Load Shifting in Response to Time-of-Day Pricing in POEMS

Prepared by
OnLocation, Inc.
8100 Oak Street
Dunn Loring, VA 22027

Prepared for the
National Energy Renewable Energy Laboratory

November 2000

Table of Contents

Introduction

When electricity markets become deregulated and consumers are offered retail choice, pricing of electricity changes from being cost-of-service to marginal cost based. These prices will vary from hour to hour as levels of demand rise and fall. Electricity service providers may offer consumers an option to purchase electricity at these hourly prices in order to align marginal costs with consumer values. Consumers who are able to reduce consumption during periods with high prices will benefit from time-of-day pricing, and the overall system costs will be reduced.

As part of the Policy Office Electricity Modeling System (POEMS), OnLocation has created the capability to analyze consumer load shifts in response to hourly pricing. This is done through a new streamlined module called the Sectoral Load Shapes and Shifts (SLSS) that replaces the Load Demand Side Management (LDSM) module of NEMS that had previously used in POEMS as well. The SLSS also contains new set of alternative load shapes than the NEMS, and the impact of these shapes was analyzed in a previous subtask under subcontract to the National Renewable Energy Laboratory (NREL).

Load shifting from peak price periods to non-peak price periods by the SLSS in POEMS is the subject of this report. The first part of the report provides an overview of how the load shapes are handled in the SLSS and how the various pieces flow through the POEMS. The next section describes the load shifting methodology that is used in the SLSS. Finally, several scenarios are developed that show the range of load shifting and the impact on the projections of the electricity model.

Overview of Load Shapes and Processes in SLSS and POEMS

The NEMS and POEMS electricity models require electricity loads at the system level that provide detail on seasonal and hourly patterns. The underlying framework for load shifting is understanding the representation of load shapes in the model and understanding how they are processed in the SLSS and how they are used in the electricity modules. The representation of load shapes and the process flow for load shapes through the SLSS are described below.

Annual Load Shape Representations

Annual load shapes are represented in various levels of detail in different parts of the modeling[1]. A complete, fully-detailed load shape is represented by each hour of the year. This means that there are 8,760 loads or data values that make up a complete load shape in a non leap year (24 hours per day times 365 days). The actual data values can be loads that sum to the total annual load or can be proportional values for each hour of the year. The complete set of values can be normalized to add up to the annual load for each year. Load shapes can represent the overall system load or can represent the load for a customer class (sector) or the load for a service (end use) in that customer class.

Load shapes can also be represented by assuming that the days in each month can be represented by average day types. A common representation used in the SLSS and the electricity model is to use three day types for each month instead of using each day of the month. These consist of an average weekday, an average weekend day, and a peak day. The 31 days of January, for example, would then be represented by only 3 days consisting of one peak day, one average weekday representing perhaps 21 weekdays, and one average weekend day representing perhaps 9 weekend days. The entire year is now represented by 12 months, each with 3 representative day types, each with 24 one-hour loads, for a total of 864 data values.

The electricity capacity planning and dispatch modules each use a separate, but more aggregate representation of annual load shapes that are constructed in the LDSM or SLSS. Currently, for the dispatch module of the POEMS, for example, the SLSS organizes the 864 data values (or "vertical slices") into 72 blocks (groups/segments), consisting of 6 groups divided into 2 segments for each of 6 seasons. Other representations can also be used. For example, the short-term version of POEMS performs dispatch and trade for all the 864 slices.

System Load Shapes Built from Sectoral Detail

The overall system load shapes in each electricity region in NEMS and POEMS are constructed from a diverse set of load shapes that represent sectoral end use and industry-type detail. The SLSS builds load shapes for each of ten end uses in the residential sector, ten end uses in the commercial sector, nine industry types in the industrial sector, and two end uses in the transportation sector, for each region. These load shapes are combined in each region to estimate an overall system load shape for that region. Load shifting is done for each of the individual sectoral and end use or industry-type load shapes, each of which has a separate sensitivity.

---

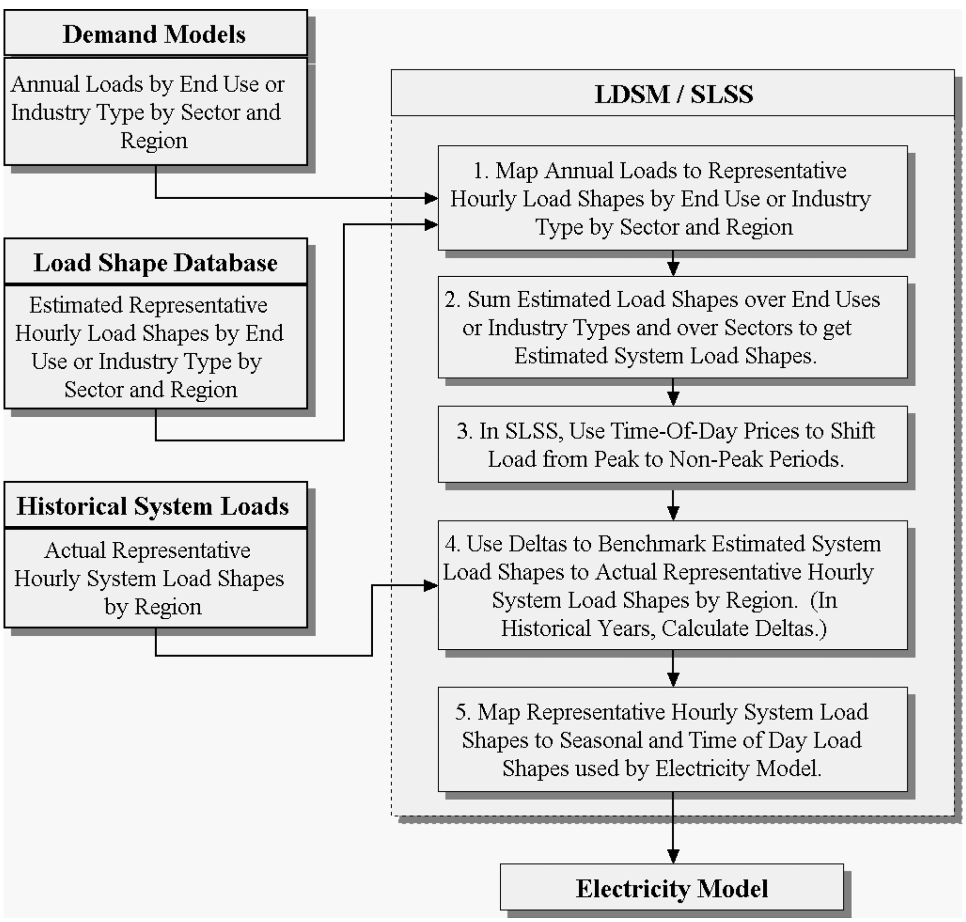
[1] The previous report that reviewed the new, alternative load shapes provided more detail on the representation of load shapes throughout the system.

