DEMAND-SIDE MANAGEMENT IN UKRAINE
PART 1: NATIONAL ASSESSMENT

Final Report

Prepared for:

U.S. Agency for International Development
Bureau for Europe and Newly Independent States
Department for Europe
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CONTENTS

EXHIBITS

ACRONYMS

ASD	adjustable speed drives
CFL	compact fluorescent lamp
CHP	combined heat and power
CSE	cost of saved energy
DSM	demand-side management
ESCo	energy service company
FEWE	Polish Foundation for Energy Efficiency — Fundacja na Rzecz Efeletywnego Wykorzystania Energia
Gencos	thermal generating companies
GOU	Government of Ukraine
GW	Gigawatt
GWh	Gigawatt-hour
IES	independent energy supplier
IRP	integrated resource planning
LEC	local electricity company
NERC	National Energy Regulatory Commission
PG&E	Pacific Gas & Electric
RFP	request for proposal
TOU	time-of-use
TRC	total resource cost
TWh	Terawatt-hour
USAID	U.S. Agency for International Development

EXECUTIVE SUMMARY

This report presents the results of work sponsored by the Bureau for Europe of the U.S. Agency for International Development (USAID). Through a bilateral program, USAID has been providing assistance to the Government of Ukraine (GOU) under the Eastern Europe Regional Energy Efficiency Project. One of the project's tasks included work on demand-side management (DSM) in Ukraine, which is the topic of this report.

S.1 BACKGROUND

Ukraine is an Eastern European country of roughly 52 million people; it gained its independence from the former Soviet Union in 1992. At that time its power system was separated from Russia's, and it now operates autonomously. Installed generation capacity in Ukraine is 54 GW, two-thirds supplied by thermal power plants (split equally between coal and natural gas), one-fourth from nuclear power plants (including 1800 MW from the RBMK reactors at Chernobyl), and the remainder from hydroelectric plants. Many of the thermal plants are old and uncontrolled for emissions, and the safety of Chernobyl's continued operation has been a topic of intense international discussion. Roughly one-third of power is generated in combined heat and power (CHP) plants that also serve the district heating needs of Ukraine's cities.

Ukraine's system peak demand in the winter has declined from 37.5 GW in 1992 to 31.9 GW in 1994, and total generation has similarly fallen from 250,000 GWh in 1992 to 201,000 GWh in 1994. This decline is attributable to the severe economic depression that Ukraine has faced during its post-communist transition.

Ukraine currently faces a major crisis in its power sector because all of the natural gas used in power generation (roughly 30 percent of total fuel requirements) is imported, mostly from Russia and a smaller amount from Turkmenistan. Since the suppliers are charging world prices in hard currency, Ukraine has accumulated a massive foreign exchange debt over the last three years. This debt, which is growing every day, creates a large strategic vulnerability for Ukraine in gas supply disruptions and political pressures.

Over the past year, the GOU has begun to introduce sweeping legal and regulatory reforms to accelerate the transition to a market-oriented economy. The Power Sector Restructuring and Regulatory Reform Program of the GOU, authorized by Executive Decree on April 21, 1994, aims to:

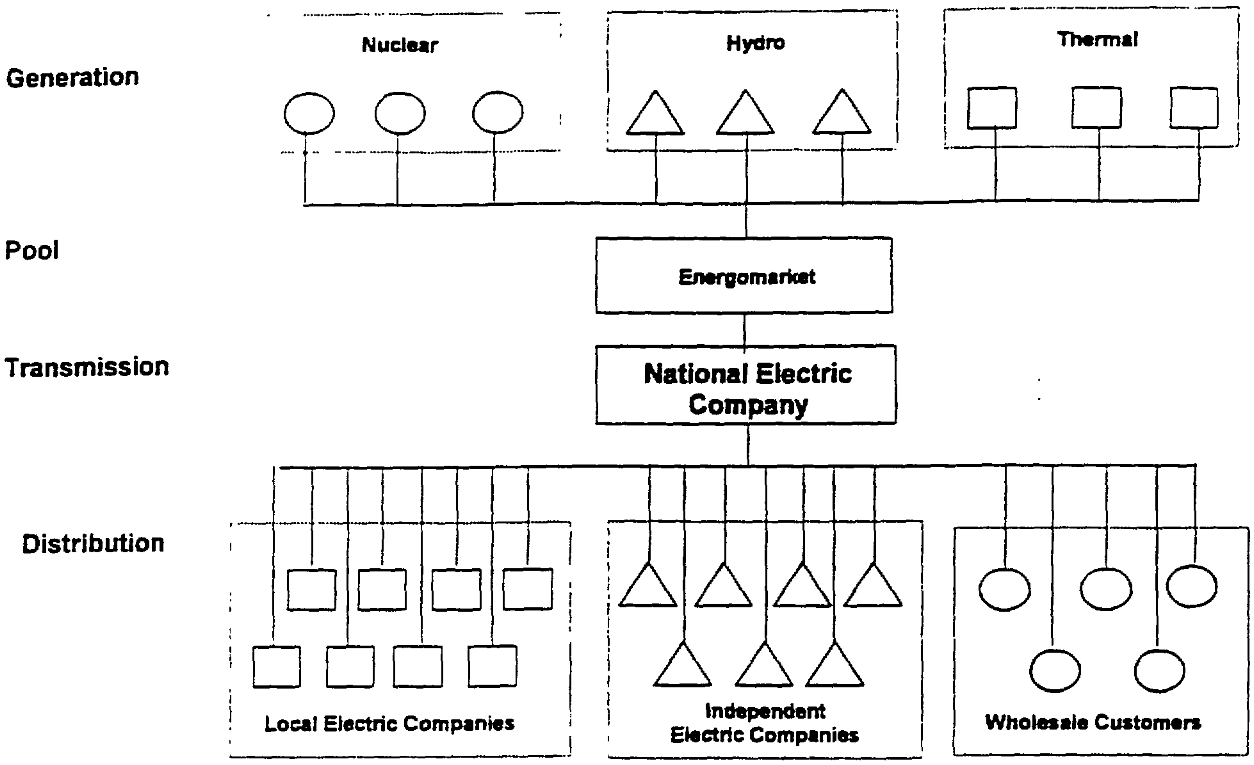
- establish a new regulatory and legal framework, including electricity tariff mechanisms
- promote enterprise competition through the elimination of barriers to market entry
- transform the governance, control, and regulation of state-owned enterprises in the power sector.

These reforms are expected to revitalize the energy sector, enhance its long-term financial viability, and encourage economically optimal investment and consumption decisions. The program has been developed in coordination with the World Bank, and involves assistance from several bilateral donors, including USAID, the sponsor of this study.

The new Ukraine power structure will rely on market forces rather than regulation to select the least-cost options. Ukraine's restructured power sector will be vertically disaggregated, with competition at the generator and at the supplier levels. Ukraine has adopted the "U.K." model of disaggregation and functional unbundling of the components of the utility system, with the introduction of full competition for generation, transmission, and supply. Exhibit S-1 presents an outline of the new structure. The utility system that is currently evolving is composed of:

- Five thermal generating companies (Gencos), which have been corporatized (to be privatized someday) and will compete in a wholesale pool. Two other generation organizations (nuclear and hydro) will remain state owned and will not compete in the pool.
- A pool administrator called Energomarket, which will operate an hourly spot market for wholesale power purchases and sales, dispatch the system according to day-ahead competitive bids received from the generators, and provide ancillary services such as reactive power and frequency regulation. Energomarket will pay all generators the marginal price bid at each hour.
- The National Electric Company, which is a state-owned operator of the transmission system.
- Twenty-seven Local Electricity Companies (LECs), corporate (soon to be private) entities at the oblast level (comparable to U.S. states) that are responsible for retail supply to final consumers. The LECs also have subsidiary operations that operate the distribution system in their region and operate CHP networks.
- Independent Energy Suppliers (IESs), private companies that operate nationwide to supply power and compete with Gencos in the pool and the LECs for retail supply.

Exhibit S-1
Overview of Power Sector Restructuring



The pool will also accept bids for demand-side resources. These bids may be by LECs or IESs, which may be acting like an energy service company (ESCo). ESCos are firms that provide turnkey services to energy customers. These services include financing, project analysis and design, implementation, and verification.

DSM programs have been widely implemented throughout the world as a means of meeting society's energy service needs. Such programs have most commonly been implemented within a vertically integrated power sector, in the context of integrated resource planning. Many countries, in addition to Ukraine, are deregulating their power sectors and are proposing to introduce or have introduced retail competition. Increasingly, utilities are seeing DSM as a technique to retain valuable customers by helping them to lower their overall bills through combinations of pricing and advice on or financing for energy efficiency and load management strategies.

S.2 PROJECT OBJECTIVES

USAID is sponsoring a project in Ukraine to:

- recommend an institutional and regulatory framework in Ukraine that would support the development of DSM programs
- identify DSM programs that should be considered within the context of the restructured power system plan
- evaluate the costs and benefits of these programs to support their consideration in multilateral development bank power sector loans
- assist Ukrainian authorities with developing a lasting capability within government, the utilities, and the private sector to design, implement, and evaluate DSM programs on a continuing basis
- design a demonstration project for two local distribution companies that will provide the basis for evaluating impact of DSM and attract further investment.

S.3 PROJECT OVERVIEW

The project comprises three components:

1. A national DSM assessment that identifies potential DSM programs and evaluates the costs and benefits of these programs.
2. A load research program to generate the data necessary for effective program design. Spot end-use and whole premise load monitoring will be conducted as part of this design component to demonstrate the principles of load research and to provide preliminary data for use in the assessment.
3. The design of two industrial pilot programs, based on discussions with utility staff and consumers.

This is the first volume of a two-volume report describing the above activities, their findings, and recommendations of the project. This volume discusses the national DSM assessment and presents recommendations for institutional and regulatory frameworks, and the companion volume describes the load research and pilot programs.

The assessment presented in this report focuses on the costs and benefits of DSM programs that can realistically be implemented over the next six years as part of a project suitable for multilateral development for bank financing. This emphasis on immediate project possibilities rather than long-term strategic potential highlights options currently available to Ukraine energy planners instead of a comprehensive evaluation of the long-term theoretical potential of DSM.

The following steps were taken in conducting the national assessment:

- analysis of the role of DSM in the restructured power sector
- development of understanding of electricity use in Ukraine
- identification of demand-side resources
- calculation of the benefits and costs of selected DSM programs.

Each of these steps and the resulting findings are summarized in the following sections.

S.4 ANALYSIS OF THE ROLE OF DSM IN THE RESTRUCTURED POWER SECTOR

This step identified the cash flows and parties affected by DSM and the indices that could be used to determine whether DSM programs would or could be pursued by these parties. DSM may be paid for at two levels in the vertically disaggregated, restructured Ukrainian power sector: at the pool level and at the supplier level. The objective functions of these two types of entities are different, and the screening considerations are different.

S.4.1 DSM at the Pool Level

The pool's objective function is to minimize rates for the suppliers. The pool will fulfill this objective function if the percentage difference between the customer's payment per kWh and the pool price is greater than the percentage reduction in system demand. For example, a load management measure that results in a relatively large reduction in system demand for a relatively small reduction in system pool price will cause the rates to the suppliers to increase. This is because the costs of payments are allocated to a smaller number of kWh. This condition is similar to passing what is known in traditional DSM as the ratepayer impact measure test (RIM) test, which identifies the effect of a DSM program on electricity rates. The calculation is somewhat different than the standard calculation approach for a RIM test, because the pool prices, equivalent to marginal energy cost in the standard test, change due to the DSM bidding.

S.4.2 DSM at the Supplier Level

The objective function of the privately owned suppliers is to maximize profits. DSM must be justifiable on a financial basis to the entity paying for it. In a competitive environment, a supplier has two motivations to pursue DSM. Both motivations relate to retaining customers:

1. to reduce its rates, thereby maintaining competitiveness
2. to provide a customer service to ensure loyalty and retention of key large customers in a competitive supply market.

The LECs and IESs will provide their customers with information, financing, and access to ESCos. This will be done at participant and shareholder expense, to minimize the rate impacts of these activities.

DSM measures that reduce rates are those that pass the RIM test, discussed in the previous section. Simply put, a measure must result in avoided generation costs that are greater than the sum of revenue losses and program costs. DSM measures can pass the RIM test if they reduce demand in periods when generation costs are higher than tariffs.

Suppliers may be interested in providing DSM to customers as a service to those customers that other suppliers would find attractive and would attempt to acquire. The types of customers that are most attractive are typically high voltage customers, with average usage levels close to peak period usage. These types of customers are typically industrial customers. Suppliers may provide DSM programs that do not pass the RIM test to these customers. To avoid cross-subsidies, such programs should be designed so that the participant pays for costs incurred for the participant's benefits. This can be done through a shared-savings program, in which amortized program costs are charged to the participant on their monthly bill, with the charges designed so that they are less than the bill reductions from energy savings.

S.5 DEVELOPMENT OF UNDERSTANDING OF ELECTRICITY USE IN UKRAINE

A sound assessment of DSM potential must be based on a sound understanding of how electricity is used. This step involved identifying annual usage levels by sector, subsector, and end use, and identifying the hourly shapes of this usage.

Total system electricity production in Ukraine in 1994 was 201 TWh. Peak production of 31.9 GW occurred in February at 6:00 p.m. The system capacity factor for the year was 0.73, meaning that average production was 73 percent of peak production.

A review of system load shapes revealed two dominant trends. The first is that system load increases as temperatures decrease, i.e., during the winter. Although additional winter lighting requirements and summer vacation schedules contribute to relatively higher winter demand, the shift may be due primarily to heating requirements and the limited presence of air conditioning. Electrical resistance space heating is rare in Ukraine. Instead, district heating is the predominant means of winter heating. District heat pumping systems depend on thousands of motors that operate almost continuously in the heating season.

The second observation is that the evening peak moves later into the evening and decreases when compared with the morning peak during the summer. This most likely results from reduced lighting requirements during the summer.

Electricity usage in Ukraine is dominated by industrial usage. As shown in Exhibit S-2, industry consumption in 1994 was 54 percent of the total annual net consumption. Residential consumption was 16 percent, commercial/institutional consumption was 12 percent, and agriculture and transportation consumption made up the remaining 18 percent.

The following sections discuss usage in the three sectors with the largest contribution to national energy use: industrial, residential, and commercial/institutional. As a part of this project, customer surveys were conducted in each of these three sectors, to obtain information on equipment presence and characteristics, and usage patterns.

S.5.1 Industrial Usage

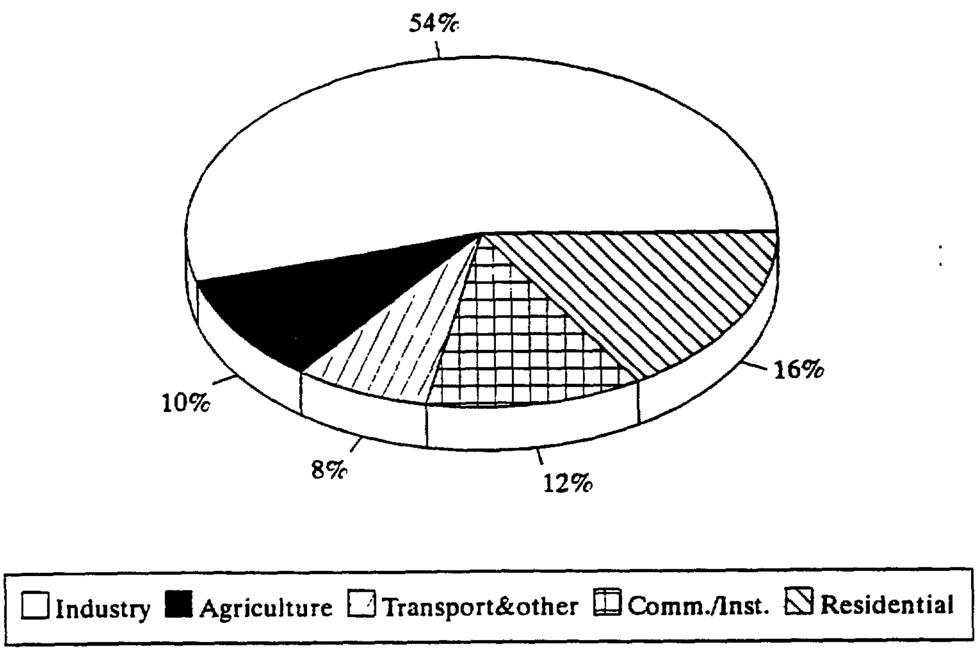
Ukrainian industry encompasses a wide range of activities. In 1994, the metallurgy and energy (primarily coal mining) subsectors accounted for over half of the 88.6 TWh consumed by industry, and metallurgy alone accounted for 41 percent. The subsectoral shares will change, however, as Ukraine's economic transformation continues. Shares of primary industries like coal mining and steel production are likely to decline as manufacturing and other downstream industries increase their shares.

Industrial electricity usage makes up 90 percent of sector sales. Very large motors use a significant portion of the electricity sold to industry, reflecting the high degree of industrial centralization in the former Soviet Union. The most common type of motor usage is compressed air (29 percent); followed by heating, ventilating, and air conditioning (HVAC, 24 percent), machine tools (21 percent), and fans/blowers (16 percent). The reported percentage of HVAC usage is unusually high for industry. There may be some fans/blowers use recorded in this category.

Lighting is the second most significant end use, making up 5 percent of sales. Over half of this usage is incandescent lighting. Mercury vapor lighting is also common. Both lighting types are good candidates for efficiency improvements.

Exhibit S-2
Electricity Consumption by Sector

1994 Electricity Consumption



Source: National Dispatch Center

Process use makes up about 5 percent of sales. The most significant types of process use are furnaces and welding.

S.5.2 Residential Usage

All of the homes surveyed in the market research study had electricity, and all reported using electricity for lighting. Most homes have refrigerators (91 percent) and televisions (96 percent). Most homes have washing machines (70 percent). Other major appliances are not common, most notably space heating (4 percent), water heating (2 percent), and air conditioning (0.4 percent).

Using estimates of connected load, hours of operation, and saturation levels from the survey, combined with standard estimates of usage by appliances and number of residential customers, Hagler Bailly estimated the total annual consumption by end use. Incandescent lighting is the most significant end use (28 percent of total use), followed by refrigerators (26 percent) and televisions (16 percent).

S.5.3 Commercial/Institutional Usage

The commercial/institutional sector is composed of public and private facilities that primarily provide services, as distinguished from the industrial sector, which produces goods. Usage in this sector is dominated by a subsector known as "communal services." This subsector includes street lighting, municipal pumping stations for the water, district heating, hot water, and sewer systems. This study estimated usage by this subsector as 90 percent of the sector sales. Metered data from the Ministry of Energy show that street lighting consumed 483 GWh in all of Ukraine in 1994, or 2.8 percent of the estimated communal services usage. Most of the remaining communal services usage is by motor-driven pumps. Communal services uses are distinctly different from other types of commercial/institutional uses, which are largely oriented toward climate modification (heating, lighting, cooling) for occupant comfort.

Total estimated lighting usage nationwide, excluding street lighting, is 1,312 GWh, which is almost two-thirds of the sales in the sector, excluding communal services. Fluorescent lighting uses the largest share of lighting energy in the sector, followed by incandescent and mercury vapor. Other types of lighting (halogen, metal halide, high pressure sodium) are insignificant.

Both electric heating and electric cooling are insignificant shares of commercial electricity use: 16 percent of facilities in the sample reported using electric heating and 25 percent reported using electric cooling. Most of these units are for supplemental space conditioning, however. Only a small fraction of one percent of the sector floor area is electrically heated or cooled.

S.6 IDENTIFICATION OF DEMAND-SIDE RESOURCES

There are many potential DSM options. Those measures that are clearly not feasible must be screened out before subjecting the remaining measures to closer scrutiny. The first step in this screening process was to identify the system requirements in terms of load shape objectives. The second step was to identify potential technical measures to meet those objectives. These measures were then screened for economic feasibility by comparing the cost of saved energy for each measure with the long-run avoided generation cost. The measures passing this screening constitute the basis for the programs described in Chapter 5 and evaluated in more detail by the DSManager program.

Some of the salient points regarding the Ukraine power system that help determine the appropriate objectives are summarized below:

- Payments for imported natural gas are a major factor in Ukraine's balance of payments problem. Ukraine has committed to closing Chernobyl by 2000. Closure of the Chernobyl units will exacerbate this problem. Natural gas is primarily used to meet energy demand during peak usage periods.

- If economic recovery takes place as planned, new capacity to replace Chernobyl will be needed. Many fossil fuel plants in Ukraine are at or near the end of their useful lives and will have to be replaced or repowered. DSM can help to defer these costs.

Although the market will ultimately judge the value of particular demand-side resources, the above points suggest that the electric DSM measures most appropriate for Ukraine are those that reduce energy consumption, primarily in the peak usage periods, and demand. The appropriate load shape objectives are strategic conservation, peak clipping, and load shifting.

The search for appropriate measures focused on the sectors and the key end uses discussed in the previous sections:

- **Industrial:** Lighting and motors, although some measures will address overall industrial use. Lighting and motors alone account for about 95 percent of industrial demand, or 51 percent of total national consumption.
- **Residential:** Lighting and refrigeration. These end uses account for approximately 54 percent of residential consumption, and about nine percent of total national consumption.
- **Commercial/Institutional:** District heating and water heating pumping, street lighting, and interior lighting. Usage by these end uses accounts for almost 97 percent of commercial/institutional consumption, or 11 percent of total national consumption.

Altogether, this assessment considered measures that target end uses accounting for about 71 percent of total domestic consumption. The omitted end uses either offer limited technical opportunities for DSM, or are relatively heterogeneous and hence beyond the scope of the basic data acquisition activities undertaken to support this assessment.[1] To the extent that the omitted sectors and end uses are not included in the analysis, this assessment understates total DSM potential in Ukraine. On the other hand, the assessment does consider a broad cross section of sectors and end uses that represent the bulk of electricity consumption in Ukraine. Since these end uses are relatively homogeneous compared to those which have been omitted, measures can be replicated and disseminated far more easily. These measures most likely represent a larger portion of total achievable DSM potential than their corresponding share of total consumption suggests. These measures therefore represent the majority of potentially feasible DSM measures in Ukraine.

Measures were screened by comparing the measure's cost of saved energy (CSE) with long-run marginal energy costs. The CSE is defined as the annualized incremental cost of the

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1 The agriculture sector is more heterogeneous than in the United States because many nonagricultural end uses are included in electricity use by collective farms.

measure relative to the cost of standard equipment, divided by the annual kilowatt-hour savings. This screening analysis aimed only to narrow the list of possible measures to the most promising ones, and not to identify a final list of programs. Because of the need for detailed data on lost production costs and hourly marginal energy costs, economic screening of industrial load management measures was not feasible using the available information. A financial screening of these types of measures was conducted and is discussed in the next section.

Out of 85 measures initially identified, 45 measures passed the screening test (plus the load management measures that were not considered in the screening analysis). If all of these measures were implemented for all eligible customers or end-use devices, the energy savings would total 30.5 TWh, or 19 percent of total 1994 total domestic electricity sales. This is referred to as the economic DSM potential, as opposed to the achievable potential, which takes into account market penetration rates of the measures.

S.7 CALCULATION OF THE BENEFITS AND COSTS OF SELECTED DSM PROGRAMS

Measures cannot install themselves at the customer's premise; economic potential remains just potential unless steps are taken to market and implement measures. This step involved identifying DSM programs that would result from packaging the measures with marketing and delivery mechanisms. The analysis of energy efficiency measures relies on a sophisticated demand-side planning tool, DSManager, to evaluate the cost-effectiveness of these potential DSM programs, taking into account the impediments to full adoption of these measures and also the overhead costs associated with program implementation. Because of the sensitivity of load management program to hourly pool prices, which, at the time of this report, are unknown, industrial load management measures were analyzed using a simplified dispatch model to simulate pool prices and identify the financial feasibility.

Exhibit S-3 presents the aggregated costs, participation, and savings associated with all of the programs passing the cost-effectiveness criteria discussed in section S-4. Exhibit S-4 summarizes the savings for each energy-efficiency program analyzed.

Exhibit S-3
National DSM Program Summary

	1996	1997	1998	1999	2000	2001
Energy Efficiency Programs						
Capital Cost ('000)*	23,130	43,159	69,251	87,423	103,692	97,760
Administrative Cost ('000)	7,121	7,115	10,765	12,807	13,917	11,767
Energy Savings (GWh)	162	460	947	1,533	2,185	2,768
Peak Demand Savings (MW)	24	68	141	229	325	405
Load Management Bidding						
Capital Cost ('000)*	18,900	57,200	56,700	75,600	94,500	94,500
Administrative Cost ('000)	1,195	2,015	2,960	3,905	4,850	4,850
Energy Savings (GWh)	191	572	1,143	1,906	2,860	3,813
Peak Demand Savings (MW)	175	525	1,050	1,750	2,625	3,500
Total						
Capital Cost ('000)*	42,030	100,359	125,951	163,023	198,192	192,260
Administrative Cost ('000)	8,316	9,130	13,725	16,712	18,767	16,617
Energy Savings (GWh)	353	1,032	2,090	3,439	5,045	6,581
Peak Demand Savings (MW)	199	593	1,191	1,979	2,950	3,905

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.

Exhibit S-4
Summary of Assessment Results for Energy Efficiency Programs

Program	Net Energy Savings for 2001 (GWh)	Net Demand Savings for 2001 (MW)
Commercial Lighting	115	15
Commercial/Institutional Motors	71	9
Commercial/Instit. Motor Drives	300	43
Commercial/Instit. Motor Downsizing	27	6
Industrial Lighting	194	34
Industrial Motors	352	45
Industrial Motor Drives	1,162	156
Industrial Motor Downsizing	115	15
Industrial Facilities Maintenance	293	48
Street Lighting	139	34
Total Energy-Efficiency Programs	**2,768**	**405**

CHAPTER 1
INTRODUCTION

This report presents the results of work sponsored by the Bureau for Europe of the U.S. Agency for International Development (USAID). Through a bilateral program, USAID has been providing assistance to the Government of Ukraine (GOU) under the Eastern Europe Regional Energy Efficiency Project. One of the project's tasks included work on demand-side management (DSM) in Ukraine, which is the topic of this report.

This introductory chapter presents background; project objectives and overview; and overviews of Ukraine's power sector, of power sector restructuring in Ukraine, of DSM, and of this report.

1.1 BACKGROUND

Over the past year, the GOU has begun to introduce sweeping legal and regulatory reforms to accelerate the transition to a market-oriented economy. The Power Sector Restructuring and Regulatory Reform Program of the GOU, authorized by Executive Decree on April 21, 1994, aims to:

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These reforms are expected to revitalize the energy sector, enhance its long-term financial viability, and encourage economically optimal investment and consumption decisions. The program has been developed in coordination with the World Bank, and involves assistance from several bilateral donors, including USAID, the sponsor of this study.

Society as a whole has two options for meeting electricity needs: (1) adding to the supply of electricity generation, which is the traditional approach, and (2) influencing the demand for electricity. Meeting electricity needs through supply-side actions means providing additional conventional generation, transmission, and distribution facilities. Meeting electricity needs through demand-side actions means providing measures or programs such as innovative tariffs, high-efficiency equipment, and financing that modify the timing and level of consumer demand for electricity.

Demand-side management (DSM) programs have been widely implemented throughout the world as a means of meeting society's energy service needs. DSM programs are utility activities intended to affect the amount and timing of customer electricity use.[1]

1.2 PROJECT OBJECTIVES AND OVERVIEW

USAID is sponsoring a project in Ukraine to:

- recommend an institutional and regulatory framework in Ukraine that would support the development of DSM programs
- identify DSM programs that should be considered within the context of the restructured power system plan
- evaluate the costs and benefits of these programs to support their consideration in multilateral development bank power sector loans
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- design a demonstration project for two local distribution companies that will provide the basis for evaluating impact of DSM and attract further investment.

The project comprises three components:

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[1] Hirst, E. and C. Sabo. "Electric-Utility DSM Programs: Terminology and Reporting Formats." Oak Ridge National Laboratory ORNL/CON-337. 1991.

3. The design of two industrial pilot programs, based on discussions with utility staff and consumers.

This is the first volume of a two-volume report describing the above activities, their findings, and recommendations of the project. This volume discusses the national DSM assessment and presents recommendations for institutional and regulatory frameworks, and the companion volume describes the load research and pilot programs.

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1.3 UKRAINE'S POWER SECTOR

Ukraine is an Eastern European country of roughly 52 million people; it gained its independence from the former Soviet Union in 1992. At that time its power system was separated from Russia's, and it now operates autonomously. Installed generation capacity in Ukraine is 54 GW, two-thirds supplied by thermal power plants (split equally between coal and natural gas), one-fourth from nuclear power plants (including 1800 MW from the RBMK reactors at Chernobyl), and the remainder from hydroelectric plants. Many of the thermal plants are old and uncontrolled for emissions, and the safety of Chernobyl's continued operation has been a topic of intense international discussion. Roughly one-third of power is generated in combined heat and power (CHP) plants that also serve the district heating needs of Ukraine's cities.

Ukraine's system peak demand in the winter has declined from 37.5 GW in 1992 to 31.9 GW in 1994, and total generation has similarly fallen from 250,000 GWh in 1992 to 201,000 GWh in 1994. This decline is attributable to the severe economic depression that Ukraine has faced during its post-communist transition. A small fraction of generation (1,500 GWh) is net-exported. The diurnal system load curve has two pronounced peaks, in late morning and early evening (the higher peak). Typical of the region, a large share of power is consumed in industry (54 percent), a much smaller amount in homes (16 percent), and the remainder in agriculture and public services (e.g., water pumping and transport). Rates are still heavily subsidized by the government, although they were raised in June to recover 40 percent of economic costs. Average rates are now about 2.4 cents (U.S.) per kWh, and industrial tariffs are higher than residential tariffs.

Ukraine currently faces a major crisis in its power sector because all of the natural gas used in power generation (roughly 30 percent of total fuel requirements) is imported, mostly from Russia and a smaller amount from Turkmenistan. Since the suppliers are charging world prices in hard currency, Ukraine has accumulated a massive foreign exchange debt over the last three years. This debt, which is growing every day, creates a large strategic vulnerability for Ukraine in gas supply disruptions and political pressures. For example, when Turkmenistan cut off supplies last winter, Ukraine was forced to curtail electric consumption by large segments of industry. Also, this summer Ukraine is cutting off rural gas supply to allow the buildup of gas storage for next winter. These measures have introduced a heavy burden on an economy and society already heavily stressed from the post-communist depression. On top of this, Ukraine has responded to intense pressure from the G-7 countries and has agreed to close the remaining operating Chernobyl nuclear reactors and to decommission the facility over the next five years.

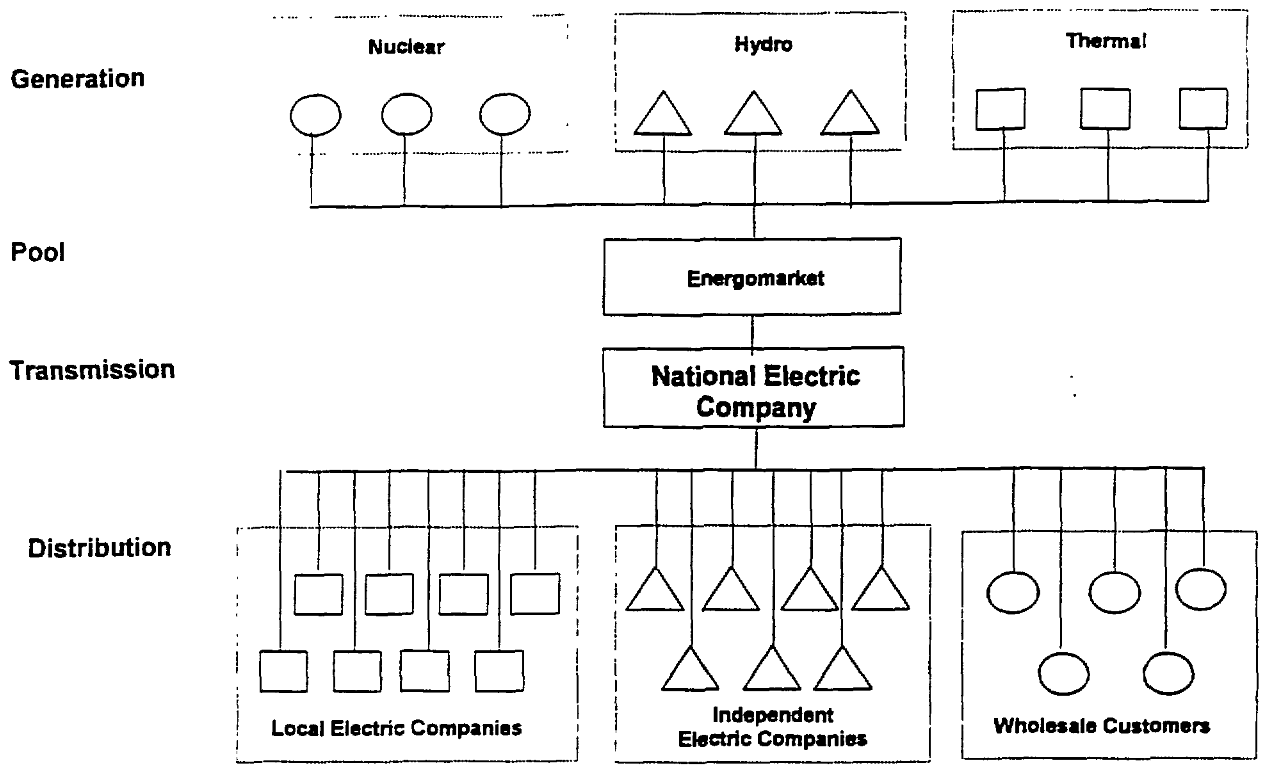
1.4 OVERVIEW OF THE POWER SECTOR RESTRUCTURING

The decision to restructure was consistent with overall agreements for macroeconomic reform that Ukraine reached with the International Monetary Fund. Donor assistance for power sector restructuring is being coordinated by the World Bank and includes advisory teams sponsored by USAID, the U.K. Know-How Fund, and the European Union. The timetable for completion of the restructuring process is the end of 1995, and so far Ukraine has met every milestone on the schedule.

In the past, the power sector was owned and operated by the state through the Ministry of Power and Electrification (Minenergo). The utility was a vertically integrated, parastatal monopoly, and power was dispatched nationally through eight regional control centers. Decisions in the power sector were directly influenced by government policy, and capital and operating expenses were paid from the government's general fund. Minenergo operated through the classic command-and-control philosophy typical of the former Soviet Union.

Ukraine's leaders recognized that such an approach to power sector operations was unsustainable economically and would fail to attract the large amount of foreign capital investment resources required to rehabilitate and modernize the system. Thus, Ukraine has proceeded to adopt the "U.K." model of disaggregation and functional unbundling of the components of the utility system, with the introduction of full competition for generation, transmission, and supply. Exhibit 1-1 presents an outline of the new structure. The utility system that is currently evolving is composed of:

Exhibit 1-1
Overview of Power Sector Restructuring



- Five thermal generating companies (Gencos), which have been corporatized (to be privatized someday) and will compete in a wholesale pool. Two other generation organizations (nuclear and hydro) will remain state owned and will not compete in the pool.

- A pool administrator called Energomarket, which will operate an hourly spot market for wholesale power purchases and sales, dispatch the system according to day-ahead competitive bids received from the generators, and provide ancillary services such as reactive power and frequency regulation. Energomarket will pay all generators the marginal price bid at each hour.

- The National Electric Company, which is a state-owned operator of the transmission system.

- Twenty-seven Local Electricity Companies (LECs), corporate (soon to be private) entities at the oblast level (comparable to U.S. states) that are responsible for retail supply to final consumers. The LECs also have subsidiary operations that operate the distribution system in their region and operate combined heat and power (CHP) networks.

- Independent Energy Suppliers (IESs), private companies that operate nation-wide to supply power and compete with Gencos in the pool and the LECs for retail supply.

All entities in the system will operate through licenses that are issued and overseen by a new National Energy Regulatory Commission (NERC), which also regulates retail tariffs, seeks to eliminate monopolistic and anticompetitive practices, and ensures consumer protection. The system will create a fully competitive market for electric generation and supply and will open access to transmission and distribution systems. Energomarket is scheduled to start simulated operations on July 15 and to operate the pool for real by the end of this year.

The pool will also accept bids for demand-side resources. These bids may be by LECs or IESs, which may be acting like an energy service company (ESCo). ESCos are firms that provide turnkey services to energy customers. These services include financing, project analysis and design, implementation, and verification.

Retail customers will be billed at average, regulated rates that are based on the LECs' and IESs' actual monthly cost. Time-of-use (TOU) rates will be probably developed for retail industrial and some commercial customers, but not residential customers. TOU rate structures include different tariffs for different times of the day. These rates reflect the utility's costs better than a single, flat energy charge. Wholesale customers (primarily industrial) that have direct access will be billed on an hourly basis. There will not be any demand charges associated with generation costs, since the supplier does not pay any such charges.

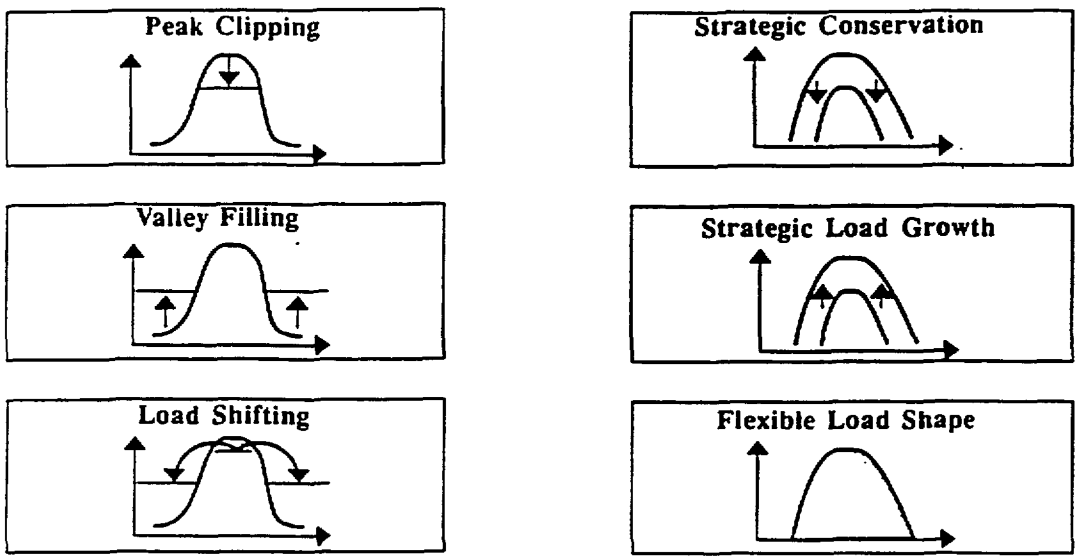
Environmental requirements at the generator will be established by law. Environmental costs therefore will be internalized by the power sector. Consideration of externalities (environmental costs that have not been internalized) and other social concerns will not be a part of power sector regulation.

1.5 OVERVIEW OF DSM

DSM is achieved through **energy efficiency**, which is the reduction of kilowatt hours (kWh) of energy consumption, or **load management**, which is the reduction of kilowatts (kW) of power demanded or the displacement of demand to off-peak times. It encompasses a broad range of measures to encourage consumers to voluntarily modify their consumption without compromising service quality or customer satisfaction. Tariffs can be designed to stimulate a shift in consumption to off-peak periods. End-use energy efficiency can reduce both energy and peak power demand. Direct load control can likewise limit peak power demand.

Just as expected changes in load shapes can guide the selection of new supply options (e.g., whether a peaking or baseload unit is called for), DSM programs can be designed to achieve particular load shape objectives. These objectives are summarized in Exhibit 1-2

Exhibit 1-2
Load Shape Objectives



In the interest of society's economic efficiency, demand-side resources should be developed when they are shown to be less costly than adding another unit of capacity or generating another unit of energy, from society's point of view. For these DSM measures to succeed, however, both utilities (or local electric companies) and consumers must have the appropriate incentives to participate in DSM programs.

It may seem irrational for a utility to try to sell less of its product. But in fact, load-reducing DSM may be an important strategy for providing electric services at least cost, since it may be cheaper to save energy than to produce it, particularly during peak usage periods when marginal production costs are highest. Where regulations encourage market choices and socially optimal investments to coincide, utilities have come to understand that managing the electric resources on the customer's side of the meter may be more cost-effective in meeting electric power needs than building expensive new power plants. Thus was born the recognition that a "negawatt" of electricity saved through DSM is as good as a megawatt of generation capacity.

For instance, if a utility manages to reduce electricity demand, it can postpone the construction of expensive new power plants or increase reliability. Additionally, reducing total generation can obviate the installation of costly environmental controls. Capturing these benefits, however, requires utilities to view their roles differently. Whereas utilities that rely solely on conventional supply-side resources such as power plants often view themselves as commodity producers, utilities that tap the potential of DSM must perceive themselves as service providers, i.e., that they are in the business of meeting consumer needs rather than simply producing kilowatt-hours.

Integrated resource planning (IRP), as it has been implemented in North America and elsewhere, is intended to ensure that the least-cost resource options, which may include DSM, are selected by a utility through long- and short-range planning exercises. This process is a regulatory requirement. In the situations where IRP has been used, the utility is a regulated, vertically integrated monopoly.

