM programming that was published by the National Association of Regulatory Utility Commissioners (NARUC).

Titled, "Incentives for Demand-Side Management," shows in detail where regulatory barriers to DSM are falling.

Interest and activity in regulatory barriers and incentives affecting DSM has increased since 1988. The project was in response to "a growing interest among regulators for a comprehensive survey of developments in this area."

NARUC passed a resolution in 1988 urging state commisions to adopt appropriate methods to compensate a utility for earning lost through the successful implementation of DSM and seek to make the least-cost plan a utility's most profitable resource plan.[4]

As a result, some states began implementing mechanisms to siimulate DSM investment, and many others opened dockets to consider the issues and formulate the incentive proposal.

According to NARUC, the ideas underlying DSM incentives are obvious. However, it cautions that myriad issues must be addressed and decisions made in considering a specific incentive proposal. NARUC commisioned this report in the expectation that a sharing of up-to-date information will improve regulators' and utility managers' understanding of several approaches to and will stimulate further research and innovations in the field.[4]

Table (IX.1) gives a summary of the state regulatory barriers and incentives for DSM. And here is how to read information in the summary table.[4]

The "Status" column provides a brief description of the overall status of DSM incentives. It focuses on two aspects of DSM regulation that figure prominently in state's efforts to remove disincentives and provide positive incentives for DSM: regulation-recovery of DSM related lost revenues, and provision for shareholder incentives (earnings) on DSM. The entry "No Action" indicates absence of formal action to provide lost revenue recovery and shareholder incentives. "In progress" means a formal proceeding to consider providing lost revenue recovery and shareholder incentive is in progress. "In place" indicates that formal action has been taken to provide lost-revenue recovery.[4]

Many states have adopted regulatory policies to alter utilities recovery of DSM program costs. The columns under "DSM program cost recovery" stress on two aspects of cost recovery.

The balancing account is the first one and it means that the state allows recovery of DSM program costs through a balancing account. A balancing account is a rate mechanism that reconciles with interest a utility's collection from ratepayers for DSM to its actual expenditures. Use of a balancing account ensures that a utility recovers its full DSM expenclitures. NARUC report that electric utility does not profit by underspending its DSM budget.[5]

As a second recovery aspects of program cost recovery, "rate-basing allowed" indicates that the state allows utilities to capitalize and amortize DSM expenditure, and to earn a return on the investment during the amortization period. NARUC reports that this practice is often but not always considered advantageous because it accords DSM a financial status similar to that of supply-side of investment." [4]

The two columns under the heading of "lost-revenue recovery" indicate which states have established mechanisms that offset the reduction in base revenues attributable to DSM programs. Under this headings there are two categories.

The first one is DSM-specific adjustment and it indicates that the state has established an incentive mechanism under which a utility can recover the estimated amount of lost base revenue that is specifically attributable to DSM program.

ERAM-type mechanism is a second category and it means that the state has established a method that automatically adjusts a utility's base revenue to an authorized amount. According to NARUC, this approach removes revenue fluctuations caused by weather and general economic conditions as well as DSM.

State	Status	DSM program cost recovery: Balancing Account	DSM program cost recovery: Rate-basing allowed	Lost-revenue recovery: DSM [specific adjustment	Lost-revenue recovery: ERAU (type mechanism	Type of shareholder Incentive mechanism	Utilities with sharehholder incentive mechanism
Alabama	no action						
Alaska	no action						
Arizona	in place[3]						
Arkansas	no action						
California[1]	in place	a	•		a	Share and markup	Pacific: Gas 8 Electric Co San Diego Gas 8 Electric Co Southern California Edison Co
Colorado	in place		•			Share	Public Service Co of Colorado
Connecticut	in place		•	•		RB bonus	United Illuminating Co
District of Columbia	in place*		•	a		Share	Potomac Electric Power Co
Delaware	no action						
Florida	in progress	■	•				
Georqia	in proqress						
Hawaii	in progress	■					
Idaho	in place[3]		•			ROE adjustments	
Illinois	no action	•9		a9			
Indiana	in place[2]			a		Share	PSI Energy
Iowa	in place3					Share	
Kansas	in place [4]		•			RB bonus	
Kentucky	no action						
Louisiana	no action						
Maine	in place	•	a	a	a	Share	Central Maine Power Co
Maryland	in place	•	•	•		Share	Potomac Electric Power Co
Massachusetts[1]	in place	•	a	•		Bonusiunit	Massachusetts Electric Western Massachusetts Electric
Michigan[1]	in place	a	a	a		Bonusiunit and ROE adjustments	Consumers Power Co
Minnesota	in place		•	•5			Northern States Power Co
Mississippi	no action						
Missouri	no action						
Montana	in place[4]		•			RB bonus	
Nebraska	no action						
Nevada	in progress		•				
New Hampshire	in place	•		•6		Share	Granite State Electric
New Jersey	in place[3]			a6		Share and bonus/unit	
New Mexico	in progress						
New York[1]	in place	a	•	a	a	Share and ROE adjustments	Central Hudson Gas 8 Electric Co Consolidated Edison Co of NY Inc Long Island Lighting Co New York State Electric 8 Gas Co Niagaa Mohawk Power Corp Orange & Rockland Utilities Co Rochester Gas 8 Electric Co
Nonh Carolina	in progress						
North Dakota	no action						
Ohio	in place3	a		•		Share	
Oklahoma	no action		•				
Oregon	in place		•	a		Share	Portland General Electric Co
Pennsylvania	in progress		•				
Rhode Island	in place	•			.	Share	Narragansett Electric Co
South Carolina	no action						
South Dakota	no action						
Tennessee	no action						
Texas	in place[4]		•			ROE adjustments	
Utah	no action						
Vermont	in place3	•	•	a		Share	
Virqinia	in progress						
Washington	in place[4,7]	•	•		•	RB bonus	
West Virqinia	no action						
Wisconsin	no action[8]	•	a				
Wyoming							