Flow of Load Shapes through the SLSS

The NEMS and POEMS demand models forecast annual electricity loads by end use or industry type for each sector. These annual loads must be mapped into the hourly load representations and detail required by the electricity model. In NEMS this consolidation and mapping is done in the LDSM and in POEMS the consolidation and mapping is done in the SLSS. The process used by the SLSS is described below, but the basic process used by each module is essentially the same.

The mapping process requires a great deal of information including estimated representative hourly load shapes by end use or industry type by region and sector and actual historical representative system load shapes by region. An illustration of the process can be seen in Figure 1. The overall annual loads are determined solely by the demand models in the NEMS system and are provided to the SLSS module by end use or industry type by sector and region.

Figure 1. Creation of System Load Shapes for the Electricity Model



1. Map Annual Loads to Representative Hourly Load Shapes. The change in the load shapes over time are jointly determined by the changes in loads by end uses and regions in the NEMS demand models and by the estimated representative hourly load shapes. This process is shown in the first step in the SLSS box in Figure 1. The demand model sectors consist of the residential, commercial, industrial, and transportation sectors. The estimated representative hourly load shapes for the SLSS are primarily but not completely from the Reload database. These estimated load shapes are used to share out the annual loads by end use or industry type and region forecasted by the demand models to representative hours of the year. The load shapes use a set of 864 representative hours.

2. Sum Estimated Load Shapes End Uses, Industry Types, and Sectors. The second step in the SLSS box in Figure 1 is to sum the estimated load shapes over the various end uses or industry types and over the sectors to estimate the overall system load shape.

3. Shift Hourly Load from Peak Price Periods to Non-Peak Price Periods. In the SLSS a methodology exists to shift hourly loads from peak price periods in one day to non-peak price periods in the same day. This is shown in the third step in the SLSS box in Figure 1. This load shifting is the subject of this report and is discussed in much more detail in the next section. The load shifting is done for each end use or industry type in each of the sectors based upon individual price elasticities in an input file. The length of the peak price period is also given in the input file.

4. Benchmark Estimated System Load Shape to Historical System Load Shape. The basic starting point for the overall system load shape used by SLSS is determined by actual system load shapes for 1998 for each of the 69 POEMS regions. This benchmarking process is shown in the fourth step in the SLSS box in Figure 1. The model inputs the historical system load shapes for each region and for the same set of 864 representative hours used for the sectoral load shapes. In historical years, the historical system load shape is compared to the estimated system load shape and a set of "deltas" (differences) are calculated for each of the 864 representative hours. These deltas represent the "error" in the estimated system load shape relative to the historical system load shape. In all forecast years the deltas are added to the estimated system load shapes for each representative hour. In the historical years, adding the deltas brings the result back to the actual historical load shape, which is then used by the electricity model. In the forecast years, the deltas continue to be applied (added) to the forecasted estimated system load shapes, so that the amount of "error" continues to be corrected.

5. Map System Load Shapes to Detail Used by Electricity Modules. The last step in the SLSS box in Figure 1 is to map the final system load shape to the season and hourly periods used by the capacity planning (ECP) and the dispatch (EFD) modules of the electricity model. The mapping is determined by instructions in a mapping structure file.

Load Shifting in the Sectoral Load and Shapes and Shifts Model

A key feature of the SLSS is the representation of consumer response to time-of-day pricing, in other words the ability to shift hourly loads for various end uses and industry types in each sector from peak price periods to non-peak price periods. This section of the report describes the methodology used for this load shifting in more detail.

Sectoral and End Use Scope

The load shapes for each of the 69 POEMS regions are represented for a variety of end uses and/or industries in each of the sectors. The load shifting is implemented at this same level of detail. Each end use or industry in each of the residential, commercial, and industrial sectors has a separate elasticity and can shift separately from the other end uses or industries. In the end all the load shapes are recalculated and the overall system load shape is the sum of the underlying load shapes. The following table shows the twenty-nine load shapes for which there are elasticities for load shifting. The two end uses for the transportation sector are not included.

Residential	**Commercial**	**Industrial**
Space Heating	Space Heating	Food
Secondary Heat	Space Cooling	Paper
Space Cooling	Water Heating	Chemicals
Water Heating	Ventilation	Stone/Clay/Glass
Cooking	Cooking	Primary Metals
Clothes Drying	Lighting	Refinery
Refrigeration	Refrigeration	Metal-Based Durables
Freezing	PC Office Use	Other Manufacturing
Lighting	Non-PC Office Use	Non-Manufacturing
Other	Other	

Months and Day Types

The load shifting that is done in each of the end uses shown above is done over the 24 hourly periods in a day. Load is shifted from the peak price hours of the day to the non-peak hours of the day. The representative load shapes with 864 data values used in the SLSS for load shapes and for load shifting represent 24 hourly loads for each of three day types in each of the twelve months. The three representative day types for each month are an average week day, and average weekend day, and a peak day. This means that there are 36 separate days in which load is shifted from some hours to other hours. The SLSS shifts loads separately and individually in each of those 36 representative days for each of the 29 end uses or industry types in each of the POEMS regions. The prices in each of the 36 representative days will vary due to considerations in the electricity model. The elasticities for each of the 29 end uses are user-specified.