The new Ukraine power structure will rely on market forces rather than regulation to select the least-cost options. As previously discussed, the power sector is to be vertically disaggregated, with competition at the generator and at the supplier levels. This is a profoundly different framework than IRP, with profoundly different implications for DSM. Cross-subsidies between customer, common in many IRPs, will not have a role in this framework. However, there will be an opportunity for bidding short-term DSM resources in this framework.

Many countries are deregulating their power sectors and are proposing to introduce or have introduced retail competition. Increasingly, utilities are seeing DSM as a technique to retain valuable customers by helping them to lower their overall bills through combinations of pricing and advice on or financing for energy efficiency and load management strategies.

1.5.1 Types of DSM Delivery Mechanisms

Utilities may invest in DSM in several ways. One way is for the utility to issue requests for proposals (RFPs) for new resources. Generation companies may come forward with contracts for firm supplies, and consumers, especially large customers, may offer energy saving opportunities. Frequently, energy service companies identify potential consumer savings and enter in contracts with one or more consumers to obtain those resources. The energy service company may then package several of these contracts into a single proposal to the utility. Once the utility receives the bids, it orders the resources by cost and contracts with the least costly projects (both supply and demand side) until utility needs are fully met.

An alternative (but not mutually exclusive) approach is for the utility to develop DSM programs on its own, and then implement the programs itself or through contractors. Programs may run the gamut from the passive, in which utilities only provide additional information to consumers to increase their awareness of the opportunities and benefits of energy efficiency, to the aggressive, in which utilities go to customer premises and install more efficient equipment. Financing programs are in between these extremes: actual installation of the measure is left to the consumer but with a financial incentive provided by the utility. Although program participation increases with utility promotion and interest payment subsidy levels, higher interest subsidies and aggressive promotion typically cost more. Part of the art of program design is to balance these costs and benefits.

1.5.2 Benefit-Cost Perspectives

Utilities, regulators, and customers commonly evaluate the cost-effectiveness of DSM programs using one or more of five different tests:

1. The Participant Test measures the financial costs and benefits to program participants.

2. The Ratepayer Impact Measure (RIM) Test measures program impacts on retail tariffs and hence on customer bills due to changes in utility revenues and operating costs caused by the program. This test assumes that utility expenses, revenue losses, and avoided cost savings resulting from the programs are passed on to ratepayers; no other costs or benefits are included. The test includes both participants and nonparticipants as customers.

3. The Utility Cost Test measures the net costs of a DSM program as a resource option based on the costs incurred by the utility, including incentive costs and excluding net costs incurred by the participant.

4. The Total Resource Cost (TRC) Test measure the net costs of a DSM program as a resource option within the power system based on the total costs of the program, including both the participants' and the utility's costs.

5. The Societal Cost Test is a variant of the TRC test in that it includes externalities, excludes tax credit benefits, and uses a societal discount rate. Whereas the TRC examines costs and benefits of resources as they accrue only within the power system, the Societal Cost Test accounts for costs and benefits of resources as they accrue to the country as a whole.

Exhibit 1-3 depicts the scope of these tests. Each cost test draws a boundary around a different entity or group of entities and evaluates the monetary flows (and opportunity costs) across that boundary resulting from program implementation. Tests 1, 2, and 3 are financial

Exhibit 1-3
Benefit-Cost Tests

Tests	*Perspectives*	*Benefits*	*Costs*
(b) Ratepayer Impact Test	Nonparticipants		- Rate Impacts of DSM
(a) Participant Test	Participants	+ Bill Savings	- Participant Net DSM Costs
(c) Utility Cost Test	Utility	+ Avoided Capital Cost + Avoided Operating Costs	- DSM Program Costs - Revenue Losses
(d) Total Resource Cost Test			
(e) Societal Cost Test	The Economy	+ Avoided Externality Costs	- Tax Benefits

analyses from the perspectives of participants, nonparticipating ratepayers, and the utility, respectively. Test 4, the TRC Test, reflects a definition of utility planning that includes the customer's side of the meter. It assesses the monetary flows between the expanded utility planning domain and the rest of the national economy. Finally, test 5, the Societal Cost Test, assesses the program costs and benefits at a national level, and may take into account environmental and other social costs.

The national assessment of DSM for Ukraine used the TRC, RIM, and Participant tests. The rationale for choosing these tests is discussed in Chapter 2.

1.6 OVERVIEW OF REPORT

The next chapter discusses DSM in the restructured power sector. Chapter 3 presents an overview of electricity use in Ukraine. Demand-side resources are identified and screened based on economic criteria in Chapter 4. Preliminary program concepts, with costs and benefits, are presented in Chapter 5.

CHAPTER 2
DSM IN THE RESTRUCTURED POWER SECTOR

The new Ukraine power structure will rely on market forces rather than regulation to select the least-cost options. As previously discussed, Ukraine's power sector is vertically disaggregated, with competition at the generator and at the supplier levels. DSM may be paid for by the power sector at two levels: at the pool level and at the supplier level. The objective functions of these two types of entities are different, and the screening considerations are different. Applications of DSM at these two levels are discussed in the next sections.

2.1 DSM AT THE POOL LEVEL

2.1.1 Background

The role of DSM in Ukraine's power sector restructuring at the pool level was confirmed by the World Bank and Minenergo in April 1995. The basic concept is that at any hour, Energomarket should be willing to buy demand curtailment on the margin, if it is less costly than the next increment of generation. If Energomarket were to pay for DSM whenever it was the least-cost resource on the margin, then all ratepayers would benefit and the result would be economic efficiency. In such case, the suppliers of DSM resources would be the LECs and IESs, in addition to large wholesale customers connected to the transmission system. DSM would be accomplished by interrupting service at customers' facilities during system peaks through load management controls. Demand curtailment would be aggregated by the LECs and IESs through load cooperatives that spread the risk of compliance with system dispatching requirements. The curtailment would be subject to stringent metering and verification protocols.

Minenergo and the World Bank have made it clear that a fully competitive, nondiscriminatory market for electric resources must be created in Ukraine, including DSM resources. This issue is relevant to the following aspects of licensing, Energomarket operations, and NERC oversight:

- Bidders of DSM resources will have full access to Energomarket operations through the Energomarket Members Agreement, Market Rules, and Market Operating Guidelines.

- Energomarket's license will require establishment of internal mechanics to properly evaluate DSM bids compared to supply-side bids, and to dispatch competitive DSM resources.

- The licenses of the LECs and the IESs will include provisions for their role of bidding DSM resources to Energomarket.

The short-term perspective of the pool will dictate that only load management DSM resources (i.e., those that can be provided on demand) will be considered. It is possible that energy-efficiency measures will eventually be bid. The uncertainties associated with verification will likely preclude this from being an option that would be acceptable to the pool, at least until the concept of DSM bidding with load management options becomes accepted.

2.1.2 Financial Flows in a Pool with DSM

To define the source of payments and the appropriate cost-effectiveness test to use, it is necessary to consider carefully the financial flows that will occur in a pool with DSM. This section presents the results of an analysis illustrating the financial flows in a pool with DSM. The complete analysis is presented in Appendix A.

Exhibit 2-1 illustrates the flows of energy and payments for a specific hour. A specific customer demands d_1 kWh in that hour and pays rate r_1 to the supplier,[1] for a total payment of $d_1 r_1$ in that hour. The supplier pays m cents per kWh to the pool, which in turn pays the same amount to the generators. A portion of the total demand is produced by incremental generation, which determines the pool price m, and the remainder is produced by other generation.

Now suppose that the customer has submitted a bid price of p per kWh of demand reduction and assume that this price is paid by the pool, as shown in Exhibit 2-2. Because of the reduced power to the customer, the customer suffers various economic costs, from lost revenues, lost profits, inconvenience or inefficiencies, and the costs of inputs such as labor and spoiled product. We will use the term "lost customer value" to denote the costs that are relevant to this discussion resulting from the curtailment and denote this value by c, in cents per kWh.

The pool needs to be made financially whole for the payment p to the customer. The pool will recover the cost of this payment by spreading it over all kWh provided to suppliers in proportion to their energy receipts from the pool.

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[1] Wherever the term "supplier" appears in this discussion, it refers to both local electricity companies (LECs) and independent electricity suppliers (IESs).

Exhibit 2-1
Power Flows and Payments in a Pool without DSM

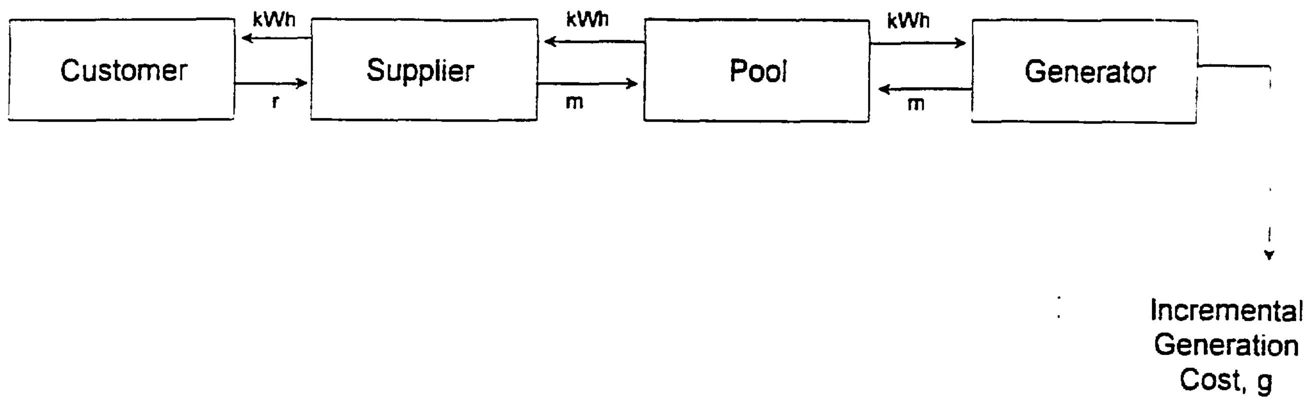
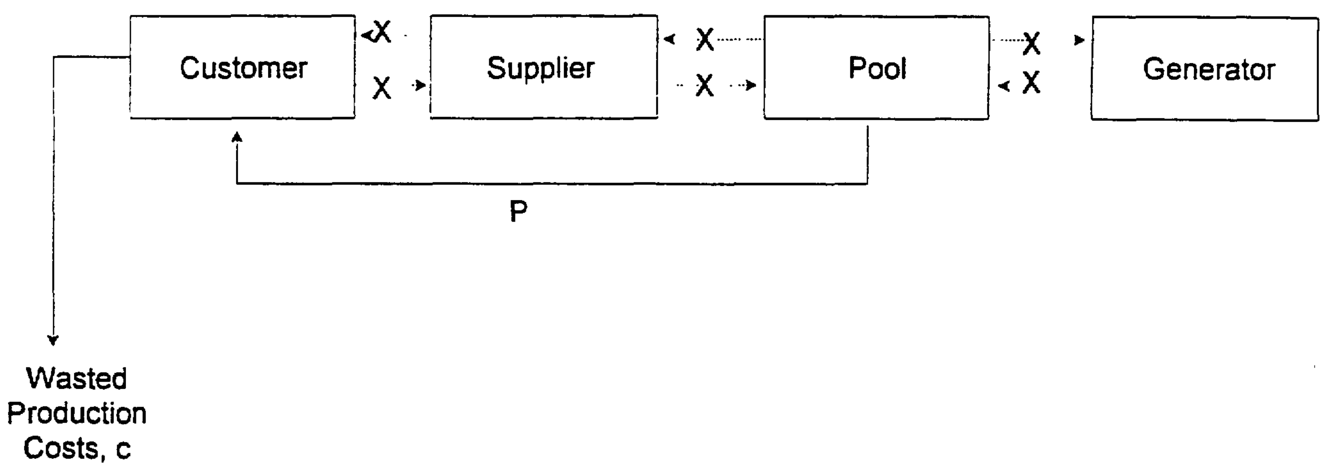


Exhibit 2-2
Power Flows and Payments in a Pool with DSM



If pool price is greater than the lost customer value, then the demand reduction is beneficial from a societal perspective. Societal economic efficiency is improved by the demand reduction if the lost customer value resulting from the curtailment is less that the incremental generation cost that would otherwise be incurred. This condition is equivalent to passing the cost-effectiveness test commonly known as the TRC Test, discussed in Chapter 1.

If the sum of the payment and avoided rate is greater than the cost to the customer of the curtailment, then the customer is better off with the demand reduction than without. In fact, this is a necessary condition for a demand reduction even to occur, assuming that participation in any of the load management programs is voluntary. The condition is equivalent to passing the Participant Test, discussed in Chapter 1.

If the hourly pool price is greater than the rate that the customer would pay the supplier for energy in that hour plus the supplier's share of the payment by the pool to the customer, then the supplier is better off with the demand reduction than without. Although it loses revenue, it avoids paying the higher rate to the pool. However, if the pool price is lower than the rate plus the DSM payment, the supplier loses. This perspective is essentially the RIM test from the supplier perspective, as discussed in Chapter 1.

The pool's rates to suppliers will decrease, fulfilling its objective function, if the percentage difference between the customer's payment per kWh and the pool price is greater than the percentage reduction in system demand. For example, a load management measure that results in a relatively large reduction in system demand for a relatively small reduction in system pool price will cause the rates to the suppliers to increase. This is because the costs of payments are allocated to a smaller number of kWh. This condition is equivalent to passing the RIM test from the pool perspective. The calculation is different than the standard calculation approach for a RIM test, because the pool prices, equivalent to marginal energy cost in the standard framework, change due to the DSM bidding.

Because this last test ensures that the pool fulfills its objective function, this is the appropriate test for evaluating DSM bids

2.2 DSM AT THE SUPPLIER LEVEL

The objective function of the privately owned suppliers is to maximize profits. DSM must be justifiable on a financial basis to the entity paying for it. In a competitive environment, a supplier has two motivations to pursue DSM. Both motivations relate to retaining customers.

1. to reduce its rates, thereby maintaining competitiveness
2. to provide a customer service to ensure loyalty and retention of key large customers in a competitive supply market.

The LECs and IESs will provide their customers with information, financing, and access to ESCOs. This will be done at participant and shareholder expense, to minimize the rate impacts of these activities.

DSM measures that reduce rates are those that pass the RIM test, as defined in Chapter 1 Simply put, a measure must result in avoided generation costs that are greater than the sum of revenue losses and program costs. DSM measures can pass the RIM test if they reduce demand in periods when generation costs are higher than tariffs.

Suppliers may be interested in providing DSM to customers as a service to those customers that other suppliers would find attractive and would attempt to acquire. The types of customers that are most attractive are typically high voltage customers, with average usage levels close to peak period usage. These types of customers are typically industrial customers. Suppliers may provide DSM programs that do not pass the RIM test to these customers. To avoid cross-subsidies, such programs should be designed so that the participant pays for costs incurred for the participant's benefits. This can be done through a shared-savings program, in which amortized program costs are charged to the participant on their monthly bill, with the charges designed so that they are less than the bill reductions from energy savings.

CHAPTER 3
ELECTRICITY USE IN UKRAINE

Demand-side resources are derived from changes in electricity consumption patterns. An assessment of DSM potential thus requires an understanding of how customers use electricity. This chapter describes the principal electricity consumption patterns by principal sector in Ukraine. These patterns provide the basis for identifying the technical opportunities for DSM.

3.1 COMPOSITION AND PATTERNS OF ELECTRICITY USAGE

Total system electricity production in Ukraine in 1994 was 201 TWh. Peak production of 31.9 GW occurred in February at 6:00 p.m. The system capacity factor for the year was 0.73, meaning that average production was 73 percent of peak production.

Net sales, which is defined as gross production less line losses and unpaid bills, were 164 TWh. Unpaid bills are a significant problem in Ukraine because the society has been accustomed to subsidies for electricity, and these subsidies have recently been removed.

A review of system load shapes can provide insight into customer behavior. System load data reflects aggregate consumer demand and can help determine load shape objectives for DSM programs. Average daily load shapes for each month based on 1994 hourly load data provided by the National Dispatch Center, part of the Ministry of Energy, are shown in Exhibits 3-1 and 3-2.

These exhibits reveal two dominant trends. The first is that system load increases as temperatures decrease, i.e., during the winter. Although additional winter lighting requirements and summer vacation schedules contribute to relatively higher winter demand, the shift may be due primarily to heating requirements and the limited presence of air conditioning. However, as discussed in more detail in Section 3.4, electrical resistance space heating is rare in Ukraine. Instead, district heating is the predominant means of winter heating. District heat pumping systems depend on thousands of motors that operate almost continuously in the heating season.

The second observation is that the evening peak moves later into the evening and decreases when compared with the morning peak during the summer. This most likely results from reduced lighting requirements during the summer.

Exhibit 3-1
Average Daily Load Shapes by Month
January - June

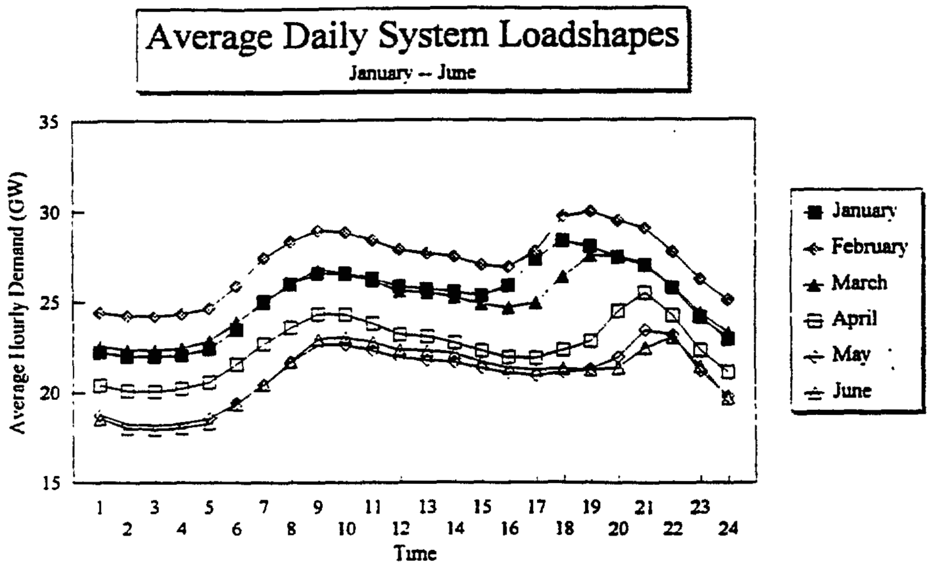
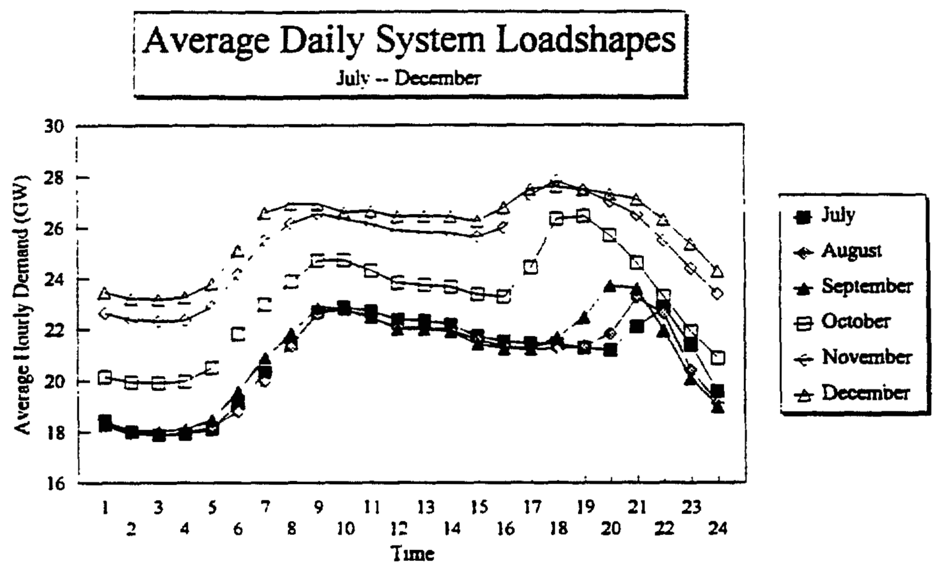


Exhibit 3-2
Average Daily Load Shapes by Month
July - December



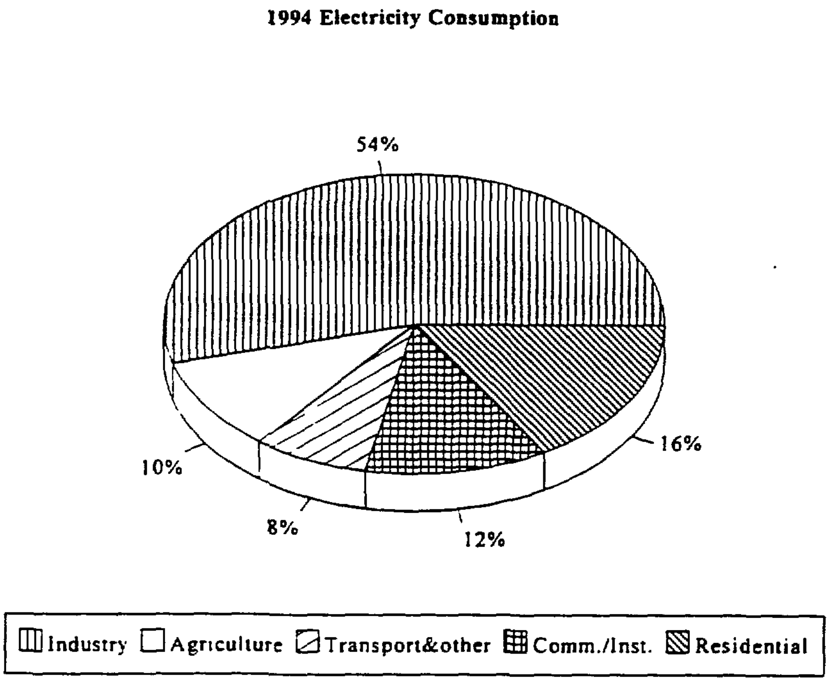
A 1994 tariff study conducted by Electricite de France defined two homogeneous periods:

1. winter: from November to February
2. summer: from March to October.

Because of the presence of hydropower, which helps to reduce the seasonal variation in requirements for expensive peaking fuels, and the even distribution of loss of load probabilities, the study found no significant differences between marginal costs in daytime hours (7:00 a.m. to 11:00 p.m.) for both seasonal periods, only between daytime and nighttime.

Net electricity usage in Ukraine is dominated by industrial usage. As shown in Exhibit 3-3, industry consumption in 1994 was 54 percent of the total annual net consumption. Residential consumption was 16 percent, commercial/institutional consumption was 12 percent, and agriculture and transportation consumption made up the remaining 18 percent.

Exhibit 3-3
Electricity Consumption by Sector



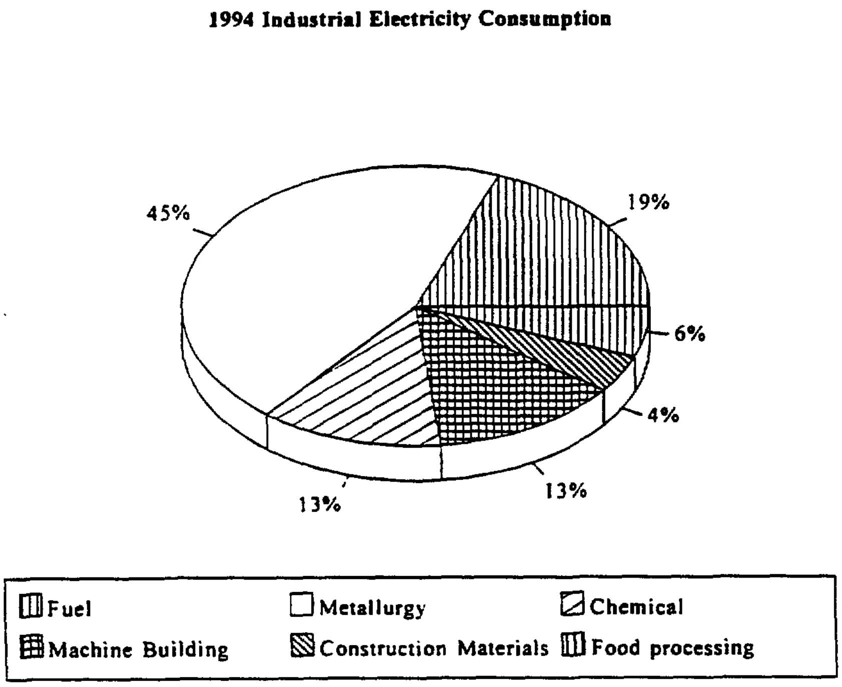
Source: National Dispatch Center

The following sections discuss usage in the three sectors with the largest contribution to national energy use: industrial, residential, and commercial/institutional. As a part of this project, customer surveys were conducted in each of these three sectors, to obtain information on equipment presence and characteristics, and usage patterns. The results from these surveys are also discussed.

3.2 THE INDUSTRIAL SECTOR

Ukrainian industry encompasses a wide range of activities. Exhibit 3-4 provides an overview of the distribution of electricity use in the principal industrial subsectors (excluding agriculture). In 1994, the metallurgy and energy (primarily coal mining) subsectors accounted for over half of the 88.6 TWh consumed by industry, and metallurgy alone accounted for 41 percent. The subsectoral shares will change, however, as Ukraine's economic transformation continues. Shares of primary industries like coal mining and steel production are likely to decline as manufacturing and other downstream industries increase their shares.

Exhibit 3-4
Distribution of Industrial Electricity Use



Source: National Dispatch Center

3.2.1 Industrial Survey

As a part of this national DSM assessment project, Hagler Bailly commissioned a survey of industrial electricity consumption patterns. A Ukrainian market research firm completed 202 surveys of a representative sample of this sector's customers. The total usage represented by the sample was 18.7 TWh, or 21 percent of sector sales in 1994.

The survey was conducted in two stages. In the first stage, 146 facilities were selected from among those where Kiev Polytechnic had installed automatic control systems and load monitoring equipment, which provided useful information on load shapes, as discussed below. In the second stage, additional facilities were selected from various regions in Ukraine. These facilities were selected so that the distribution of employees by subsector in the overall sample was similar to the distribution of employees by subsector in the nation. Sample design and interview methods are discussed in detail in a separate report.[1]

The survey asked questions about the presence, nameplate capacity, and usage patterns for key equipment types, such as motors, lighting, and process. Equipment size (e.g., motor horsepower) and type (e.g., Fluorescent, incandescent, or other lighting) were identified as appropriate. Other questions addressed facility function and size, the importance of energy costs and environmental concerns, and past energy efficiency actions.

3.2.2 Industrial End Uses

Industrial electricity usage is dominated by motor usage. As shown in Exhibit 3-5, motor usage makes up 90 percent of sector sales. Very large motors use a significant portion of the electricity sold to industry, reflecting the high degree of industrial centralization in the former Soviet Union. The most common type of motor usage is compressed air (29 percent); followed by heating, ventilating, and air-conditioning (HVAC, 24 percent), machine tools (21 percent), and fans/blowers (16 percent). The reported percentage of HVAC usage is unusually high for industry. There may be some fans/blowers use recorded in this category.

Lighting is the second most significant end use, making up 5 percent of sales. Over half of this usage is incandescent lighting. Mercury vapor lighting is also common. Both lighting types are good candidates for efficiency improvements.

Process use makes up about 5 percent of sales. The most significant types of process use are furnaces and welding.

A total of 269 GWh was self-generated by survey respondents in 1994. This amounts to 1.4 percent of consumption. Seven customers said that they could increase self-generation. The average estimated increase was 30 percent.

[1] Socis-Gallup. 1995. "Electricity Consumption Survey: Industrial Sector." Report prepared for Hagler Bailly Kiev, Ukraine.

Exhibit 3-5
Summary of Industrial Usage

End Use	Avg. kW per Installation	Annual Hours of Operation	Average kWh per Installation	Number of Installations	Total Annual Consumption (GWh)	Percent of Total Annual Consumption
Motors (an 80% load factor is assumed to apply to nameplate ratings)						
Small Motors (0 to 7 kW)						
- high use	3.1	3,490	8,655	383,422	3,319	4%
- low use	4.2	1,650	5,544	56,837	315	0%
Medium Motors (7 to 28 kW)						
- high use	10	3,760	30,080	640,724	19,273	22%
- low use	15	1,690	20,280	583,077	11,825	13%
Large Motors (28 to 212 kW)						
- high use	75	4,060	243,600	71,567	17,434	20%
- low use	46	1,980	72,864	44,571	3,248	4%
Very Large Motors (>212 kW)						
- high use	538	4,800	2,065,920	8,577	17,719	20%
- low use	283	3,390	767,496	8,858	6,798	8%
Lighting						
Fluorescent Lighting						
- high use	0.08	3,332	253	2,378,791	602	1%
- low use	0.07	1,733	113	3,325,557	375	0%
Mercury vapor	0.47	2,729	1,288	487,502	628	1%
Incandescent Lighting						
-high wattage (>100)	0.26	2,526	652	3,985,457	2,597	3%
- low wattage (<=100)	0.08	1,933	152	692,547	105	0%
Other	1.22	3,101	3,796	7,192	27	0%
Process Use						
Furnace	223	2,410	537,430	1,855	997	1%
Welding	89	2,340	208,260	13,655	2,844	3%
Other	-	-	-	-	495	1%
Total					88,600	100%

Source: Hagler Bailly Consulting, 1995.

3.2.3 Other Survey Responses

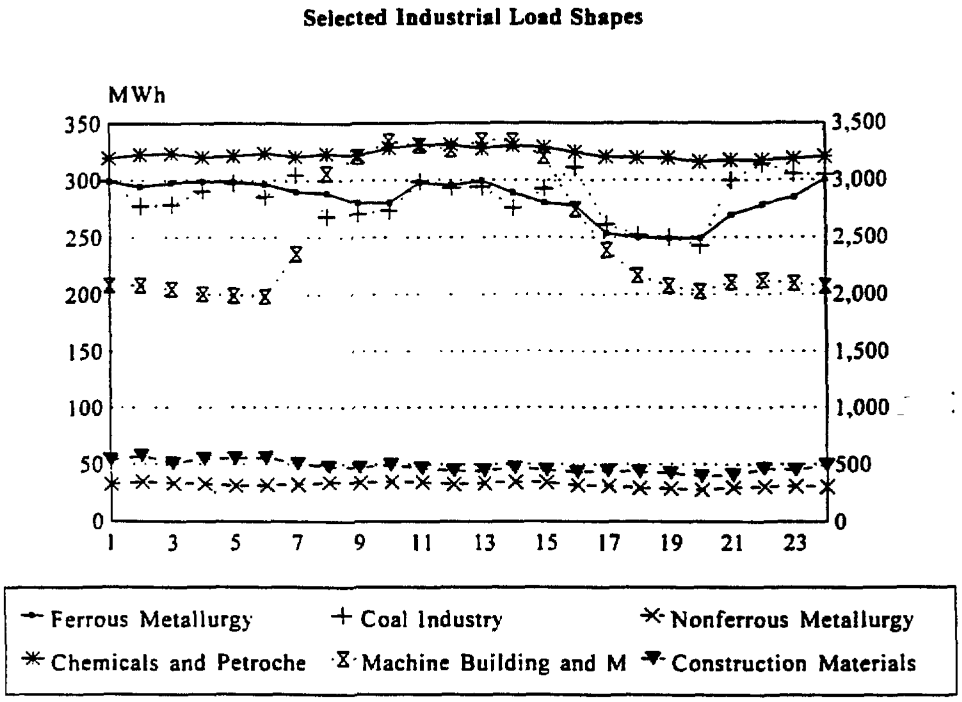
Other survey responses that provide insight into attitudes and actions related to energy efficiency include the following:

- 28 percent of respondents reported seasonal operations.
- 46 percent reported that electricity costs were a major concern.
- 10 percent reported that environmental considerations were a major concern (interest in environmental improvement can be a motivating factor for energy efficiency).
- 92 percent reported that the enterprise currently implemented measures or activities to reduce electricity costs. These included energy saving technologies, energy-efficient replacement equipment, and work curtailment.
- 24 percent wanted more information on energy efficiency.
- 25 percent were interested in having an energy specialist visit their enterprise.
- 41 percent were interested in price incentives for energy-efficient equipment.
- 16 percent were interested in workshops on energy efficiency.
- Respondents were more interested in energy-efficiency programs offered by a private company than their Energo, or local distribution company (64 to 40 percent).

3.2.4 Industrial Load Shapes

Hagler Bailly developed load shapes for 231 industrial enterprises in Ukraine from data collected by load research equipment maintained by Kiev Polytechnic. Load data were compiled for a one- week period in December 1994. From these data, average weekday load shapes were developed for the principal subsectors, as shown in Exhibit 3-6. During this period, electricity production was unable to meet demand because of a severe energy crisis (gas supply disruption), forcing involuntary curtailments (blackouts), primarily during the evening hours. These curtailments are most noticeable in the metallurgy and coal industry subsectors. Other than the curtailment periods, most of the load shapes are relatively flat, except machine building and the "other" category, which includes food processing, although certain enterprises showed peaks in various parts of the day.

Exhibit 3-6
Industrial Load Shapes by Subsector



Source: Load research conducted by Kiev Polytechnic
Right y-axis units apply to ferrous metallurgy, left y-axis units apply to all other subsectors

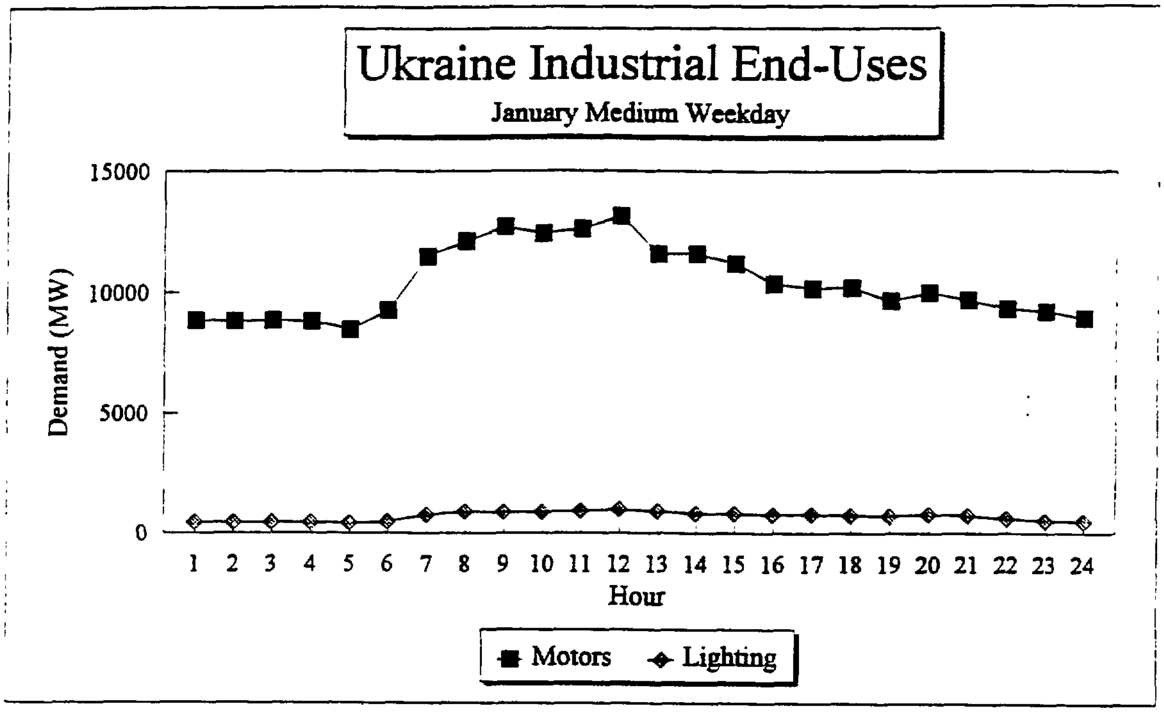
Exhibit 3-7 shows typical usage, as winter and summer load shapes, for the two most significant end uses in the industrial sector: motors and lighting. The shapes are based on statistical analysis of metered loads by the Institute of Power Engineering in Katowice, Poland. The characteristics of these shapes are similar to those of the subsector shapes, i.e., higher use in the day time, but significant nighttime use. There is little seasonal variation.

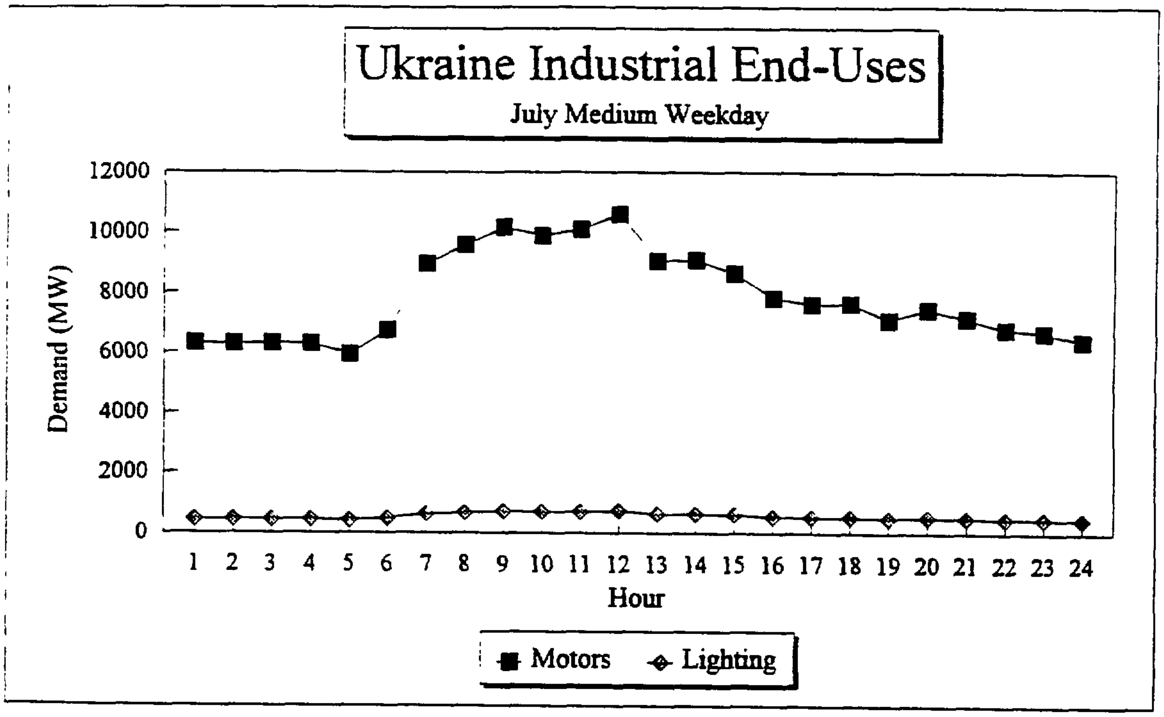
3.3 RESIDENTIAL USAGE

The residential sector is the second-largest electricity consuming sector in Ukraine after the industrial sector. The bulk of residential load is lighting, which, because of its seasonal and diurnal variation, is coincident with the system peak demands. According to the Ministry of Energy, there were 17 million residential customers in 1994.

As a part of the national DSM assessment project, Hagler Bailly commissioned a survey of residential electricity consumption patterns. The same firm that completed the surveys in the other sectors completed 1,200 in-home interviews.

Exhibit 3-7
Industrial End-Use Load Shapes





Source: Hagler Bailly.

A multistage sample selection approach was used in this survey. The first stage included grouping the oblasts (regions) of Ukraine into 10 regions. Kiev, the capital, was included in the sample as a separate region. In the second stage, the most typical oblasts for each region were selected. The third stage included selecting the sampling points, and differentiating between urban and rural settlement. There were 31 urban and 32 rural sampling points in the survey. In the fourth stage, the routes within the sampling points were determined for interviewers to sample households. The fifth stage included the selection of respondents within each household. Respondents were those household members who normally take care of electrical appliances and pay electricity bills. The sampling and interview procedures are described in detail in a separate report.[2]

Key characteristics of survey respondents are summarized in Exhibit 3-8. The average electricity usage of the sample (1,540 kWh/year) was almost the same as the average usage for the residential sector (1,576 kWh/year, based on sector use of 26.8 TWh and 17 million customers). The data on appliance saturations and end-use characteristics obtained in the survey are discussed in the following sections.

Exhibit 3-8
Key Characteristics of Respondents

Characteristic	Value
Living space	47 m^3
Classification of household	
Urban	65.2%
Rural	34.8%
Annual consumption	
Urban	1,378 kWh/year
Rural	1,845 kWh/year
All	1,540 kWh/year
Number of people per household	2.9
Type of house	
Apartment	42.8%
Detached	49.9%
Other	6.1%

Source: Customer survey conducted by Socis-Gallup.

[2] Socis-Gallup International, 1995. "Residential Electricity Usage." Report prepared for Hagler Bailly Kiev, Ukraine.