Table IX.1 State regulatory barriers and incentives for DSM [4]

In another column listed is "Shareholder Incentive Mechanism." There are several abbreviation used in this column:

- "Markup" indicates that the utility may receive a percentage markup on certain DSM expenditures.
- "RB bonus" means that rate-based DSM expenditures are eligible to earn a greater-than-normal return on equity.
- "ROE adjustment" implies that the utility's overall return on equity may be adjusted in response to qualitative evaluations of DSM performance.
- "Share" denotes the utility may receive a percentage share of benefits attributable to DSM program.
- "Bonus/unit" indicates that the utility may receive a specific bonus amount for each kilowatt through its DSM program.

IX.4 The role of DSM in regulated utilities

The role of DSM upon utility is very complex. DSM can give opportunities to reduce cost, improve cash flow, or maintain the viability of electric utility as a business. DSM affects energy cost; the need for capacity system reliability, spinning reserves and other operational considerations. It affects including the generation system, transmission and distribution system.

Many regulatory authorities have been influential in accepting and encouraging certain types of demand-side management programs, especially those involving conservation and load management. As a result, some utilities have active programs which called their direct investment in residential energy conservation measure. The idea that conservation investment might be an economic substitute for investment in new generating capacity.[1]

Since the early 1970's economic, political, social, technological, and resource supply factors have combined to change the utility industry's operating environment and its outlook for the future. Many utilities were faced with stagger capital requirements for new plants,, significant fluctuation in demand and energy growth rate, decling financial performance, and regulatory. Since then, some of the problems have abated; however, there were other problems rising. Such as increased concern about the environmental consequence.

Due to the above challenges, many regulated utilities turned to demand-side managements program. These utilities recognize the benefits of focusing more attention on electric-energy services than electricity as a product. Such energy-efficiency and load management efforts can [5]

1) provide utilies with low-cost energy and capacity resources

2) save money for utility customers

3) improve the utilities relations with customer because additional services are offered

4) improve relation with the state Public Utility Commision (PUC)

5) improve environment quality

6) enhance the economic competitiveness of the utility and its service area.

The residential refrigerator provides a simple example of how electricity savings occur as shown in Fig.(IX.1).[5]

During the 1950's and 1960's, electricity use per unit increased as more features were added, refrigerator size increased, and manufacturers used cheaper components. In 1972, electricity use per unit has been declining. The average refrigerator sold in 1987 consumed 42 % less electricity then average model sold in 1972. The efficiency improvements were stimulated by rising electricity prices, greater public awareness of energy-efficiency options, federal appliance-labeling requirements, and utility program that provide information and financial incentives for purchase of efficient appliances.[5]