Prices from the Electricity Model

Prices are determined in the electricity model and passed to the SLSS. There are 72 separate prices that are determined in the electricity model consisting of 36 groupings of the 864 representative hours, each with 2 segments based upon relative loads and length of time[2]. In SLSS it is necessary to map these 72 prices back into the full 864 representative hours that describe all the load shapes by end uses and or industry types. The 36 groups are mapped back to the same months, day types, and hours that were used to create the loads for the 36 groups. Within each group the prices for each segment are used along with the load heights to create a price gradient that produces prices that vary over all the hours in the group.

Methodology for Hourly Load Shifting

Load shifting is done over the 24 hours for one day. Load is shifted from the hours of that day in which prices are high to hours of that day in which prices are lower. The baseline load shapes that the SLSS uses for the various end uses and industry types for each day represent the desired loads for each hour when the consumer is faced with an average price over the whole day. The loads in these baseline load shapes vary from hour to hour because the demand for electricity services vary from hour to hour, not because electricity prices vary from hour to hour. An obvious example might be residential lighting, which varies by the time of day and the activities of the household. The set of baseline electricity loads in the lighting load shape reveals the preferences of the household (or other consumer in other sectors) for that particular electricity service.

For load shifting we are now assuming that the consumer is faced with different electricity prices for each of the twenty-four hours of the day. The result is that the consumer will consume less in those hours that have high prices and shift all or part of that load to hours that have lower prices. The SLSS uses an *own-price load shift elasticity* to measure the responsiveness of the consumer to the higher electricity price. Since the baseline load shape defines the hourly loads when the consumer is faced with an average price for the day, the SLSS uses the set of 24 hourly prices to calculate a baseline, or weighted average price for the day. The weighted average price is simply the sum of the price for each hour of the day multiplied by the load for each hour of the day, divided by the total load for the day. The baseline price is used as the base or starting point for measuring the "change" in each hourly price. For example, if the average price over the day is 8 cents per kWh and the new price for the hour between 4pm and 5pm is 10 cents per kWh, then the change is 10 divided by 8 or 1.25. It is this change in the price from the baseline to the time-of-day price that is used along with the elasticity to calculate the change in the load from the baseline to the time-of-day load.

The elasticity formula that is used by the model for an individual hour is given by:

$$OwnPeakElasticity = \frac{\ln\left(\frac{TimeOfDayLoad}{BaselineLoad}\right)}{\ln\left(\frac{TimeOfDayPrice}{BaselinePrice}\right)}$$

[2]The SLSS creates the load groupings and segments based upon a "structure" or mapping file and passes these load blocks to the electricity model. The electricity model uses these to determine prices and assigns a price to each one of these blocks. These prices are returned to the SLSS and are used for load shifting. The number of groupings and segments can be changed by changing the structure file. Currently (the run described here) the model uses 36 groups, each with 2 segments, for a total of 72 blocks.

where: *PeakOwnElasticity* is an own price elasticity for a one-hour segment,
TimeOfDayLoad is the load for one hour under time-of-day pricing,
BaselineLoad is the load for one hour from the baseline load shape,
TimeOfDayPrice is the price for one hour under time-of-day pricing, and
BaselinePrice is the per-hour price averaged over all the hours of the day.

The elasticity formula shown above can be rewritten to directly solve for the time-of-day electricity load for the one-hour period. This is given by:

$$TimeOfDayLoad = \exp(\ln(BaselineLoad) + PeakOwnElasticity * \ln(\frac{TimeOfDayPrice}{BaselinePrice}))$$

This result can be illustrated using the prices that were given in the example above. The baseline price was 8 cents per kWh and the time-of-day price was 10 cents per kWh. The ratio of the prices is 1.25. Assuming that the elasticity is -0.25 and that the baseline load is equal to 1000 kWh, the equation can be solved to find that the load for that hour has decreased (shifted) from 1000 kWh to 945.7 kWh.

Shifting from the Peak Price Period to the Non-Peak Price Period

Hourly loads are shifted from peak price periods (hours) to non-peak price periods. The SLSS defines the *peak price period* as the number of hours in a twenty-four hour period for which the consumer will shift away from the baseline load. The load is shifted into a non-peak price period which consists of the remaining hours of the day. The number of hours that make up the peak price period is an user defined assumption of the model. This number of hours of the day that have the highest time-of-day prices are defined as the peak price period. It is for these hours only that calculations are made for load shifting and for which load is shifted out.

However, depending upon how many hours are in the peak price period, there may be some hours in the peak price period for which the time-of-day price is not higher than the average price. Load shifting would not occur in hours in which the time-of-day price is not higher than the average price. Therefore, if there are hours in the predefined peak price period for which this happens, the peak price period is redefined to eliminate these hours for consideration for load shifting.

All of the load or some portion of it that is shifted out of the peak price period is shifted back into the hours that are not in the peak price period. In current runs of SLSS all of the shifted load is put back into the non-peak hours of the day to conserve the total amount of the load. The total amount of the load comes from the demand models in the system and it is important to conserve their forecasted results. The SLSS puts the shifted load back into the day by finding the portion of the entire non-peak period load that each individual non-peak hour represents. Then the total amount of load that was shifted out of the peak period is allocated to each hour of the non-peak period based upon that hour's portion of the non-peak hour load.