3.3.1 Appliance Saturations

All of the homes surveyed had electricity, and all reported using electricity for lighting. Most homes have refrigerators (91 percent) and televisions (96 percent). Most homes have washing machines (70 percent). Other major appliances are not common, most notably space heating (4 percent), water heating (2 percent), and air conditioning (0.4 percent). Appliance saturations are summarized in Exhibit 3-9.

Exhibit 3-9
Saturation Rates of Residential Appliances

Appliance	Saturation Rate*
Interior lighting	650%
Exterior lighting	149%
Refrigerators	91%
Freezers	2%
Air conditioners	0.4%
Water heaters	2%
Water pump	8%
Stove	12%
Oven	12%
Space heater	4%
Fans	9%
Color TV	69%
Black& white TV	43%
Video cassette recorder	4%
Irons	94%
Dishwasher	0.5%
Washing machine	70%
Clothes dryer	4%
Vacuum cleaner	51%
Tape recorder	20%

* Saturation rate of greater than 100 percent indicates that the average home has more than one of this appliance or equipment.

Source: Residential customer survey conducted by Socis-Gallup.

Customers were also asked about plans to purchase appliances. Few respondents reported any plans to purchase specific types of appliances.

3.3.2 Lighting

Most residential lighting (97 percent) is incandescent, and the remainder are standard fluorescent lamps (only one compact fluorescent lamp was reported by the sample). The average wattage of interior lamps is 69 W. The average home uses two lamps for more than one hour per day. Based on reported usage for lamps and their connected load, the average home uses 693 kWh per year for lamps used more than one hour per day for interior lighting. Exterior lighting is also common, and the average usage for exterior lamps used more than one hour per day is 192 kWh. Lighting usage is approximately 60 percent of residential usage.

3.3.3 Refrigerators

As was shown in Exhibit 3-9, ownership of refrigeration is common. The residential survey produced the following information regarding refrigerators:

- The average capacity is 0.19 cubic meters (6.8 cubic feet); 41 percent are 0.17 cubic meters or less.
- The average nameplate connected load is 567 W.
- Refrigerators are not used for the entire year by 48 percent of owners; the average usage period is 10.6 months.
- The average age of refrigerators is 11 years.
- Six percent of owners have plans to replace their refrigerators.

3.3.4 Summary of Residential Usage

Using estimates of connected load, hours of operation, and saturation levels from the customer survey, combined with standard estimates of usage by appliances and number of residential customers, Hagler Bailly estimated the total annual consumption by end use, as presented in Exhibit 3-10. As shown in that exhibit, incandescent lighting is the most significant end use (28 percent of total use), followed by refrigerators (26 percent), and televisions (16 percent).

Exhibit 3-10
Summary of Residential Usage

End Use	Avg. kW per Installation	Annual Hours of Operation	Average kWh per Installation	Average Installations per customer	Number of Installations (millions)	Total Annual Consumption (GWh)	Percent of Total Annual Consumption
Incandescent Lighting							
Low-use (<=1 hour per day)	0.069	270	19	10.00	165.94	3,096	11.6%
High-use (>1 hour per day)	0.069	1700	117	2.25	37.36	4,388	16.4%
Refrigerators							
Large (>0.17 cubic meters)	-	-	473	0.54	8.90	4,212	15.7%
Small (<=0.17 cubic meters)	-	-	410	0.37	6.19	2,537	9.5%
Washing Machines	-	-	300	0.70	11.61	3,482	13.0%
Televisions							
Color	-	-	320	0.69	11.45	3,665	13.7%
Black & white	-	-	100	0.43	7.11	711	2.7%
Stoves & ovens	-	-	700	0.12	1.99	1,394	5.2%
Other appliances	-	-	-	-	-	3,279	12.3%
Total						26,764	100.0%

Sources: Lighting connected load and hours from market research survey; average number of installations from market research study; refrigerator average kWh per installation from FEWE, Poland; television and stove/oven kWh estimates from NYSERDA, washing machine estimates from ACEEE.

47

Exhibit 3-11 shows winter and summer load shapes for the most important end uses from the perspective of DSM: lighting and refrigeration. The lighting load shape is based on survey responses to queries about time of use. There is likely to be some seasonal variation to lighting use that could not be captured by survey questions. The refrigeration shape is based on metered data from the United States. The refrigeration shape shows some seasonal and diurnal variation, but is relatively flat compared to lighting.

3.4 THE COMMERCIAL/INSTITUTIONAL SECTOR

The commercial/institutional sector is composed of public and private facilities that primarily provide services, as distinguished from the industrial sector, which produces goods. This sector is the third most important with respect to electricity consumption, accounting for 19.1 TWh in 1994, or 12 percent of electricity sales.

3.4.1 Distribution of Sales by Subsector

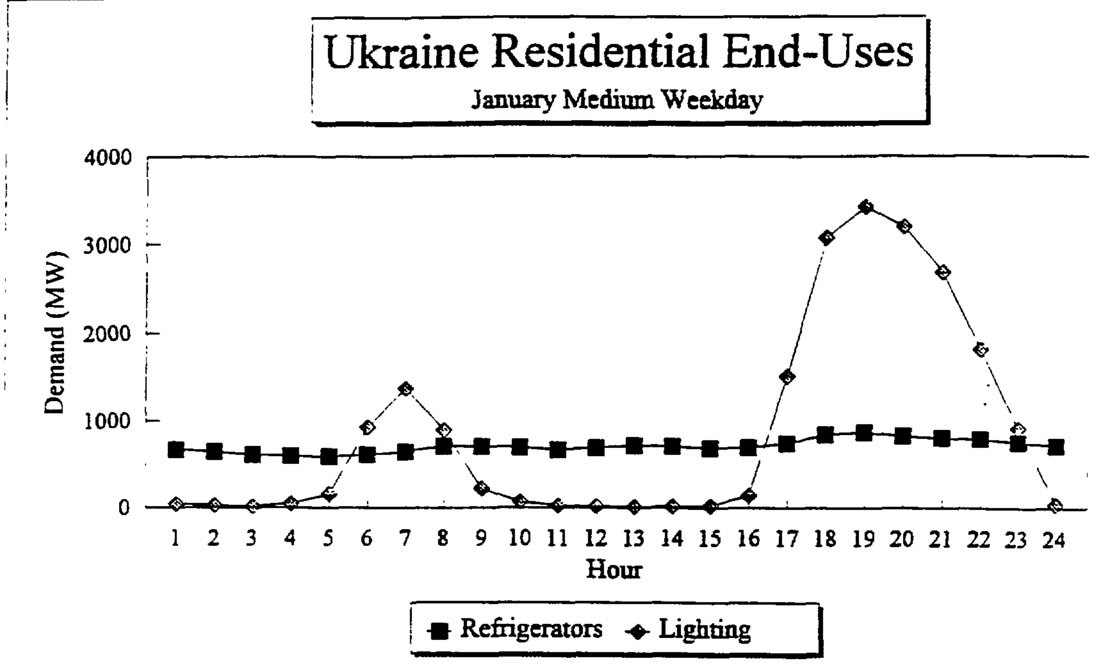
As a part of this national DSM assessment project, Hagler Bailly commissioned a survey of commercial/institutional electricity consumption patterns. The same firm that completed the industrial survey completed 422 on-site surveys of a representative sample of this sector's customers. The total usage represented by the sample was 731 GWh, or 3.8 percent of sector sales.

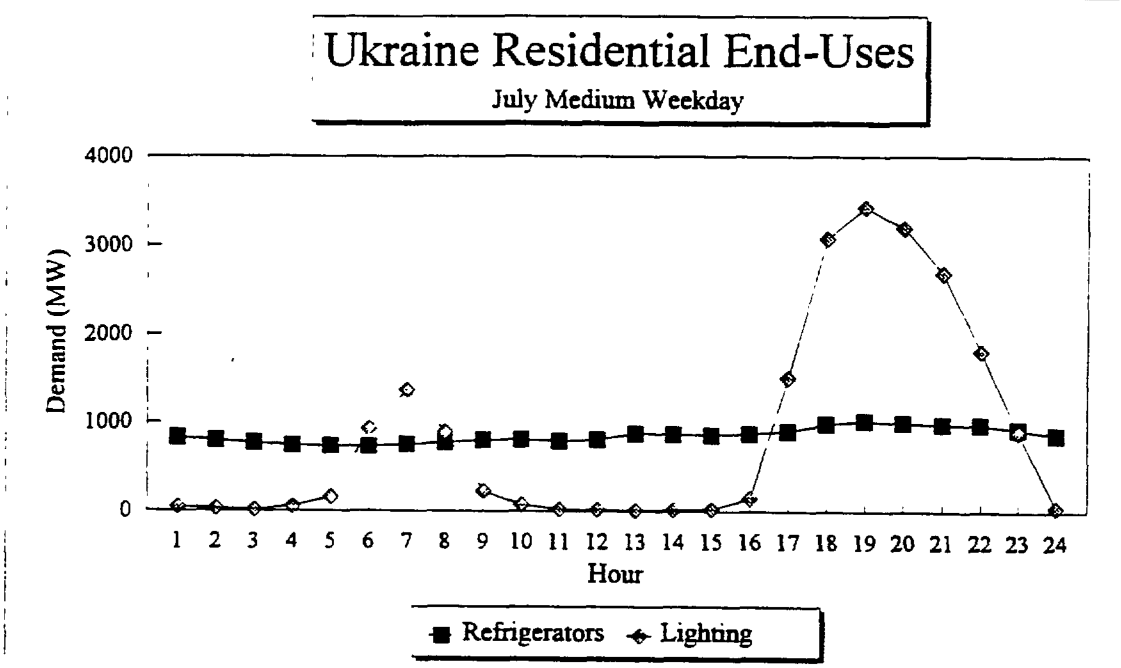
The sample design was based on the data provided by the Ministry of Statistics of Ukraine on the numbers of employees by subsector in Ukraine. Employee data were used because of an absence of data on number of facilities for each region. Sites were selected from all regions of Ukraine. The sample design and interview methods are discussed in more detail in a separate report.[3]

Usage in this sector is dominated by a subsector known as "communal services." This subsector includes street lighting and municipal pumping stations for the water, district heating, hot water, and sewer systems. Usage by this subsector is 90 percent (658 GWh) of the sector sales in the sample, and this share of national sector usage is 17.2 TWh. Metered data from the Ministry of Energy show that street lighting consumed 483 GWh in all of Ukraine in 1994, or 2.8 percent of the estimated communal services usage. Most of the remaining communal services usage is by motor-driven pumps. Communal services uses are distinctly different from other types of commercial/institutional uses, which are largely oriented toward climate modification (heating, lighting, cooling) for occupant comfort.

[3] Socis-Gallup. 1995. "Commercial Electricity Usage." Report prepared for Hagler Bailly Kiev, Ukraine.

Exhibit 3-11
Residential End-Use Load Shapes

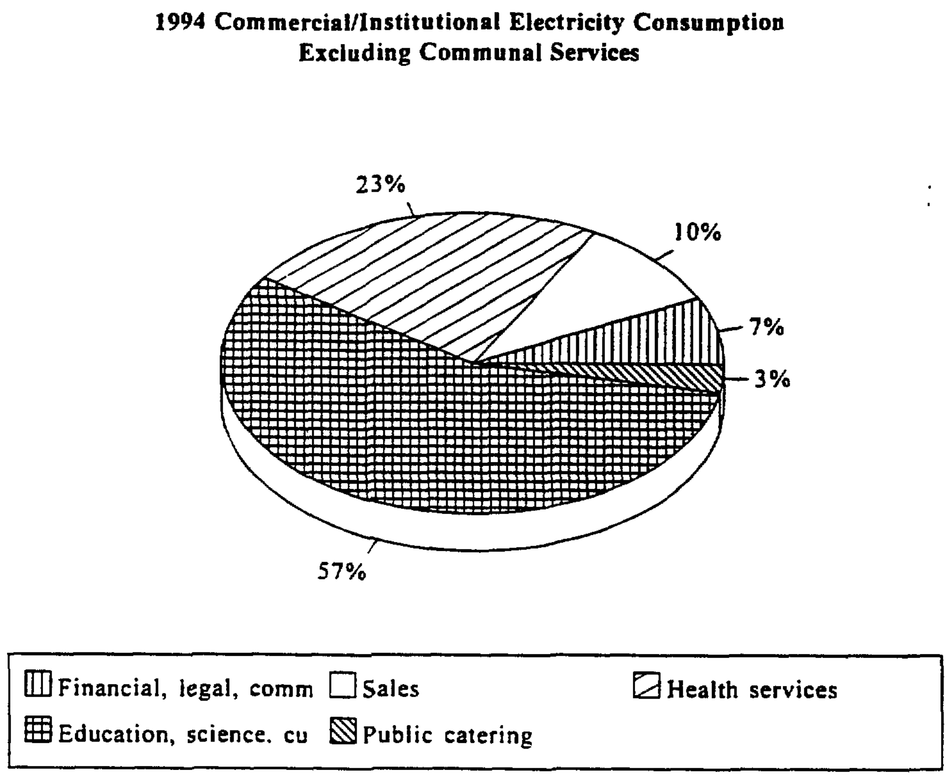




Source: Hagler Bailly.

Other than the communal services subsector, the largest share of the commercial/institutional use is by the education, science, culture, and arts subsector, followed by health services. The distribution of sales by subsector, excluding communal services is shown in Exhibit 3-12.

Exhibit 3-12
Commercial/Institutional Distribution of Sales by Subsector
Excluding Communal Services



Source: National Dispatch Center

In 1994, self-generation of electricity amounted to 7.6 percent of consumption by the sample.

3.4.2 Lighting Usage (excluding street lighting)

Total estimated lighting usage nationwide, excluding street lighting, is 1,312 GWh, which is almost two-thirds of the sales in the sector, excluding communal services. Fluorescent lighting uses the largest share of lighting energy in the sector, followed by incandescent and mercury vapor. Other types of lighting (halogen, metal halide, high pressure sodium) are insignificant. Exhibit 3-13 presents estimates average connected load, annual hours of operation, number of installations, and sector consumption by lamp type and usage level. Number of installations

Exhibit 3-13
Inventory of Commercial/Institutional Lighting
(excluding street lighting)

End Use	Avg. kW per Installation	Annual Hours of Operation	Number of Installations	Total Annual Consumption (GWh)
Fluorescent Lighting				
- High Use	0.040	3,100	2,600,000	322
- Low Use	0.130	800	2,500,000	260
Incandescent Lighting				
- High Use	0.076	3,100	1,700,000	401
- Low Use	0.080	860	1,200,000	83
Mercury Vapor	0.302	1,020	800,000	246
Lighting Total	n/a	n/a	n/a	1,312

Source: Hagler Bailly Consulting, Inc.

have been estimated by extrapolating number of installations in the sample to the population based on the ratio of population to sample consumption.

3.4.3 Other Commercial/Institutional Usage

The remaining usage, after considering pumping and lighting, is approximately 3 percent of commercial/industrial use and a fraction of 1 percent of national usage.

Both electric heating and electric cooling are insignificant shares of commercial electricity use: 16 percent of facilities in the sample reported using electric heating and 25 percent reported using electric cooling. Most of these units are for supplemental space conditioning, however. Only a small fraction of 1 percent of the sector floor area is electrically heated or cooled.

Forty-two percent of facilities report use of fan systems. Eighty-seven percent of these serve a variable load, although 90 percent of the fans are constant speed. This suggests some potential for variable speed drives, a technology that reduces motor speed as load decreases, greatly reducing energy use in this sector.

51

Residential-type refrigerators are quite common, with most (71 percent) facilities reporting presence of more than one — the average number per facility was 7.7. Fourteen percent of facilities have at least one commercial refrigerator, and the saturation rate[4] is 38 percent.

Other equipment saturations in this sector are summarized in Exhibit 3-14.

Exhibit 3-14
Commercial/Institutional Electric Equipment Saturations

Equipment	Share of Facilities with Equipment	Saturation
Freezer	2%	20%
Storage water heater	16%	80%
Electric oven, range, and/or grill	37%	191%
Microwave	4%	5%
Photocopier	20%	34%
Personal computer	35%	459%
Main frame computers	9%	89%
Pumps	19%	221%
Air compressors	14%	60%
Clothes washers	17%	35%
Clothes dryers	13%	43%

Source: Customer survey conducted by Socis-Gallup.

Sixteen percent of respondents reported that they have taken actions to reduce electricity consumption.

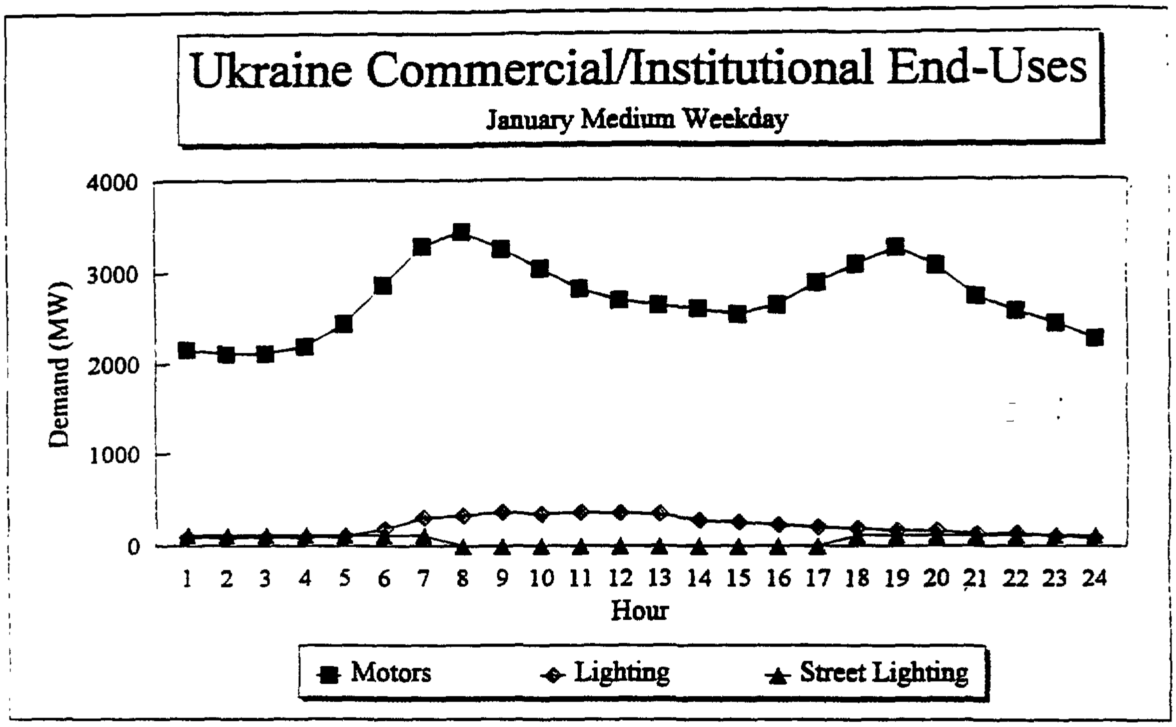
4 Saturation rate is defined as total number of units reported by the sample divided by the number of facilities in the sample. Saturation rates are higher than number of units with equipment because of presence of multiple units.

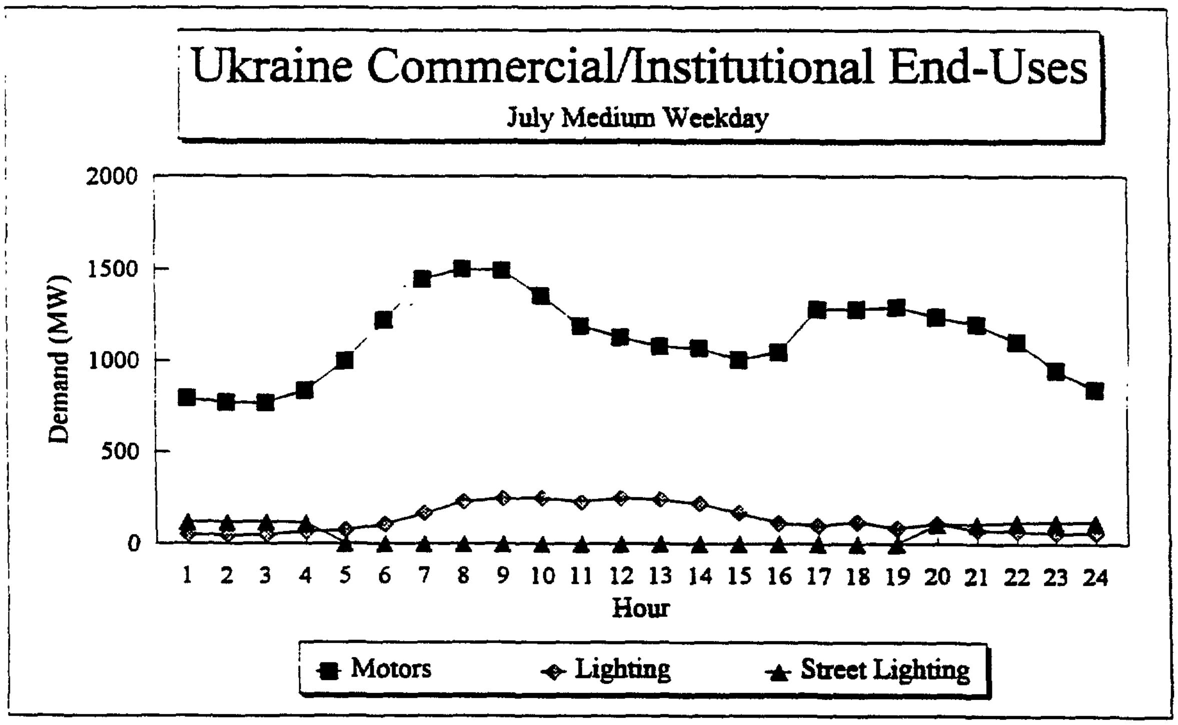
3.4.4 Summary of Commercial/Institutional Usage

Pumping or motor use dominates the commercial/institutional sector's usage (87 percent of sales). Lighting is the second highest (7 percent of sales); followed by other use (3 percent); and street lighting (2.5 percent).

Exhibit 3-15 shows winter and summer load shapes by the three highest end uses in the sector. motors (pumping), street lighting, and other lighting. The motors shape is based on metered data from a Ukraine pumping station. The street lighting load shapes reflect daylight hours in winter and summer. The lighting load shape is based on the statistical analysis of load data by the Institute of Power Engineering mentioned in Section 3.2.4. Load research to be discussed as Part 2 of this report will help to further define these load shapes.

Exhibit 3-15
Commercial/Institutional Load Shapes





Source: Hagler Bailly.

CHAPTER 4
IDENTIFYING DEMAND-SIDE RESOURCES

There are many potential DSM options. Those measures that are clearly not feasible must be screened out before subjecting the remaining measures to closer scrutiny. The first step in this screening process is to identify the system requirements in terms of load shape objectives. The second step is to identify potential technical measures to meet those objectives. These measures are then screened for economic feasibility by comparing the cost of saved energy for each measure with the long-run avoided generation cost. The measures that pass this screening constitute the basis for the programs described in Chapter 5.

4.1 LOAD SHAPE OBJECTIVES

Exhibit 1-2 provided a taxonomy of load shape objectives that can be met by DSM. Some of the salient points regarding the Ukraine power system that help determine the appropriate objectives are summarized below:

- Payments for imported natural gas are a major factor in Ukraine's balance of payments problem. Ukraine has committed to closing Chernobyl by the year 2000. Closure of the Chernobyl units will exacerbate this problem. Natural gas is primarily used to meet energy demand during peak usage periods.

- If economic recovery takes place as planned, new capacity to replace Chernobyl will be needed. Many fossil fuel plants in Ukraine are at or near the end of their useful lives and will have to be replaced or repowered. DSM can help to defer these costs.

Although the market will ultimately judge the value of particular demand-side resources, the above points suggest that the electric DSM measures most appropriate for Ukraine are those which reduce energy consumption, primarily in the peak usage periods, and demand. The appropriate load shape objectives are strategic conservation, peak clipping, ans load shifting.

4.2 POTENTIAL DSM MEASURES

Measures to improve electric end-use efficiency and better manage peak load will vary with the sector and end use. The search for appropriate measures focused on the sectors and the key end uses discussed in Chapter 3:

- Residential: Lighting and refrigeration. These end uses account for approximately 54 percent of residential consumption, and about 9 percent of total net, national consumption.

- Commercial/institutional: District heating and water heating pumping, street lighting, and interior lighting. Usage by these end uses accounts for almost 97 percent of commercial/institutional consumption, or 11 percent of total net, national consumption.

- Industrial: Lighting and motors, although some measures will address overall industrial use. Lighting and motors alone account for about 95 percent of industrial demand, or 51 percent of total net, national consumption.

Altogether, this assessment considers measures that target end uses accounting for about 71 percent of total domestic consumption. The omitted end uses either offer limited technical opportunities for DSM, or are relatively heterogeneous and hence beyond the scope of the basic data acquisition activities undertaken to support this assessment.[1] To the extent that the omitted sectors and end uses are not included in the analysis, this assessment understates total DSM potential in Ukraine. On the other hand, the assessment does consider a broad cross section of sectors and end uses that represent the bulk of electricity consumption in Ukraine. Since these end uses are relatively homogeneous compared to those which have been omitted, measures can be replicated and disseminated far more easily. These measures most likely represent a larger portion of total achievable DSM potential than their corresponding share of total consumption suggests. These measures therefore represent the majority of potentially feasible DSM measures in Ukraine.

The following sections describe potential DSM measures for each sector and end use, which, if shown to be economically justified, could form the basis for a DSM program. Several factors affect economic attractiveness. One is whether the technical intervention such as the installation of a higher efficiency end-use device is made when the existing conventional equipment is due to be replaced. If so, it is termed a "replacement." If not, i.e., if the technical intervention is made regardless of the condition or remaining life of the existing equipment, it is referred to as a "retrofit." One economic benefit of a replacement that does not accrue to a retrofit is the savings which result from not having to purchase a new piece of standard equipment to replace the end-use device, since it is already being replaced with the improved equipment.

Another important factor is the amount of time that the end use is in operation. Most measures are designed to improve the efficiency of the end use and thereby reduce system

[1] The agriculture sector is more heterogeneous than in the United States because many non-agricultural end uses are included in electricity use by collective farms.

load. The more hours per year that an end use operates, the greater the energy savings from a measure that improves efficiency, and the greater the economic benefits.

Similarly, more powerful end uses consume more energy than smaller end uses for a given period of operation. Examples of "larger" end uses include motors with greater horsepower ratings, or lamps with higher wattage. Although the electricity savings that can be achieved through efficiency improvements increase with the size of an end use, the cost of the improvement is typically greater. These additional costs and benefits must be traded off to determine whether economic feasibility increases with the size of the end use.

These three factors, replacement versus retrofit, annual hours of use, and size are used to disaggregate the measures associated with each end use into classes of varying economic attractiveness. This disaggregation provides a more accurate estimate of the total economic potential for DSM in Ukraine, as well as a more effective screen for determining which measures are good candidates for further program design and assessment.

Appendix B lists the potential DSM measures considered for Ukraine, along with their economic and technical characteristics. These characteristics are based on a variety of sources from both Eastern Europe and the United States, which are also documented in Appendix B. Hours of operation, existing nameplate connected load, and numbers of units were derived from the market research study described in Chapter 3. Only measures that provide the same quality of service as the standard equipment are considered. Costs are reported in economic terms, i.e., in border price equivalents and not financial terms.

The information in Appendix B was used to calculate the cost of saved energy (CSE, the levelized incremental cost of the measure per kilowatt-hour of conserved energy) and the cost of saved capacity (CSC, the levelized incremental cost of the measure per kilowatt of saved generation, transmission, and distribution capacity). Additional details on the candidate measures are given below.

4.2.1 Industrial Measures

Industrial Motors

Given the widespread use of motors in Ukraine industry, motor measures can provide substantial energy savings. There are three principal ways in which motor performance can be improved:

- *Efficiency improvements.* Motors can be manufactured with improved cooling fan designs to reduce windage losses, larger cross sections, thinner laminates, special steel alloys for stators and rotors to reduce magnetic losses, better ball bearings to reduce friction losses, and larger gauge conductors to reduce resistive losses.

- *Improved control.* Standard alternating current motors operate at fixed speeds, even though loads vary in many motor applications. A variety of technologies can be used to better match motor speed with load. Electronic adjustable speed drives (ASDs) have emerged as one of the most flexible technologies for motor control. ASDs typically use invertors to vary the motor voltage or current and thereby vary motor speed.

- *Motor downsizing.* Many motors are installed with capacities far in excess of that required by the load. Underloaded motors generally operate at lower efficiencies. Oversizing of motors is common in Eastern Europe.

- *High-efficiency drive applications.* By improving the efficiency of such drive rotating equipment as pumps and compressors, overall drive system energy consumption can be reduced. Better controls, seals, bearings, and belt and lubrications systems can contribute to high applications efficiency. In addition, there is often room for selecting better pump and compressor technologies to match user needs.

A total of 25 motor measures were identified, including 16 for efficiency improvements, 8 for improved control (primarily ASDs) and high efficiency drive applications, and 1 for motor downsizing. Motor efficiency and ASD measures were defined for both high and low use motors in each of four size classes. Drive measures were considered on a retrofit basis only, whereas efficiency measures were defined for both replacement and replace upon rewind (in lieu of retrofitting).

Hours of operation were derived from the industrial customer survey. Standard efficiency levels were based on experience in the United States with motors of similar sizes; these levels may not be much less in Ukraine. This is because over the years, U.S. motors became less efficient because of lower electricity costs and competitive market forces to reduce first costs. In centrally-planned economics, these market forces did not exist and motors retained efficiency (e.g., through the use of larger diameter conductors and magnets). Counteracting this effect is the prevalence of rewinding motors in Eastern Europe.[2] The process of rewinding motors tends to reduce their efficiency over time, particularly if ovens without adequate temperature controls are used to soften the windings.

The motor downsizing program assumes that existing motors are switched among enterprises, or within individual enterprises, to yield better utilization of total motor capacity and to avoid additional expenditures on the purchase of new motors.

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2 According to FEWE in Poland, a technical organization that conducted market research for USAID motors are typically rewound about five times before they are replaced.

Industrial Lighting

The industrial sector uses the widest range of lighting technologies including incandescent, fluorescent, and mercury vapor. Other lighting types are found in the sector, but are not considered as candidates for DSM measures because they are already sufficiently efficient or there are limited opportunities for exchanging them.

Eight fluorescent lighting measures are proposed, and these are virtually identical to those put forward for the commercial sector. Measures are also proposed to retrofit mercury vapor lights with high pressure sodium, and to retrofit high wattage incandescents with metal halide lamps. Mercury vapor lights are typically used for lighting large exterior areas such as service yards, but may be used for large interior applications such as warehouses where color rendering may not be important. They generally offer the lowest efficacy ratio of luminous output to power input of all high intensity discharge lamps, and emit a bluish light with poor color rendering properties. High pressure sodium lights have been developed for similar applications, but typically offer far higher efficacy.

Incandescent lamps are available in sizes up to 1,000 W. Some of these lamps may be used in large-area lighting applications where color rendering is more important. Metal halide lamps can approach the color rendering of incandescent lamps, and do so with much higher efficacy. Compact fluorescent lamps can replace incandescents in the lower wattage.

Process Optimization and Facilities Maintenance Measures

As part of USAID's Emergency Energy Program for Eastern and Central Europe, 27 energy audits were conducted of industrial facilities in eight countries, including Ukraine. The audited firms represented a comprehensive cross section of industries and covered all forms of energy forms, including electricity.

These audits identified two principal electricity saving measures. First, most industrial facilities in Eastern Europe lack even rudimentary instrumentation and monitoring equipment, not to mention automated control systems. Many processes are operated solely on the basis of operator experience and without the benefit of real-time information on process status or operating parameters. This is understandable, since the previous economic system valued gross production rather than economic efficiency and optimization; instrumentation that could help optimize processes was an unnecessary expense. Therefore, the first measure involves the installation of instrumentation, monitoring, and low-cost control systems that can be used to optimize production processes using economic criteria. The audits estimated that simply providing operators with such information and capability would typically save 2 to 3 percent of total plant electricity consumption. Costs estimates for systems proposed for the audited plants ranged from US$4,500 to US$37,000 per plant. Here it has been assumed that 3 percent energy savings are achieved with an investment of US$5,000. The investment cost has been taken at the lower end of the range of costs noted in the audit reports since the audits focused on large industrial consumers. In this assessment, we consider all industrial consumers. The application of this measure has not been limited to the largest consumers to provide the access for all consumers, large and small.

Similarly, incentives were also previously insufficient to encourage a level of maintenance justified under current economic conditions. The audits revealed that simple maintenance such as the proper lubrication of motors and machinery, repair of compressor leaks, frequent cleaning of filters and screens, and replacement of door gaskets and curtains could reduce electricity consumption by 5 percent on average. The audits estimated that improved maintenance measures for the large plants that were evaluated would include initial costs of $5,000 to $9,000 and up to US$50,000 per year thereafter. As with the process optimization measure, costs have been taken at the lower end of this range to reflect the large number of smaller companies that would be included in the program to implement these measures.

Load Management Options

Load management options are those that cause usage to be shifted from or reduced during peak periods. In the industrial sector, these options generally involve rate designs or incentives for customers to modify their energy usage, sometimes in conjunction with existing equipment.

Rate measures are generally effective for peak clipping and load shifting. Time of use (TOU) tariffs in which consumers pay different electricity rates depending on the time of day or season will be standard for industrial customers under the new power sector structure. Interruptible or curtailable rates (I/C) are an option for Ukraine that could be implemented as a resource that is bid to the pool. Curtailable rates provide a rate reduction or an incentive payment in exchange for the utility calling up the consumer on short notice and requesting a reduction in demand of a predetermined amount for a specified period. Interruptible rates involve automatic cutoff of customers' power supply with no notice. The total amount of interruption or curtailment per year, season, or day can be capped by mutual agreement between the consumer and the utility; failure by the consumer to provide the agreed demand reductions will usually result in financial penalties. Both TOU and interruptible rates require the installation of a meter that for the TOU rates can tally consumption during different rate periods, and for the I/C rates can verify consumer compliance with the interruption call. Since TOU rates will be required for industrial customers, there will be no incremental hardware cost associated with I/C rates.

One variation of I/C rates that is being used in the United States is group load curtailment. By bidding a certain load reduction as a group, the group can obtain better rates and conditions than individual bids, and not necessarily curtail as great a portion of their load. Local group curtailment programs have been proposed by PG&E to deal with distribution constraints.[3] Typical reductions seen are approximately 10 to 20 percent, and curtailment periods range from four to six hours, up to 20 times per year. Such programs generally require that automatic control systems already be in place and that they can be preprogrammed to shut down certain processes. Verification is done through time-of-use meters and econometric techniques. Because of the lack of modern control systems in Ukraine, this option is likely to be limited in the near future.

Real-time pricing is another alternative that is seeing increasing use in the United States. This involves notifying customers what the next day (or sooner) hourly prices will be. Notification techniques include faxes and modems. Customers can then make decisions about what levels of production they want to have. Because of the state of the telecommunications system in Ukraine, this is not a feasible option at this time.

Standby capacity networks were considered for screening. This type of program involves customers allowing the utility to take control of on-site generators that have been installed as emergency backup. This gives the utility additional capacity. As discussed in Chapter 3, there were few customers who reported available standby generation, so this measure was not screened.

4.2.2 Residential Measures

Residential Lighting

The residential survey data showed that the only significant residential lighting source is incandescent lamps. As in the commercial sector, CFLs represent an efficient alternative. A total of four residential lighting measures are considered for Ukraine representing the use of CFLs in place of both high use (1,700 hours per year of operation) and low use (270 hours per year of operation) incandescent lamps on both a retrofit and a replacement basis. Because of the high cost differential between CFLs and incandescent bulbs, the economic attractiveness would be expected to be quite sensitive to the annual hours of operation.

Residential Refrigeration

There are approximately 91 refrigerators per 100 households in Ukraine. Refrigerator electricity consumption (and hence savings potential) varies with the volume of the unit. This assessment splits the refrigerator stock into two classes representing those smaller and larger than 0.17 cubic meters.

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[3] "Evaluation of Pacific Gas & Electric Company's Pilot Interruptible Bidding Program," The Tellus Institute, Boston, MA. October 1994.

Per unit of volume, East European refrigerators are about half as efficient as refrigerators currently sold in the United States. Refrigerator efficiency can be improved through several changes in refrigerator design and manufacture. According to a report from Lawrence Berkeley Laboratory,[4] the principal methods for increasing refrigerator efficiency are to use polyurethane foam instead of fiberglass insulation, increase the thickness of the insulation, use a more efficient compressor, reduce defroster energy use, and improve door gaskets. Analysis in the United States of options for improving refrigerator efficiency indicates that electricity use can be reduced 30-40 percent with a 15-20 percent increase in manufacturing costs.

Four residential refrigeration measures are put forward here, corresponding to two levels of efficiency improvement for each of the two size categories. The first level of efficiency improvement represents efficiency comparable to the 1990 U.S. refrigerator average at a 20 percent increase in cost. The second level corresponds the 1993 U.S. standard for new refrigerators at a 40 percent increase in cost. All of these measures would replace existing refrigerators.

Other Residential End Uses

Electric space heating, water heating, and air conditioning represent insignificant portions of electricity consumption in Ukraine because of the low saturation rates of these appliances. Televisions and washing machines contribute significant shares of residential consumption; however, there is little potential for application of DSM to these end uses.

Load Management Options

Direct load control of water heaters and air conditioners is a common residential load management option in the United States. Thermal heat storage using ceramics is also common. The low saturations rates of these electric end uses prevent these measures from having significant potential.

4.2.3 Commercial/Institutional Measures

Communal Services Pumping

As mentioned in Chapter 3, this sector's usage is dominated by pumping for the water, sewage, district heating, and water heating distribution systems. This type of motor usage is similar to industrial motor usage. The same types of measures were assumed to apply to this

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[4] Meyers, S., et al., *Energy Efficiency and Household Electric Appliances in Developing and Newly Industrialized Countries*, LBL-29678, Lawrence Berkeley Laboratory, 1990.

end use. Hours of operation are likely to be somewhat longer for this category of use, since the district heating motors operate almost continuously in the heating season.

Commercial/Institutional Lighting

Both incandescent and fluorescent lighting is found in the commercial/institutional sector. Four incandescent lighting measures are considered corresponding to replacement and retrofit of both high use and low use bulbs.

Compact fluorescent lamps (CFLs) have been developed as high efficiency alternatives to conventional incandescent lighting. Advantages of CFLs include a lifetime about 10 times greater and energy consumption about 70 percent less than incandescent bulbs providing the same amount of light. Disadvantages include the following: CFLs cannot be dimmed; they may introduce harmonics and may have a relatively low power factor; they may not fit in all fixtures that previously used incandescent bulbs; some CFLs do not operate properly at low temperatures; some individuals do not like the light quality; some units with lower frequency ballasts hum; and, most important, they cost about 15 times more than incandescent bulbs.

There are several possible measures to improve the efficiency of fluorescent lighting. In the United States, delamping or replacement of tubes with high efficiency fluorescent lamps that slightly reduce lighting levels are common measures. However, these measures are appropriate only where areas are overlit. Ukraine commercial/institutional space is typically underlit by U.S. standards. These measures were therefore not considered as part of this assessment.

The use of higher efficiency ballasts is the primary fluorescent lighting measure proposed for Ukraine. The standard magnetic, or core-coil, ballasts currently used in Ukraine can be replaced with either high efficiency core-coil ballasts or with solid state electronic ballasts. Standard core-coil ballasts often use aluminum wiring, whereas high efficiency versions use copper wiring and better ferromagnetic materials that produce about a 10 percent improvement in efficiency.[5] Electronic ballasts, on the other hand, consume power at 50 Hz, but operate the lamps at 20 to 30 kHz. These ballasts generally reduce flicker and improve lamp/ballast system efficacy (lumens/watt of power) by 20 to 25 percent.

These fluorescent lighting measures entail the exchange of ballasts, which provides an opportunity to upgrade to more efficient lamps requiring specially adapted fixtures. A common high efficiency fluorescent tube light that does not result in lower illumination levels is the T-8. These lamps are designed to be used as part of a dedicated electronic ballast system. T-8s are characterized by a smaller diameter, which allows the lamp plasma to be

[5] Lawrence Berkeley Laboratory, *Technology Assessment: Energy Efficient Commercial Lighting*, LBL-27032, Berkeley, California, 1989.

irradiated with lower losses, as well as more efficient phosphor coatings. An electronic ballast for standard fluorescent tubes can be expected to cost about US$15 more than an standard core-coil ballast and yield 20 to 25 percent greater efficacy. For an additional US$20 over the cost of the standard electronic ballast, one can purchase a T-8 system which would boost efficacy by another 20 percent or so.

Eight fluorescent lighting measures are put forward, representing both retrofit and replacement options for high use and low use lamps. One set of these options involves the exchange of high efficiency core-coil ballasts for standard ballasts, while the other exchanges standard fluorescent fixtures with T-8 systems.

Besides measures for lighting efficiency improvements, two measures have also been included for daylighting controls. Occupancy sensors can turn lights on and off using sonic, motion, or heat sensors to detect whether a room is occupied. Daylighting controls regulate illumination levels so that artificial lighting is used only to augment natural lighting to maintain desired illumination levels within the building.