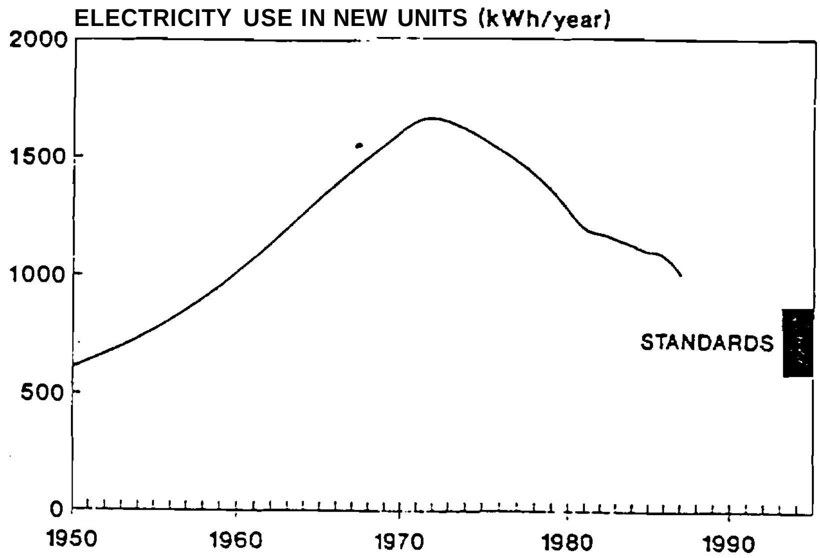


Fig.(IX.1). An example of how electricity savings occur [5]

However, there are some questions raised, although, many electric utilities pursue DSM options; Even if abundant, cost-effective efficiency improvements are available but are not being adopted because of market failure, why should not government be responsible for this?

Electric utilities have been social agents. Their monopoly franchise, active participation in their commuties, and promotion of economic development all speak to their sense of public responsibility. More important, demand-side programs offer resources that are often less expensive in $/KW, then supply resources. Thus, this nice-utility program save money for customers, by lowering overall energy-service costs. In addition, these demand-side programs provide environmental-quality and risk-reduction benefits not available with power plants.[5]

Also, electric utility have long-standing relationships and mostly contacts with their customers. Utilities are generally highly regarded as sources of reliable and credible information on efficiency options. As a result, utility should calculate and benefits of changes in customer load shapes and level.

However, utility are not always the best agents to overcome market barrier that prevent adoption of cost-effective efficient improvement. New building and appliance improvement can be achieved mostly by regulatory standards that mandate minimum efficiency levels. Utility can play important supporting role, and often influential in state legislatures and can use this influence to encourage adoption of meaningful standards.

The National Association of Regulatory Commissioners Energy Conservation Committe recently adopted a resolution stating that a "utility's least-cost plan for consumers should be its most profitable plan. However, because incremental energy sales increase profits, traditional rate-of return calculations generally provide much lower earnings to utilities for demand-side sources then for supply-side resources. Therefore, the committee has begun to explore alternative regulation mechanism that would compensate utilities for revenues lost though the successful implementation of DSM program and perhaps reward utilities that run exemplery DSM programs.[5]

Utilities and their regulatory commisions, however, had not work together on revising the "regulatory compact" with respect to resource planning, acquisition, and financing. Agreement should be reached on the appropriate economic tests to use in assessing DSM programs, and on whether DSM-program costs should be capitalized or expensed, so that all regulated utilities could participate in DSM-program.

However, PUC are encouraging utilities to experiment on a small scale with DSM program, and not penalizing for inevitable or small failures.[1]

IX.5 Conclusion

I have briefly introduced what is DSM and have listed some incentives and barriers that regulated industry has in order to adopt DSM program. I also briefly described the role of DSM in regulated industry.

The electric utility can play a important role in realizing the large potential to save energy and peak demands. As a result, it is morally wrong to waste any energy. In that case, the regulatory agents will not tolerate their failure and the utility will not get the fixed profit. However, some of the regulatory agents reward utilities (i.e. increase earning) who has done the successful implementation of DSM program by running exemplery DSM program.

The concept of demand-side management must be an integral part of utility's overall planning as it approaches the uncertainties of the future. Demand-side management is one of the powerful program to be utilizedin the optimization of this industrial resources, and each utility should remain dedicated to its application wherever and whenever benefits are indicated.

IX.6 References

[1] Gellings, C.W. and Chamberlin J.H., Demand-Side Management: Concepts & Methods. The Fairmont Press Inc.: Lilburn, GA 1988

[2] Terry H. Morlan, "The Impact of Demand-Side Management on Load Growth". American Society of Civil Engineers. Conference Proceedings, 1985

[3] Talukdar S. and Gellings C.W. "Load Management." IEEE Press, 1987

[4] Staff. (1992, March) "State Regulatory DSM Incentives Listed". Electrical World, pp 25-26.

[5] Hirst, E. "Electric Utility Side Program." American Power Conference. Conference Proceedings, 1989