Persistence of Load Shapes

The end use and industry type load shapes in the SLSS represent the monthly, daily, and hourly patterns of consumption given historical conditions. In other words, they represent consumer preferences for consumption based on average electricity prices, not time-of-day prices. They reflect different levels of consumption due to environmental considerations, consumer life-style behavior, equipment operating characteristics, etc. To model the changes in these intrinsic patterns due to variations in price, we measure the price change from the average price and the consumption pattern change from the base consumption pattern. To perform load shifting in the SLSS, we begin with the “persistent” baseline consumption pattern and measure changes from it.

Scenarios and Load Shift Results

Four Scenarios

There are three basic scenarios that were created for reviewing the load shifting in the SLSS model. These are a Reference or base scenario, a Core or low scenario, and a Pervasive or high scenario. One additional scenario was chosen which represents an initial attempt to define a Best Guess scenario that falls between the low and high, for a total of four scenarios.

Reference (Base). The reference scenario is one in which there is no load shifting. In other words, the load shapes that are passed to the electricity model are the baseline load shapes.

Core (Low). The core scenario has a smaller level of load shifting. The amount of load shifting is low with the intention to represent what might be considered the core group of industries and commercial end uses in which time-of-day pricing is most likely to occur. This assumes that there is no time-of-day pricing or load shifting in the residential sector. The input elasticities are given in the table below and the peak price period is defined to be 12 hours (which could end up being less).

Residential

	SpHt	SpCl	WtHt	Cook	EDry	Refg	Frez	Lite	Othr	SecH
Elasticity	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Commercial

	SpHt	SpCl	WtHt	Vent	Cook	Lite	Refg	OffP	OffN	Othr
Elasticity	-0.200	-0.200	-0.200	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Industrial

	Food	Papr	Chem	SCGl	PMet	MetC	OthC	NonM	Refn
Elasticity	-0.200	-0.200	-0.200	-0.200	-0.200	-0.200	-0.200	-0.200	-0.200

Best Guess (Mid). The best guess scenario has an amount of load shifting that might be considered the current best guess. This is based upon a reasonable assumptions, but since there is so little knowledge at this point of what might occur it is difficult to pinpoint any one scenario. The input elasticities are given in the table below and the peak price period is defined to be 12 hours (which could end up being less).

Residential

	SpHt	SpCl	WtHt	Cook	EDry	Refg	Frez	Lite	Othr	SecH
Elasticity	-0.200	-0.200	-0.200	-0.100	-0.200	-0.050	-0.050	-0.100	-0.200	-0.100

Commercial

	SpHt	SpCl	WtHt	Vent	Cook	Lite	Refg	OffP	OffN	Othr
Elasticity	-0.250	-0.250	-0.250	-0.100	-0.100	-0.100	-0.050	-0.100	-0.100	-0.100

Industrial

	Food	Papr	Chem	SCGl	PMet	MetC	OthC	NonM	Refn
Elasticity	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250

Pervasive (High). The pervasive scenario has a higher level of load shifting. The amount of load shifting is high with the intention to represent what might be considered a pervasive amount of time-of-day pricing in all sectors. The input elasticities are given in the table below and the peak price period is defined to be 12 hours (which could end up being less).

Residential

	SpHt	SpCl	WtHt	Cook	EDry	Refg	Frez	Lite	Othr	SecH
Elasticity	**-0.300**	**-0.300**	**-0.300**	**-0.150**	**-0.300**	**-0.050**	**-0.050**	**-0.150**	**-0.300**	**-0.200**

Commercial

	SpHt	SpCl	WtHt	Vent	Cook	Lite	Refg	OffP	OffN	Othr
Elasticity	**-0.300**	**-0.300**	**-0.300**	**-0.150**	**-0.150**	**-0.150**	**-0.050**	**-0.150**	**-0.150**	**-0.150**

Industrial

	Food	Papr	Chem	SCGl	PMet	MetC	OthC	NonM	Refn
Elasticity	**-0.300**	**-0.300**	**-0.300**	**-0.300**	**-0.300**	**-0.300**	**-0.300**	**-0.300**	**-0.300**

Example of Hourly Shifts in the Pervasive Scenario

An example from the pervasive (high) scenario provides an illustration of how the load shifting works in detail and the impact that such a response would have on loads. The example chosen is for a weekday in July for one region. Although the load shifting is done for each end use and industry type, the tables below show only the result for one end use or industry type in each sector.

The first column in each table shows the hours. The second column shows the baseline load for each of the hours, with the rank from highest to lowest shown in parentheses. The third column shows the baseline price which is the average weighted time-of-day price over all the hours of the day. The fourth column shows the time-of-day price, with the rank from highest to lowest shown in parentheses. The rank of the prices is not necessarily the same as the loads for a particular end use. It is the rank of the prices that is used in determining the peak price period. The fifth column shows the relative price (price ratio) for each hour, given by the time-of-day price divided by the baseline price for that hour. The sixth column shows the own price load shift elasticity for the hours in the peak price period. The peak price period was defined as 12 hours, but the load shifts take place only in hours in which the time-of-day price is higher than the base price (otherwise load would be shifting in instead of out). It can be seen in the tables that there are some hours for which this is the case. These columns show the information that is used to determine the amount of load that is shifted.

The seventh column shows the resulting time-of-day load after the load shifts have taken place. Note that the sum over all the hours of the day is equal to zero, indicating that all of the load shifted from the peak price period was shifted back into the non-peak price period. The eighth column shows the amount of load that was shifted in each hourly period.