Street Lighting

Mercury vapor lamps are common in Ukraine. In Eastern Europe, typically about half of all streetlights still use mercury vapor lamps. Mercury vapor lighting was discussed in the section on industrial lighting. The same measure described for the industrial sector, retrofitting mercury vapor lights with high pressure sodium, is also proposed here for street lighting.

Load Management Options

Thermal cool storage is a common commercial/industrial load management option in the United States. The lack of air conditioning in Ukraine prevents this measure from being feasible. Standby capacity networks, as mentioned in the section on industrial measures, have been implemented in other countries as a commercial/institutional sector option, but the low levels of standby generation prevent this measure from having a significant potential impact.

4.3 SCREENING DSM MEASURES

All of the above measures are technically feasible, though not necessarily economically justified. By screening these measures in terms of whether they can save electricity for less than the cost of generating and distributing it, the most promising measures can be selected as a basis for subsequent program design and a more detailed assessment of DSM potential in Ukraine. Economically justified measures are a necessary condition for feasible programs. The results of this economic screening analysis provide little indication of whether these measures would be of interest to the utilities or consumers. Economic feasibility suggests only that it is *possible* to design incentives that are financially attractive without compromising the principal objective of least-cost planning. Financial feasibility, in the sense of cost-effectiveness from the participant and LEC perspective, is addressed in Chapter 5.

4.3.1 The Screening Methodology

Measures are screened by comparing the measure's cost of saved energy (CSE) with long-run marginal energy costs. The CSE is defined as the annualized incremental cost of the measure relative to the cost of standard equipment, divided by the annual kilowatt-hour savings. Because of the surplus of capacity in Ukraine, measures were not screened based on the cost of saved capacity. These values have been calculated using the technical and economic characteristics of the measures and standard equipment presented in Exhibit 4-1.

Exhibit 4-1
Avoided Energy and Capacity Costs[1]

Season	Period	High Voltage	Low Voltage
Winter Energy	On-Peak[2]	$0.073/kWh	$0.123/kWh
	Off-Peak	$0.018/kWh	$0.021/kWh
	Weighted average	$0.044/kWh	$0.068/kWh
Summer Energy	On-Peak	$0.026/kWh	$0.027/kWh
	Off-Peak	$0.014/kWh	$0.014/kWh
Capacity[2]		$72.40/(kW*yr)	$112.78/(kW*yr)

1 Costs are at the meter, i.e., line losses are included.
2 Winter on-peak energy costs includes allocation of capacity costs.
3 Costs include transmission avoided costs for high voltage and distribution and transmission costs for low voltage.

Source: National Dispatch Center.

Because of the need for detailed data on lost production costs and hourly marginal energy costs, economic screening of industrial load management measures is not feasible using the available information. A financial screening of these types of measures is presented in Chapter 5.

This screening analysis does not aim to capture all costs and benefits of each measure. Costs for example, do not include the administrative expenses that would be incurred in building and marketing DSM programs based on these measures. Capacity- and energy-saving benefits are assessed separately. Measures pass the screening only if they pass on the basis of at least one of these tests. Measures that marginally fail both criteria separately could conceivably pass if capacity and energy benefits were considered simultaneously. This screening analysis aims only to narrow the list of possible measures to the most promising ones, and not to identify a final list of programs.

As mentioned in Chapter 1, in the restructured power sector, environmental emissions will be controlled by law, not utility regulation. Consequently, environmental externalities were not considered in this screening.

Average avoided energy and capacity costs are taken from the long-run marginal cost analysis presented in the tariff study. The avoided energy cost used as the cutoff value for the energy supply curve was US$0.068/kWh. This represents the average winter peak energy cost at the low voltage level, plus the avoided capacity cost allocated to the on-peak hours. This value is intentionally higher than the annual average avoided energy cost for all customers to avoid screening any measure out of the analysis prematurely. Similarly, the cutoff value used for the capacity supply curve was US$113/kW/year, the low voltage avoided capacity cost. The average avoided cost for all sectors is lower because distribution avoided costs are not included for high-voltage customers. Avoided costs are summarized in Exhibit 4-1 by customer class.

This screening is essentially a simplified TRC test (TRC test was defined in Chapter 1). Avoided energy and capacity costs are compared with equipment costs. A complete TRC test would include consideration of program administrative costs. This screening is therefore slightly less restrictive than a complete TRC test.

4.3.2 Screening Results

The CSE and CSC for each measure are shown in Appendix C along with the physical energy and capacity savings that would be expected if each measure applied to every eligible end-use device currently in use. Interruptible rate programs were not included because they are not amenable to this type of analysis. Unlike energy-efficiency measures, there are typically minimal hardware costs associated with these types of programs — the costs are primarily transfer payments to customers, which are typically not included in supply curves.

Measures with a CSE below the avoided energy cost were listed along with their total potential savings in ascending cost order to yield an energy conservation supply curve. Since there were no measures that passed on a CSC basis but did not pass on a CSE basis, only the energy conservation supply curve is presented.

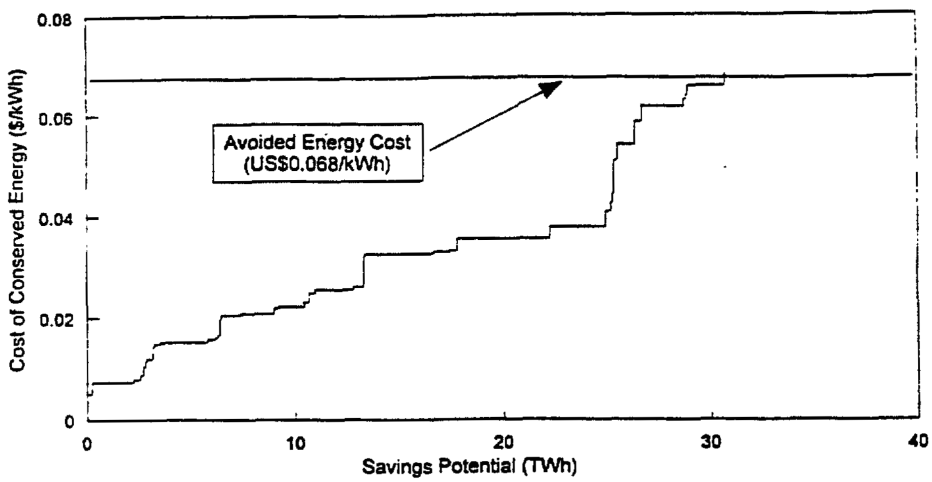
Many measures with CSEs below the avoided energy cost are mutually exclusive. For example, measures to improve refrigerator efficiency to the average 1990 U.S. level and to improve it to 1993 U.S. standards cannot be implemented simultaneously; the latter would supersede the former. Similarly, if both retrofit and replacement versions of a particular measure passed, replacements would be a subset of the retrofits. To avoid double counting of energy savings, the following rule was adopted to determine which measure would be listed: If two mutually exclusive measures have a CSE below the avoided energy cost, the one that offers quicker implementation would be selected. For example, retrofit measures would be selected over replacement measures since retrofit measures would not have to wait for standard equipment retirement. If both measures could be implemented with the same speed, the one with the lower CSE is selected. For example, in the refrigerator case, the measure corresponding to 1990 U.S. average performance is cheaper and thus is selected over the 1993 U.S. standards.

Exhibit 4-2 depicts the energy conservation supply curve derived from this analysis. Out of 85 measures initially identified, 45 measures pass the screening test (plus the load management measures that were not considered in the screening analysis). If all of these measures were implemented for all eligible customers or end-use devices, the energy savings would total 30.5 TWh, or 19 percent of total 1994 total domestic electricity sales. This is referred to as the economic DSM potential, as opposed to the achievable potential, which takes into account market penetration rates of the measures. Achievable potential is assessed in Chapter 5.

Screening analyses carried out on a regional basis elsewhere have suggested economic potentials of about 25 percent to 40 percent of total consumption. For example, an assessment of economic potential carried out for the State of New York concluded that there was an economic savings potential of 38 percent of annual consumption.[6] Given the skewed price signals that have existed for a long time in Ukraine, and the fact that energy efficiency programs have not yet been implemented there, one might expect the potential savings in Ukraine to be greater than in New York, at least in percentage terms. Although the approach used in Ukraine has been deliberately conservative, the discrepancy is to a large extent due to differences in the range and types of end uses considered in each case. Whereas the measures considered for New York were directed at end uses constituting over 87 percent of total consumption, the measures in Ukraine target only 71 percent of total consumption because, as mentioned previously, several end uses offer limited technical opportunities or are relatively heterogeneous. Moreover, the largest single sector in terms of savings in New York was the commercial sector, followed by the residential sector. A large portion of these savings were

[6] New York State Energy Research and Development Authority, *The Potential for Electricity Conservation in New York State*, Report No. 89-12, Albany, NY, 1989.

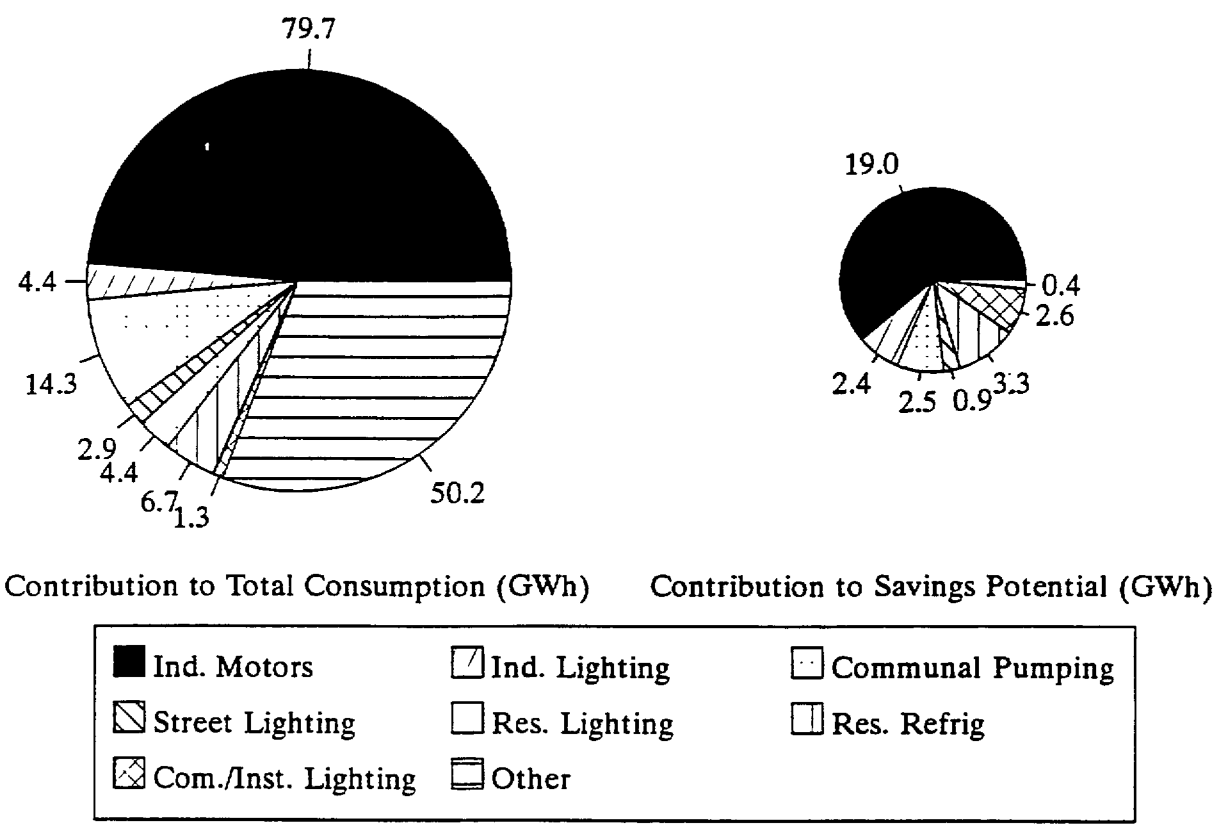
Exhibit 4-2
Energy Conservation Supply Curve



attributable to heating, ventilating, water heating, and air conditioning measures, which are not relevant to Ukraine. Commercial lighting was a major component of the potential savings in the New York study, but a small one in Ukraine because commercial lighting is a much smaller share of usage. Much of residential lighting has low usage rates, and CFLs are not cost-effective at those rates.

Exhibit 4-3 summarizes the contribution of measures in each of these sectors and end uses to total savings potential. The industrial sector offers the greatest potential savings.

Exhibit 4-3
Sectoral and End Use Composition of Savings Potential



Source: Hagler Bailly

CHAPTER 5
THE BENEFITS AND COSTS OF SELECTED DSM PROGRAMS

The preceding chapter identified economically justified DSM measures that could be used to meet Ukraine's load shape objectives. The potential savings resulting from these measures were also estimated. However, measures cannot install themselves at the customer's premise; economic potential remains just potential unless steps are taken to market and implement measures. This chapter identifies DSM programs that would result from packaging the measures with marketing and delivery mechanisms. The analysis of energy efficiency measures relies on a sophisticated demand-side planning tool, DSManager, to evaluate the cost-effectiveness of these potential DSM programs, taking into account the impediments to full adoption of these measures and also the overhead costs associated with program implementation. Because of the sensitivity of load management program to hourly pool prices, which, at the time of this report, are unknown, industrial load management measures were analyzed using a simplified dispatch model to simulate pool prices and identify the financial feasibility.

5.1 THE ASSESSMENT METHODOLOGY

5.1.1 Analysis of Energy-Efficiency Programs

The DSManager Approach

DSM programs change the way customers use energy. DSManager traces these changes through the energy system to determine, for example, how the amount of electricity generation changes over time in response to changes in consumption patterns. Using input values that describe how these changes affect costs, DSManager translates these physical measures into monetary measures, and ultimately into costs and benefits.

DSManager represents changes in consumer demand patterns by comparing the end-use load shape of an average target customer before enrollment in a DSM program with the customer's load shape after the DSM measure is in place. A load management program may shift a customer's total consumption away from system peak periods; though the customer's load shape would change, total energy consumption may remain unchanged. More efficient lighting, on the other hand, may leave the shape of the customer's end-use load curve for lighting unchanged, but reduce the customer's total lighting energy consumption, so that the intact load shape shifts downward.

Ukrainian "before" end-use load shapes were shown in Chapter 3. The "after" load shapes for all efficiency programs except industrial motor drives entail only a change in energy consumption and not the load shapes; therefore, "after" load shapes in these cases are simply scaled down from the "before" shape to reflect the higher efficiency of the end-use technology adopted under the program. The energy and capacity savings resulting from these efficiency improvements are noted in Exhibit 4-1. "After" load shapes for the drive programs involve changes in the shape of the "before" load curve; these are discussed later in this chapter.

Changes in customer load shapes are aggregated by summing over all participants to determine the hourly changes in utility system load shape. Changes in system load shapes are in turn used to calculate the hour-by-hour production cost savings and the coincident demand reductions and avoided capacity savings. System load data were taken from 1994 hourly system data provided by the Ministry of Energy. The avoided costs used were presented in Chapter 3.

Program costs are similarly tracked and aggregated. Costs include the direct cost of the technology and its installation, and also overhead costs related to program management, design, marketing, and evaluation. Evaluation is necessary to determine the size and reliability of the demand-side resource for future system planning and for issuance of performance payments or other impact-based incentives.

Because a measure is shown to be less costly economically than the system avoided cost does not guarantee that the program based on that measure will similarly find economic justification. For example, high fixed administrative costs spread over only a few participants could cause the program to be rejected despite the economic soundness of the measure upon which the program is based. DSManager therefore calculates benefit-cost ratios for each program to determine its cost-effectiveness. These ratios are the present value of program benefits to the present value of program costs.[1] The estimates of benefits and costs for a program are different depending on which of the five tests discussed in Section 1.4 is evaluated.

Developing Program Concepts

Identifying cost-effective measures does not ensure they will be adopted. Experience in many countries, whether advanced, formerly socialist, or developing, shows the difficulty in persuading customers to make energy-related technology decisions based on life-cycle operating costs. Sometimes this may be attributed to market distortions, the most important of which may be simply a lack of information. Alternatively, prices may not reflect true economic

[1] Present values are calculated using a 12 percent real discount rate, reflecting the high opportunity costs of capital in a rapidly evolving economy such as Ukraine. This value is typically used by multilateral development bank's when conducting an economic assessment of projects in Ukraine.

costs or benefits of different investment options. Lack of financing may also be an important obstacle.

Programs combine measures with marketing, delivery, and evaluation. Marketing and delivery are particularly important to overcome the obstacles noted above and ensure that demand-side resources are effectively exploited. Program design and marketing, if performed properly, will ensure an effective mix of education, market-based incentives, and applicability of a measure to a customer segment. Delivery or implementation may involve a promotional campaign and/or actual installation of a measure on behalf of a customer. This can be particularly suitable for relatively new technologies such as ASDs with which the customer may not be familiar. Programs must be also evaluated to provide the utility with essential information on the impact on demand that DSM programs are having, to account for these impacts in future least-cost plans.

Several DSM measures may be aggregated and delivered within a single program directed toward a particular market segment. Offering customers multiple measures can help meet site-specific applications, reduce program overheads by spreading fixed administrative costs over several measures, maximize market penetration, and reduce the impact on the customer's residential routine, commercial business activities, or industrial production by implementing several measures at once. In some cases, sector-specific DSM measures targeting multiple end uses have been aggregated for delivery to a specific customer class. By combining measures in this way, marketing and delivery overheads can be further reduced. For example, motors, variable drives, and motor downsizing measures can be delivered as part of a single program to maximize the opportunity to achieve savings when visiting a customer site. However, for the purposes of this benefit/cost assessment, which does not attempt to undertake a detailed program design, measures were aggregated by customer class and end use only. This reflects a conservative assumption that each end use will incur its own administrative costs.

Administrative costs are included at three levels. Within any program, each technology will incur an administrative cost that can be calculated on a per-measure or per-customer basis. The variable costs at the measure level vary widely, depending on the technology, type of program, and mix of resources devoted to program design, implementation, and evaluation. In this study, these variable administrative costs were estimated for Ukraine based on the type of program being evaluated and local labor costs. The specific figures used are discussed below.

Administrative costs are also accrued at the program level. These costs are required to design, market, manage, implement, track, and evaluate each program. These costs are often fixed overheads incurred whether the program has 10 or 10,000 participants. As with variable costs, we estimated a fixed program overhead based on Ukrainian labor rates and the size and duration of each program. The specific figures used are also discussed below.

Finally, to capture the administrative costs incurred in undertaking DSM on a national scale, the assessment also accounts for fixed administrative overhead pertaining to the cost of establishing a DSM group within each of Ukraine's LECs. Each LEC will require these resources to plan strategically and coordinate DSM programs throughout all sectors within each service territory. These overheads would accrue whether the LECs actually deliver the programs or not, and despite the number or size of programs they administer. Specific estimates are discussed below.

Estimating Fixed Administrative Overheads

Accounting for fixed administrative costs at both the program and national level required a "bottom-up" methodology using Ukrainian labor rates. The national overheads could not be allocated to specific programs without adopting a complex set of largely unsubstantiated assumptions; therefore, these costs were factored into the overall, nationwide, aggregated benefit/cost analyses performed as a last step in this analysis. National overhead costs would cover the staff costs of a small DSM group within each utility responsible for DSM planning and program supervision. These costs are shown in Exhibit 5-1.

Exhibit 5-1
Estimated National DSM Program Overhead Costs

Resources	Number	Rate (US$)	Cost (US$/yr)
Professional Staff	4	5,000	20,000
Administrative Staff	2	2,500	5,000
Office Equipment		35,000/5 years	7,000
Miscellaneous		5,000	5,000
Subtotal (per energo)			37,000
Total for Ukraine (all energos)			**296,000**

Source: Hagler Bailly Consulting, Inc.

In addition to these "national" overheads, each program also includes a set of fixed overheads to cover program design, marketing and evaluation. The figures used for each program are shown in Exhibit 5-2. These figures are also based on Ukrainian labor rates.

Exhibit 5-2
Fixed Administrative Costs for Each Program

Program	Design Costs (1st year only)	Marketing Costs	Evaluation Costs
Industrial Motors	$250,000	$150,000	$100,000
Industrial Drives	$250,000	$150,000	$100,000
Industrial Motors Downsizing	$200,000	$75,000	$75,000
Industrial Facilities Maintenance	$250,000	$150,000	$100,000
Industrial Lighting	$200,000	$75,000	$75,000
Commercial/Instit. Motors	$250,000	$150,000	$100,000
Commercial/Instit. Drives	$250,000	$150,000	$100,000
Commercial/Instit. Motor Downsizing	$200,000	$75,000	$75,000
Commercial/Instit. Lighting	$200,000	$75,000	$75,000
Street Lighting	$200,000	$75,000	$75,000
Residential Lighting	$200,000	$75,000	$75,000

Source: Hagler Bailly Consulting, Inc.

Design costs include the identification of target consumers and the formulation of detailed marketing, implementation, monitoring, and evaluation plans. Marketing costs cover the expense of actually reaching the target consumers. Evaluation costs include the cost of data acquisition and analysis needed to carry out both process and impact evaluations. Although evaluation costs are expressed annually, this value takes into account that evaluations may be conducted every two or three years depending on the program. The industrial programs identified as high-cost programs require more extensive customer contact and assistance, and also provisions to better tailor the measures to individual customer needs.

Separate variable costs are also associated with marketing and evaluation; these variable costs are described under each program. The distinction between fixed and variable costs for marketing and evaluation overheads helps to better estimate overall administrative costs. For example, fixed costs for these activities could be attributed to the personnel needed to carry them out. Variable costs, on the other hand, would be associated with the data collection or site visits necessary to carry out the activity.

The Screening Methodology

In a competitive environment, LECs and IESs will only pursue DSM programs that offer some type of financial benefit. As discussed in Chapter 2, these benefits may be either lower rates or increased or maintained market share. Programs that have avoided energy costs greater than the resulting revenue losses and the program costs will tend to reduce rates. The RIM test, discussed in Section 1.4, identifies whether this is the case. To increase or maintain market share, LECs and IESs are likely to offer DSM as a customer service to those customers who are likely to be pursued by competing suppliers. These customers are generally high voltage, industrial, or commercial/institutional customers that have high load factors.

To prevent cross subsidies, payment for any such programs that do not pass the RIM test would have to come from shareholder profits or from an unregulated subsidiary. In either case, the funding organization would attempt to recover costs, and profits, from the participating customer. A typical financing approach is shared savings, where costs for equipment and technical expertise are paid for through utility bills from the savings realized by the installed measures. Payments are designed so that total bills are less than before implementation — no customer out-of-pocket costs are required.

The programs must also be financially attractive to customers. This implies that the programs must pass the participant test.

These market-based requirements imply that the financial criteria for programs must be as follows:

- Programs for low-voltage customers and low load factor, high-voltage customers must pass the RIM test and the participant test.
- Programs for high load factor, high-voltage customers (i.e., industrial customers and communal services pumping) must pass the participant test.

To determine the likelihood of success of the two types of residential programs (lighting and refrigeration) and the one type of low load factor commercial/institutional measure (commercial/institutional lighting) passing the economic screening, an "upper-bound" RIM test was conducted as an additional screen to eliminate program concepts that would clearly not be financially appealing to an LEC. The test was simplified by ignoring administrative costs and participant costs. If programs did not pass this relaxed test, they could not pass a more rigorous RIM test. As a result, the evaluation team dropped from consideration the residential refrigeration program that failed the "upper-bound" RIM test. All other programs were considered for in-depth evaluation as described in the following sections.

To design a program, one needs to group all the similar measures that passed the screening in Chapter 4. For example, in designing a motors program, all the motor measures that passed the initial screening should be considered together in a motor program. The program benefit/cost results reflect the participation assumptions made at the measure level, the administrative costs at both the measure and program level, and the load shape impacts of the program based on the magnitude of energy and demand savings for each measure.

5.1.2 Load Management Programs

Because of the sensitivity of load management program to hourly pool prices, which, at the time of this report, are unknown, industrial load management measures were analyzed using a simplified dispatch model to simulate pool prices. As was described in Chapter 2, the pool will accept bids for DSM up to the amount that increases rates. The amount of DSM bid and accepted is dependent on the cost and available capacity of competing supply-side resources, and the customers' lost production costs. To evaluate the potential for load management, a simplified pool model was developed. The model contains data on energy costs and available capacities of nuclear, hydro, coal, gas, and oil supply-side resources in Ukraine. Actual system demands for 1994 were used in the model. Six typical days were modeled — weekdays and weekends in winter (November through February), shoulder (March, April, September, and October), and summer (May through August). Two cases were run: with and without DSM. In the without DSM case, supply side resources are bid to the pool, in each hour of each typical day, in order of energy cost, until the demand is met. In the DSM case, load management priced at several levels is allowed to be bid to the pool, to the extent that rates charged to suppliers are not increased.

5.2 DSM PROGRAMS IN UKRAINE

5.2.1 Energy-Efficiency Programs

Residential Lighting

In the case of residential lighting, only one measure passed the initial screening: high-use compact fluorescent lamps. The high-use CFL program was assessed as a retrofit application. This is in part attributed to the nominal value lost in removing incandescent lamps prematurely, the advantage of enjoying CFL benefits immediately, and the low impact of installation on a customer's daily routine.

Participation. In this program, which begins in 1996 and ends in 2001, high-use compact fluorescents could attract 2 percent of the 1994 base population over the lifetime of the program. (This ratio is defined here as *cumulative final market penetration* in 2001.) This penetration is based on an estimate that only 20 percent of the total population of such lamps would even be suitable for compact fluorescents since some applications in Ukraine have low usage, and since CFLs will not fit all standard fixtures in Ukraine. While a figure higher than 20 percent could have been chosen in the modeling of this program, 20 percent has been selected as a conservative estimate of feasibility/applicability for this measure yielding a 20 percent *eligible* population. Of the potential 20 percent market, it was assumed that the program would attract 10 percent of the 1994 population of eligible participants. That is, 10 percent of the incandescent fixtures that could be replaced by CFLs would, in fact, be replaced over the six-year life of the program. Cumulative final market penetration is calculated as follows:

20 percent (feasibility/applicability) × 10 percent (market penetration of the 1991 eligible participants over the life of the program) = **2 percent** (cumulative final market penetration in 2001 expressed as a percentage of the 1991 base population)

This final market penetration figure requires two important caveats:

- All cumulative final market penetration estimates, including those that follow in this chapter, will actually be lower when expressed as a percentage of the year 2001 end-use population because of growth in the base population.

- In the case of measures with a lifetime shorter than that of the program, cumulative final market penetration will not correspond to the number of installations operating in the year 2001. For measures with a lifetime less than six years, equipment installed in the early years will have expired by 2001. Not all these expired units will be replaced with similar measures. Consequently, the number of installations operating in 2001 will be less, in these instances, than the cumulative participation over the life of the program.

  This is the case, for example, with high-use, residential CFLs. Although cumulative final penetration is calculated above as 2 percent, the number of units in service in 2001 would actually be less, resulting from subtracting fixtures installed in the first tenth of a year of the program since the lifetime of these high-use CFLs is only 5.9 years.

  This issue seems minor in this situation. It arises again however for high-use compact fluorescents in the commercial/institutional sector, which have a lifetime of only three years given that the hours of operations in that sector are higher. In that instance, if the final market penetration was 2 percent, the actual number of installed units would be 1.3 percent, resulting from subtracting the units that burnt out in the first three years. *As a general rule in this chapter, unless stated otherwise, cumulative final market penetration in 2001 is synonymous with the number of installed units in 2001.*

The cumulative final market penetration rates for CFLs are conservative. In the United States, residential lighting programs have achieved between 5 percent and 48 percent market penetration of the *eligible* population with programs of varying lifetimes.[2] One U.S. program achieved a 14 percent market penetration after five years, but this figure is based on the number of households participating, not on the number of *eligible* fixtures retrofitted (the approach used here). A program targeting low-income customers in southern California reached 48 percent of *eligible* customers after seven years compared with the 10 percent over six years assumed here.[3] This type of program, with its emphasis on job creation and helping consumers overcome high first costs of a measure, may be especially suitable for Ukraine. Final market penetration as defined above is not available for this California program, but final market penetration would be far less than 48 percent in this instance. Another U.S. program achieved 38 percent final market penetration at the end of three years, but that penetration was achieved using a leasing approach, which was not considered in this rudimentary program design.[4]

Market penetration is often "bell shaped," reaching its maximum midway toward the latter part of the program. The market penetration for the measures in this program were 5 percent in the first year, 10 percent in the second, 20 percent in the third, 25 percent in the fourth and fifth, and 15 percent in the last, the year 2001. This distribution is a derivative of the "S"-shaped market penetration curve used in modeling market penetration, in which adoption is slow initially, picks up speed at an increasing rate, reaches a maximum rate of adoption, and then slows because of market saturation. Exhibit 5-3 shows annually the total number of new participants in this program over its six-year duration.

Administrative Costs. In addition to fixed program administrative overheads included in all program assessments, a variable administrative cost specific to residential lighting programs was included. These costs were allocated on a per-fixture basis: $1.00 per fixture for marketing, nothing for implementation, and $2.00 for program evaluation for a total variable overhead cost of **$3.00/fixture**. Marketing costs were relatively low based on the assumption that this program would deliver these energy services rebates or door to door at Ukrainian labor rates. Implementation costs are nonexistent since customers would install their own lamps. Evaluation costs were higher than marketing costs because trained personnel would need to visit a sample of customer sites to spot check whether lamps have actually been installed. All these costs were based on Ukrainian labor rates and are shown in Exhibit 5-3 with the fixed program costs.

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2 *Electric Utility Conservation Programs: A Review of the Lessons Taught by a Decade of Program Experience*, ACEEE 1990 Summer Study on Energy Efficiency in Buildings (Proceedings), 1990, Vol. 8, pp. 179-205.

3 *Southern California Edison: Low Income Relamping, The Results Center*, IRT Environment, Inc., Vol. 2, 1992, p. 13.

4 *Burlington Electric Department: Smartlight, The Results Center*, IRT Environment, Inc., Vol. 3, 1992, p. 14.

Exhibit 5-3
Residential Lighting Program Summary

	1996	1997	1998	1999	2000	2001
Capital Costs ('000)*	565	1,130	2,259	2,824	2,824	1,695
Administrative Costs ('000)	462	374	598	710	710	486
New Participants ('000)**	37	75	149	187	187	112
Energy Savings (GWh)	4	11	26	44	63	74
Peak Demand Savings (MW)	2	5	11	19	28	32

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are variously defined as fixtures, units, or customers depending on the measure.

Screening Results. The residential lighting program, as a low voltage customer program, should be implemented only if it passes the RIM test. The residential lighting program passed the relaxed RIM test, as discussed above. However, the inclusion of administrative costs and other customer costs in a full-fledged screening analysis indicates that the residential lighting program fails the rigorous RIM test, with a benefit/cost ratio of only 0.81. This program should therefore not be considered for implementation in Ukraine.

Commercial/Institutional Lighting

In the United States, commercial/institutional lighting has offered many opportunities for cost-effective savings. Some same technologies used for residential end uses and screened in the previous chapter are applicable here, too, such as compact fluorescent lamps. Some more recently commercialized technologies such as occupancy sensors have now become cost-competitive for commercial/institutional applications and are playing an increasing role in commercial/institutional DSM resources.

The Commercial/Institutional Lighting Program combines a few select but very different technologies that are likely to be cost-effective in Ukraine. The following measures were included in this program:

- low-use compact fluorescent lamps
- high-use compact fluorescent lamps
- occupancy sensors
- high-use efficient core-coil ballasts.

The first three measures were designed as retrofit applications just as in the residential lighting program. As in that program, the value of waiting for lamps to burn out before replacing them — and giving up energy savings meanwhile — may not be economically justified as the screening analysis has shown. There are programmatic reasons for a retrofit design as well, such as the economic efficiency of performing installations all at once rather than piecemeal. This retrofit design is not as appropriate for core-coil ballasts, which require the retirement of standard ballasts, a relatively expensive component in relation to associated operational costs and the cost of fluorescent lamps. This measure is included in the program evaluation as a replacement measure, as in the screening exercise.

Participation. For commercial/institutional CFL programs in Ukraine, participation could occur at 20 percent of the eligible population over the life of the program and these participants would be distributed across the six-year program in a bell-shaped distribution: 5 percent entering during the first year, 10 percent in the second, 20 percent in the third, 25 percent in the fourth and fifth, and 15 percent in the sixth. For the core-coil ballasts replacement measure, a technology lifetime of 15 years was assumed, translating into a turnover rate of 6.6 percent per year at an escalating rate: 5 percent in the first and second years, 10 percent in the fourth and fifth years, and 15 percent in the fifth and sixth years, resulting in an average market penetration of 10 percent per year. For occupancy sensors, it was estimated that 30 percent of lighting sites would participate in the program. The penetration pattern used was 5 percent in the first year, 10 percent in the second year, 20 percent in the third year, 25 percent in the fourth and fifth years, and 15 percent in the sixth year.

In each case, the penetration rates used in evaluating the Commercial/Institutional Lighting Program assumed that less than 100 percent of the entire population of fixtures would be suitable for the energy-efficiency applications evaluated here. For example, as in residential lighting, CFLs are sometimes not applicable if a lighting application requires very low use and sometimes the efficient bulbs simply do not fit the fixtures. It was estimated that only 40 percent of the low-use applications would be suitable for CFLs in Ukraine's commercial/institutional sector and 70 percent for high-use.

For core-coil ballasts, 60 percent of the base population was assumed to be eligible for replacements. For occupancy sensors, it was assumed that only 50 percent of the total population of applications would be suitable for occupancy sensors. Many commercial/institutional establishments, such as retail enterprises, must remain lit during business hours regardless of whether people are present. Other commercial/institutional lighting applications, such as conference rooms, may be used infrequently, and staff are conscientious about turning out the lights when the rooms are not in use.

Final market penetration rates in 2001 as a share of the 1994 base population were calculated as follows:

- *Low-Use Commercial/Institutional CFLs*: 40 percent (feasible/applicable) × 20 percent (participation rate) = **8 percent** (cumulative final market penetration).
- *High-Use Commercial/Institutional CFLs*: 70 percent (feasible/applicable) × 20 percent (participation) = **14 percent** (cumulative final market penetration).
- *Core-Coil Ballasts*: 6.7 percent (annual turnover rate of 1994 population) × 60 percent (feasible/applicable) × 60 percent (10 percent average annual market penetration × 6 years) = **2.4 percent** (cumulative final market penetration).
- *Occupancy Sensors*: 50 percent (feasible/applicable) × 30 percent (participation) = **15 percent** (cumulative final market penetration).

The annual participants in the Commercial/Institutional Lighting Program are shown in Exhibit 5-4.

Exhibit 5-4
Commercial/Institutional Lighting Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	578	1,131	2,262	2,814	2,840	1,735
Administrative Cost ('000)	510	448	747	886	906	629
New Participants ('000)**	79	153	307	381	386	238
Energy Savings (GWh)	6	19	45	76	104	115
Peak Demand Savings (MW)	1	3	7	12	16	18

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are variously defined as fixtures.

In the United States, commercial/institutional and industrial lighting programs have attracted participation across a wide range — 0.1 percent to 36.7 percent for programs reported — of the *eligible* participants.[5] A California utility even reported a 45 percent market penetration of the *eligible* population.[6] A midpoint value of 20 percent of the eligible population was used in this analysis.

Administrative Costs. Variable administrative costs for commercial/institutional lighting are similar to residential lighting except that marketing would be more expensive (US$2.00/fixture) because special attention would have to be paid to each customer site to execute an optimal relamping strategy. Implementation costs are already embedded into the cost of the technologies screened in the previous chapter. Evaluation costs would be the same as those for residential ($2.00/fixture), bringing the total for commercial/institutional lighting to **$4.00/fixture**. Because occupancy sensors have a very different cost structure from conventional commercial/institutional lighting technologies, their administrative costs were calculated on a per customer, not a per-fixture, basis. We estimated that these costs would be $10 each for marketing, implementation and evaluation for a total of $30/customer. It was then assumed that on average each customer had 25 fixtures, resulting in a cost of **$1.20/fixture**. Annual variable and fixed administrative costs for the program are shown in Exhibit 5-4.

Screening Results. Screening results show that the commercial/institutional lighting program passes the participant test with a benefit/cost ratio of 3.72.

Load Shape Impacts. The Commercial/institutional Lighting Program could save Ukraine 115,100 MWh in energy and 17.9 MW in demand in the year 2001. The impact on the system would primarily be to conserve energy because the system load profile would not change shape because of this program.

Commercial/Institutional Motors

The Commercial/Institutional Motors Program comprises all commercial/institutional high-efficiency motor measures. This program targets only replacement applications upon rewind. Replacement on rewind was evaluated based on the incremental costs and benefits of a new, high-efficiency motor over the benefits and costs of a single rewind.

This large program includes eight measures:

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[5] *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers*, New York State Energy Research and Development Authority, April 1990.

[6] *Sacramento Municipal Utility District: Commercial Lighting Installation Program*, The Results Center, IRT Environment, Inc., Vol. 13, 1992, p. 13.

- both low and high-use small high-efficiency motors
- both low and high-use medium high-efficiency motors
- both low and high-use large high-efficiency motors
- both low and high-use very large high-efficiency motors.

Participation. Assuming the average low-use motor is rewound every 5 years and the average high-use motor every three years, corresponding to 20 percent annual turnover on low-use motors and 33 percent on high-use motors. Of the eligible high-use motors, 5 percent are exchanged annually during the first two years of the program, and 10 percent annually for the remaining four years. Of the eligible low-use motors, 5 percent are exchanged annually during the first two years, 10 percent annually during the next two years, and 15 percent annually during the last two years. Total annual participation is shown in Exhibit 5-5. Cumulative final market penetration rates in 2001 as a percent of the 1994 base population was calculated as follows:

Exhibit 5-5
Commercial/Institutional Motor Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	350	350	701	701	794	794
Administrative Cost ('000)	533	283	316	316	323	323
New Participants**	2,049	2,049	4,097	4,097	4,574	4,574
Energy Savings (GWh)	7	14	27	41	56	72
Peak Demand Savings (MW)	1	2	3	5	7	9

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as units (motors).

- *Low-Use Small Motors*: 20 percent (annual turnover) × 90 percent (feasibility/applicability) × 10 percent (average annual penetration among eligible motors) × 6 years = **10.8 percent** (cumulative final market penetration).

- *Low-Use Medium, Large, and Very Large Motors*: 20 percent (annual turnover) × 70 percent (feasibility/applicability) × 10 percent (average annual penetration among eligible motors) × 6 years = **8.4 percent** (cumulative final market penetration).

- *High-Use Motors (all sizes)*: 33 percent (annual turnover) × 90 percent (feasibility/applicability) × 8.3 percent (average annual turnover) × 6 years = **14.8 percent** (cumulative final market penetration).

Penetration rates for motor programs implemented in the United States fall in a range from less than 1 percent all the way up to 33 percent, according to one study undertaken on the subject.[7] Low participation rates have sometimes been attributed in the United States to a number of factors including unfavorable early customer experiences with high-efficiency motors due to improper sizing and installation, unfamiliarity of customers and dealers with the substantial operating cost savings that efficient motors can provide, diffuse decision-making on motor purchases, predisposition to buying an identical model or rewinding an old one to avoid any possible delays in installation, or hesitation to shut down production lines to replace a motor. The program considered here avoids this last barrier because all measures were modeled as replacements. The pilot program described in the companion volume to this report addresses these issues to maximize penetration rates.

Administrative Costs. Variable administrative costs for marketing each motor measure to customers are considerably higher than for lighting applications (US$10.00/motor). Customer sites, while fewer in number than in the residential or commercial/institutional sectors, would require more one-on-one attention to ensure that the new motors were correctly sized to each specific process. In the case of British Columbia Hydro, a Canadian power company, the utility marketing staff contact large industrial customers routinely, and a specialist representing the motors program calls on all of the motor vendors and rewind shops regularly to ensure their familiarity with the operation and benefits of the program.[8] A Niagara Mohawk (New York utility) program also emphasized close customer relations in the large industrial segment.[9] Implementation costs have been included in the cost of the measure. Spot metering may be used for evaluation, which would boost the cost (US$6.00/motor) beyond the evaluation cost of other measures such as lighting. This brings the total variable administrative costs at **US$16.00/motor**. Total administrative costs, including fixed program costs, are shown in Exhibit 5-5 for each year of the program.

Screening Results. Screening results show that the commercial/institutional motors program passes the participant test with a benefit/cost ratio of 7.69.

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7 *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers*, New York State Energy Research and Development Authority (NYSERDA), April 1990, pp. S-6 to S-8.

8 *British Columbia Hydro: Power Smart High-Efficiency Motors*, The Results Center, Vol. 38, 1992, IRT Environment, Inc., p. 7.

9 *Lessons Learned*, op. cit., p. 82.

Load Shape Impacts. This program is expected to save 71,932 MWh and 9.28 MW in the year 2001. The energy savings of each motor type was provided in Exhibit 3-1. This program could have a significant impact on reducing peak demand in Ukraine; however, the program would not change the profile of the system hourly demand curve and instead simply reduce it. Savings are also shown in Exhibit 5-5.

Commercial/Institutional Drives

Adjustable speed drives are a relatively new technology to many utility customers even in the OECD countries. This places an added burden on adequate program marketing and implementation in Ukraine. The higher, related costs and limited participation are reflected here in the modeling of ASD applications in Ukraine.