The residential table is an example of load shifting in a typical weekday in July for residential space cooling. The base price (weighted average price) for the day is 0.060, while the time-of-day prices range from 0.048 to 0.067. The peak period was designated as the 12 hours with the highest prices which are those in the table from the 10^{th} hour to the 21^{st} hour (shown by those hours that have elasticities). However, the time-of-day price is higher than the base price in only 8 hours, so those are the only hours in which there will be load shifting. In those 8 hours the elasticity of -0.300 is applied and a new load is calculated for that hour using the equation listed above. For example, consider the 15^{th} hour which has the highest price. In that hour the relative price is 1.133, the elasticity is -0.300, and the base load is 2.41. Using the elasticity equation above the resulting load is 2.32 and the amount of load shifted would be the difference or 0.09. Note that although this hour has the highest price, it has only the sixth highest load.

In each region, this same calculation is done for each of the 12 months and 3 representative day types for residential space cooling. It is also done for each of the other residential and commercial end uses and for the industry types. All of these are then summed together to calculate an overall system load shape for that region. The system load shape for the region is then benchmarked using the “deltas” originally determined in a historical year.

Residential - Space Cooling - July - Weekday

Hours	Base Load		Base Price	TOD Price		Rel. Price	Own Elas	TOD Load	Load Shift
12- 1	.77	(17)	.060	.048	(19)	.812	.000	.80	.03
1- 2	.64	(18)	.060	.048	(20)	.810	.000	.66	.03
2- 3	.53	(20)	.060	.048	(21)	.809	.000	.56	.02
3- 4	.47	(21)	.060	.048	(23)	.804	.000	.48	.02
4- 5	.42	(23)	.060	.048	(24)	.804	.000	.44	.02
5- 6	.40	(24)	.060	.048	(22)	.807	.000	.41	.02
6- 7	.46	(22)	.060	.048	(18)	.814	.000	.48	.02
7- 8	.59	(19)	.060	.054	(16)	.902	.000	.61	.02
8- 9	.80	(16)	.060	.057	(13)	.952	.000	.84	.03
9-10	1.03	(14)	.060	.058	(10)	.975	-.300	1.07	.04
10-11	1.36	(12)	.060	.059	(9)	.994	-.300	1.41	.05
11-12	1.62	(10)	.060	.065	(7)	1.097	-.300	1.58	-.04
12- 1	1.89	(9)	.060	.067	(3)	1.125	-.300	1.83	-.07
1- 2	2.09	(7)	.060	.067	(4)	1.122	-.300	2.02	-.07
2- 3	2.41	(6)	.060	.067	(1)	1.133	-.300	2.32	-.09
3- 4	2.77	(4)	.060	.067	(5)	1.117	-.300	2.68	-.09
4- 5	3.02	(2)	.060	.067	(2)	1.128	-.300	2.91	-.11
5- 6	3.11	(1)	.060	.066	(6)	1.107	-.300	3.02	-.09
6- 7	2.90	(3)	.060	.063	(8)	1.065	-.300	2.84	-.05
7- 8	2.46	(5)	.060	.058	(11)	.974	-.300	2.56	.10
8- 9	1.93	(8)	.060	.057	(12)	.953	-.300	2.00	.08
9-10	1.47	(11)	.060	.056	(14)	.936	.000	1.53	.06
10-11	1.22	(13)	.060	.054	(15)	.914	.000	1.27	.05
11-12	.89	(15)	.060	.049	(17)	.815	.000	.93	.04
Total	35.26		.060	.060		1.000		35.26	.00

Commercial - Space Cooling - July - Weekday

Hours	Base Load		Base Price	TOD Price		Rel. Price	Own Elas	TOD Load	Load Shift
12- 1	.54	(19)	.051	.038	(19)	.746	.000	.55	.01
1- 2	.52	(20)	.051	.038	(20)	.744	.000	.54	.01
2- 3	.49	(21)	.051	.038	(21)	.743	.000	.51	.01
3- 4	.47	(22)	.051	.037	(23)	.737	.000	.49	.01
4- 5	.46	(24)	.051	.037	(24)	.736	.000	.47	.01
5- 6	.46	(23)	.051	.038	(22)	.740	.000	.48	.01
6- 7	.63	(18)	.051	.038	(18)	.749	.000	.65	.02
7- 8	.81	(15)	.051	.043	(16)	.852	.000	.83	.02
8- 9	1.11	(12)	.051	.046	(13)	.910	.000	1.14	.03
9-10	1.34	(9)	.051	.048	(10)	.937	-.300	1.38	.04
10-11	1.46	(7)	.051	.049	(9)	.960	-.300	1.50	.04
11-12	1.54	(4)	.051	.055	(7)	1.079	-.300	1.51	-.03
12- 1	1.59	(3)	.051	.057	(3)	1.113	-.300	1.54	-.05
1- 2	1.62	(2)	.051	.056	(4)	1.109	-.300	1.57	-.05
2- 3	1.63	(1)	.051	.057	(1)	1.122	-.300	1.57	-.06
3- 4	1.48	(5)	.051	.056	(5)	1.104	-.300	1.44	-.04
4- 5	1.46	(6)	.051	.057	(2)	1.116	-.300	1.41	-.05
5- 6	1.44	(8)	.051	.056	(6)	1.092	-.300	1.40	-.04
6- 7	1.31	(10)	.051	.053	(8)	1.043	-.300	1.29	-.02
7- 8	1.12	(11)	.051	.048	(11)	.936	-.300	1.15	.03
8- 9	1.01	(13)	.051	.046	(12)	.912	-.300	1.04	.03
9-10	.88	(14)	.051	.045	(14)	.891	.000	.90	.02
10-11	.77	(16)	.051	.044	(15)	.865	.000	.79	.02
11-12	.65	(17)	.051	.038	(17)	.750	.000	.67	.02
Total	24.80		.051	.051		1.000		24.80	.00

Industrial - Other - July - Weekday

Hours	Base Load		Base Price	TOD Price		Rel. Price	Own Elas	TOD Load	Load Shift
12- 1	.47	(20)	.038	.028	(19)	.751	.000	.49	.02
1- 2	.46	(21)	.038	.028	(20)	.748	.000	.48	.02
2- 3	.46	(22)	.038	.028	(21)	.747	.000	.48	.02
3- 4	.45	(24)	.038	.028	(23)	.738	.000	.47	.02
4- 5	.45	(23)	.038	.028	(24)	.738	.000	.47	.02
5- 6	.48	(19)	.038	.028	(22)	.743	.000	.50	.02
6- 7	.54	(16)	.038	.028	(18)	.755	.000	.56	.03
7- 8	.63	(9)	.038	.034	(16)	.894	.000	.66	.03
8- 9	.67	(7)	.038	.037	(13)	.974	.000	.70	.03
9-10	.67	(3)	.038	.038	(10)	1.009	-.300	.67	.00
10-11	.68	(2)	.038	.039	(9)	1.040	-.300	.67	-.01
11-12	.67	(5)	.038	.045	(7)	1.203	-.300	.64	-.04
12- 1	.67	(6)	.038	.047	(3)	1.249	-.300	.63	-.04
1- 2	.69	(1)	.038	.047	(4)	1.243	-.300	.65	-.04
2- 3	.67	(4)	.038	.047	(1)	1.261	-.300	.63	-.05
3- 4	.64	(8)	.038	.046	(5)	1.236	-.300	.60	-.04
4- 5	.60	(10)	.038	.047	(2)	1.253	-.300	.56	-.04
5- 6	.57	(11)	.038	.046	(6)	1.219	-.300	.54	-.03
6- 7	.56	(12)	.038	.043	(8)	1.153	-.300	.53	-.02
7- 8	.55	(13)	.038	.038	(11)	1.009	-.300	.55	.00
8- 9	.55	(14)	.038	.037	(12)	.976	-.300	.57	.03
9-10	.54	(15)	.038	.036	(14)	.947	.000	.56	.03
10-11	.53	(17)	.038	.034	(15)	.913	.000	.55	.02
11-12	.50	(18)	.038	.028	(17)	.757	.000	.53	.02
Total	13.69		.038	.038		1.000		13.69	.00

Overall Results for Four Scenarios

The following table shows the results for each of the four scenarios for each of the sixty-nine POEMS regions. The four scenarios were described earlier and consist of a base, a low (core), a mid (best guess), and a high (pervasive) scenarios. In the base scenario the total load is shown, while in the other scenarios, the amount of the peak-price period load that was shifted to non-peak price period load is shown. The table also shows the peak to average ratio for each of the scenarios. This is the ratio of the highest hourly load to the average hourly load for that region.

Some load was shifted in all regions in all scenarios. The amount that is shifted is dependent upon the amount of load in the region and the mix of sectors and end uses or industry types in each of the regions. This mix also determines which hourly loads are shifted which in turn determines the amount of change in the peak-to-average ratio. It is possible in a few unusual cases for the peak-to-average ratio to increase. Because the total load is conserved in these runs of SLSS, it is not possible for the average load to change, so any increase in the peak-to-average ratio must be caused by an increase in the peak load. This is an anomaly that is due to the way that the overall system load is created by adding up all the end uses and industry load shapes. The system peak hour is the hour that has the highest load based upon summing the load for that hour across all the end uses and industry types. In a few cases it is possible for the individual peaks for end uses and industry types to be in different enough hours that some increase and some decrease, but for there to be a net increase in that hour that is the peak hour.

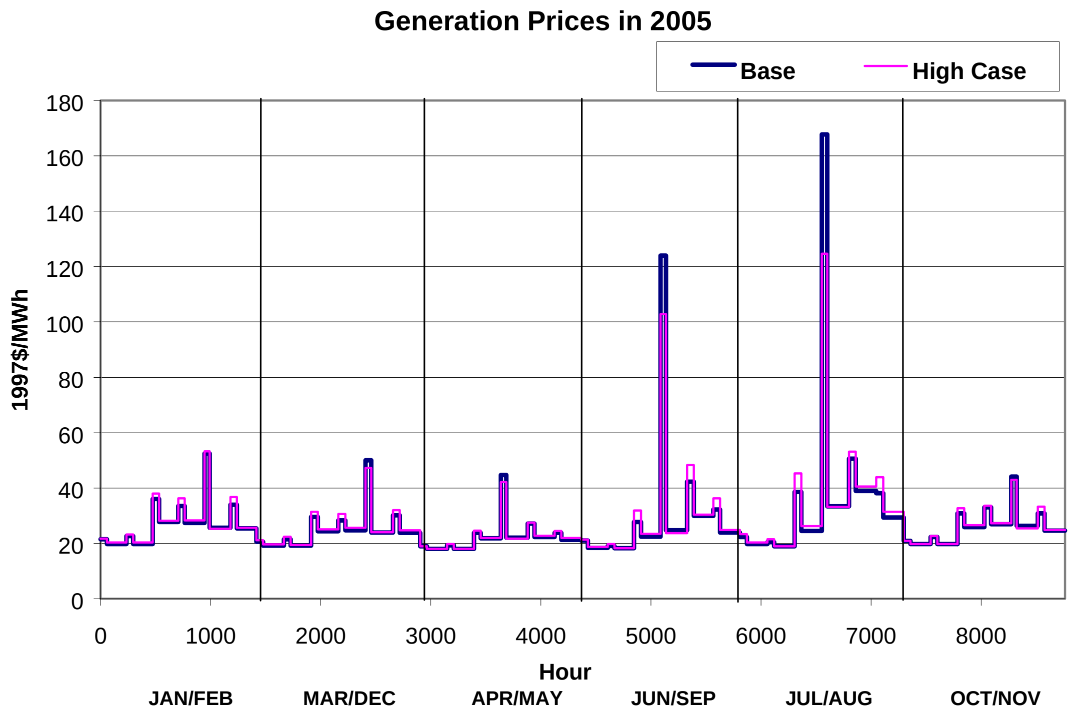
Load, Load Shifted, and Peak-to-Average Ratios for Four Scenarios