The eight measures aggregated into a program were:

- drives for both low and high-use small motors
- drives for both low and high-use medium motors
- drives for both low and high-use large motors
- drives for both low and high-use very large motors.

Participation. Because ASDs complement rather than replace existing motor technology, all measures in this program were modeled as retrofit applications. As such, participation was not tied to turnover in the motor population. Analysis conducted in the United States suggests that between 20 percent to 40 percent of all commercial/institutional motors are suitable for ASD installation.[10] In this analysis it was assumed that ASD applications would be feasible for 30 percent of Ukrainian motors, and that of these, one in six would actually receive an ASD during the program. Cumulative final penetration in 2001, expressed as a percentage of the 1994 population, is derived as follows:

30 percent (feasible/applicable) × 17 percent (cumulative penetration) = **5 percent** (final market penetration).

There is little documentation on the U.S. experience in ASD program market penetration with which to easily compare our figure, this value is fairly conservative given the attractive payback of these technologies and some of their load shifting characteristics. As in other measures discussed above, participants were distributed across time using a "bell-shaped market penetration curve: 5 percent in the first year, 10 percent in the second, 20 percent in the third, 25 percent in the fourth and fifth, and 15 percent in the last. The total number of participating motors is shown by year in Exhibit 5-6.

10 Nadel, S. et al., *Energy Efficient Motor Systems*, ACEEE, 1992.

Exhibit 5-6
Commercial/Institutional Drives Program Summary

	1996	1997	1999	1999	2000	2001
Capital Cost ('000)*	2,178	4,339	6,513	8,699	10,895	10,895
Administrative Cost ('000)	586	422	508	595	681	681
New Participants**	431	862	1,293	1,724	2,155	2,155
Energy Savings (GWh)	15	45	89	149	224	300
Peak Demand Savings (MW)	2	6	13	22	32	43

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are variously defined as units (motors).

Administrative Costs. Marketing ASDs in Ukraine would be a relatively expensive effort on a per-unit basis (US$150/unit), though marketing costs as a percentage of the technology capital cost is low. Because ASDs are a relatively complex technology, technical expertise is required to effectively promote these measures effectively, and this promotion must be done at the customer site. These factors escalate the cost of marketing this program.

Because of the complexity of the technology, additional administrative costs of US$40/unit would be associated with implementation, in addition to the actual installation costs included as part of the capital cost of the measure. Evaluation costs would be comparable to the efficient motors program (US$10/unit). This brings the total costs for the drives to **US$200/drive**. Variable plus fixed costs for the entire program by year are available in Exhibit 5-6.

Screening Results. Screening results show that the commercial/institutional drives program passes the participant test with a benefit/cost ratio of 2.22.

Load Shape Impacts. A commercial/institutional ASD program could save Ukraine 299,700 MWh and 43.31 MW in demand in the year 2001. The load reduction resulting from the use of ASDs decreases as motor load increases since the primary purpose of an ASD is to reduce power demand as motor load falls. This analysis assumes that ASDs would yield a 10 percent reduction in motor peak demand but would reduce total annual energy consumption by 35 percent. Annual savings are summarized in Exhibit 5-6.

Commercial/Institutional Motor Downsizing

Motor downsizing is a separate program of its own because of the unique cost and programmatic features of a motor-swap program, the type of program modeled here. Because this program entails swapping of existing motors, there are no capital costs associated with the program other than average data collection and installation costs of US$300/motor. While programs like this have not been tried in the United States, the Sao Paulo (Brazil) municipal utility, Companhia Energetica de Sao Paulo, has implemented this type of program which they call the "Fleximotor" program.

Participation. It is assumed that out of the total commercial/institutional motor stock of 172,368 in 1994, 50 percent of the motors would be ineligible because either their motors were already properly sized or were too small to be downsized. It is also assumed that 5 percent of the eligible population would, in fact, participate over six years ending in 2001. This low figure reflects the potential difficulty with implementing this innovative program.

Cumulative final market penetration in 2001 as a percentage of the 1994 population was calculated as:

50 percent (feasible/applicable) × 5 percent (participation rate) = **2.5 percent** (cumulative final market penetration)

Participation over time has been modeled as 5 percent in the first year, 10 percent in the second year, 15 percent in the third year, 20 percent in the fourth year, and 25 percent in the fifth and sixth year. Annual participation is shown in Exhibit 5-7.

Exhibit 5-7
Commercial/Institutional Motor Downsizing Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	64	129	194	259	323	323
Administrative Cost ('000)	393	236	279	322	365	365
New Participants**	215	431	646	862	1,077	1,077
Energy Savings (GWh)	1	4	8	14	20	27
Peak Demand Savings (MW)	0.3	1	2	3	5	6

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as customers.

Administrative Costs. Marketing, implementation, and evaluation overheads are estimated to cost US$50.00, $100.00, and $50.00 respectively, for a total of **$200/motor**. The variable plus fixed costs per year for this program are shown in Exhibit 5-7.

Screening Results. Screening results show that the commercial/institutional motor downsizing program passes the participant test with a benefit/cost ratio of 10.51.

Load Shape Impacts. This program would achieve 27,345 MWh in energy and 6 MW in demand savings in the year 2001. This program would primarily be an energy conservation program. Annual savings are also summarized in Exhibit 5-7.

Industrial Lighting

The Industrial Lighting Program was modeled primarily as a retrofit program using technologies that were not applied in the residential or commercial/institutional programs. The exception is core-coil ballasts which were modeled as replacement measures for the same reasons used in designing the commercial/institutional lighting program above. Four measures were included in this program:

- high-pressure sodium retrofits
- metal halide retrofits
- low-use core-coil ballasts replacements
- high-use core-coil ballasts replacements.

Participation. Different penetration rates were assumed for each measures. Mercury vapor lamps require a ballast and are typically used for high use applications in which color rendering is not important. Since high pressure sodium lamps offer similar characteristics, the feasibility of replacing mercury vapor lamps with high pressure sodium was estimated to be 90 percent. (A small allowance of 10 percent was made to account for mercury vapor lamps that may be seldom used.) Metal halide lamps are not nearly as applicable when used to replace incandescent lamps because they may not fit or the existing incandescent lamps may be seldom used; therefore, a much lower feasibility of 40 percent is assumed for this measure. For core-coil ballasts, it was estimated that replacement was feasible for 60 percent of the cases.

In the retrofit measures (metal halide lamps and high-pressure sodium lamps), participation is expected to reach 25 percent of eligible customers over the life of the program. The participation was modeled in an escalating distribution: 5 percent in the first year; 15 percent in the second year; and 20 percent in the third, fourth, fifth and sixth years.

For the replacement measures (the core-coil ballasts, both low-use and high-use) the lifetime of the technology is used to determine the annual turnover rate. For the high-use core-coil ballasts replacement measure, a technology lifetime of 13.5 years was assumed, resulting in a turnover rate of 7.4 percent. For the low-use core-coil ballasts, the lifetime was assumed to be 26 years, giving an annual turnover rate of 3.8 percent. For both measures, the participation schedule used was 5 percent in the first and second years, 10 percent in the third and fourth years, and 15 percent in the fifth and sixth years, resulting in an average market penetration of 10 percent per year. Cumulative final market penetration for these measures in the year 2001 (as a percent of the 1991 base population) is:

- *High Pressure Sodium*: 90 percent (feasible/applicable) × 25 percent (participation rate) = **22.4 percent** (final market penetration).

- *Metal Halide*: 40 percent (feasible/applicable) × 25 percent (participation rate) = **10 percent** (final market penetration).

- *Low-Use Core Coil Ballasts*: 3.8 percent (annual turnover rate) × 60 percent (feasible/applicable) × 60 percent (10 percent average annual participation × 6 years) = **1.4 percent** (final market penetration).

- *High-Use Core Coil Ballasts*: 7.4 percent (annual turnover rate) × 60 percent (feasible/applicable) × 60 percent (10 percent average annual participation × 6 years) = **2.7 percent** (final market penetration).

As mentioned in the commercial/institutional lighting section, utilities in the United States have achieved anywhere from 0.5 percent to 45 percent participation of the *eligible* population across multiple measures within any single program. Program lifetimes have also varied greatly. The estimates used here are towards the lower end of the range. Annual participation in this program is shown in Exhibit 5-8.

Administration. Industrial lighting variable administrative costs were estimated exactly as those used in the commercial/institutional lighting program, for a total of US$4.00/fixture (US$2.00/fixture for marketing; US$0.00 for implementation; and US$2.00 for evaluation). Total annual variable plus fixed costs are shown in Exhibit 5-8.

Screening Results. Screening results show that the industrial lighting program passes the participant test with a benefit/cost ratio of 2.57.

Load Impacts. An industrial lighting program could achieve 193,500 MWh in energy and 33.72 MW in demand savings in the year 2001. The program would serve primarily to meet utility energy conservation load shape objectives. Exhibit 5-8 also shows the annual savings for both energy and demand.

Exhibit 5-8
Industrial Lighting Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	1,000	2,910	3,911	3,911	3,956	3,956
Administrative Cost ('000)	486	491	630	630	666	666
New Participants ('000)**	34	85	120	120	129	129
Energy Savings (GWh)	13	53	107	151	177	193
Peak Demand Savings (MW)	2	9	19	26	31	34

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.

** Participants are defined as fixtures.

Industrial Motors

The industrial motors, drives and motor downsizing programs are similar to their commercial/institutional counterparts. The Industrial Motors Program comprises all industrial high-efficiency motor measures. This program targets only replacement applications upon rewind. Replacement on rewind was evaluated based on the incremental costs and benefits of a new, high-efficiency motor over the benefits and costs of a single rewind. This program includes eight measures:

- both low and high-use small high-efficiency motors
- both low and high-use medium high-efficiency motors
- both low and high-use large high-efficiency motors
- both low and high-use very large high-efficiency motors.

Participation. The participation figures are the same as those used in the commercial/institutional motors program. Cumulative final market penetration rates in 2001 as a percent of the 1994 base population were calculated as follows:

- *Low-Use Small Motors*: 20 percent (annual turnover) × 90 percent (feasibility/applicability) × 10 percent (average annual penetration among eligible motors) × 6 years = **10.8 percent** (cumulative final market penetration).

- *Low-Use Medium, Large, and Very Large Motors:* 20 percent (annual turnover) × 70 percent (feasibility/applicability) × 10 percent (average annual penetration among eligible motors) × 6 years = **8.4 percent** (cumulative final market penetration).

- *High-Use Motors (all sizes)*: 33 percent (annual turnover) × 90 percent (feasibility/applicability) × 8.3 percent (average annual turnover) × 6 years = **14.8 percent** (cumulative final market penetration).

Administrative Costs. The total variable administrative costs for industrial motors is **US$16.00/motor**, based on the same cost structure used for the commercial/institutional motors program. Total administrative costs, including fixed program costs, are shown in Exhibit 5-9 for each year of the program.

Exhibit 5-9
Industrial Motor Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	3,663	3,663	7,331	7,331	8,295	8,295
Administrative Cost ('000)	842	592	934	934	1,013	1,013
New Participants ('000)**	21	21	43	43	48	48
Energy Savings (GWh)	34	68	136	205	278	352
Peak Demand Savings (MW)	4	9	18	26	36	45

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as units (motors).

Screening Results. Screening results show that the industrial motors program passes the participant test with a benefit/cost ratio of 3.62.

Load Shape Impacts. This program is expected to save 352,300 MWh and 45.40 MW in the year 2001. The energy savings of each motor type was provided in Exhibit 3-1. This program could have a significant impact on reducing peak demand in Ukraine; however, the program would not change the profile of the system hourly demand curve and instead simply reduce it. Savings are also shown in Exhibit 5-9.

Industrial Adjustable Speed Drives

Again, this program is modeled in the same fashion as the commercial/institutional motors program. In this case, however, only 5 measures passed the initial screening described in Chapter 4:

- drives for high-use medium motors
- drives for both low and high-use large motors
- drives for both low and high-use very large motors.

Participation. Because ASDs complement rather than replace existing motor technology, all measures in this program were modeled as retrofit applications. As such, participation was not tied to turnover in the motor population. The participation figures used here are identical to those in the commercial/institutional program, and result in the following final market penetrations, based on the 1994 population:

30 percent (feasible/applicable) × 17 percent (cumulative penetration) = **5 percent** (final market penetration).

As in other measures discussed above, participants were distributed across time using a "bell-shaped market penetration curve: 5 percent in the first year, 10 percent in the second, 20 percent in the third, 25 percent in the fourth and fifth, and 15 percent in the last. The total number of participating motors is shown by year in Exhibit 5-10.

Exhibit 5-10
Industrial Drives Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	12,207	24,460	36,662	48,944	61,151	61,151
Administrative Cost ('000)	887	1,024	1,411	1,799	2,186	2,186
New Participants**	1,935	3,879	5,806	7,744	9,679	9,679
Energy Savings (GWh)	58	174	348	581	871	1,161
Peak Demand Savings (MW)	8	23	47	78	117	156

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as units (motors).

Administrative Costs. Again, administrative costs used for this program are identical to those used in the commercial/institutional motors program, or **US$200/drive**. Variable plus fixed costs for the entire program by year are available in Exhibit 5-10.

Screening Results. Screening results show that the industrial drives program passes the participant test with a benefit/cost ratio of 1.50.

Load Shape Impacts. An industrial ASD program could save Ukraine 1,161,500 MWh and 155.7 MW in demand in the year 2001. The load reduction resulting from the use of ASDs decreases as motor load increases since the primary purpose of an ASD is to reduce power demand as motor load falls. Annual savings are summarized in Exhibit 5-10.

Industrial Motor Downsizing

Motor downsizing for the industrial sector was modeled in a similar fashion to the commercial/institutional motor downsizing program. Because this program entails swapping of existing motors, there are no capital costs associated with the program other than average data collection and installation costs of US$300/motor.

Participation. It is assumed that out of the total industrial motor stock of 1,797,633 in 1994, 50 percent of the motors would be ineligible because either their motors were already properly sized or were too small to be downsized. It is also assumed that 5 percent of the eligible population would, in fact, participate over six years ending in 2001. This low figure reflects the potential difficulty with implementing this innovative program.

Cumulative final market penetration in 2001 as a percentage of the 1994 population was calculated as:

50 percent (feasible/applicable) × 5 percent (participation rate) = **2.5 percent** (cumulative final market penetration).

Participation over time has been modeled as 5 percent in the first year, 10 percent in the second year, 15 percent in the third year, 20 percent in the fourth year, and 25 percent in the fifth and sixth year. Annual participation is shown in Exhibit 5-11.

Administrative Costs. Marketing, implementation, and evaluation overheads are estimated to cost US$50.00, $100.00, and $50.00 respectively, for a total of **$200/motor**. The variable plus fixed costs per year for this program are shown in Exhibit 5-11.

Screening Results. Screening results show that the industrial motor downsizing program passes the participant test with a benefit/cost ratio of 3.36.

Load Shape Impacts. This program would achieve 115 MWh in energy and 15 MW in demand savings in the year 2001. Annual savings are also summarized in Exhibit 5-11.

Exhibit 5-11
Industrial Motor Downsizing Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	674	1,348	2,022	2,696	3,370	3,370
Administrative Cost ('000)	799	1,049	1,498	1,948	2,397	2,397
New Participants**	2,247	4,494	6,741	8,988	11,235	11,235
Energy Savings (GWh)	6	17	34	57	86	115
Peak Demand Savings (MW)	1	2	4	7	11	15

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as customers.

Optimization of Industrial Operations

Improved instrumentation and monitoring to optimize operations, and better maintenance practices can add up to substantial savings at low cost. This program entails two measures designed to address both monitoring and maintenance as discussed in the previous chapter. This type of program, though offering attractive savings often at low cost, requires special attention for evaluating the savings actually achieved.

Participation. In the case of both measures, 20 percent of the existing industrial population might already be operating at high levels of energy efficiency or might otherwise be unsuitable for this type of program. Of the remaining population, the analysis assumes that 5 percent of all facilities would participate with respect to each measure. Cumulative final market penetration in the year 2001 as a percentage of the 1994 population of industries would be, therefore (for both measures):

80 percent (feasible/applicable) × (5 percent + 5 percent) (participation rate for each measure) = **8 percent** (final penetration).

Five percent of the total cumulative participation would occur in the first years of the program, 10 percent in the next year, 20 percent in the third year, 25 percent in the fourth and fifth years, and 15 percent in the final year, consistent with the bell shaped participation distribution associated with other programs.

While the market penetration of specific measures such as these have not necessarily been evaluated in the United States, data does exist on the penetration of some broader programs that include measures such as energy management systems and low-cost measures. One such program achieved 8.3 percent participation of eligible large customers and a final market penetration of 2.75 percent after three years.[11] This figure may not be appropriate for Ukraine, however, since this particular program required extensive intrusion on the customer site for the purposes of detailed data collection, and customers were required to submit formal proposals to the utility.

Annual participation in this program is shown in Exhibit 5-12.

Exhibit 5-12
Industrial Operations Optimization Program

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	2,270	4,540	9,080	11,350	11,350	6,810
Administrative Cost ('000)	1,408	2,066	3,882	4,790	4,790	2,974
New Participants**	454	908	1,816	2,270	2,270	1,362
Energy Savings (GWh)	15	44	103	176	249	293
Peak Demand Savings (MW)	2	7	17	29	41	48

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as customers.

Administrative Costs. The marketing of this program could be relatively inexpensive employing low-cost techniques such as advertisements in industry trade journals. Although implementation would be entirely the responsibility of the customer entailing no variable administrative costs, there would be the cost of an audit to identify the appropriate measures for a particular customer. Evaluation would be relatively expensive to carefully check whether recommended improvements have been implemented by participants, the amount of energy actually saved, and whether or not improved maintenance practices persist. This would require metering with site visits by trained personnel. Considering these considerations, the total variable administrative costs are estimated to be **US$2000/participant**. Total variable plus fixed administrative costs for this program are shown in Exhibit 5-12.

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[11] *Bonneville Power Administration: Energy Savings Plan*, The Results Center, IRT Environment, Inc., Vol. 18, 1992, p. 6 and 13.

Screening Results. Screening results show that the industrial operations optimization program passes the participant test with a benefit/cost ratio of 1.47.

Load Shape Impacts. This program could save Ukraine 292,800 MWh in energy and 48.3 MW in demand savings in the year 2001. Overall, this program would represent an energy conservation program in Ukraine. Energy and demand savings estimates are also included in Exhibit 5-12.

Street Lighting

Retrofitting mercury vapor with high pressure sodium lamps was the only measure included in the Street Lighting Program. This measure is likely a top candidate in targeting this public lighting market segment in Ukraine.

Participation. As a retrofit program unconstrained by the turnover rate in the existing stock of technologies in a market segment under government control, this program should achieve high rates of participation. It is assumed that 100 percent of the street lights in Ukraine could be retrofitted with high-pressure sodium lamps and that 50 percent of the lamps would be retrofitted over the six-year lifetime of the program in a bell-shaped distribution: 5 percent in the first year; 10 percent in the second; 20 percent in the third; 25 percent in the third and fourth; and 15 percent in the last. Cumulative final market penetration in 2001 as a percentage of the 1991 population was calculated as follows:

100 percent (feasible/applicable) × 50 percent (participation rate) = **50 percent** (final market penetration).

Administration. Variable costs were assumed to be US$1.00 per fixture for marketing because only the government and municipalities would need to be targeted. There would be no administrative cost associated with implementation since each jurisdiction would itself install the measures. (The capital costs reported in Exhibit 3-1 include a component for installation). Finally, US$1.00 per fixture was assumed for evaluation which should require a fairly straightforward check of local government records and some spot checking in the field. The total variable expenditure is **US$2.00/fixture**. Annual administrative costs are also shown in Exhibit 5-13.

Screening Results. Screening results show that the street lighting program passes the participant test with a benefit/cost ratio of 7.20.

Load Impacts. This program could save Ukraine 132,224 MWh in energy and 33 MW in demand in the year 2001. This program would primarily be an energy conservation program. The annual savings are also shown in Exhibit 5-13.

Exhibit 5-13
Street Lighting Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	143	287	574	717	717	430
Administrative Cost ('000)	379	207	265	293	293	176
New Participants ('000)**	14	29	57	72	72	43
Energy Savings (GWh)	7	21	49	83	118	132
Peak Demand Savings (MW)	2	5	12	20	29	33

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.
** Participants are defined as fixtures.

5.2.2 Load Management Bidding

The analysis of load management bidding potential identified the times of day and seasons in which load management was most likely to be cost effective and provide dimensions to the potential size of the load management impacts. More detailed estimates of load management impacts will be possible after the preliminary pilot programs are completed.

The analysis initially assumed that load management would be available at $0.03, $0.04, $0.06 and $0.08 per kWh in 1 GW blocks. During the recent energy crisis, in December 1994, approximately 2 GW of mandatory curtailment was realized. Up to 4 GW seems possible given pool payments that are attractive enough. Utility costs for load management per kWh have been higher — for interruptible/curtailable programs in the United States, costs per kWh are commonly $0.50 or more, but the state of the Ukraine economy and the lower value of service make significantly lower payment levels plausible. Customers are likely to have to install some type of control equipment. The typical cost for this equipment is approximately $10,000.

Using the initial assumptions about load management costs and availability, a maximum of 1 GW was purchased by the pool in the simulation. Additional load management resources were not purchased because of the availability of additional supply-side resources for less than $0.04 per kWh. Additional load management would be purchased, because rates charged to suppliers would be less than if no load management were bid, if it were available for $0.03 per kWh — up to 3.5 GW, or 12 percent of the average winter weekday system peak demand of 28.6 GW. If this much resource were available at that cost, a total of 3,813 GWh could be realized annually, or about 1.5 percent of 1994 annual electricity production. Total annual resource payments for thermal and DSM options in this scenario would be $3.079 billion, 6 percent less than what the payments would be without load management bidding

Most (86 percent) of the load management would occur on winter weekdays, because these are the days with the highest demand and the greatest need for additional, higher priced resources. Exhibits 5-14 and 5-15 present the types of resource options selected by the pool on a typical winter weekday in these two simulated cases. Detailed data used in the modeling are presented in Appendix D.

Participation. Load management will be feasible only for those customers that are able to shift or curtail loads. It is assumed that about one-third of industrial customers (37,800) will be able to and choose to participate in this program. Average savings per customer, assuming the total of 3,813 GWh discussed above, would be 101 MWh, or about 13 percent of average industrial customer consumption. Because of the potential reluctance of firms to enroll in such a program, it has been assumed that 5 percent of participating firms enroll in the first year, 10 percent in the second, 15 percent in the third, 20 percent in the fourth, and 25 percent in the fifth and sixth years.

Administration. The fixed administrative costs of this program are estimated to be US$250,000 in the first year and US $125,000 in following years. In addition, a variable administrative cost of US $500 per participant has been included to cover the cost of helping customers develop strategies to maximize their benefits under the program.

Screening Results. Because the load management program will essentially change the marginal energy costs used in the standard benefit-cost tests, these standard tests are not applicable. The program is designed to fulfill the objective function of the pool, i.e., to minimize pool rates.

Load Impacts. This program could save Ukraine 3.5 GW in demand and 3,813 GWh in energy in the year 2001. The annual savings are also shown in Exhibit 5-16.

5.3 SUMMARY OF RESULTS

Exhibit 5-17 aggregates the costs, participation, and savings associated with all of the programs, excluding the residential lighting program which failed to pass the RIM test.

Using DSManager, Total Resource Cost (TRC), Ratepayer Impact Measure (RIM); and Participant Tests were conducted for each individual measure, each program, and all programs together, excluding load management bidding. The assessment of individual measures did not include any fixed administrative overheads. The assessment of the each aggregated program

Exhibit 5-14
Case #1: No DSM

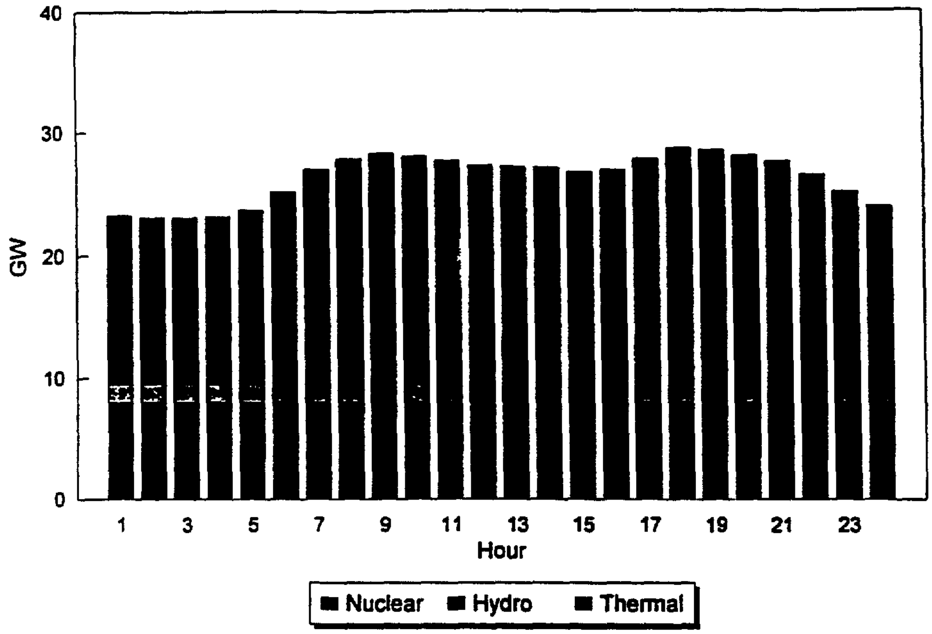


Exhibit 5-15
Case #2: DSM Bidding

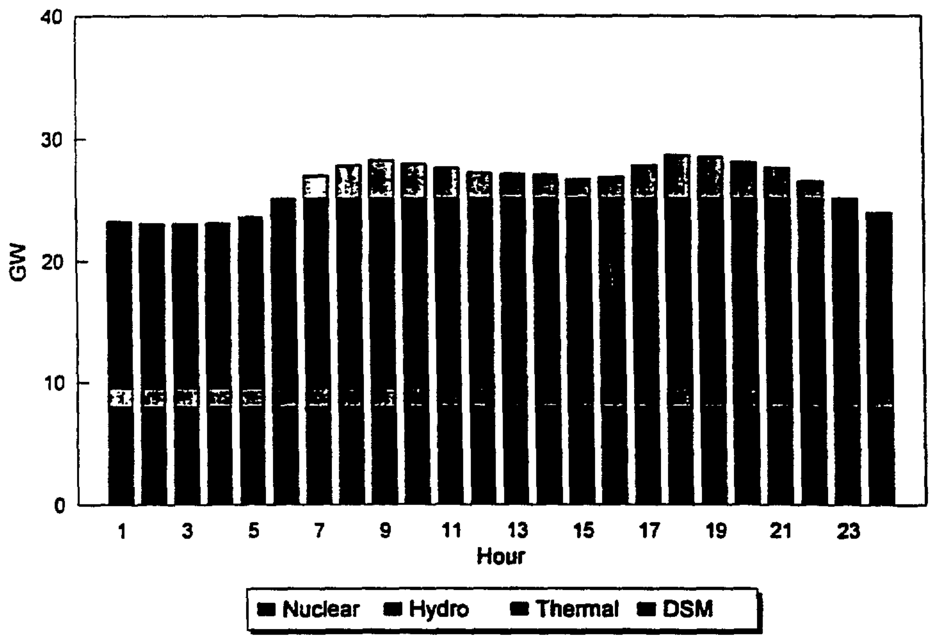


Exhibit 5-16
Load Management Bidding Program Summary

	1996	1997	1998	1999	2000	2001
Capital Cost ('000)*	18,900	37,800	56,700	75,600	94,500	94,500
Administrative Cost ('000)	1,195	2,015	2,960	3,905	4,850	4,850
New Participants**	1,890	3,780	5,670	7,560	9,450	9,450
Energy Savings (GWh)	191	572	1,143	1,906	2,860	3,813
Peak Demand Savings (MW)	175	525	1,050	1,750	2,625	3,500

* Assuming an average of $10,000 per facility for a load management control system. Complete consideration of capital costs from a participant perspective requires information on lost production costs which cannot be quantified at this time.

** Participants are defined as customers.

includes not only the direct costs of the individual programs, but the fixed administrative costs which accrue to the aggregated program. The assessment of all programs took into account direct program costs, fixed overheads for each program, and the national program overheads that pertain to all programs. The assessment was built up in this way because there was no clear way to allocate fixed overheads to individual programs.

Exhibit 5-18 summarizes the benefit/cost results for each energy efficiency program outlined in this chapter (including the national DSM aggregate), for the TRC, RIM and Participant tests. It also shows the net energy and demand savings attributable to each program.

Results show that all programs pass the participant test, with ratios ranging from 1.47 for the industrial facilities maintenance program to 10.51 for the commercial/institutional motor downsizing program. Most programs also pass the TRC test, except for the facilities management program with a TRC B/C ratio of 0.85.

No programs pass the RIM test. The highest B/C ratio, 0.73, is achieved by both the industrial and commercial/institutional motor drives programs, and the lowest, 0.55, by the industrial motor downsizing program.

The benefit/cost ratio of set of energy efficiency programs is 1.31 for the TRC test, 0.68 for the RIM test and 2.06 for the participant test. These results are based on streams of benefits and costs that often go beyond the lifetime of the program since measures installed during the program yield savings during their entire lifetime, which is usually longer than the program.

Exhibit 5-17
National DSM Program Summary

	1996	1997	1998	1999	2000	2001
Energy Efficiency Programs						
Capital Cost ('000)*	23,130	43,159	69,251	87,423	103,692	97,760
Administrative Cost ('000)	7,121	7,115	10,765	12,807	13,917	11,767
Energy Savings (GWh)	162	460	947	1,533	2,185	2,768
Peak Demand Savings (MW)	24	68	141	229	325	405
Load Management Bidding						
Capital Cost ('000)*	18,900	57,200	56,700	75,600	94,500	94,500
Administrative Cost ('000)	1,195	2,015	2,960	3,905	4,850	4,850
Energy Savings (GWh)	191	572	1,143	1,906	2,860	3,813
Peak Demand Savings (MW)	175	525	1,050	1,750	2,625	3,500
Total						
Capital Cost ('000)*	42,030	100,359	125,951	163,023	198,192	192,260
Administrative Cost ('000)	8,316	9,130	13,725	16,712	18,767	16,617
Energy Savings (GWh)	353	1,032	2,090	3,439	5,045	6,581
Peak Demand Savings (MW)	199	593	1,191	1,979	2,950	3,905

* Capital costs incurred by current and O&M costs incurred by current or previous year participants.

Exhibit 5-18
Summary of Assessment Results

Program	TRC Test B/C Ratio	RIM Test B/C Ratio	Participant Test B/C Ratio	Net Energy Savings for 2001 (GWh)	Net Demand Savings for 2001 (MW)
Commercial Lighting	2.06	0.68	3.72	115	15
Commercial/Institutional Motors	3.23	0.63	7.69	71	9
Commercial/Instit. Motor Drives	1.56	0.73	2.22	300	43
Commercial/Instit. Motor Downsizing	2.65	0.58	10.51	27	6
Industrial Lighting	1.72	0.71	2.57	194	34
Industrial Motors	2.15	0.65	3.62	352	45
Industrial Motor Drives	1.08	0.73	1.50	1,162	156
Industrial Motor Downsizing	1.30	0.55	3.36	115	15
Industrial Facilities Maintenance	0.85	0.63	1.47	293	48
Street Lighting	3.12	0.65	7.20	139	34
Total Energy-Efficiency Programs	**1.31**	**0.68**	**2.06**	**2,768**	**405**

APPENDIX A
ANALYSIS OF POWER FLOWS, COSTS, AND PAYMENTS RELATED TO DSM

APPENDIX A
ANALYSIS OF POWER FLOWS, COSTS, AND PAYMENTS RELATED TO DSM

DSM may be procured by the power sector at two levels: at the pool level and at the supplier level. At both levels, DSM must be economic. But, the objective functions of the entities at these two levels are different, and therefore the screening considerations are also different.

To define the responsibilities for payments and the appropriate criteria to use in selecting DSM options, it is necessary to consider carefully the financial flows that will occur in a pool with DSM. This appendix presents an analysis illustrating the financial flows in a pool with DSM. Although the analysis herein applies conceptually to both load management and energy efficiency, the pool will purchase only load management given the current policy being developed for the Ukrainian pool. The suppliers will the entities responsible for purchasing energy efficiency.

The analysis provides insight on the following questions:

- What criteria should be used in procuring DSM? Are any of the cost-effectiveness tests used in the U.S. appropriate — such as the total resource cost test or the rate-impact measure test?
- How should the costs of DSM be recovered from the customers or suppliers?
- What is the financial impact of DSM on the various players in the power market?

A.1 DSM AT THE POOL LEVEL

This examination of DSM at the pool level considers two cases:

- Case 1 examines DSM in a pool in which the cost of the DSM *is not* recovered in the pool uplift charge.
- Case 2 examines DSM in a pool in which the cost of DSM *is* recovered in the uplift charge.

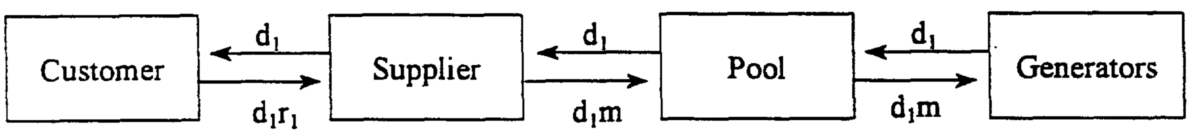
The uplift charge is the fee that the pool adds to the hourly energy price that it charges the wholesale customer to cover the costs of the services provided by the pool.

A.1.1 Case 1 — DSM in a Pool without Uplift Charge

Case 1 is the simplest case to analyze and provides a good illustration of the analytical methodology. However, this case has some flaws, as are evident below. Therefore, we are not recommending the structure presented in Case 1.

Exhibit A-1 illustrates the flows of energy and payments for a specific hour. A specific customer demands d_1 kWh and pays rate r_1 to the supplier,[1] for a total payment of d_1 r_1 in that hour. The supplier pays m cents per kWh to the pool, which in turn pays the same amount to the generators. A portion of the total demand is produced by incremental generation, which determines the pool price m, and the remainder is produced by other generation.

Exhibit A-1
Power Flows and Payment in a Pool

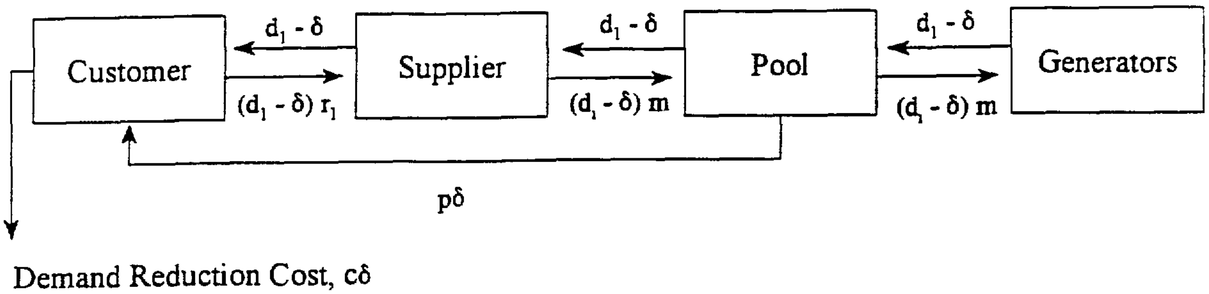


A DSM option changes the demand and the payments. Typically the change in demand is a reduction. But load shifting options have the effect of increasing demand in some hours to compensate for the reduction of demand in peak hours. The power flows and payments after a DSM option reduces the power demand of the customer by the amount δ are shown in Exhibit A-2. The supplier now provides the customer the amount $d_1 - \delta$. The amounts transacted between the supplier, the pool, and the generator on behalf of the customer are reduced accordingly.

The customer incurs a cost c in cents/kWh for reducing his demand — in lost product or wasted production costs or something. The total cost to the customer of the demand reduction is pδ. The pool pays the customer the price p cents/kWh to compensate him for the

[1] Wherever the term "supplier" appears in this discussion, it refers to both local electricity companies (LECs) and independent electricity suppliers (IESs).

Exhibit A-2
Power Flows and Payments with Demand Reduction



demand reduction. The total payment to the customer for the demand reduction is $c\delta$. The customer's payment to the supplier is reduced because he has lower demand. It is now $(d_1 - \delta)\ r_1$. The supplier's payment to the pool is also reduced. It is now $(d_1 - \delta)m$. Also, the pool's payment to the generator is reduced to $(d_1 - \delta)\ g$.

Exhibit A-3 shows the cash flows associated with serving the customer with and without the demand reduction. Before the demand reduction, the customer makes total payments to the supplier of $d_1 r_1$; after the demand reduction the payments reduced to $(d_1 - \delta)\ r_1$. Payments are indicated by the negative sign. The supplier receives identical amounts from the customer.

The customer pays rate r_1 per kWh, the supplier receives rate r_1 and pays the pool price m, the pool pays out exactly what it receives so its net is zero, and the generator receives pool price m and pays out incremental generation cost g. But because this is the incremental generator, $m = g$, so his net is zero.

Because of the reduced power to the customer, the customer suffers various economic costs, from lost revenues, lost profits, inconvenience or inefficiencies, and the costs of inputs such as labor and spoiled product. We will use the term "lost customer value" to denote the costs that are relevant to this discussion resulting from the curtailment. Let us denote this value by c, in cents per kWh. It reduces its payments to the supplier. The supplier is no longer providing the δ kWh or receiving them from the pool, and the pool is no longer handling the δ kWh of generation, but it is paying the price p to the customer.

The net position of the customer after the demand reduction relative to before is a gain of $p\delta$ for the payment from the pool, a loss of $c\delta$ for the costs the customer incurs for demand reduction, plus a gain of $r_1\delta$ from not having to pay for the power that is no longer received.

Exhibit A-3
Financial Effects of Demand Reduction
Case 1 — Without Uplift Charge

	Customer	Supplier	Pool	Generator	Total
Without Demand Reduction					
Demand reduction costs	0				0
Rate paid by customer	$-d_1 r_1$	$d_1 r_1$			0
Price paid by supplier		$-d_1 m$	$d_1 m$		0
Price paid by pool			$-d_1 m$	$d_1 m$	0
Incremental generation				$-d_1 g$	$-d_1 g$
NET	$-d_1 r_1$	$d_1 (r_1 - m)$	0	$d_1 (m-g)$	$-d_1 g$
With Demand Reduction					
Demand reduction costs	$-c \delta$				$-c \delta$
Rate paid by customer	$-(d_1-\delta) r_1$	$(d_1-\delta) r_1$			0
Price paid by supplier		$-(d_1-\delta) m$	$(d_1-\delta) m$		0
Price paid by pool	$p \delta$		$-p \delta$ $-(d_1-\delta)m$	$(d_1-\delta) m$	0
Incremental generation				$-(d_1-\delta) g$	$-(d_1-\delta) g$
NET	$p \delta - c \delta$ $-(d_1-\delta) r_1$	$(d_1-\delta)$ $\bullet(r_1 - m)$	$(d_1-\delta) m$ $-p \delta$	$-(d_1-\delta)m$	$-c \delta - (d_1-\delta) g$
DIFFERENCE	$(p-c+r_1)\delta$	$-\delta (r_1 - m)$	$-p \delta$	$\delta (m-g)$	$(g - c) \delta$

Source: Hagler Bailly Consulting, 1995

The supplier is better of by the difference between the pool price, which he now doesn't have to pay for the kWh that was formerly supplied to the customer, and the rate r_1, which he is no longer receiving from the customer. The pool, however, is worse off by the amount $p\delta$, because it is paying the customer p to reduce the demand, but by our definition of the case he is not recovering that cost through the uplift fee.

The net impact on the incremental generator is $(g - m)\delta$, which is zero. The net impact on society is $(g - c)\delta$. This is positive if $g > c$, that is, if the incremental generation cost exceeds demand reduction cost.

There are several conclusions that we can draw from this case in which the pool does not recover the DSM costs through the uplift fee:

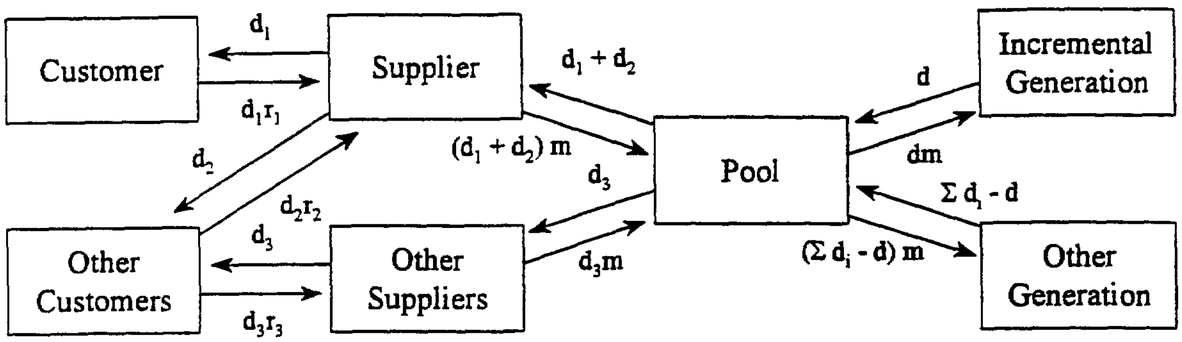
- First, the demand reduction is cost effective to society if the cost of demand reduction is less than the marginal generation cost.
- Second, the customer is better off if the cost of demand reduction is less than the pool payment for demand reduction plus the price he would otherwise have paid for electricity.
- Third, the supplier is better off if the lost sales revenue is less than the pool price.
- Fourth, unless the pool can recover the demand reduction payment through an uplift fee or another service fee, it loses that payment.
- Finally, the incremental generator is indifferent between the cases with and without demand reduction if the pool price equals the marginal generation cost.

The fourth point reflects a serious flaw in Case 1: The pool is paying for DSM but it is not recovering the cost. Case 2 corrects this flaw by allowing the DSM cost to be recovered through the uplift fee.

A.1.2 Case 2 — DSM with Uplift Fee

Including DSM costs in the uplift fee affects payments made by other customers or suppliers. Therefore it is necessary to consider others in the analysis, as shown in Exhibit A-4. A specific customer, who is able to reduce demand, ordinarily demands d_1 kWh in that hour and pays rate r_1 to the supplier, for a total payment of $d_1 r_1$ in that hour. Other customers take d_2 from the same supplier and d_3 from other suppliers, at rates r_2 and r_3. The suppliers pay m cents per kWh to the pool, which in turn pays the same amount to the generators. Of the total demand

Exhibit A-4
Power Flows, Costs, and Payments without Demand Reduction



D = $d_1 + d_2 + d_3$, d is produced by incremental generation and the remainder is produced by other generation.

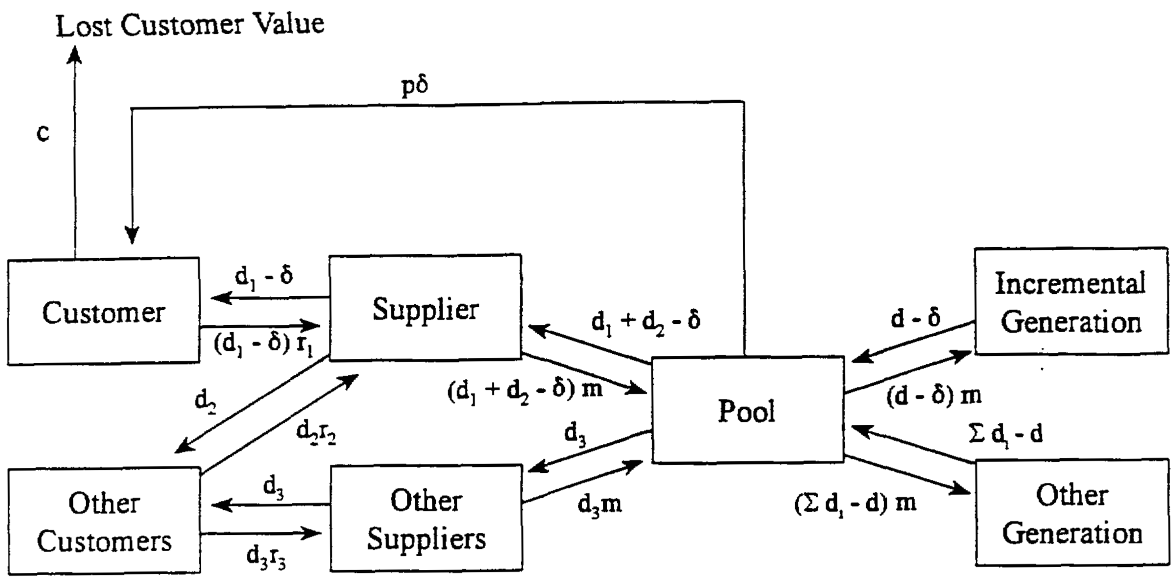
Now suppose that the customer has submitted a bid price p per kWh of demand reduction. Assume that this price is paid by the pool. If the customer's load is reduced by δ kWh in that hour, then the flows of energy between the incremental generation and the pool, between the pool and the supplier, and between the supplier and the customer in Exhibit A-4 are reduced by δ, the corresponding payments are reduced, and there is the payment of p cents per kWh from the pool to the customer, as shown in Exhibit A-5.

The pool needs to be made whole for the payment p to the customer. We will assume that the pool recovers the cost of this payment by spreading it over all kWh provided to suppliers in proportion to their energy receipts from the pool.

The suppliers also need to be made whole for their additional payments to the pool. However, we will not make any assumptions in this analysis about how the suppliers recover these costs. Instead, we will evaluate the net change in the suppliers costs. If this net change is negative, then the reduction in costs provides the supplier the opportunity to reduce the prices it charges its customers. The amount by which it reduces prices to a particular customer will depend on its competitive situation. If the net change in a supplier's costs is positive, then the supplier will attempt to recover the increased costs from its customers, if it can do so given its competitive situation.

Exhibits A-6a-c summarize the payments and costs that change between the cases with and without the demand reduction and the differences between the two cases. There may other

Exhibit A-5
Power Flows, Costs, and Payments with Demand Reduction



payments, costs, or values that remain unchanged between the two cases, but the values that are the same with or without the demand reduction and that do not affect the net costs or benefits of a DSM option are not shown.

Exhibit A-6a shows the monetary flows for the case without the demand reduction. The customers receive value from their consumption of electricity. This value must be greater than the price they pay for the electricity, since they are free to discontinue their consumption if that is not the case. But the value they receive from the portion of their consumption that is not reduced in the case with demand reduction is constant between the two cases and is not shown in Exhibit A-6. Therefore the "NET" value shown for the customer includes only the price the customer pays for electricity.

The rightmost column expresses the net social impact of the payments or costs in the other columns. The payments by customers equal the receipts by the suppliers, and therefore have a net social impact of zero. The same goes for the payments by suppliers and by the pool. But generation costs and other costs do have a non-zero net social impact.

The payments by suppliers in Exhibits A-6a and b include the recovery of both energy costs and other costs by the pool. If the payment for the marginal DSM option is less than the

Exhibit A-6a
Financial Effects of Demand Reduction
Case 2 — Without Demand Reduction

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	0							0
Payments by Customers	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1 r_1 + d_2 r_2$	$d_3 r_3$				0
Payments by Suppliers			$-\frac{(d_1+d_2)}{D}(mD+k)$	$-\frac{d_3}{D}(mD+k)$	$mD+k$			0
Payments by Pool					$-mD$	md	$m(D-d)$	0
Generation Costs						$-md$	$-m_0(D-d)$	$-m_0(D-d)$ $-md$
Other Costs					$-k$			$-k$
NET	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1 r_1 + d_2 r_2$ $-\frac{(d_1+d_2)}{D}(mD+k)$	$d_3 r_3$ $-\frac{d_3}{D}(mD+k)$	0	0	$(m-m_0)(D-d)$	$-m_0(D-d)$ $-md-k$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-6b
Financial Effects of Demand Reduction
Case 2 — With Demand Reduction, Pool Pays Customer, Spreads Cost

	Customer	**Other Customers**	**Supplier**	**Other Suppliers**	**Pool**	**Incremental Generation**	**Other Generation**	**Total**
Customer Value	$-c\,\delta$							$-c\,\delta$
Payments by Customers	$-(d_1-\delta)\,r_1$	$-d_2r_2-d_3r_3$	$(d_1-\delta)\,r_1+d_2r_2$	d_3r_3				0
Payments by Suppliers			$-\frac{d_1+d_2-\delta}{D-\delta}(pD+k)$	$-\frac{d_3}{D-\delta}(pD+k)$	$pD+k$			0
Payments by Pool	$p\delta$				$-pD$		$p(D-\delta)$	0
Generation Costs							$-m_0(D-\delta)$	$-m_0(D-\delta)$
Other Costs					$-k$			$-k$
NET	$-c\delta$ $-(d_1-\delta)\,r_1$ $+p\delta$	$-d_2r_2-d_3r_3$	$(d_1-\delta)r_1+d_2r_2$ $-\frac{d_1+d_2-\delta}{D-\delta}(pD+k)$	d_3r_3 $-\frac{d_3}{D-\delta}(pD+k)$	0	0	$(p-m_0)(D-\delta)$	$-c\delta-k$ $-m_0(D-\delta)$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-6c
Financial Effects of Demand Reduction
Case 2 — Pool Pays Customer, Spreads Cost

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Without Demand Reduction	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1r_1 + d_2r_2$ $\frac{(d_1+d_2)}{D}(mD+k$	d_3r_3 $-\frac{d_3}{D}(mD+k)$	0	0	$(m-m_0)(D-d)$	$-m_0(D-d)$ $-md-k$
With Demand Reduction	$-c\delta-(d_1-\delta)$ r_1 $+p\delta$	$-d_2 r_2 - d_3 r_3$	$(d_1-\delta)r_1 + d_2r_2$ $\frac{d_1+d_2-\delta}{D-\delta}(pD+k$	d_3r_3 $-\frac{d_3}{D-\delta}(pD+k)$	0	0	$(p-m_0)(D-\delta)$	$-c\delta-k$ $-m_0(D-\delta)$
Difference	$(p+r_1-c)\,\delta$	0	$(d_1+d_2)(m-p)$ $+\left(p+\frac{k}{D}\right)\frac{d_3}{D}\delta$ $-\delta r_1$	$d_3(m-p)$ $-\left(p+\frac{k}{D}\right)\frac{d_3}{D}\delta$	0	0	$-(m-p)(D-\delta)$ $-(m-m_0)(\delta-d)$	$(m-m_0)\,d$ $+(m_0-c)\,\delta$
Difference per kWh	$p+r_1-c$	0	$\frac{d_1+d_2}{\delta}(m-p)$ $+\left(p+\frac{k}{D}\right)\frac{d_3}{D}$ $-r_1$	$\frac{d_3}{\delta}(m-p)$ $-\left(p+\frac{k}{D}\right)\frac{d_3}{D}$	0	0	$-(m-p)\frac{D}{\delta}$ $+(m-m_0)\frac{d}{\delta}$ $-(p-m_0)$	$(m-m_0)\frac{d}{\delta}+m_0$ $-c$

Source: Hagler Bailly Consulting, 1995.

marginal generation cost, then this payment changes the basis for the pool price. All suppliers, including both the supplier that serves the customer in question and the other suppliers, face a different pool price. The pool price is not exactly equal to p when DSM is the marginal resource for the same reasons that it is not exactly equal to m when generation is the marginal resource, because of the pool fee on top of the marginal cost, whether it be m or p.

Equivalently, the pool price is the total pool cost in an hour divided by the number of kWh sold in that hour. In the case without the demand reduction, the total costs are:

$$m \cdot (d_1 + d_2 + d_3) + k \tag{A-1}$$

where k denotes the other costs that are recovered and are assumed not to change with the amount of energy dispatched by the pool. In the case with the demand reduction; the total costs are:

$$p \cdot (d_1 + d_2 + d_3 - \delta) + p\delta + k \tag{A-2}$$

There are two $p\delta$ terms, with opposite signs. The pool pays the amount $p\delta$ to the customer for the demand reduction. But the pool also avoids paying for the generation of δ kWh at the price p. The reduction in total costs from the case without the demand reduction to the case with the demand reduction is therefore:

$$(m - p) \cdot (d_1 + d_2 + d_3) \tag{A-3}$$

The reduction of total costs is guaranteed by the premise that the cost to the pool of the demand reduction is less than the cost of incremental generation, $p < m$.

But this benefit is not divided uniformly between the supplier that serves the customer providing the demand reduction and the other suppliers. In the case without the demand reduction, the supplier that serves the customer makes total payments to the pool of:

$$\frac{(d_1 + d_2)}{D} (mD + k) \tag{A-4}$$

With the demand reduction this supplier makes total payments to the pool of:

$$\frac{d_1 + d_2 - \delta}{D - \delta} (pD + k) \tag{A-5}$$

To determine the net impact on the supplier, we take the difference between these two expressions. But at the same time the supplier realizes a reduction in payments to the pool, its revenues are also reduced by $r_1\ \delta$.

The difference is complicated because of the term involving δ in both the numerator and denominator. To simplify the difference, we take a first order MacLaurin expansion of this term, and obtain:

$$(d_1 + d_2)(m - p) + \left(p + \frac{k}{D}\right)\frac{d_3}{D}\delta - r_1\delta \qquad \text{(A-6)}$$

The sum of the first two terms is always positive and indicates a net reduction in total payments by this supplier to the pool after implementation of the demand reduction. The first term on the right hand side represents the cost savings realized as a result of a reduction in the pool price. The second term represents a reallocation of pool costs from this supplier to the other suppliers because this supplier now has a smaller share of the total demand served by the pool.

The net benefit per kWh of demand reduction is obtained by dividing the net benefit by the demand reduction δ:

$$\frac{d_1 + d_2}{\delta}(m - p) + \left(p + \frac{k}{D}\right)\frac{d_3}{D} - r_1 \qquad \text{(A-7)}$$

The first term on the right hand side, representing the pool price reduction, includes the factor $(d_1 + d_2) / \delta$. The smaller the value of δ, the greater this factor. This can be thought of as "leverage" — even a small amount of DSM at a cost p lower than the marginal generation cost m can reduce the price paid to all generation.

The total payments from other suppliers to the pool in the case without demand reduction are:

$$\frac{d_3}{D}(mD + k) \qquad \text{(A-8)}$$

With demand reduction, the payments are:

$$\frac{d_3}{D - \delta}(pD + k) \qquad \text{(A-9)}$$

The reduction in total payments resulting from demand reduction is approximately:

$$d_3(m-p) - \left(p+\frac{k}{D}\right)\frac{d_3}{D}\,\delta \qquad \text{(A-10)}$$

The second term on the right hand side is exactly the negative of a term in the corresponding expression for the supplier serving the customer with the load reduction. The benefit that this supplier realizes through the reallocation of pool costs is taken directly from the other suppliers. The net benefit to other suppliers per kWh reduced is:

$$\frac{d_3}{\delta}(m-p) - \left(p+\frac{k}{D}\right)\frac{d_3}{D} \qquad \text{(A-11)}$$

These values may not necessarily be positive. They will be positive only if:

$$\frac{\delta}{d} < \frac{m-p}{p+\frac{k}{D}} \qquad \text{(A-12)}$$

That is, suppliers other than the supplier serving the customer that makes the demand reduction will realize a net benefit only if the proportional reduction in demand is smaller than the proportional reduction in price. In other words, a large demand reduction that yields only a marginal reduction in price relative to the incremental generation cost does not provide sufficient leverage on the pool price and will make others worse off.

But the big losers are the owners of "other generation." The pool cost m before the demand reduction was determined by the incremental generation cost. The costs of other generation are something less, which we will denote as m_0. Their payments from the pool are reduced from m to p, and their profits are therefore reduced from $(m-m_0)(D-d)$ to $(p-m_0)(D-\delta)$. This is primarily a consequence of the marginal generation losing in the competition against marginal DSM. The net benefit to the generators from the demand reduction is negative, and in terms of net benefit per kWh reduced is:

$$-(m-p)\frac{D}{\delta} + (m-m_0)\frac{d}{\delta} - (p-m_0) \qquad \text{(A-13)}$$

The net societal impact of the demand reduction is:

$$(m-m_0)\frac{d}{\delta} + m_0 - c \qquad \text{(A-14)}$$

The term involving c represents the lost customer value. The rest of the expression represents the avoided generation cost.

The difference between the two cases for the customer is $p - c + r_1$. This is the same as the result obtained in Case 1. The customer receives payment p and incurs cost c because of the demand reduction, but avoids the rate r_1 paid to the supplier. If $p - c + r_1 > 0$, then the customer is better off in the case with the demand reduction than without. Equivalently, $p + r_1 > c$, or the sum of the payment and avoided rate is greater than the cost to the customer of the curtailment. In fact, this is a necessary condition for a demand reduction even to occur, assuming that participation in any of the load management programs is voluntary.[2]

The difference between the two cases for the supplier is as stated in equation (7). The supplier is always better off with the demand reduction than without, because although it loses revenue r, it avoids paying the higher marginal energy cost m and it realizes the pool price reduction and a beneficial reallocation of pool costs.

The difference for the other suppliers is as stated in equation (11). This may be negative or positive depending on whether the condition in equation (12) holds. This condition will be required for DSM paid for by the Ukrainian pool, in order to avoid DSM that would defeat the pool's objective of minimizing rates.

As shown in the rightmost column, societal economic efficiency is improved by the demand reduction if the value of equation (14) is positive, that is, if the lost customer value c resulting from the curtailment is less that the incremental generation cost that would otherwise be incurred.[3]

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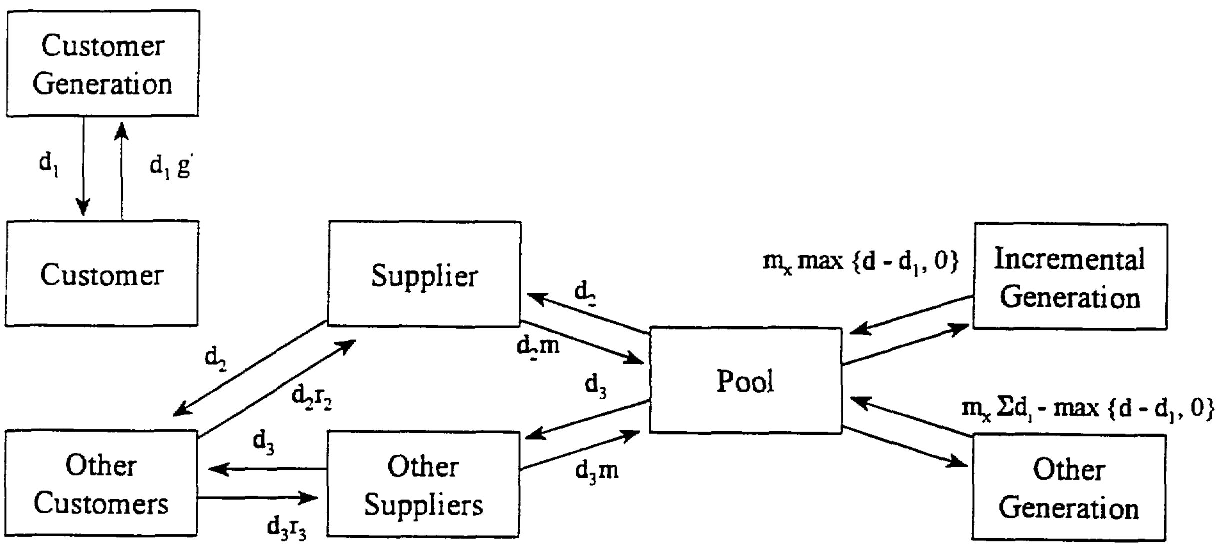
2 The condition $p - c + r > 0$ is equivalent to the participant test, discussed in Chapter 1. California Public Utility Commission and California Energy Commission. "Standard Practice Manual: Economic Analysis of DSM Programs." Sacramento, CA. 1987.

3 The condition $m - c > 0$ is equivalent to the cost-effectiveness test commonly known as the total resource cost (TRC) test.

A.2 DSM AT THE SUPPLIER LEVEL

The objective function of the privately-owned suppliers is to maximize profits. DSM must be justifiable on a financial basis to the entity paying for it. All of the discussion in the preceding section assumes that the reference case for assessing the impact of demand reduction is the case in which the supplier would be serving the full demand of the customer. Let us now consider another reference case, in which the customer would leave the supplier and invest in its own generation. Exhibit A-7 illustrates this case. Whereas previously we assumed that the demand reduction is not enough to change the price of incremental generation, here the loss of the entire demand of the customer may be sufficient to curtail all generation from the incremental block and cut into other generation. The demand of other customers is not changed.

Exhibit A-7
Power Flows, Costs, And Payments if Customer is Lost to Self Generation



Now suppose that the payment p was paid ultimately by the supplier, either directly to the customer or through the pool. These two cases are same as Exhibit A-5, except that either the payment p δ goes directly from the supplier to the customer or from the supplier to the pool and then from the pool to the customer. The financial effects are shown in Exhibit A-8. The net effects for the two cases are the same, whether or not the payment flows through the pool.

Exhibit A-8a
Financial Effects of Demand Reduction
Case 3 — Customer Lost to Self Generation

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	0							0
Payments by Customers	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2$	$d_3 r_3$				$-d_1 g$
Payments by Suppliers			$-\frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$-\frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$m'(d_2+d_3)+k$			0
Payments by Pool					$-m'(d_2+d_3)$		$m'(d_2+d_3)$	0
Generation Costs							$-m_0(d_2+d_3)$	$-m_0(d_2+d_3)$
Other Costs					$-k$			$-k$
NET	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2 - \frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$d_3 r_3 - \frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	0	0	$(m'-m_0) \cdot (d_2+d_3)$	$-d_1 g - m_0(d_2+d_3) - k$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-8b
Financial Effects of Demand Reduction
Case 3 — With Demand Reduction, Customer Kept, Supplier Pays Customer

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	$-c\delta$							$-c\delta$
Payments by Customers	$-(d_1-\delta)r_1$	$-d_2r_2-d_3r_3$	$(d_1-\delta)r_1+d_2r_2$	d_3r_3				0
Payments by Suppliers	$p\delta$		$-\frac{d_1+d_2-\delta}{D-\delta}\cdot[m''(D-\delta)+k]-p\delta$	$-\frac{d_3}{D-\delta}\cdot[m''(D-\delta)+k]$	$m''(D-\delta)+k$			0
Payments by Pool					$-m''(D-\delta)$		$m''(D-\delta)$	0
Generation Costs							$-m_0(D-\delta)$	$-m_0(D-\delta)$
Other Costs					$-k$			$-k$
NET	$-c\delta-(d_1-\delta)r_1+p\delta$	$-d_2r_2-d_3r_3$	$(d_1-\delta)r_1+d_2r_2-\frac{d_1+d_2-\delta}{D-\delta}\cdot[m''(D-\delta)+k]-p\delta$	$d_3r_3-\frac{d_3}{D-\delta}\cdot[m''(D-\delta)+k]$	0	0	$(m''-m_0)\cdot(D-\delta)$	$-c\delta-k-m_0(D-\delta)$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-8c
Financial Effects of Demand Reduction
Case 3 — Supplier Pays Customer, to Retain Customer

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Without Demand Reduction	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2 - \frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$d_3 r_3 - \frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	0	0	$(m'-m_0) \cdot (d_2+d_3)$	$-d_1 g - m_0(d_2+d_3) - k$
With Demand Reduction	$-c\delta - (d_1-\delta) r_1 + p\delta$	$-d_2 r_2 - d_3 r_3$	$(d_1-\delta) r_1 + d_2 r_2 - \frac{d_1+d_2-\delta}{D-\delta} \cdot [m''(D-\delta)+k] - p\delta$	$d_3 r_3 - \frac{d_3}{D-\delta} \cdot [m''(D-\delta)+k]$	0	0	$(m''-m_0) \cdot (D-\delta)$	$-c\delta - k - m_0(D-\delta)$
Difference	$(p+r_1-c)\,\delta - (r_1-g)\,d_1$	0	$d_1(r_1-m'') - d_2(m''-m') - \delta(r_1-m''-p) - k\left(\frac{d_1+d_2}{D} - \frac{d_2}{D-d_1} - \frac{d_3\delta}{D^2}\right)$	$-d_3(m''-m') + kd_3\left(\frac{1}{D-d_1} - \frac{1}{D}\right) - \frac{kd_3}{D^2}\delta$	0	0	$D(m'-m') + d_1(m'-m_0) - \delta(m''-m_0)$	$d_1(g-m_0) + \delta(m_0-c)$
Difference per kWh	$(p+r_1-c) - (r_1-g)\,d_1/\delta$	0	$\frac{d_1}{\delta}\left(r_1-m''-\frac{k}{D}\right) - \frac{d_2}{\delta}\left(m''-m'+\frac{kd_1}{d(d-d_1)}\right) \cdot \left(r_1-m''-p+\frac{kD_3}{D^2}\right)$	$-\frac{d_3}{\delta}(m''-m') + k\frac{d_3}{\delta}\left(\frac{1}{D-d_1} - \frac{1}{D}\right) - \frac{kd_3}{D^2}$	0	0	$\frac{D}{\delta}(m''-m') + \frac{d_1}{\delta}(m'-m_0) - (m'-m_0)$	$d_1/\delta\,(g-m_0) + (m_0-c)$

Source: Hagler Bailly Consulting, 1995.

ANALYSIS OF POWER FLOWS, COSTS, AND PAYMENTS RELATED TO DSM ▸ A-18

The conclusion from the customer's perspective depends on the cost g of self generation. The customer is better off staying with the original supplier and taking the demand reduction only if g is not too low.

The conclusion from the supplier's perspective is that it is better off paying the customer for the demand reduction and keeping the remainder of the customer's demand if that would be required to keep the customer.

The conclusion from the other suppliers' perspective is that they have a greater chance of being worse off because the supplier that offers the demand reduction does not consider the effect that reduction would have on the other suppliers.

The conclusion from the societal perspective also depends on whether the cost g of self generation is less than the cost of incremental or other generation.

The overall conclusion is that the supplier does have a financial incentive to pay its own customers for demand reduction in particular instances, if that would be required to keep the customer. Other suppliers may or may not be harmed by this demand reduction.

A similar analysis could be performed for the case in which the customer would switch to another supplier in the absence of a DSM payment.

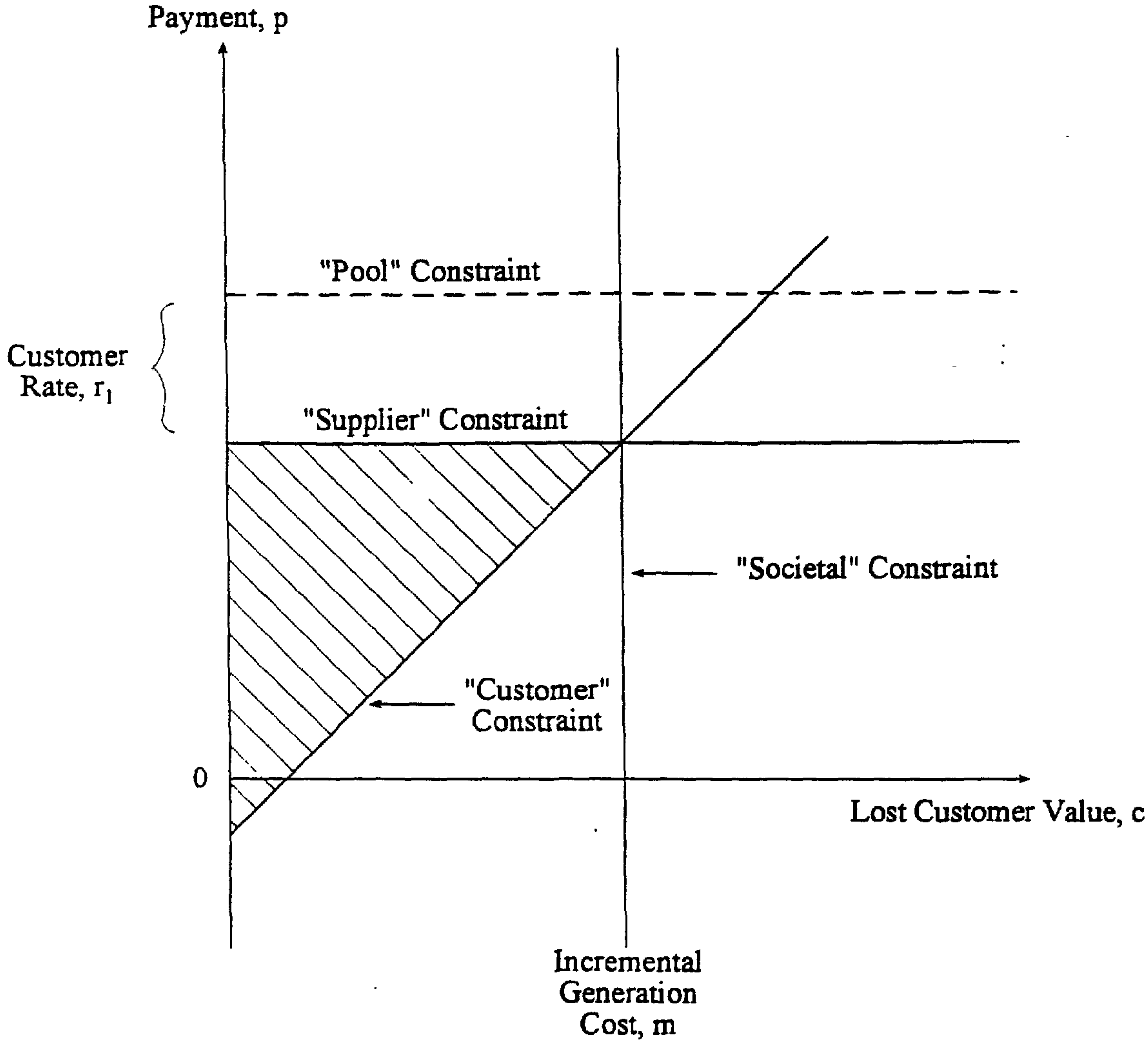
The differences between the assumptions underlying Cases 2 and 3 provide the rationale for using two different tests for low voltage and high voltage customers. Low voltage customers are assumed not to have the option of leaving a supplier. Therefore, the tests for evaluating DSM options for these customers are derived from the results of Case 2. High voltage customers, on the other hand, have other supply options. Therefore, it is appropriate to evaluate DSM options for high voltage customers using tests derived from Case 3.

A.3 RELATIONSHIPS BETWEEN THE CONDITIONS

In Case 1, we identified the conditions under which various interests in the power market are better or worse off as a result of DSM. Exhibit A-9 shows combinations of lost customer value c and payments p that satisfy the various conditions for making an interest better off.[4] The vertical line identified as "total" represents the equation $m = c$. Demand reduction opportunities with lost customer value c less than incremental generation cost m satisfy this

[4] This figure is derived from one that appeared previously in Berman, J. and D. Logan, 1990. "A Comprehensive Cost-Effectiveness Methodology for Integrated Least-Cost Planning." Proceedings of the 1990 Summer Study on Energy-Efficiency in Buildings. American Council for an Energy-Efficient Economy, Berkeley, California.

Exhibit A-9
Relationship between the Conditions



condition, regardless of the value of payment *p*. Therefore, all points to the left of the "total" constraint are desirable to society.

The diagonal line represents the equation $p - c + r_1 = 0$. All points above and to the left of this line have values of lost customer value *c* less than the sum of the avoided rate r_1 and the payment *p* and are desirable to the customer whose demand would be reduced.

The horizontal line identified as "Supplier" represents the equation $m - r_1 - p = 0$. This condition is concerned only with the costs and payments seen by the supplier in this situation. This condition does not take into account the cost of the DSM option. That cost is borne by the customer. Therefore, all points below this line are acceptable to the supplier

The shaded area satisfies all three conditions — total, customer, and supplier. A fourth condition, identified as the "pool," is represented by the horizontal line marked "Pool." This line represents the equation $p = m$. All points below this line represent demand reduction options that have a cost to the pool that is less that the marginal generation cost. Therefore, all points that satisfy the other three conditions also meet this condition.

Further, it can be seen that if the "Pool" condition were to be used *instead* of the "Supplier" condition, then demand reduction options that *do not* satisfy the "Total" condition could be dispatched. If the incremental generating cost were m, but all demand reduction options satisfying the "Pool" condition were accepted, then all options in the trapezoid bounded by the Pool and Supplier Constraints above and below, and the y axis and Customer Constraint on the left and right would be accepted in addition to those that would be accepted under the Supplier constraint. This area can be divided into two subareas, both of which are of concern. All of the options in the triangle bounded by the Pool and Customer Constraints and the Incremental Generation Cost have lost customer value c greater than the incremental generation cost m. Therefore, these options do not satisfy the Total condition. This is of concern from a societal perspective.

The remaining rectangle represents options that are efficient from a societal perspective. However, the supplier simply pays a higher price than it would if the Supplier constraint were binding. This is of concern to both the supplier and its other customers who face other competitive options.

As observed above, Case 1 has a serious flaw and is not recommended. Yet the relationships between the conditions as illustrated in Exhibit A-9 are illuminating.

Exhibit A-6a
Financial Effects of Demand Reduction
Case 2 — Without Demand Reduction

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	0							0
Payments by Customers	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1 r_1 + d_2 r_2$	$d_3 r_3$				0
Payments by Suppliers			$-\frac{(d_1+d_2)}{D}(mD+k)$	$-\frac{d_3}{D}(mD+k)$	$mD+k$			0
Payments by Pool					$-mD$	md	$m(D-d)$	0
Generation Costs						$-md$	$-m_0(D-d)$	$-m_0(D-d)$ $-md$
Other Costs					$-k$			$-k$
NET	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1r_1+d_2r_2$ $-\frac{(d_1+d_2)}{D}(mD+k)$	d_3r_3 $-\frac{d_3}{D}(mD+k)$	0	0	$(m-m_0)(D-d)$	$-m_0(D-d)$ $-md-k$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-6b
Financial Effects of Demand Reduction
Case 2 — With Demand Reduction, Pool Pays Customer, Spreads Cost

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	$-c\,\delta$							$-c\,\delta$
Payments by Customers	$-(d_1-\delta)\,r_1$	$-d_2\,r_2-d_3\,r_3$	$(d_1-\delta)\,r_1+d_2\,r_2$	$d_3\,r_3$				0
Payments by Suppliers			$-\frac{d_1+d_2-\delta}{D-\delta}(pD+k)$	$-\frac{d_3}{D-\delta}(pD+k)$	$pD+k$			0
Payments by Pool	$p\delta$				$-pD$		$p(D-\delta)$	0
Generation Costs							$-m_0(D-\delta)$	$-m_0(D-\delta)$
Other Costs					$-k$			$-k$
NET	$-c\delta$ $-(d_1-\delta)\,r_1$ $+p\delta$	$-d_2\,r_2-d_3\,r_3$	$(d_1-\delta)r_1+d_2r_2$ $-\frac{d_1+d_2-\delta}{D-\delta}(pD+k)$	d_3r_3 $-\frac{d_3}{D-\delta}(pD+k)$	0	0	$(p-m_0)(D-\delta)$	$-c\delta-k$ $-m_0(D-\delta)$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-6c
Financial Effects of Demand Reduction
Case 2 — Pool Pays Customer, Spreads Cost

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Without Demand Reduction	$-d_1 r_1$	$-d_2 r_2 - d_3 r_3$	$d_1 r_1 + d_2 r_2$ $\frac{(d_1+d_2)}{D}(mD+k$	$d_3 r_3$ $-\frac{d_3}{D}(mD+k)$	0	0	$(m-m_0)(D-d)$	$-m_0(D-d)$ $-md-k$
With Demand Reduction	$-c\delta-(d_1-\delta)$ r_1 $+p\delta$	$-d_2 r_2 - d_3 r_3$	$(d_1-\delta)r_1 + d_2 r_2$ $\frac{d_1+d_2-\delta}{D-\delta}(pD+k$	$d_3 r_3$ $-\frac{d_3}{D-\delta}(pD+k)$	0	0	$(p-m_0)(D-\delta)$	$-c\delta-k$ $-m_0(D-\delta)$
Difference	$(p+r_1-c)\,\delta$	0	$(d_1+d_2)(m-p)$ $+\left(p+\frac{k}{D}\right)\frac{d_3}{D}\delta$ $-\delta r_1$	$d_3(m-p)$ $-\left(p+\frac{k}{D}\right)\frac{d_3}{D}\delta$	0	0	$-(m-p)(D-\delta)$ $-(m-m_0)(\delta-d)$	$(m-m_0)\,d$ $+(m_0-c)\,\delta$
Difference per kWh	$p+r_1-c$	0	$\frac{d_1+d_2}{\delta}(m-p)$ $+\left(p+\frac{k}{D}\right)\frac{d_3}{D}$ $-r_1$	$\frac{d_3}{\delta}(m-p)$ $-\left(p+\frac{k}{D}\right)\frac{d_3}{D}$	0	0	$-(m-p)\frac{D}{\delta}$ $+(m-m_0)\frac{d}{\delta}$ $-(p-m_0)$	$(m-m_0)\frac{d}{\delta}+m_0$ $-c$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-8a
Financial Effects of Demand Reduction
Case 3 — Customer Lost to Self Generation

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	0							0
Payments by Customers	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2$	$d_3 r_3$				$-d_1 g$
Payments by Suppliers			$-\frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$-\frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$m'(d_2+d_3)+k$			0
Payments by Pool					$-m'(d_2+d_3)$		$m'(d_2+d_3)$	0
Generation Costs							$-m_0(d_2+d_3)$	$-m_0(d_2+d_3)$
Other Costs					$-k$			$-k$
NET	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2 - \frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$d_3 r_3 - \frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	0	0	$(m'-m_0) \cdot (d_2+d_3)$	$-d_1 g - m_0(d_2+d_3) - k$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-8b
Financial Effects of Demand Reduction
Case 3 — With Demand Reduction, Customer Kept, Supplier Pays Customer

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Customer Value	$-c\delta$							$-c\delta$
Payments by Customers	$-(d_1-\delta)r_1$	$-d_2r_2-d_3r_3$	$(d_1-\delta)r_1+d_2r_2$	d_3r_3				0
Payments by Suppliers	$p\delta$		$-\frac{d_1+d_2-\delta}{D-\delta}\cdot[m''(D-\delta)+k]$ $-p\delta$	$-\frac{d_3}{D-\delta}\cdot[m''(D-\delta)+k]$	$m''(D-\delta)+k$			0
Payments by Pool					$-m''(D-\delta)$		$m''(D-\delta)$	0
Generation Costs							$-m_0(D-\delta)$	$-m_0(D-\delta)$
Other Costs					$-k$			$-k$
NET	$-c\delta$ $-(d_1-\delta)r_1$ $+p\delta$	$-d_2r_2-d_3r_3$	$(d_1-\delta)r_1+d_2r_2$ $-\frac{d_1+d_2-\delta}{D-\delta}\cdot[m''(D-\delta)+k]$ $-p\delta$	d_3r_3 $-\frac{d_3}{D-\delta}\cdot[m''(D-\delta)+k]$	0	0	$(m''-m_0)\cdot(D-\delta)$	$-c\delta-k$ $-m_0(D-\delta)$

Source: Hagler Bailly Consulting, 1995.

Exhibit A-8c
Financial Effects of Demand Reduction
Case 3 — Supplier Pays Customer, to Retain Customer

	Customer	Other Customers	Supplier	Other Suppliers	Pool	Incremental Generation	Other Generation	Total
Without Demand Reduction	$-d_1 g$	$-d_2 r_2 - d_3 r_3$	$d_2 r_2 - \frac{d_2}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	$d_3 r_3 - \frac{d_3}{d_2+d_3} \cdot [m'(d_2+d_3)+k]$	0	0	$(m'-m_0) \cdot (d_2+d_3)$	$-d_1 g - m_0(d_2+d_3) - k$
With Demand Reduction	$-c\delta - (d_1-\delta) r_1 + p\delta$	$-d_2 r_2 - d_3 r_3$	$(d_1-\delta)r_1 + d_2 r_2 - \frac{d_1+d_2-\delta}{D-\delta} \cdot [m''(D-\delta)+k] - p\delta$	$d_3 r_3 - \frac{d_3}{D-\delta} \cdot [m''(D-\delta)+k]$	0	0	$(m''-m_0) \cdot (D-\delta)$	$-c\delta - k - m_0(D-\delta)$
Difference	$(p+r_1-c)\,\delta - (r_1-g)\,d_1$	0	$d_1(r_1-m'') - d_2(m''-m') - \delta(r_1-m''-p) - k\left(\frac{d_1+d_2}{D} - \frac{d_2}{D-d_1} - \frac{d_3\delta}{D^2}\right)$	$-d_3(m''-m') + kd_3\left(\frac{1}{D-d_1} - \frac{1}{D}\right) - \frac{kd_3}{D^2}\delta$	0	0	$D(m'-m') + d_1(m'-m_0) - \delta(m''-m_0)$	$d_1\,(g-m_0) + \delta\,(m_0-c)$
Difference per kWh	$(p+r_1-c) - (r_1-g)\,d_1/\delta$	0	$\frac{d_1}{\delta}\left(r_1-m''-\frac{k}{D}\right) - \frac{d_2}{\delta}\left(m''-m'+\frac{kd_1}{d(d-d_1)}\right) - \left(r_1-m''-p+\frac{kD_3}{D^2}\right)$	$-\frac{d_3}{\delta}(m''-m') + k\frac{d_3}{\delta}\left(\frac{1}{D-d_1} - \frac{1}{D}\right) - \frac{kd_3}{D^2}$	0	0	$\frac{D}{\delta}(m''-m') + \frac{d_1}{\delta}(m'-m_0) - (m'-m_0)$	$d_1/\delta\,(g-m_0) + (m_0-c)$

Source: Hagler Bailly Consulting, 1995.