POEMS Region	NERC Region	Base: Total Load	Base: Peak to Average	Low: Load Shifted	Low: Peak to Average	Mid: Load Shifted	Mid: Peak to Average	High: Load Shifted	High: Peak to Average
1	NEPX	44.22	1.94	0.21	1.94	0.47	1.93	0.61	1.92
2	NYPP	3.56	1.99	0.01	1.99	0.02	1.97	0.02	1.98
3	NYPP	14.03	2.25	0.01	2.25	0.13	2.24	0.06	2.24
4	NYPP	9.41	2.22	0.00	2.22	0.08	2.27	0.03	2.21
5	NYPP	24.80	1.94	0.09	1.93	0.30	1.92	0.22	1.93
6	MAAC	20.68	1.94	0.14	1.93	0.28	1.92	0.36	1.92
7	MAAC	49.26	1.96	0.44	1.98	0.92	1.99	1.20	1.96
8	MAAC	21.31	2.18	0.09	2.19	0.32	2.17	0.43	2.15
9	MAAC	7.70	1.93	0.04	1.92	0.09	1.91	0.11	1.90
10	ECAR	47.92	1.80	0.69	1.78	1.01	1.77	1.24	1.75
11	ECAR	20.61	1.83	0.23	1.81	0.37	1.80	0.46	1.79
12	ECAR	35.40	1.89	0.52	1.87	0.87	1.84	1.10	1.82
13	ECAR	20.41	1.87	0.25	1.86	0.40	1.84	0.50	1.83
14	ECAR	17.67	1.89	0.25	1.86	0.40	1.84	0.49	1.82
15	ECAR	31.02	1.97	0.36	1.96	0.63	1.94	0.79	1.92
16	SERC	25.43	2.02	0.20	2.00	0.41	1.97	0.52	1.94
17	SERC	33.51	1.94	0.30	1.93	0.49	1.91	0.65	1.90
18	SERC	14.98	1.92	0.15	1.90	0.26	1.88	0.32	1.86
19	SERC	33.84	2.14	0.15	2.13	0.42	2.10	0.55	2.08
20	SERC	51.38	1.90	0.55	1.88	0.92	1.86	1.15	1.84
21	SERC	48.12	2.00	0.33	1.99	0.65	1.97	0.81	1.96
22	SERC	28.94	1.91	0.27	1.89	0.42	1.88	0.56	1.86
23	SERC	8.00	2.35	0.02	2.34	0.04	2.30	0.06	2.28
24	SERC	44.03	2.06	0.33	2.05	0.55	2.04	0.72	2.03
25	FL	33.13	2.22	0.11	2.21	0.45	2.17	0.59	2.14
26	FL	53.76	2.27	0.09	2.26	0.56	2.23	0.74	2.21
27	FL	5.16	2.07	0.03	2.06	0.08	2.03	0.10	2.01
28	FL	9.41	2.16	0.04	2.16	0.13	2.13	0.16	2.10
29	MAIN	28.77	2.00	0.40	2.00	0.79	1.97	0.97	1.93
30	MAIN	27.37	1.98	0.43	1.95	0.71	1.92	0.86	1.90
31	MAIN	5.33	1.92	0.08	1.90	0.13	1.87	0.17	1.85
32	MAIN	12.82	1.84	0.26	1.82	0.41	1.81	0.49	1.78
33	MAPP	6.10	1.90	0.11	1.88	0.18	1.85	0.22	1.84
34	MAPP	10.88	2.07	0.14	2.05	0.27	2.01	0.35	1.99
35	MAPP	1.52	1.62	0.08	1.58	0.10	1.58	0.12	1.57
36	MAPP	20.54	2.00	0.27	1.98	0.44	1.97	0.55	1.96
37	MAPP	15.67	2.23	0.07	2.22	0.18	2.20	0.23	2.18
38	SPP	0.49	1.97	0.01	1.96	0.01	1.96	0.01	1.95
39	SPP	22.88	2.16	0.12	2.15	0.25	2.14	0.34	2.13
40	SPP	9.99	2.11	0.07	2.10	0.12	2.09	0.17	2.09
41	SPP	24.72	2.16	0.15	2.16	0.29	2.15	0.39	2.14
42	ERCOT	9.58	2.16	0.07	2.14	0.14	2.09	0.17	2.07
43	ERCOT	3.13	2.17	0.03	2.14	0.07	2.07	0.08	2.08
44	ERCOT	21.99	2.03	0.29	1.99	0.49	1.94	0.60	1.91
45	ERCOT	16.06	2.33	0.07	2.31	0.17	2.25	0.22	2.22
46	ERCOT	48.31	2.26	0.32	2.23	0.73	2.17	0.95	2.14
47	NWP	6.43	1.91	0.04	1.89	0.08	1.86	0.10	1.85
48	NWP	3.83	1.92	0.02	1.92	0.03	1.92	0.04	1.91
49	NWP	10.72	1.70	0.09	1.71	0.14	1.72	0.19	1.67
50	NWP	2.91	1.79	0.04	1.79	0.06	1.78	0.07	1.77
51	NWP	4.15	1.81	0.01	1.82	0.03	1.82	0.04	1.83
52	NWP	22.45	1.64	0.23	1.63	0.37	1.63	0.43	1.62
53	NWP	2.12	1.68	0.01	1.68	0.02	1.67	0.03	1.68
54	NWP	5.44	1.75	0.03	1.75	0.07	1.75	0.08	1.74
55	NWP	7.99	1.79	0.05	1.79	0.12	1.81	0.16	1.81
56	NWP	14.40	1.82	0.05	1.82	0.16	1.81	0.22	1.86
57	RA	11.55	1.99	0.11	1.95	0.26	2.02	0.33	1.87
58	RA	7.47	1.92	0.06	1.90	0.11	1.89	0.14	1.87
59	RA	13.33	2.01	0.07	2.00	0.15	1.99	0.24	1.98
60	RA	1.79	2.21	0.02	2.19	0.04	2.14	0.05	2.12
61	RA	4.36	1.92	0.03	1.92	0.07	1.94	0.09	1.94
62	RA	12.05	2.02	0.05	2.02	0.15	1.94	0.21	2.11
63	RA	3.74	1.81	0.04	1.79	0.07	1.75	0.09	1.73
64	RA	1.18	1.92	0.00	1.92	0.02	1.90	0.02	1.92
65	RA	8.73	1.88	0.07	1.88	0.14	1.73	0.18	1.77
66	CNV	8.03	1.66	0.05	1.66	0.09	1.66	0.12	1.65