APPENDIX B
TECHNICAL AND ECONOMIC CHARACTERISTICS OF DSM MEASURES IN UKRAINE

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std. Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip. kW (1)	Power Consumption Measure kW	Load Factor (2)
RESIDENTIAL (16% of Total Consumption)														
1	Replace small refrigerators (approx. 150 l) upon retirement with 1990 US average	6,190,000	na	254 (f)	410	119 (j)	0.00	142 (o)	0.00	20 (j)	20	0.007	0.005 (x)	79%
2	Replace small refrigerators (approx. 150 l) upon retirement with 1993 US standard	6,190,000	na	198 (f)	410	119 (j)	0.00	166 (o)	0.00	20 (j)	20	0.007	0.005 (x)	79%
3	Replace large refrigerators (approx. 230 l) upon retirement with 1990 US standard	8,900,000	na	294 (f)	473	139 (j)	0.00	167 (o)	0.00	20 (j)	20	0.007	0.005 (x)	79%
4	Replace large refrigerators (approx. 230 l) upon retirement with 1993 US standard	8,900,000	na	228 (f)	473	139 (j)	0.00	195 (o)	0.00	20 (j)	20	0.007	0.005 (x)	79%
5	Replace low-use incandescent lamps with CFLs upon retirement (residential)	165,940,000	270	5 (q)	19 (h)	0.44 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0.069	0.020 (q)	59%
6	Replace hi-use incandescent lamps with CFLs upon retirement (residential)	37,360,000	1,700	28 (q)	117 (h)	0.37 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0.069	0.017 (q)	59%
7	Retrofit low-use incandescent lamps with CFLs (residential)	165,940,000	270	5 (q)	19 (h)	0.44 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0.069	0.020 (q)	59%
8	Retrofit hi-use incandescent lamps with CFLs (residential)	37,360,000	1,700	28 (q)	117 (h)	0.37 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0.069	0.017 (q)	59%
COMMERCIAL/INSTITUTIONAL (12% of Total Consumption)														
9	Retrofit street lighting mercury vapor lamps with high-pressure sodium	287,019 (e)	4,015 (e)	373 (e)	843 (h)	17 (n)		27 (n)	0.5	20,000 (q)	20,000 (q)	0.21 (e)	0.093 (q)	50%
10	Replace small low-use motors with hi-eff. motors upon retirement	5,450 (y)	7,000 (y)	22,187 (k)	23,520 (i)	150 (j)		213 (k)		20 (j)	20	4.2	4 (k)	64%
11	Replace medium low-use motors with hi-eff. motors upon retirement	55,909 (y)	7,000 (y)	80,297 (k)	84,000 (i)	500 (j)		650 (k)		20 (j)	20	15.0	14 (k)	64%
12	Replace large low-use motors with hi-eff. motors upon retirement	4,274 (y)	7,000 (y)	250,594 (k)	257,600 (i)	1,334 (k)		1,794 (k)		20 (j)	20	46	45 (k)	64%
13	Replace very large low-use motors with hi-eff. motors upon retirement	849 (y)	7,000 (y)	1,553,104 (k)	1,584,800 (i)	8,207 (k)		11,037 (k)		20 (j)	20	283	277 (k)	64%
14	Replace small hi-use motors with hi-eff. motors upon retirement	36,765 (y)	7,000 (y)	16,376 (k)	17,360 (i)	150 (j)		197 (k)		20 (j)	20	3.1	3 (k)	64%
15	Replace medium hi-use motors with hi-eff. motors upon retirement	61,436 (y)	7,000 (y)	53,531 (k)	56,000 (i)	500 (l)		600 (k)		20 (j)	20	10.0	10 (k)	64%
16	Replace large hi-use motors with hi-eff. motors upon retirement	6,862 (y)	7,000 (y)	408,577 (k)	420,000 (i)	2,175 (k)		2,925 (k)		20 (j)	20	75	73 (k)	64%

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std. Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std. Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip. kW (1)	Power Consumption Measure kW	Load Factor (2)
17	Replace very large hi-use motors with hi-eff. motors upon retirement	822 (y)	7,000 (y)	2,952,544 (k)	3,012,800 (i)	15,602 (k)		20,982 (k)		20 (j)	20	538	527 (k)	64%
18	Replace small low-use motors with hi-eff. motors upon rewind	5,450 (y)	7,000 (y)	22,187 (k)	24,000 (i)	82 (m)		197 (k)		20 (j)	20	4.3 (v)	4 (k)	64%
19	Replace medium low-use motors with hi-eff. motors upon rewind	55,909 (y)	7,000 (y)	80,297 (k)	85,714 (i)	279 (m)		600 (k)		20 (j)	20	15.3 (v)	14 (k)	64%
20	Replace large low-use motors with hi-eff. motors upon rewind	4,274 (y)	7,000 (y)	250,594 (k)	262,857 (i)	1,609 (m)		2,925 (k)		20 (j)	20	47 (v)	45 (k)	64%
21	Replace very large low-use motors with hi-eff. motors upon rewind	849 (y)	7,000 (y)	1,553,104 (k)	1,617,143 (i)	11,540 (m)		20,982 (k)		20 (j)	20	288.78 (v)	277 (k)	64%
22	Replace small hi-use motors with hi-eff. motors upon rewind	36,765 (y)	7,000 (y)	16,376 (k)	17,714 (i)	82 (m)		197 (k)		20 (j)	20	3.2 (v)	3 (k)	64%
23	Replace medium hi-use motors with hi-eff. motors upon rewind	61,436 (y)	7,000 (y)	53,531 (k)	57,143 (i)	279 (m)		600 (k)		20 (j)	20	10.2 (v)	10 (k)	64%
24	Replace large hi-use motors with hi-eff. motors upon rewind	6,892 (y)	7,000 (y)	408,577 (k)	428,571 (i)	1,609 (m)		2,925 (k)		20 (j)	20	77 (v)	73 (k)	64%
25	Replace very large hi-use motors with hi-eff. motors upon rewind	822 (y)	7,000 (y)	2,952,544 (k)	3,074,286 (i)	11,540 (m)		20,982 (k)		20 (j)	20	548.98 (v)	527 (k)	64%
26	Retrofit small low-use motors with drive measures	1,635 (y)	7,000 (y)	15,288 (k)	23,520 (i)			2845 (k)	20		15	4.2	3.78	64%
27	Retrofit medium low-use motors with drive measures	16,773 (y)	7,000 (y)	54,600 (k)	84,000 (i)			5,200 (k)	20		15	15.0	13.5	64%
28	Retrofit large low-use motors with drive measures	1,282 (y)	7,000 (y)	167,440 (k)	257,600 (i)			10,160 (k)	20		15	46	41.4	64%
29	Retrofit very large low-use motors with drive measures	255 (y)	7,000 (y)	1,030,120 (k)	1,584,800 (i)			27,735 (k)	20		15	283	254.7	64%
30	Retrofit small hi-use motors with drive measures	11,030 (y)	7,000 (y)	11,284 (k)	17,360 (i)			2617 (k)	20		15	3.1	2.79	64%
31	Retrofit medium hi-use motors with drive measures	18,431 (y)	7,000 (y)	36,400 (k)	56,000 (i)			4,400 (k)	20		15	10.0	9	64%
32	Retrofit large hi-use motors with drive measures	2,059 (y)	7,000 (y)	273,000 (k)	420,000 (i)			14,800 (k)	20		15	75	67.5	64%
33	Retrofit very large hi-use motors with drive measures	247 (y)	7,000 (y)	1,958,320 (k)	3,012,800 (i)			36,707 (k)	20		15	538	484 2	64%

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std. Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip. kW (1)	Power Consumption Measure kW	Load Factor (2)
34	Motor downsizing (commercial)	32,538 (y)	7,000 (y)	116,362 (k)	122,486 (i)			1000 (s)			20	22	21	64%
35	Replace low-use fluorescent ballasts with eff. core-coil ballasts upon retirement	2,500,000	800	96 (p)	104 (h)	18 (j)	0.30	23 (p)	0.30	40,000	45,000 (p)	0.130	0.120 (p)	70%
36	Replace hi-use fluorescent ballasts with eff. core-coil ballasts upon retirement	2,600,000	3,100	114 (p)	124 (h)	26 (j)	0.30	31 (p)	0 30	40,000	45,000 (p)	0.040	0 037 (p)	70%
37	Replace low-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,500,000	800	71 (p)	104 (h)	18 (j)	0.30	54 (q)	0.30	40,000 (p)	70,000 (p)	0.130	0.088 (p)	70%
38	Replace hi-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,600,000	3,100	84 (p)	124 (h)	26 (j)	0.30	62 (q)	0 30	40,000 (p)	70,000 (p)	0 040	0 027 (p)	70%
39	Retrofit low-use fluorescent ballasts with efficient core-coil ballasts	2,500,000	800	96 (p)	104 (h)	18 (j)	0.30	23 (p)	0.30	40,000 (p)	45,000 (p)	0.130	0.120 (p)	70%
40	Retrofit hi-use fluorescent ballasts with efficient core-coil ballasts	2,600,000	3,100	114 (p)	124 (h)	26 (j)	0 30	31 (p)	0 30	40,000 (p)	45,000 (p)	0.040	0 037 (p)	70%
41	Retrofit low-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,500,000	800	71 (p)	104 (h)	18 (j)	0.30	54 (q)	0.30	40,000 (p)	70,000 (p)	0.130	0 088 (p)	70%
42	Retrofit hi-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,600,000	3,100	84 (p)	124 (h)	26 (j)	0.30	62 (q)	0.30	40,000 (p)	70,000 (p)	0 040	0 027 (p)	70%
43	Replace low-use incandescent lamps with CFLs upon retirement	1,200,000	860	25 (f)	69 (h)	0.49 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0 080	0.029 (u)	70%
44	Replace hi-use incandescent lamps with CFLs upon retirement	1,700,000	3,100	63 (f)	236 (h)	0.41 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0.076	0.020 (u)	70%
45	Retrofit low-use incandescent lamps with CFLs	1,200,000	860	25 (f)	69 (h)	0.49 (j)	0.10	15 (j)	0 10	1,000 (j)	10,000 (u)	0.080	0.029 (u)	70%
46	Retrofit hi-use incandescent lamps with CFLs	1,700,000	3,100	63 (f)	236 (h)	0.41 (j)	0.10	15 (j)	0.10	1,000 (j)	10,000 (u)	0 076	0 020 (u)	70%
47	Occupancy sensors (commercial)	5,327,400 (a)						5 (r)			15			
48	Daylighting controls (commercial)	260,000 (b)						60 (r)			15			
	INDUSTRIAL (54% of Total Consumption)													
49	Replace small low-use motors with hi-eff. motors upon retirement	56,837	1,650	5,230 (k)	5,544 (i)	150 (j)		213 (k)		20 (j)	20	4 2	4 (k)	72%
50	Replace medium low-use motors with hi-eff. motors upon retirement	583,077	1,690	19,386 (k)	20,280 (i)	500 (j)		650 (k)		20 (j)	20	15 0	14 (k)	71%

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std. Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std. Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip. kW (1)	Power Consumption Measure kW	Load Factor (2)
51	Replace large low-use motors with hi-eff. motors upon retirement	44,571	1,980	70,882 (k)	72,864 (i)	1,334 (k)		1,794 (k)		20 (j)	20	46	45 (k)	71%
52	Replace very large low-use motors with hi-eff. motors upon retirement	8,858	3,390	752,146 (k)	767,496 (i)	8,207 (k)		11,037 (k)		20 (j)	20	283	277 (k)	72%
53	Replace small hi-use motors with hi-eff. motors upon retirement	383,422	3,490	8,165 (k)	8,655 (i)	150 (j)		197 (k)		20 (j)	20	3.1	3 (k)	72%
54	Replace medium hi-use motors with hi-eff. motors upon retirement	640,724	3,760	28,754 (k)	30,080 (i)	500 (j)		600 (k)		20 (j)	20	10.0	10 (k)	71%
55	Replace large hi-use motors with hi-eff. motors upon retirement	71,567	4,060	236,975 (k)	243,600 (i)	2,175 (k)		2,925 (k)		20 (j)	20	75	73 (k)	71%
56	Replace very large hi-use motors with hi-eff. motors upon retirement	8,577	4,800	2,024,602 (k)	2,065,920 (i)	15,602 (k)		20,982 (k)		20 (j)	20	538	527 (k)	72%
57	Replace small low-use motors with hi-eff. motors upon rewind	56,837	1,650	5,230 (k)	5,657 (i)	82 (m)		197 (k)		20 (j)	20	4.3 (v)	4 (k)	72%
58	Replace medium low-use motors with hi-eff. motors upon rewind	583,077	1,690	19,386 (k)	20,694 (i)	279 (m)		600 (k)		20 (j)	20	15.3 (v)	14 (k)	71%
59	Replace large low-use motors with hi-eff. motors upon rewind	44,571	1,980	70,882 (k)	74,351 (i)	1,609 (m)		2,925 (k)		20 (j)	20	47 (v)	45 (k)	71%
60	Replace very large low-use motors with hi-eff. motors upon rewind	8,858	3,390	752,146 (k)	783,159 (i)	11,540 (m)		20,982 (k)		20 (j)	20	288.78 (v)	277 (k)	72%
61	Replace small hi-use motors with hi-eff. motors upon rewind	383,422	3,490	8,165 (k)	8,832 (i)	82 (m)		197 (k)		20 (j)	20	3.2 (v)	3 (k)	72%
62	Replace medium hi-use motors with hi-eff. motors upon rewind	640,724	3,760	28,754 (k)	30,694 (i)	279 (m)		600 (k)		20 (j)	20	10.2 (v)	10 (k)	71%
63	Replace large hi-use motors with hi-eff. motors upon rewind	71,567	4,060	236,975 (k)	248,571 (i)	1,609 (m)		2,925 (k)		20 (j)	20	77 (v)	73 (k)	71%
64	Replace very large hi-use motors with hi-eff. motors upon rewind	8,577	4,800	2,024,602 (k)	2,108,082 (i)	11,540 (m)		20,982 (k)		20 (j)	20	548.98 (v)	527 (k)	72%
65	Retrofit small low-use motors with drive measures	17,051	1,650	3,604 (k)	5,544 (i)			2845 (k)	20		15	4.2	3.78	72%
66	Retrofit medium low-use motors with drive measures	174,923	1,690	13,182 (k)	20,280 (i)			5,200 (k)	20		15	15.0	13.5	71%
67	Retrofit large low-use motors with drive measures	13,371	1,980	47,362 (k)	72,864 (i)			10,160 (k)	20		15	46	41 4	71%
68	Retrofit very large low-use motors with	2,657	3,390	498,872 (k)	767,496 (i)			27,735 (k)	20		15	283	254 7	72%

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std. Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std. Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip kW (1)	Power Consumption Measure kW	Load Factor (2)
	drive measures													
69	Retrofit small hi-use motors with drive measures	115,027	3,490	5,626 (k)	8,655 (i)			2617 (k)	20		15	3.1	2 79	72%
70	Retrofit medium hi-use motors with drive measures	192,217	3,760	19,552 (k)	30,080 (i)			4,400 (k)	20		15	10 0	9	71%
71	Retrofit large hi-use motors with drive measures	21,470	4,060	158,340 (k)	243,600 (i)			14,800 (k)	20		15	75	67.5	71%
72	Retrofit very large hi-use motors with drive measures	2,573	4,800	1,342,848 (k)	2,065,920 (i)			36,707 (k)	20		15	538	484.2	72%
73	Motor downsizing (Industrial)	339,344 (c)	2,832 (c)	47,087 (k)	49,566 (i)			1000 (s)			20	22 (c)	21 (k)	71%
74	Replace low-use fluorescent ballasts with efficient core-coil ballasts upon retirement	3,325,557	1,733	104 (p)	113 (h)	18 (j)	0.30	23 (p)	0.30	40,000	45,000 (p)	0.065	0 060 (p)	67%
75	Replace hi-use fluorescent ballasts with efficient core-coil ballasts upon retirement	2,378,791	3,332	233 (p)	253 (h)	26 (j)	0 30	31 (p)	0.30	40,000	45,000 (p)	0.076	0 070 (p)	67%
76	Replace low-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	3,325,557	1,733	77 (p)	113 (h)	18 (j)	0.30	54 (q)	0.30	40,000 (p)	70,000 (p)	0.065	0 044 (p)	67%
77	Replace hi-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,378,791	3,332	172 (p)	253 (h)	26 (j)	0.30	62 (q)	0.30	40,000 (p)	70,000 (p)	0.076	0.052 (p)	67%
78	Retrofit low-use fluorescent ballasts with efficient core-coil ballasts	3,325,557	1,733	104 (p)	113 (h)	18 (j)	0.30	23 (p)	0.30	40,000 (p)	45,000 (p)	0.065	0.060 (p)	67%
79	Retrofit hi-use fluorescent ballasts with efficient core-coil ballasts	2,378,791	3,332	233 (p)	253 (h)	26 (j)	0.30	31 (p)	0.30	40,000 (p)	45,000 (p)	0 076	0.070 (p)	67%
80	Retrofit low-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	3,325,557	1,733	77 (p)	113 (h)	18 (j)	0.30	54 (q)	0.30	40,000 (p)	70,000 (p)	0.065	0.044 (p)	67%
81	Retrofit hi-use fluorescent lamps & ballasts with T-8 lamps and solid state ballasts	2,378,791	3,332	172 (p)	253 (h)	26 (j)	0.30	62 (q)	0.30	40,000 (p)	70,000 (p)	0.076	0 052 (p)	67%
82	Retrofit mercury vapor lamps with high pressure sodium	487,502	2,729	573 (p)	1,288 (h)	17 (j)		27 (n)	0.50	20,000 (q)	20,000 (p)	0 472	0 21 (p)	67%
83	Retrofit high wattage incandescent with metal halide (industrial)	3,985,457	2,526	202 (p)	652 (h)	5 (j)		45 (t)	0.50	2,500 (t)	8,000 (t)	0 258 (t)	0 08 (t)	67%
84	Optimize production processes through process monitoring	113,476 (d)		757,359 (d)	780,782 (d)	5000 (d)					10	289 (d)	272 (d)	70%
85	Industrial Maintenance	113,476 (d)		741,743 (d)	780,782 (d)	7825 (d)					10	289 (d)	275 (d)	70%

Technical and Economic Characteristics of Potential DSM Measures

No.	Measure	Number of Eligible Installations (1)	Annual Hours of Operation (1)	Annual Measure Consumption kWh/yr	Annual Consumption of Std. Equipment kWh/yr (1)	Cost of Standard Equipment $	Labor Hrs for Standard Equipment $	Cost of Measure $	Labor Hours for Measure	Life of Std. Equipment hr or yr	Life of Measure hr or yr	Power Consumption Std. Equip. kW (1)	Power Consumption Measure kW	Load Factor (2)

Notes and References:

(1) Unless otherwise noted, data is taken from surveys performed in Ukraine
(2) Load Factors calculated as annual energy use divided by (8760*demand at peak daytype and hour). Annual use and peak demand are in loadshapes presented in Chapter 2.
(a) The figure is in square meters. A study by the New York State Energy and Research Development Authority, "The Potential for Electric Conservation in New York State", 1989, indicates that occupancy sensors can save 50% of energy in 15% of lighting installations. Assuming an energy intensity of 30 kWh/m2-yr, there are 5,327,400 m2 of eligible floor space
(b) The NYSERDA report (see a) estimates that daylighting saves between 13% to 40% of lighting energy depending on building type. It is assumed for Ukraine that the most promising 880,000 fixtures (10% of all fixtures) account for 20% of total building lighting load, and could reduce total lighting load by 10% if they were retrofit with controls.
(c) Assumes 25% of medium, large, and very large motors are candidates for downsizing. Hours of use and power demand are averages for these motor sizes. Cost based on motor swapping program.
(d) The average energy consumption for each site is calculated by dividing the total industrial consumption by the number of industrial sites.
The demand figure is the sum of the product of the number of industrial installations (e.g., lighting, small motors) and the power draw for a typical installation, divided by the total number of industrial sites.
(e) Assumes 50% of street lighting installations are eligible. Operating hours are equivalent to 11 hours/day, 365 days/week. Consumption figures derived using total street lighting consumption and data from the Poland DSM Assessment.
(f) Office of Technology Assessment, "Energy Efficiency Technologies for Central and Eastern Europe", (draft report) 1993.
(h) Standard Equipment Power multiplied by operating hours
(i) Standard Equipment Power multiplied by operating hours and a .8 load factor
(j) Based on Surveys from the Poland DSM Assessment
(k) American Council for an Energy Efficient Economy, "Energy Efficient Motor Systems", 1992.
(m) FEWE reported that average rewind costs are about 50% of the cost of a standard motor. The exact proportions used here, which allocate lower percentage costs to smaller motors, is consistent with the FEWE finding, and is based on USAID (Office of Energy and Infrastructure), "Mexico: DSM Assessment", 1993.
(n) Grainger Net Wholesale Catalog, 1992
(o) Lawrence Berkeley Laboratory "Energy Efficiency and Household Electric Appliances in Developing and Newly Industrialized countries", 1990.
(p) Lawrence Berkeley Laboratory, "Technology Assessment: Energy-Efficient Commercial Lighting", 1989
(q) Electric Power Software
(r) Cost based on NYSERDA Study (see (a)) and Poland DSM Assessment
(s) Cost Based on Motor Swapping Program. The cost includes $300 for installation and $700 to identify participants and arrange swapping.
(t) Sylvania Large Lamp Price Schedule 91-1-1.
(u) Electric Power Software and Hagler Bailly
(v) Power draw was increased by 2% to reflect a decrease in efficiency of 2% due to rewind
(x) Calculated assuming that half of the total efficiency improvement results from more efficient (lower kW) compressors and motors)
(y) For Communal Services the number of motors was derived assuming that total consumption is 14.3 TWh, with OH of 700 hours for all motors, and power draw and motor distribution are identical to those of the industrial sector.

Values without notes or references are assumed

Global Assumptions:
Real Discount Rate: 12.0%
Labor Cost: 1.2$/hr
Drive Applicability: 30.0%

APPENDIX C
COST OF CONSERVED ENERGY AND CAPACITY

Measures Selected for the Energy Supply Curve

#	No.	Measure	Cost of Conserved Energy ($/kWh)	Savings Potential (GWh)
1	33	Retrofit very large hi-use motors with drive measures (commercial)	$0.005	260
2	29	Retrofit very large low-use motors with drive measures (commercial)	$0.007	141
3	72	Retrofit very large hi-use motors with drive measures (industrial)	$0.007	1,861
4	19	Replace medium low-use motors with hi-eff. motors upon rewind (commercial)	$0.008	303
5	18	Replace small low-use motors with hi-eff. motors upon rewind (commercial)	$0.008	10
6	24	Replace large hi-use motors with hi-eff. motors upon rewind (commercial)	$0.009	138
7	25	Replace very large hi-use motors with hi-eff. motors upon rewind (commercial)	$0.010	100
8	22	Replace small hi-use motors with hi-eff. motors upon rewind (commercial)	$0.011	49
9	23	Replace medium hi-use motors with hi-eff. motors upon rewind (commercial)	$0.012	222
10	20	Replace large low-use motors with hi-eff. motors upon rewind (commercial)	$0.014	52
11	32	Retrofit large hi-use motors with drive measures (commercial)	$0.015	303
12	64	Replace very large hi-use motors with hi-eff. motors upon rewind (industrial)	$0.015	716
13	68	Retrofit very large low-use motors with drive measures (industrial)	$0.015	714
14	63	Replace large hi-use motors with hi-eff. motors upon rewind (industrial)	$0.015	830
15	82	Retrofit mercury vapor lamps with high pressure sodium (industrial)	$0.016	349
16	9	Retrofit street lighting mercury vapor lamps with high-pressure sodium	0.016	135
17	28	Retrofit large low-use motors with drive measures (commercial)	$0.017	116
18	21	Replace very large low-use motors with hi-eff. motors upon rewind (commercial)	$0.020	54
19	1	Replace small refrigerators (approx. 150 l) upon retirement with 1990 US average	$0.020	963
20	3	Replace large refrigerators (approx. 230 l) upon retirement with 1990 US standard	$0.021	1,597
21	34	Motor downsizing (commercial)	$0.022	199
22	62	Replace medium hi-use motors with hi-eff. motors upon rewind (industrial)	$0.022	1,243
23	61	Replace small hi-use motors with hi-eff. motors upon rewind (industrial)	$0.023	256
24	46	Retrofit hi-use incandescent lamps with CFLs (commercial)	$0.025	294
25	71	Retrofit large hi-use motors with drive measures (industrial)	$0.026	1,831
26	27	Retrofit medium low-use motors with drive measures (commercial)	$0.026	493

#	No.	Measure	Cost of Conserved Energy ($/kWh)	Savings Potential (GWh)
27	75	Replace hi-use fluorescent ballasts with efficient core-coil ballasts upon retirement (industrial)	$0.032	48
28	8	Retrofit hi-use incandescent lamps with CFLs (residential)	$0.033	3,328
29	58	Replace medium low-use motors with hi-eff. motors upon rewind (industrial)	$0.033	763
30	31	Retrofit medium hi-use motors with drive measures (commercial)	$0.033	361
31	85	Industrial Maintenance	$0.035	4,430
32	57	Replace small low-use motors with hi-eff. motors upon rewind (industrial)	$0.036	24
33	84	Optimize production processes through process monitoring (industrial)	$0.038	2,658
34	60	Replace very large low-use motors with hi-eff. motors upon rewind (industrial)	$0.041	275
35	47	Occupancy sensors (commercial)	$0.042	92
36	45	Retrofit low-use incandescent lamps with CFLs (commercial)	$0.044	53
37	59	Replace large low-use motors with hi-eff. motors upon rewind (industrial)	$0.051	155
38	26	Retrofit small low-use motors with drive measures (commercial)	$0.051	13
39	73	Motor downsizing (Industrial)	$0.054	841
40	67	Retrofit large low-use motors with drive measures (industrial)	$0.059	341
41	70	Retrofit medium hi-use motors with drive measures (industrial)	$0.062	2,024
42	30	Retrofit small hi-use motors with drive measures (commercial)	$0.064	67
43	36	Replace hi-use fluorescent ballasts with ef core-coil ballasts upon retirement (commercial)	$0.065	26
44	83	Retrofit high wattage incandescent with metal halide (industrial)	$0.066	1,792
45	74	Replace low-use fluorescent ballasts with efficient core-coil ballasts upon retirement (industrial)	$0.068	30
Total				**30,547**

Measures Selected for the Demand Supply Curve

No.	#	Measure	Cost of Conserved Capacity ($/kW-yr)	Savings Potential (MW)
1	33	Retrofit very large hi-use motors with drive measures (commercial)	$28	47
2	29	Retrofit very large low-use motors with drive measures (commercial)	$41	25
3	19	Replace medium low-use motors with hi-eff. motors upon rewind (commercial)	$44	54
4	18	Replace small low-use motors with hi-eff. motors upon rewind (commercial)	$47	2
5	72	Retrofit very large hi-use motors with drive measures (industrial)	$47	293
6	24	Replace large hi-use motors with hi-eff. motors upon rewind (commercial)	$49	25
7	25	Replace very large hi-use motors with hi-eff. motors upon rewind (commercial)	$58	18
8	54	Replace medium hi-use motors with hi-eff. motors upon retirement (industrial)	$63	137
9	22	Replace small hi-use motors with hi-eff. motors upon rewind (commercial)	$64	9
10	23	Replace medium hi-use motors with hi-eff. motors upon rewind (commercial)	$66	40
11	13	Replace very large low-use motors with hi-eff. motors upon retirement (commercial)	$66	5
12	17	Replace very large hi-use motors with hi-eff. motors upon retirement (commercial)	$66	9
13	9	Retrofit street lighting mercury vapor lamps with high-pressure sodium (commercial)	$70	31
14	20	Replace large low-use motors with hi-eff. motors upon rewind (commercial)	$80	9
15	53	Replace small hi-use motors with hi-eff. motors upon retirement (industrial)	$80	30
16	32	Retrofit large hi-use motors with drive measures (commercial)	$82	54
17	82	Retrofit mercury vapor lamps with high pressure sodium (industrial)	$92	60
18	28	Retrofit large low-use motors with drive measures (commercial)	$92	21
19	63	Replace large hi-use motors with hi-eff. motors upon rewind (industrial)	$95	133
20	64	Replace very large hi-use motors with hi-eff. motors upon rewind (industrial)	$96	113
21	68	Retrofit very large low-use motors with drive measures (industrial)	$96	113
22	21	Replace very large low-use motors with hi-eff. motors upon rewind (commercial)	$110	10
Total				**1,236**

APPENDIX D
DATA USED IN MODELING OF LOAD MANAGEMENT BIDDING

Case #1: No DSM Winter Weekday

Hour:	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Demand		23 33	23 12	23.09	23 20	23 73	25 20	27.04	27.88	28 30	28 03	27.70	27.28	27 20	27 13	26 77	26 94	27 89	28 74	28 59	28 18	27 71	26.62	25 24	24 07	633 0
Less: Nuclear capacity operating		8 0	8 0	8.0	8.0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8.0	8.0	8 0	8 0	192 0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1 5	1.5	1.5	1.5	1.5	1 5	36 0
Equals: Residual demand		13.8	13.6	13.6	13.7	14.2	15.7	17 5	18.4	18 8	18 5	18 2	17 8	17 7	17.6	17.3	17 4	18.4	19 2	19 1	18.7	18.2	17.1	15.7	14 6	405.0
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6 5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	
Coal-fired 2	2.2	6.4	6.4	6 4	6.4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6 4	6 4	6 4	6.4	6 4	6 4	
Coal-fired 3	2.5	2 8	2 8	2.8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2.8	2 8	
Oil-fired 1	3 5	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2.0	2 0	
Oil-fired 2	3.6	0 5	0.5	0.5	0.5	0 5	0 5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0.5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	
Gas-fired 1	3.7	1 0	1 0	1 0	1.0	1.0	1.0	1.0	1 0	1 0	1.0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1 0	1 0	
Gas-fired 2	3 9	0 5	0.5	0 5	0 5	0.5	0 5	0.5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0.5	0 5	
Coal-fired 4	4.5	0.8	0.8	0 8	0 8	0 8	0.8	0 8	0.8	0.8	0 8	0 8	0.8	0 8	0 8	0 8	0.8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	
Oil-fired 3	5.0	0 3	0 3	0 3	0 3	0.3	0.3	0 3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0.3	0.3	0.3	0.3	0 3	
Gas-fired 3	6.1	0.3	0 3	0.3	0 3	0 3	0.3	0.3	0.3	0 3	0 3	0.3	0.3	0 3	0 3	0.3	0 3	0 3	0 3	0.3	0 3	0 3	0.3	0 3	0.3	
Oil-fired 4	7.5	1.0	1 0	1.0	1.0	1.0	1 0	1.0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1.0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1 0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		40%	41%	41%	41%	37%	29%	21%	17%	15%	16%	18%	20%	20%	20%	22%	21%	17%	13%	14%	16%	18%	22%	29%	35%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6.5	6 5	6 5	6.5	6 5	6.5	156 0
Coal-fired 2		6.4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6.4	6 4	6 4	6 4	6.4	6 4	6 4	6.4	6 4	6.4	153 6
Coal-fired 3		0.93	0 72	0 69	0.8	1 33	2 8	2 8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	1.67	56.5
Oil-fired 1		0	0	0	0	0	0	1 84	2	2	2	2	2	2	1.93	1.57	1 74	2	2	2	2	2	1 42	0.04	0	30 5
Oil-fired 2		0	0	0	0	0	0	0	0 5	0 5	0 5	0.5	0.08	0	0	0	0	0.5	0.5	0.5	0.5	0.5	0	0	0	4 6
Gas-fired 1		0	0	0	0	0	0	0	0 18	0.6	0.33	0.00	0	0	0	0	0	0.19	1	0 89	0.48	0.01	0	0	0	3 7
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.04	0	0	0	0	0	0	0 0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		13 8	13.6	13.6	13.7	14.2	15.7	17.5	18.4	18 8	18.5	18.2	17.8	17 7	17.6	17.3	17.4	18.4	19.2	19.1	18.7	18.2	17.1	15.7	14 6	405 0

Case #1: No DSM — Winter Weekday

Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2 2	2.2	2 2	2.2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2.2	2 2	2 2	2 2	2 2	2 2	2.2	2 2	
Coal-fired 3	2.5	2.5	2.5	2.5	2.5	2.5	2 5	2.5	2 5	2 5	2 5	2 5	2 5	2 5	2 5	2 5	2.5	2 5	2 5	2 5	2 5	2 5	2.5	2.5	
Oil-fired 1	0	0	0	0	0	0	3.5	3 5	3 5	3 5	3 5	3 5	3.5	3.5	3.5	3.5	3 5	3 5	3 5	3 5	3 5	3.5	3.5	0	
Oil-fired 2	0	0	0	0	0	0	0	3.6	3.6	3 6	3 6	3.6	0	0	0	0	3.6	3.6	3.6	3 6	3.6	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	3.7	3.7	3.7	3.7	0	0	0	0	0	3.7	3.7	3.7	3.7	3.7	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.9	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.5	2.5	2.5	2.5	2.5	2.5	3.5	3.7	3 7	3.7	3.7	3.6	3.5	3.5	3.5	3.5	3.7	3.9	3.7	3.7	3.7	3.5	3.5	2.5	
Resource payment	milion $																								million $
Coal-fired 1	0 16	0.16	0.16	0.16	0.16	0.16	0.23	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.24	0.25	0.24	0.24	0.24	0.23	0.23	0.16	5 1
Coal-fired 2	0 16	0.16	0.16	0.16	0.16	0.16	0.22	0.24	0.24	0.24	0.24	0.23	0.22	0.22	0.22	0.22	0.24	0.25	0.24	0.24	0.24	0.22	0.22	0.16	5.1
Coal-fired 3	0.02	0.02	0.02	0.02	0.03	0 07	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.11	0.1	0.1	0.1	0.1	0.1	0.04	1.9
Oil-fired 1	0	0	0	0	0	0	0 06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.05	0.06	0.07	0.08	0.07	0.07	0.07	0.05	0.00	0	1.1
Oil-fired 2	0	0	0	0	0	0	0	0.02	0 02	0.02	0.02	0.00	0	0	0	0	0.02	0.02	0.02	0.02	0.02	0	0	0	0 2
Gas-fired 1	0	0	0	0	0	0	0	0.01	0.02	0.01	0.00	0	0	0	0	0	0.01	0.04	0.03	0.02	0.00	0	0	0	0 1
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.35	0.34	0.34	0.34	0.36	0.39	0.61	0.68	0.7	0.69	0.67	0.64	0.62	0.62	0.6	0.61	0.68	0.75	0.71	0.69	0.67	0.6	0.55	0.36	13.6

[redacted]

Case #1: No DSM — **Winter Weekend**

	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Demand		22.78	22.45	22.41	22.42	22.68	23.30	23.86	24.24	24.64	24.73	24.71	24.51	24.35	24.24	24.22	25.02	26.50	27.42	27.31	26.84	26.57	25.46	24.39	23.43	588.5
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		13.3	13	12.9	12.9	13.2	13.8	14.4	14.7	15.1	15.2	15.2	15	14.8	14.7	14.7	15.5	17	17.9	17.8	17.3	17.1	16	14.9	13.9	360.5
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.0	2.0	2.0	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		43%	45%	45%	45%	44%	40%	37%	34%	32%	32%	32%	33%	34%	34%	35%	30%	23%	19%	19%	21%	23%	28%	34%	39%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	153.6
Coal-fired 3		0.38	0.05	0.01	0.02	0.28	0.9	1.46	1.84	2.24	2.33	2.31	2.11	1.95	1.84	1.82	2.62	2.8	2.8	2.8	2.8	2.8	2.8	1.99	1.03	42.0
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.3	2	2	1.64	1.37	0.26	0	0	8.6
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.22	0.11	0	0	0	0	0	0.3
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		13.3	13	12.9	12.9	13.2	13.8	14.4	14.7	15.1	15.2	15.2	15	14.8	14.7	14.7	15.5	17	17.9	17.8	17.3	17.1	16	14.9	13.9	360.5

Case #1: No DSM	Winter Weekend																								Daily
Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.5	3.5	3.5	3.5	3.5	3.5	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3.6	3.6	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.5	3.6	3.6	3.5	3.5	3.5	2.5	2.5	
Resource payment																									million $
Coal-fired 1	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.23	0.23	0.23	0.23	0.23	0.23	0.16	0.16	4.3
Coal-fired 2	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.22	0.23	0.23	0.22	0.22	0.22	0.16	0.16	4.2
Coal-fired 3	0.01	0.00	0.00	0.00	0.01	0.02	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.07	0.1	0.1	0.1	0.1	0.1	0.1	0.05	0.03	1.2
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.05	0.07	0.07	0.06	0.05	0.01	0	0	0.3
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.01	0.00	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.33	0.32	0.32	0.32	0.33	0.34	0.36	0.37	0.38	0.38	0.38	0.38	0.37	0.37	0.37	0.39	0.59	0.65	0.64	0.61	0.6	0.56	0.37	0.35	10.1

[redacted]

Case #1: No DSM — **Shoulder Weekday**

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Demand		20 49	20 28	20.26	20 36	20 87	22.23	23 69	24 85	25 81	25 67	25 18	24 51	24 49	24 31	23 82	23 43	23 67	24 69	25 34	25 88	25 63	24.22	22 46	21 31	563 5
Less: Nuclear capacity operating		8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	192 0
Less: Hydro capacity operating		1 5	1.5	1.5	1 5	1 5	1.5	1.5	1 5	1.5	1.5	1.5	1 5	1 5	1.5	1 5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1 5	36 0
Equals: Residual demand		11	10 8	10.8	10.9	11 4	12.7	14 2	15.3	16 3	16 2	15 7	15	15	14 8	14 3	13 9	14 2	15 2	15 8	16 4	16.1	14 7	13	11.8	335 5
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	
Coal-fired 2	2 2	6 4	6 4	6 4	6 4	6 4	6.4	6.4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	
Coal-fired 3	2.5	2 8	2 8	2.8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2.8	2 8	2 8	
Oil-fired 1	3 5	2 0	2.0	2 0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2 0	
Oil-fired 2	3 6	0.5	0.5	0.5	0 5	0.5	0.5	0 5	0.5	0 5	0.5	0.5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	0.5	0 5	0 5	0.5	0 5	0 5	
Gas-fired 1	3 7	1.0	1.0	1.0	1.0	1.0	1.0	1 0	1.0	1 0	1 0	1.0	1 0	1 0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1.0	1.0	1 0	
Gas-fired 2	3.9	0 5	0.5	0 5	0.5	0.5	0.5	0 5	0 5	0.5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	
Coal-fired 4	4 5	0 8	0.8	0 8	0.8	0 8	0.8	0 8	0.8	0 8	0 8	0 8	0 8	0 8	0.8	0 8	0.8	0 8	0 8	0 8	0 8	0 8	0.8	0 8	0 8	
Oil-fired 3	5.0	0 3	0.3	0 3	0.3	0 3	0.3	0.3	0 3	0 3	0 3	0.3	0 3	0 3	0 3	0 3	0.3	0 3	0 3	0.3	0 3	0 3	0.3	0.3	0 3	
Gas-fired 3	6 1	0 3	0 3	0.3	0 3	0 3	0.3	0 3	0.3	0 3	0 3	0.3	0 3	0 3	0 3	0 3	0.3	0 3	0 3	0.3	0 3	0 3	0 3	0.3	0 3	
Oil-fired 4	7.5	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1.0	1 0	1 0	1.0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		59%	61%	61%	60%	56%	47%	38%	31%	26%	27%	29%	33%	33%	34%	37%	39%	38%	32%	29%	26%	27%	35%	45%	53%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6 5	6.5	6.5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6.5	6.5	6 5	6 5	6 5	6 5	6.5	6.5	156 0
Coal-fired 2		4 49	4 28	4.26	4.36	4.87	6 23	6 4	6.4	6.4	6 4	6.4	6.4	6.4	6.4	6 4	6.4	6.4	6.4	6 4	6 4	6 4	6.4	6.4	5.31	142 6
Coal-fired 3		0	0	0	0	0	0	1 29	2.45	2.8	2 8	2.78	2.11	2.09	1.91	1.42	1.03	1.27	2.29	2.8	2.8	2.8	1.82	0.06	0	34 5
Oil-fired 1		0	0	0	0	0	0	0	0	0.61	0 47	0	0	0	0	0	0	0	0	0.14	0.68	0.43	0	0	0	2 3
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Total thermal		11	10.8	10 8	10.9	11.4	12.7	14 2	15.3	16.3	16 2	15.7	15	15	14.8	14.3	13.9	14.2	15.2	15.8	16.4	16.1	14.7	13	11 8	335 5

Case #1: No DSM	Shoulder Weekday																								Daily
	Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2 2	2.2	2 2	2 2	2.2	2.2	2 2	2.2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	2.5	2.5	2 5	2 5	2.5	2 5	2.5	2.5	2 5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	
Oil-fired 1	0	0	0	0	0	0	0	0	3 5	3.5	0	0	0	0	0	0	0	0	3 5	3.5	3.5	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	3.5	3.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.5	3.5	3.5	2.5	2.5	2.2	
Resource payment																									million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.23	0.23	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.23	0 23	0.23	0.16	0.16	0.14	4.1
Coal-fired 2	0.1	0.09	0.09	0.1	0.11	0.14	0.16	0.16	0.22	0.22	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0 22	0.22	0.22	0.16	0.16	0.12	3.8
Coal-fired 3	0	0	0	0	0	0	0 03	0.06	0.1	0.1	0.07	0.05	0.05	0.05	0.04	0.03	0.03	0.06	0.1	0.1	0.1	0.05	0.00	0	1.0
Oil-fired 1	0	0	0	0	0	0	0	0	0 02	0 02	0	0	0	0	0	0	0	0	0.01	0.02	0.02	0	0	0	0.1
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.24	0.24	0.24	0.24	0.25	0.28	0 35	0.38	0.57	0.57	0.39	0.38	0.37	0.37	0.36	0.35	0.35	0.38	0.55	0.57	0.56	0.37	0.32	0.26	9.0

Case #1: No DSM — **Shoulder Weekend**

		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
	Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Demand		20.08	19.77	19.68	19.79	20.01	20.50	20.99	21.40	21.97	22.01	21.80	21.53	21.33	21.14	20.95	21.20	21.84	23.03	23.64	24.11	24.08	22.81	21.46	20.42	515.5
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		10.6	10.3	10.2	10.3	10.5	11	11.5	11.9	12.5	12.5	12.3	12	11.8	11.6	11.4	11.7	12.3	13.5	14.1	14.6	14.6	13.3	12	10.9	287.5
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		62%	65%	66%	65%	63%	59%	55%	52%	48%	48%	50%	51%	53%	54%	56%	54%	49%	42%	38%	35%	35%	43%	52%	60%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		4.08	3.77	3.68	3.79	4.01	4.5	4.99	5.4	5.97	6.01	5.8	5.53	5.33	5.14	4.95	5.2	5.84	6.4	6.4	6.4	6.4	6.4	5.46	4.42	125.9
Coal-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.63	1.24	1.71	1.68	0.41	0	0	5.7
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		10.6	10.3	10.2	10.3	10.5	11	11.5	11.9	12.5	12.5	12.3	12	11.8	11.6	11.4	11.7	12.3	13.5	14.1	14.6	14.6	13.3	12	10.9	287.5

Case #1: No DSM	Shoulder Weekend																								Daily
Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.5	2.5	2.5	2.5	2.5	0	0	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.5	2.5	2.2	2.2	
Resource payment																									million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.16	0.16	0.14	0.14	3.5
Coal-fired 2	0.09	0.08	0.08	0.08	0.09	0.1	0.11	0.12	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.13	0.16	0.16	0.16	0.16	0.16	0.12	0.1	2.9
Coal-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.02	0.03	0.04	0.04	0.01	0	0	0.1
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.23	0.23	0.22	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.27	0.26	0.26	0.26	0.25	0.26	0.27	0.34	0.35	0.37	0.36	0.33	0.26	0.24	6.5

Case #1: No DSM **Summer Weekday**

	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour:		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Demand		18 56	18.17	18.10	18 20	18 50	19 57	20 95	22 44	23 80	23 88	23 51	23 05	23 02	22 93	22 42	22 01	21 79	21 82	21 82	22 07	23 24	23 34	21.39	19 77	514.3
Less: Nuclear capacity operating		8.0	8.0	8.0	8 0	8 0	8 0	8.0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8.0	8 0	8 0	8 0	8 0	192 0
Less: Hydro capacity operating		1.5	1.5	1 5	1 5	1.5	1 5	1 5	1.5	1.5	1.5	1 5	1.5	1.5	1.5	1 5	1.5	1 5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36 0
Equals: Residual demand		9.06	8.67	8 6	8.7	9	10.1	11.4	12 9	14 3	14.4	14	13 5	13 5	13 4	12 9	12.5	12 3	12 3	12.3	12.6	13.7	13.8	11.9	10.3	286.3
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6.5	6 5	6.5	
Coal-fired 2	2 2	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	
Coal-fired 3	2 5	2 8	2 8	2 8	2.8	2 8	2 8	2 8	2.8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2.8	2 8	2 8	2 8	2 8	2.8	2 8	
Oil-fired 1	3 5	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2.0	2.0	2 0	2 0	2 0	2 0	2.0	
Oil-fired 2	3 6	0.5	0.5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0.5	0.5	0 5	
Gas-fired 1	3.7	1 0	1.0	1.0	1.0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	1.0	1 0	1 0	1.0	1 0	1 0	1.0	1 0	1 0	1 0	1.0	1.0	1.0	
Gas-fired 2	3 9	0 5	0.5	0.5	0 5	0 5	0.5	0 5	0 5	0.5	0.5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	0.5	0 5	0.5	0 5	0 5	0 5	0.5	
Coal-fired 4	4.5	0 8	0.8	0.8	0 8	0 8	0.8	0 8	0.8	0.8	0 8	0.8	0 8	0 8	0 8	0 8	0.8	0.8	0 8	0 8	0 8	0.8	0 8	0 8	0 8	
Oil-fired 3	5 0	0 3	0.3	0 3	0.3	0 3	0.3	0.3	0.3	0 3	0 3	0 3	0 3	0.3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0 3	0 3	0.3	
Gas-fired 3	6 1	0.3	0.3	0.3	0.3	0.3	0 3	0.3	0.3	0 3	0 3	0 3	0 3	0.3	0.3	0 3	0.3	0 3	0 3	0 3	0 3	0.3	0 3	0.3	0 3	
Oil-fired 4	7 5	1.0	1.0	1.0	1.0	1 0	1 0	1.0	1.0	1.0	1 0	1.0	1 0	1 0	1.0	1 0	1.0	1 0	1.0	1 0	1 0	1 0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		76%	79%	80%	79%	76%	67%	56%	45%	37%	36%	39%	41%	42%	42%	45%	48%	50%	49%	49%	48%	40%	40%	52%	65%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6 5	6 5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6.5	6.5	6.5	6.5	6.5	6 5	6.5	6.5	6.5	156 0
Coal-fired 2		2 56	2 17	2 1	2 2	2 5	3 57	4 95	6.4	6 4	6 4	6 4	6.4	6.4	6 4	6.4	6.01	5 79	5.82	5 82	6.07	6.4	6.4	5.39	3.77	122 7
Coal-fired 3		0	0	0	0	0	0	0	0.04	1 4	1 48	1 11	0.65	0.62	0 53	0.02	0	0	0	0	0	0.84	0 94	0	0	7 6
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Total thermal		9.06	8.67	8.6	8.7	9	10.1	11.4	12.9	14 3	14.4	14	13.5	13.5	13.4	12 9	12.5	12.3	12.3	12.3	12.6	13.7	13.8	11.9	10.3	286.3

Case #1: No DSM	Summer Weekday																								Daily
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0	0	0	0	0	2.5	2.5	0	0	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.2	2.2	
Resource payment	milion $																								million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.14	0.14	3.6
Coal-fired 2	0.06	0.05	0.05	0.05	0.06	0.08	0.11	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.13	0.13	0.13	0.13	0.13	0.16	0.16	0.12	0.08	2.9
Coal-fired 3	0	0	0	0	0	0	0	0.00	0.04	0.04	0.03	0.02	0.02	0.01	0.00	0	0	0	0	0	0.02	0.02	0	0	0.2
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.2	0.19	0.19	0.19	0.2	0.22	0.25	0.32	0.36	0.36	0.35	0.34	0.34	0.34	0.32	0.28	0.27	0.27	0.27	0.28	0.34	0.35	0.26	0.23	6.7

Case #1: No DSM — Summer Weekend

		Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Demand		18.36	17.77	17.64	17.70	17.78	18.18	18.64	19.22	19.96	20.22	20.15	19.93	19.78	19.59	19.41	19.54	19.71	19.83	19.88	20.25	21.67	21.81	20.25	18.88	466.2
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		8.86	8.27	8.14	8.2	8.28	8.68	9.14	9.72	10.5	10.7	10.7	10.4	10.3	10.1	9.91	10	10.2	10.3	10.4	10.7	12.2	12.3	10.8	9.38	238.2
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		78%	83%	85%	84%	83%	79%	75%	70%	63%	61%	62%	64%	65%	66%	68%	67%	65%	64%	64%	61%	50%	49%	61%	73%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		2.36	1.77	1.64	1.7	1.78	2.18	2.64	3.22	3.96	4.22	4.15	3.93	3.78	3.59	3.41	3.54	3.71	3.83	3.88	4.25	5.67	5.81	4.25	2.88	82.2
Coal-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		8.86	8.27	8.14	8.2	8.28	8.68	9.14	9.72	10.5	10.7	10.7	10.4	10.3	10.1	9.91	10	10.2	10.3	10.4	10.7	12.2	12.3	10.8	9.38	238.2

Case #1: No DSM — **Summer Weekend**

Price needed to dispatch: (c/kWh)	Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Resource payment																									million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	3.4
Coal-fired 2	0.05	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.09	0.09	0.09	0.09	0.08	0.08	0.07	0.08	0.08	0.08	0.09	0.09	0.12	0.13	0.09	0.06	1.8
Coal-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.19	0.18	0.18	0.18	0.18	0.19	0.2	0.21	0.23	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.27	0.27	0.24	0.21	5.2

Case #1: No DSM

July		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour:		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Demand		18.4	18	17.9	17.9	18.1	19.1	20.3	21.4	22.7	22.9	22.7	22.4	22.3	22.2	21.7	21.5	21.5	21.4	21.3	21.2	22.1	22.9	21.4	19.6	500.9
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		8.93	8.51	8.38	8.42	8.62	9.62	10.8	11.9	13.2	13.4	13.2	12.9	12.8	12.7	12.2	12	12	11.9	11.8	11.7	12.6	13.4	11.9	10.1	272.9
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		77%	81%	82%	82%	80%	70%	60%	52%	44%	42%	44%	46%	46%	47%	50%	51%	52%	52%	53%	54%	47%	43%	53%	67%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		2.43	2.01	1.88	1.92	2.12	3.12	4.33	5.44	6.4	6.4	6.4	6.38	6.34	6.19	5.73	5.52	5.46	5.42	5.28	5.18	6.11	6.4	5.36	3.57	115.4
Coal-fired 3		0	0	0	0	0	0	0	0	0.29	0.49	0.32	0	0	0	0	0	0	0	0	0	0	0.46	0	0	1.6
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		8.93	8.51	8.38	8.42	8.62	9.62	10.8	11.9	13.2	13.4	13.2	12.9	12.8	12.7	12.2	12	12	11.9	11.8	11.7	12.6	13.4	11.9	10.1	272.9

Case #1: No DSM

	July																								Daily
Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2 2	2 2	2 2	2.2	2 2	2.2	2.2	2.2	2.2	2.2	2 2	2.2	2.2	2 2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	0	0	2.5	2.5	2 5	0	0	0	0	0	0	0	0	0	0	2.5	0	0	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2 2	2.2	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.2	2.2	
Resource payment																									million $
Coal-fired 1	0 14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0 14	0.14	0.14	0.14	0.14	0.14	0.16	0.14	0.14	3.5
Coal fired 2	0.05	0.04	0.04	0.04	0.05	0.07	0.1	0.12	0.16	0 16	0.16	0.14	0.14	0.14	0.13	0.12	0.12	0.12	0.12	0.11	0.13	0 16	0.12	0.08	2.6
Coal-fired 3	0	0	0	0	0	0	0	0	0.01	0.01	0.01	0	0	0	0	0	0	0	0	0	0	0.01	0	0	0 0
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.2	0.19	0.18	0.19	0.19	0.21	0.24	0.26	0 33	0.33	0.33	0.28	0.28	0.28	0.27	0.26	0.26	0.26	0.26	0.26	0.28	0.33	0.26	0.22	6.2

Case #1: No DSM		August																								Daily
	Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Demand		18.3	17.9	17.9	18	18.2	18 8	20	21 3	22.6	22.8	22 4	22.1	22 1	22	21 6	21.3	21 2	21.2	21 3	21.8	23 3	22.6	20 4	19 1	498 2
Less: Nuclear capacity operating		8.0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	192 0
Less: Hydro capacity operating		1.5	1.5	1.5	1 5	1 5	1 5	1.5	1 5	1 5	1.5	1 5	1.5	1.5	1 5	1.5	1 5	1 5	1 5	1 5	1.5	1.5	1.5	1.5	1.5	36 0
Equals: Residual demand		8.76	8.41	8.38	8.47	8 69	9.3	10.5	11.8	13 1	13.3	12.9	12 6	12 6	12 5	12.1	11 8	11.7	11.7	11 8	12.3	13 8	13.1	10.9	9 62	270 2
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	
Coal-fired 2	2 2	6 4	6.4	6.4	6.4	6 4	6 4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6 4	6 4	
Coal-fired 3	2 5	2 8	2 8	2.8	2 8	2.8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	
Oil-fired 1	3 5	2 0	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	
Oil-fired 2	3 6	0.5	0.5	0.5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	0.5	0 5	
Gas-fired 1	3 7	1.0	1.0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	1.0	1.0	1.0	1 0	1 0	1 0	1.0	1 0	1 0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0.5	0 5	
Coal-fired 4	4 5	0.8	0 8	0.8	0.8	0 8	0 8	0.8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0.8	0 8	0 8	0.8	0 8	0 8	0 8	0.8	0 8	
Oil-fired 3	5.0	0 3	0.3	0.3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0.3	0 3	0 3	0 3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	
Gas-fired 3	6.1	0 3	0.3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0 3	0.3	0 3	0 3	0.3	0.3	0 3	
Oil-fired 4	7 5	1.0	1.0	1 0	1 0	1.0	1.0	1 0	1.0	1.0	1.0	1 0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1.0	1 0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Reserve margin		78%	82%	82%	81%	79%	73%	63%	53%	44%	43%	45%	48%	48%	48%	51%	53%	54%	53%	53%	49%	40%	44%	60%	71%	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6 5	6.5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6.5	6.5	6.5	6.5	6.5	6 5	6.5	6.5	6.5	6.5	6 5	6.5	6.5	6.5	156 0
Coal-fired 2		2 26	1 91	1 88	1 97	2.19	2.8	3.98	5 32	6 4	6 4	6.4	6 07	6.08	5.97	5.58	5.33	5.22	5.24	5 32	5 82	6.4	6.4	4.39	3.12	112 5
Coal-fired 3		0	0	0	0	0	0	0	0	0.2	0.4	0.04	0	0	0	0	0	0	0	0	0	0.85	0 22	0	0	1 7
Oil-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 1		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 2		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Coal-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 3		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Oil-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0 0
Gas-fired 4		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal		8.76	8.41	8.38	8.47	8.69	9.3	10 5	11 8	13 1	13.3	12.9	12.6	12.6	12.5	12.1	11.8	11.7	11.7	11.8	12.3	13.8	13.1	10.9	9 62	270.2

Case #1: No DSM	August																								Daily
Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0	0	0	0	0	0	0	0	2.5	2.5	2.5	0	0	0	0	0	0	0	0	0	2.5	2.5	0	0	
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.2	2.2	
Resource payment																									million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.14	0.14	3.5
Coal-fired 2	0.05	0.04	0.04	0.04	0.05	0.06	0.09	0.12	0.16	0.16	0.16	0.13	0.13	0.13	0.12	0.12	0.11	0.12	0.12	0.13	0.16	0.16	0.1	0.07	2.6
Coal-fired 3	0	0	0	0	0	0	0	0	0.00	0.01	0.00	0	0	0	0	0	0	0	0	0	0.02	0.01	0	0	0.0
Oil-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Coal-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Oil-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Gas-fired 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0
Total thermal	0.19	0.19	0.18	0.19	0.19	0.2	0.23	0.26	0.33	0.33	0.32	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.26	0.27	0.34	0.33	0.24	0.21	6.1

Case #2: DSM Bidding Winter Weekday

	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour		GW																								GWh
Demand		23.3	23.1	23.1	23.2	23.7	25.2	27	27.9	28.3	28	27.7	27.3	27.2	27.1	26.8	26.9	27.9	28.7	28.6	28.2	27.7	26.6	25.2	24.1	633.0
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		13.8	13.6	13.6	13.7	14.2	15.7	17.5	18.4	18.8	18.5	18.2	17.8	17.7	17.6	17.3	17.4	18.4	19.2	19.1	18.7	18.2	17.1	15.7	14.6	405.0
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		68%	69%	69%	69%	65%	55%	45%	40%	38%	40%	41%	43%	44%	44%	46%	45%	40%	36%	37%	39%	41%	47%	55%	62%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	153.6
Coal-fired 3		0.9	0.7	0.7	0.8	1.3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	1.7	56.5
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	1.8	2.7	3.1	2.8	2.5	2.1	2.0	1.9	1.6	1.7	2.7	3.5	3.4	3.0	2.5	1.4	0.0	0.0	38.8
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		13.8	13.6	13.6	13.7	14.2	15.7	17.5	18.4	18.8	18.5	18.2	17.8	17.7	17.6	17.3	17.4	18.4	19.2	19.1	18.7	18.2	17.1	15.7	14.6	405.0
Total supply		13.8	13.6	13.6	13.7	14.2	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	15.7	14.6	368.2
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	1.8	2.7	3.1	2.8	2.5	2.1	2.0	1.9	1.6	1.7	2.7	3.5	3.4	3.0	2.5	1.4	0.0	0.0	38.8

Case #2: DSM Bidding Winter Weekday

Hour.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.5	2.5	2.5	2.5	2.5	2.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.5	3.0	3.0	3.0	3.0	3.0	2.5	
Resource payment revenue	million $																								million $
Coal-fired 1	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.23	0.20	0.20	0.20	0.20	0.20	0.16	4.48
Coal-fired 2	0.16	0.16	0.16	0.16	0.16	0.16	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.22	0.19	0.19	0.19	0.19	0.19	0.16	4.42
Coal-fired 3	0.02	0.02	0.02	0.02	0.03	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.10	0.08	0.08	0.08	0.08	0.08	0.04	1.67
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.08	0.09	0.08	0.08	0.06	0.06	0.06	0.05	0.05	0.08	0.12	0.10	0.09	0.08	0.04	0.00	0.00	1.18
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.35	0.34	0.34	0.34	0.36	0.39	0.53	0.55	0.56	0.56	0.55	0.53	0.53	0.53	0.52	0.52	0.55	0.67	0.57	0.56	0.55	0.51	0.47	0.36	11.75
Total supply	0.35	0.34	0.34	0.34	0.36	0.39	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.55	0.47	0.47	0.47	0.47	0.47	0.36	10.57
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.08	0.09	0.08	0.08	0.06	0.06	0.06	0.05	0.05	0.08	0.12	0.10	0.09	0.08	0.04	0.00	0.00	1.18

Case #2: DSM Bidding — **Winter Weekend**

	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour:		GW																								GWh
Demand		22.8	22.5	22.4	22.4	22.7	23.3	23.9	24.2	24.6	24.7	24.7	24.5	24.3	24.2	24.2	25	26.5	27.4	27.3	26.8	26.6	25.5	24.4	23.4	588.5
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		13.3	13	12.9	12.9	13.2	13.8	14.4	14.7	15.1	15.2	15.2	15	14.8	14.7	14.7	15.5	17	17.9	17.8	17.3	17.1	16	14.9	13.9	360.5
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		72%	74%	75%	74%	72%	68%	64%	61%	59%	58%	58%	60%	61%	61%	61%	56%	48%	43%	43%	46%	47%	54%	60%	67%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	

Dispatched resources:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
	GW																								Gwh
Coal-fired 1	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	153.6
Coal-fired 3	0.4	0.1	0.0	0.0	0.3	0.9	1.5	1.8	2.2	2.3	2.3	2.1	1.9	1.8	1.8	2.6	2.8	2.8	2.8	2.8	2.8	2.8	2.0	1.0	42.0
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.2	2.1	1.6	1.4	0.3	0.0	0.0	8.9
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13.3	13.0	12.9	12.9	13.2	13.8	14.4	14.7	15.1	15.2	15.2	15.0	14.8	14.7	14.7	15.5	17.0	17.9	17.8	17.3	17.1	16.0	14.9	13.9	360.5
Total supply	13.3	13.0	12.9	12.9	13.2	13.8	14.4	14.7	15.1	15.2	15.2	15.0	14.8	14.7	14.7	15.5	15.7	15.7	15.7	15.7	15.7	15.7	14.9	13.9	351.6
Total DSM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.2	2.1	1.6	1.4	0.3	0.0	0.0	8.9

Case #2: DSM Bidding — **Winter Weekend**

Price needed to *dispatch:* (*c/kWh*)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Coal-fired 3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	0.0
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Pool Price	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.0	3.0	3.0	3.0	3.0	3.0	2.5	2.5

Resource payment revenue (million $)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total (*million $*)
Coal-fired 1	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.16	4.10
Coal-fired 2	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.19	0.19	0.19	0.19	0.19	0.19	0.16	0.16	4.03
Coal-fired 3	0.01	0.00	0.00	0.00	0.01	0.02	0.04	0.05	0.06	0.06	0.06	0.05	0.05	0.05	0.05	0.07	0.08	0.08	0.08	0.08	0.08	0.08	0.05	0.03	1.13
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.06	0.05	0.04	0.01	0.00	0.00	0.27
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.33	0.32	0.32	0.32	0.33	0.34	0.36	0.37	0.38	0.38	0.38	0.38	0.37	0.37	0.37	0.39	0.51	0.54	0.53	0.52	0.51	0.48	0.37	0.35	9.53
Total supply	0.33	0.32	0.32	0.32	0.33	0.34	0.36	0.37	0.38	0.38	0.38	0.38	0.37	0.37	0.37	0.39	0.47	0.47	0.47	0.47	0.47	0.47	0.37	0.35	9.26
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.07	0.06	0.05	0.04	0.01	0.00	0.00	0.27

[redacted]

Case #2: DSM Bidding — Shoulder Weekday

	c/kWh	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Hour:		GW																								GWh
Demand		20.5	20.3	20.3	20.4	20.9	22.2	23.7	24.8	25.8	25.7	25.2	24.5	24.5	24.3	23.8	23.4	23.7	24.7	25.3	25.9	25.6	24.2	22.5	21.3	563.5
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		11.0	10.8	10.8	10.9	11.4	12.7	14.2	15.3	16.3	16.2	15.7	15.0	15.0	14.8	14.3	13.9	14.2	15.2	15.8	16.4	16.1	14.7	13.0	11.8	335.5
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		91%	93%	93%	92%	87%	76%	65%	57%	51%	52%	55%	60%	60%	61%	64%	67%	65%	58%	54%	51%	53%	61%	74%	83%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		4.5	4.3	4.3	4.4	4.9	6.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	5.3	142.6
Coal-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.4	2.8	2.8	2.8	2.1	2.1	1.9	1.4	1.0	1.3	2.3	2.8	2.8	2.8	1.8	0.1	0.0	34.5
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.7	0.4	0.0	0.0	0.0	2.3
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		11.0	10.8	10.8	10.9	11.4	12.7	14.2	15.3	16.3	16.2	15.7	15.0	15.0	14.8	14.3	13.9	14.2	15.2	15.8	16.4	16.1	14.7	13.0	11.8	335.5
Total supply		11.0	10.8	10.8	10.9	11.4	12.7	14.2	15.3	15.7	15.7	15.7	15.0	15.0	14.8	14.3	13.9	14.2	15.2	15.7	15.7	15.7	14.7	13.0	11.8	333.1
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.7	0.4	0.0	0.0	0.0	2.3

Case #2: DSM Bidding — Shoulder Weekday

Price needed to dispatch: (c/kWh) Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.0	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	3.0	0.0	0.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	3.0	3.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3.0	3.0	3.0	2.5	2.5	2.2	

Resource payment revenue (million $)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total (million $)
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.20	0.20	0.20	0.16	0.16	0.14	3.93
Coal-fired 2	0.10	0.09	0.09	0.10	0.11	0.14	0.16	0.16	0.19	0.19	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.19	0.19	0.19	0.16	0.16	0.12	3.62
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.08	0.08	0.07	0.05	0.05	0.05	0.04	0.03	0.03	0.06	0.08	0.08	0.08	0.05	0.00	0.00	0.93
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.07
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.24	0.24	0.24	0.24	0.25	0.28	0.35	0.38	0.49	0.49	0.39	0.38	0.37	0.37	0.36	0.35	0.35	0.38	0.48	0.49	0.48	0.37	0.32	0.26	8.55
Total supply	0.24	0.24	0.24	0.24	0.25	0.28	0.35	0.38	0.47	0.47	0.39	0.38	0.37	0.37	0.36	0.35	0.35	0.38	0.47	0.47	0.47	0.37	0.32	0.26	8.48
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.07

[redacted]

Case #2: DSM Bidding — Shoulder Weekend

	c/kWh	Hour 1	2	3	4	5	6	7	8	9	10	11	12
		GW											
Demand		20.1	19.8	19.7	19.8	20	20.5	21	21.4	22	22	21.8	21.5
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Equals: Residual demand		10.6	10.3	10.2	10.3	10.5	11.0	11.5	11.9	12.5	12.5	12.3	12.0
Available resources:	c/kWh	GW											
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6
Reserve margin		95%	98%	99%	98%	95%	91%	86%	83%	78%	78%	79%	82%
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Dispatched resources:		GW											
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Coal-fired 2		4.1	3.8	3.7	3.8	4.0	4.5	5.0	5.4	6.0	6.0	5.8	5.5
Coal-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		10.6	10.3	10.2	10.3	10.5	11.0	11.5	11.9	12.5	12.5	12.3	12.0
Total supply		10.6	10.3	10.2	10.3	10.5	11.0	11.5	11.9	12.5	12.5	12.3	12.0
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	Hour 13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
													GWh
Demand	21.3	21.1	20.9	21.2	21.8	23	23.6	24.1	24.1	22.8	21.5	20.4	515.5
Less: Nuclear capacity operating	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand	11.8	11.6	11.4	11.7	12.3	13.5	14.1	14.6	14.6	13.3	12.0	10.9	287.5
Available resources:													
Coal-fired 1	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin	83%	85%	87%	84%	79%	70%	65%	62%	62%	71%	82%	91%	
Total supply	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:													Gwh
Coal-fired 1	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2	5.3	5.1	4.9	5.2	5.8	6.4	6.4	6.4	6.4	6.4	5.5	4.4	125.9
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.7
DSM 1	0.0	0.0	0.0	0.0	0.0	0.6	1.2	1.7	1.7	0.4	0.0	0.0	0.0
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	11.8	11.6	11.4	11.7	12.3	13.5	14.1	14.6	14.6	13.3	12.0	10.9	287.5
Total supply	11.8	11.6	11.4	11.7	12.3	13.5	14.1	14.6	14.6	13.3	12.0	10.9	287.5
Total DSM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Case #2: DSM Bidding — **Shoulder Weekend**

Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	0.0	0.0	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.5	2.5	2.2	2.2	
Resource payment revenue	million $																								million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.16	0.16	0.14	0.14	3.53
Coal-fired 2	0.09	0.08	0.08	0.08	0.09	0.10	0.11	0.12	0.13	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.13	0.16	0.16	0.16	0.16	0.16	0.12	0.10	2.86
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03	0.04	0.04	0.01	0.00	0.00	0.14
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.23	0.23	0.22	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.27	0.26	0.26	0.26	0.25	0.26	0.27	0.34	0.35	0.37	0.36	0.33	0.26	0.24	6.54
Total supply	0.23	0.23	0.22	0.23	0.23	0.24	0.25	0.26	0.27	0.28	0.27	0.26	0.26	0.26	0.25	0.26	0.27	0.34	0.35	0.37	0.36	0.33	0.26	0.24	6.54
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Case #2: DSM Bidding — Summer Weekday

		Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
		GW																								GWh
Demand		18.6	18.2	18.1	18.2	18.5	19.6	20.9	22.4	23.8	23.9	23.5	23	23	22.9	22.4	22	21.8	21.8	21.8	22.1	23.2	23.3	21.4	19.8	514.3
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		9.06	8.67	8.6	8.7	9	10.1	11.4	12.9	14.3	14.4	14	13.5	13.5	13.4	12.9	12.5	12.3	12.3	12.3	12.6	13.7	13.8	11.9	10.3	286.3
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		111%	115%	116%	115%	111%	100%	87%	74%	64%	64%	66%	70%	70%	71%	74%	78%	79%	79%	79%	77%	68%	68%	83%	98%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		2.6	2.2	2.1	2.2	2.5	3.6	4.9	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.0	5.8	5.8	5.8	6.1	6.4	6.4	5.4	3.8	122.7
Coal-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	1.5	1.1	0.6	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.9	0.0	0.0	7.6
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		9.1	8.7	8.6	8.7	9.0	10.1	11.4	12.9	14.3	14.4	14.0	13.5	13.5	13.4	12.9	12.5	12.3	12.3	12.3	12.6	13.7	13.8	11.9	10.3	286.3
Total supply		9.1	8.7	8.6	8.7	9.0	10.1	11.4	12.9	14.3	14.4	14.0	13.5	13.5	13.4	12.9	12.5	12.3	12.3	12.3	12.6	13.7	13.8	11.9	10.3	286.3
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Case #2: DSM Bidding

Summer Weekday

Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.2	2.2	
Resource payment revenue	million $																								million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.14	0.14	3.63
Coal-fired 2	0.06	0.05	0.05	0.05	0.06	0.08	0.11	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.13	0.13	0.13	0.13	0.13	0.16	0.16	0.12	0.08	2.89
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.03	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.19
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.20	0.19	0.19	0.19	0.20	0.22	0.25	0.32	0.36	0.36	0.35	0.34	0.34	0.34	0.32	0.28	0.27	0.27	0.27	0.28	0.34	0.35	0.26	0.23	6.71
Total supply	0.20	0.19	0.19	0.19	0.20	0.22	0.25	0.32	0.36	0.36	0.35	0.34	0.34	0.34	0.32	0.28	0.27	0.27	0.27	0.28	0.34	0.35	0.26	0.23	6.71
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Case #2: DSM Bidding		Summer Weekend																								Daily
	Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
		GW																								GWh
Demand		18.4	17.8	17.6	17.7	17 8	18.2	18 6	19 2	20	20 2	20.2	19 9	19.8	19 6	19 4	19 5	19.7	19 8	19 9	20.2	21.7	21.8	20.3	18 9	466 2
Less: Nuclear capacity operating		8 0	8 0	8.0	8.0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	8 0	192 0
Less: Hydro capacity operating		1.5	1.5	1.5	1 5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1 5	1 5	1 5	1.5	1.5	1.5	1 5	1.5	1 5	1.5	1.5	36 0
Equals· Residual demand		8.86	8 27	8.14	8.2	8 28	8 68	9.14	9.72	10 5	10 7	10.7	10 4	10 3	10.1	9 91	10	10.2	10 3	10 4	10 7	12 2	12.3	10.8	9 38	238 2
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6 5	6 5	6 5	6 5	6.5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	6 5	
Coal-fired 2	2.2	6 4	6 4	6 4	6 4	6.4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6 4	6.4	6 4	
Coal-fired 3	2.5	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2.8	2.8	2 8	2 8	2 8	2.8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	2 8	
DSM 1	3 0	3 5	3 5	3.5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	3 5	
Oil-fired 1	3 5	2 0	2 0	2.0	2.0	2 0	2 0	2 0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	2 0	2 0	2.0	2 0	2 0	
Oil-fired 2	3 6	0 5	0 5	0.5	0.5	0.5	0 5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	
Gas-fired 1	3.7	1 0	1.0	1.0	1 0	1 0	1.0	1.0	1 0	1 0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	
Gas-fired 2	3 9	0.5	0 5	0.5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0 5	0.5	0 5	0.5	0 5	0 5	0.5	0 5	0 5	0 5	0 5	0.5	0 5	0 5	
DSM 2	4.0	1.0	1.0	1 0	1 0	1.0	1.0	1.0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	
Coal-fired 4	4 5	0 8	0.8	0.8	0.8	0.8	0 8	0 8	0 8	0 8	0 8	0.8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0 8	0.8	0 8	
Oil-fired 3	5.0	0 3	0 3	0.3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0 3	0.3	0 3	0.3	0.3	0 3	0 3	0.3	
DSM 3	6 0	1 0	1 0	1.0	1 0	1 0	1 0	1.0	1 0	1 0	1 0	1 0	1.0	1 0	1.0	1 0	1.0	1 0	1 0	1 0	1.0	1.0	1 0	1 0	1 0	
Gas-fired 3	6 1	0.3	0.3	0 3	0 3	0 3	0 3	0 3	0.3	0.3	0 3	0.3	0 3	0.3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0 3	0.3	0 3	0 3	
Oil-fired 4	7 5	1 0	1.0	1 0	1 0	1 0	1.0	1.0	1 0	1 0	1.0	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1.0	
DSM 4	8 0	1 0	1.0	1 0	1 0	1 0	1 0	1.0	1.0	1.0	1 0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1.0	
Gas-fired 4	9 0	1.0	1.0	1 0	1.0	1 0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29 6	29.6	29.6	29 6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		113%	120%	122%	121%	120%	115%	110%	103%	96%	93%	94%	96%	98%	100%	101%	100%	98%	97%	97%	93%	80%	79%	93%	107%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6 5	6 5	6.5	6 5	6.5	6.5	6.5	6 5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6 5	6 5	6 5	6.5	6 5	6 5	6.5	6 5	6 5	6 5	6.5	6.5	6 5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6 5	6.5	156 0
Coal-fired 2		2 4	1.8	1.6	1 7	1.8	2.2	2.6	3 2	4.0	4 2	4.2	3.9	3.8	3 6	3.4	3.5	3.7	3.8	3.9	4 2	5.7	5.8	4.3	2.9	82 2
Coal-fired 3		0 0	0.0	0 0	0 0	0.0	0 0	0 0	0 0	0.0	0.0	0 0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0 0
DSM 1		0.0	0.0	0.0	0.0	0 0	0.0	0 0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0 0	0 0	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0
Gas-fired 1		0 0	0 0	0.0	0.0	0 0	0 0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0 0	0.0
Gas-fired 2		0 0	0.0	0.0	0.0	0.0	0.0	0 0	0 0	0.0	0 0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0 0	0.0	0 0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0
Coal-fired 4		0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0 0	0.0	0.0	0.0	0 0	0 0	0 0	0.0	0 0	0.0	0.0	0.0	0 0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0 0	0 0
Gas-fired 3		0.0	0 0	0 0	0.0	0 0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0 0	0 0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0 0	0 0
DSM 4		0.0	0.0	0.0	0.0	0 0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0.0	0.0	0 0
Gas-fired 4		0 0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		8 9	8.3	8.1	8.2	8.3	8.7	9.1	9 7	10.5	10.7	10.7	10.4	10.3	10.1	9.9	10.0	10.2	10 3	10.4	10.7	12.2	12.3	10 8	9 4	238 2
Total supply		8 9	8.3	8.1	8 2	8.3	8.7	9.1	9.7	10.5	10.7	10.7	10.4	10.3	10.1	9.9	10.0	10.2	10.3	10.4	10.7	12.2	12.3	10.8	9.4	238 2
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0 0	0.0	0 0

Case #2: DSM Bidding	Summer Weekend																								Daily
	Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Price needed to dispatch:	c/kWh																								
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Resource payment revenue	million $																								million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	3.43
Coal-fired 2	0.05	0.04	0.04	0.04	0.04	0.05	0.06	0.07	0.09	0.09	0.09	0.09	0.08	0.08	0.07	0.08	0.08	0.08	0.09	0.09	0.12	0.13	0.09	0.06	1.81
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.19	0.18	0.18	0.18	0.18	0.19	0.20	0.21	0.23	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.27	0.27	0.24	0.21	5.24
Total supply	0.19	0.18	0.18	0.18	0.18	0.19	0.20	0.21	0.23	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.27	0.27	0.24	0.21	5.24
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Case #2: DSM Bidding

	c/kWh	July Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
		GW																								GWh
Demand		18.4	18	17.9	17.9	18.1	19.1	20.3	21.4	22.7	22.9	22.7	22.4	22.3	22.2	21.7	21.5	21.5	21.4	21.3	21.2	22.1	22.9	21.4	19.6	500.9
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		8.9	8.5	8.4	8.4	8.6	9.6	10.8	11.9	13.2	13.4	13.2	12.9	12.8	12.7	12.2	12.0	12.0	11.9	11.8	11.7	12.6	13.4	11.9	10.1	272.9
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		112%	117%	119%	118%	116%	104%	92%	82%	72%	71%	72%	75%	75%	76%	80%	82%	82%	83%	84%	85%	77%	71%	83%	100%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		2.4	2.0	1.9	1.9	2.1	3.1	4.3	5.4	6.4	6.4	6.4	6.4	6.3	6.2	5.7	5.5	5.5	5.4	5.3	5.2	6.1	6.4	5.4	3.6	115.4
Coal-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.0	0.0	1.6
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		8.9	8.5	8.4	8.4	8.6	9.6	10.8	11.9	13.2	13.4	13.2	12.9	12.8	12.7	12.2	12.0	12.0	11.9	11.8	11.7	12.6	13.4	11.9	10.1	272.9
Total supply		8.9	8.5	8.4	8.4	8.6	9.6	10.8	11.9	13.2	13.4	13.2	12.9	12.8	12.7	12.2	12.0	12.0	11.9	11.8	11.7	12.6	13.4	11.9	10.1	272.9
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Case #2: DSM Bidding

Price needed to dispatch: (c/kWh) July, Hour.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	0.0	0.0
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.2	2.2

Resource payment revenue (million $)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total (million $)
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.14	0.14	3.51
Coal-fired 2	0.05	0.04	0.04	0.04	0.05	0.07	0.10	0.12	0.16	0.16	0.16	0.14	0.14	0.14	0.13	0.12	0.12	0.12	0.12	0.11	0.13	0.16	0.12	0.08	2.62
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.04
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.20	0.19	0.18	0.19	0.19	0.21	0.24	0.26	0.33	0.33	0.33	0.28	0.28	0.28	0.27	0.26	0.26	0.26	0.26	0.26	0.28	0.33	0.26	0.22	6.16
Total supply	0.20	0.19	0.18	0.19	0.19	0.21	0.24	0.26	0.33	0.33	0.33	0.28	0.28	0.28	0.27	0.26	0.26	0.26	0.26	0.26	0.28	0.33	0.26	0.22	6.16
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Case #2: DSM Bidding — August

	c/kWh	Hour: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total GWh
		GW																								
Demand		18.3	17.9	17.9	18	18.2	18.8	20	21.3	22.6	22.8	22.4	22.1	22.1	22	21.6	21.3	21.2	21.2	21.3	21.8	23.3	22.6	20.4	19.1	498.2
Less: Nuclear capacity operating		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	192.0
Less: Hydro capacity operating		1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	36.0
Equals: Residual demand		8.8	8.4	8.4	8.5	8.7	9.3	10.5	11.8	13.1	13.3	12.9	12.6	12.6	12.5	12.1	11.8	11.7	11.7	11.8	12.3	13.8	13.1	10.9	9.6	270.2
Available resources:	c/kWh	GW																								
Coal-fired 1	2.0	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Coal-fired 2	2.2	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	
Coal-fired 3	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	
DSM 1	3.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
Oil-fired 1	3.5	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Oil-fired 2	3.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
Gas-fired 1	3.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 2	3.9	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	
DSM 2	4.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Coal-fired 4	4.5	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	
Oil-fired 3	5.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
DSM 3	6.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 3	6.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Oil-fired 4	7.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
DSM 4	8.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Gas-fired 4	9.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	
Total capacity		29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	29.6	
Reserve margin		114%	118%	119%	118%	115%	108%	96%	83%	73%	72%	74%	77%	77%	78%	81%	83%	84%	84%	83%	79%	68%	73%	92%	105%	
Total supply		23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	23.1	
Total DSM		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	
Dispatched resources:		GW																								Gwh
Coal-fired 1		6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	156.0
Coal-fired 2		2.3	1.9	1.9	2.0	2.2	2.8	4.0	5.3	6.4	6.4	6.4	6.1	6.1	6.0	5.6	5.3	5.2	5.2	5.3	5.8	6.4	6.4	4.4	3.1	112.5
Coal-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9	0.2	0.0	0.0	1.7
DSM 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 1		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 2		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 3		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired 4		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		8.8	8.4	8.4	8.5	8.7	9.3	10.5	11.8	13.1	13.3	12.9	12.6	12.6	12.5	12.1	11.8	11.7	11.7	11.8	12.3	13.8	13.1	10.9	9.6	270.2
Total supply		8.8	8.4	8.4	8.5	8.7	9.3	10.5	11.8	13.1	13.3	12.9	12.6	12.6	12.5	12.1	11.8	11.7	11.7	11.8	12.3	13.8	13.1	10.9	9.6	270.2
Total DSM		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Case #2: DSM Bidding

Price needed to dispatch: (c/kWh) — August, Hour:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Daily Total
Coal-fired 1	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	
Coal-fired 2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	
Coal-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	2.5	0.0	0.0	
DSM 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Coal-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Oil-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DSM 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Gas-fired 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
System Pool Price	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.5	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.5	2.5	2.2	2.2	
Resource payment revenue (million $)																									million $
Coal-fired 1	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.16	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.16	0.16	0.14	0.14	3.53
Coal-fired 2	0.05	0.04	0.04	0.04	0.05	0.06	0.09	0.12	0.16	0.16	0.16	0.13	0.13	0.13	0.12	0.12	0.11	0.12	0.12	0.13	0.16	0.16	0.10	0.07	2.57
Coal-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.04
DSM 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Coal-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Oil-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DSM 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas-fired 4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total revenue	0.19	0.19	0.18	0.19	0.19	0.20	0.23	0.26	0.33	0.33	0.32	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.26	0.27	0.34	0.33	0.24	0.21	6.14
Total supply	0.19	0.19	0.18	0.19	0.19	0.20	0.23	0.26	0.33	0.33	0.32	0.28	0.28	0.27	0.27	0.26	0.26	0.26	0.26	0.27	0.34	0.33	0.24	0.21	6.14
Total DSM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00