67	CNV	36.54	1.77	0.24	1.76	0.48	1.76	0.62	1.76
68	CNV	6.89	1.79	0.03	1.80	0.07	1.80	0.09	1.81
69	CNV	28.73	1.73	0.26	1.73	0.47	1.73	0.60	1.72

Resultant Aggregate Peaks and Electricity Prices

The shifts in loads lead to changes in electricity prices by time period. In peak periods where loads have been reduced, the marginal cost of production will be reduced as well. On the other hand, in off-peak hours where load has increased, the marginal costs will be increased. The figure below shows generation prices in 2005 for a representative region in the base and high elasticity scenarios. Within each two month season, twelve hourly prices are shown. These represent 6 four-hour time blocks in chronological order with 2 segments each, one of which has the highest 25 percent of load. The highest prices occur during the summer peak periods in both cases. These peaks are also where largest price differences occur as a result of load shifting. Smaller price increases occur during several off-peak periods.



One would expect that the average prices to consumers would be lower overall, primarily because consumption has shifted from more expensive on-peak periods to off-peak. For a single customer, this would be the only effect. When a large proportion of customers shift their loads, then the hourly prices change as seen above. Depending on the increase in off-peak prices relative to on-peak price reductions, it is possible for the average price to increase. Prices are usually reduced, as shown in the following tables. The tables provide the changes in peak demands and generation prices for the low, mid, and high cases relative to the base case for 2005 and 2010.

Demand and Prices in the Low Case (Percentage Change from the Base Case)

Region	2005		2010	
	Peak Demand	Generation Price	Peak Demand	Generation Price
ECAR	-3.3%	-0.9%	-3.3%	-0.8%
ERCOT	-2.2%	-0.4%	-2.4%	-1.7%
MAAC	-2.8%	-0.6%	-2.7%	-2.0%
MAIN	-3.9%	-0.8%	-3.6%	-1.4%
MAPP	-3.0%	-0.8%	-2.9%	0.0%
NY	-0.5%	-0.4%	-1.5%	-1.6%
NE	-1.7%	0.0%	-2.3%	-0.6%
FL	-1.2%	-0.4%	-1.1%	-0.2%
SERC	-2.1%	0.2%	-2.1%	-1.5%
SPP	-0.9%	-0.9%	-2.1%	-1.7%
NWP	-1.3%	-0.3%	-1.4%	-0.5%
RA	-1.5%	-1.0%	-1.6%	-0.2%
CNV	-2.1%	-0.6%	-2.0%	-0.9%
National	-2.2%	-0.5%	-2.3%	-1.1%

Demand and Prices in the Mid Case (Percentage Change from the Base Case)

Region	2005		2010	
	Peak Demand	Generation Price	Peak Demand	Generation Price
ECAR	-5.2%	-1.6%	-5.3%	-0.3%
ERCOT	-4.5%	-0.5%	-5.0%	-2.0%
MAAC	-6.9%	-1.4%	-6.6%	-2.0%
MAIN	-6.7%	-1.6%	-6.4%	-1.4%
MAPP	-5.3%	0.1%	-5.4%	-0.4%
NY	-4.0%	-0.8%	-4.6%	-1.2%
NE	-4.1%	-0.5%	-5.0%	-0.5%
FL	-4.6%	-1.0%	-4.8%	0.5%
SERC	-3.8%	-0.4%	-4.2%	-0.1%
SPP	-1.6%	-0.3%	-4.2%	-0.8%
NWP	-3.0%	-0.5%	-2.8%	-1.4%
RA	-2.9%	-0.8%	-2.8%	-0.6%
CNV	-4.0%	-1.3%	-3.8%	-1.4%
National	-4.5%	-0.9%	-4.7%	-0.8%

Demand and Prices in the High Case (Percentage Change from the Base Case)

Region	2005		2010	
	Peak Demand	Generation Price	Peak Demand	Generation Price
ECAR	-6.0%	-2.2%	-5.8%	-1.1%
ERCOT	-4.4%	-0.6%	-4.4%	-2.2%
MAAC	-8.1%	-1.2%	-7.5%	-1.4%
MAIN	-7.3%	-2.8%	-7.1%	-2.6%
MAPP	-6.0%	-1.9%	-5.3%	-0.6%
NY	-1.1%	-0.7%	-1.1%	-0.2%
NE	-4.9%	-0.3%	-5.4%	0.3%
FL	-5.5%	-0.2%	-5.6%	1.3%
SERC	-4.4%	0.2%	-4.9%	0.3%
SPP	-1.8%	-2.2%	-4.5%	-2.3%
NWP	-3.5%	-1.6%	-2.8%	-1.0%
RA	-3.0%	-0.9%	-3.2%	-0.2%
CNV	-4.9%	-1.1%	-4.8%	-0.7%
National	-4.9%	-1.1%	-5.0%	-0.7%