Peak Electricity Demand and the Feasibility of Solar PV in the Greater Boston Area

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Abstract

This IQP gives an overview of peak electrical demand and DSM programs in the US and suggests large-scale PV solar projects as a method to mitigate peak demand. New England was chosen for a potential case study, due the declining load capacity, and high electricity prices in the region, and because of the possible PV capacity growth in the next decade. The state of Massachusetts projects the addition of 400 MW of PV solar installations between 2013 and 2021. The state also guarantees a minimum SREC price making renewable investments safer. A financial study in this report shows that a typical 1MW commercial (rooftop) project can be expected to yield 24%-30% Internal Rate of Return (IRR).

Executive Summary

The main goal of this IQP is to study peak demand characteristics, demand side management, and suggest methods for mitigating peak electrical demands. Specifically, the New England region was investigated in detail due to the high price of electricity. The electricity demand in this region has been growing over the past decade and it is projected to do so in the future as industries grow and the region sees an inflow of migrants. As a result, the peak demand in the region is expected to grow at 1.5% annually until 2021 [1, p. 5].

There is a comprehensive Demand Response (DR) strategy to reduce the commercial peak load. By means of power cycling air conditioners, utility companies can shave peak electricity demands in real time. However, the same strategy does not apply to all residential customers. Firstly, because controlling residential loads becomes more complicated and expensive as the overall electricity usage in a household is scattered in smaller electrical loads. Second, surveys show that customers are unwilling to let utility companies take control of their appliances. The loads currently under residential demand response program are central air conditioners and swimming pool pumps. Power cycling a smaller load is not worth the cost and effort. Thus, it is difficult to expand the traditional DR strategies drastically.

This IQP suggests the use of solar PV technology as a means of DR, as the PV power output period partially coincides with the peak demands of the day. While residential solar has been hype in the past decade, larger commercial and utility scale PV generation has been neglected specially in Massachusetts. Recent renewable energy policies have generated new interest in the state of Massachusetts for utility scale solar, making it one of the most lucrative and secure state for renewable energy investment. This report provides a feasibility study and sensitivity analysis for such a project. Potential investors may find this report as a starting point for further investigation.

Introduction

Weather, economic activity, and demand side management programs can potentially affect the peak electrical load. Thus, the actual growth in demand can only be fully realized with a weather normalized growth in demand is shown in figure 2. Extreme summer weather can cause up to a 5-8% increase in peak load, compared to a typical year [2]. The high demand peak during 2005 – 2007 shown in figure 1, occurred due to extreme summer temperatures. The Green label in the graph indicates projected data. The non-coincidental peak load is the highest peak load in a year that occurred from summing the loads of Regional Entities across the US. The Regional Entities are explained later in this chapter.
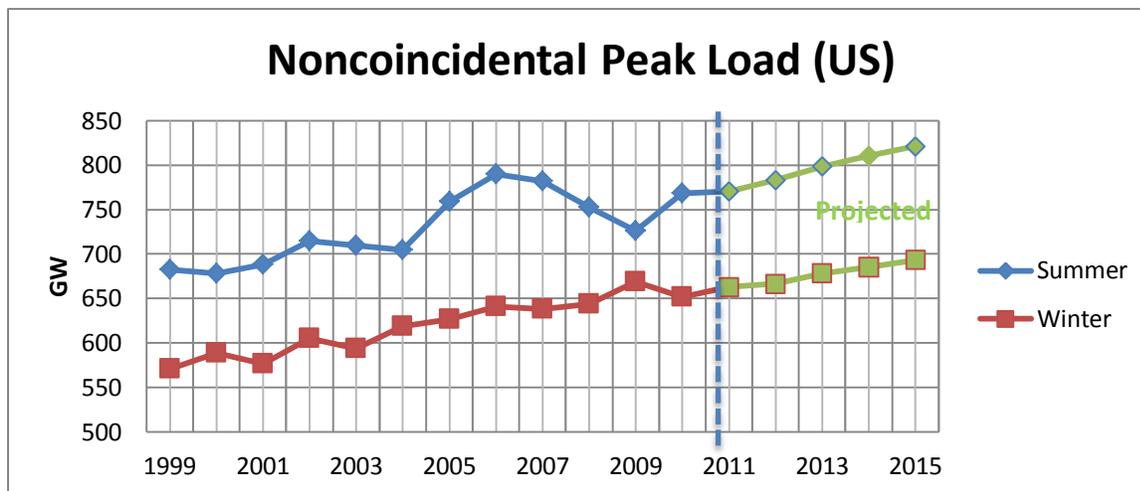
Figure 1: Non Coincidental Peak Load 1999-2011 (actual)

Figure 2 shows the annual growth rate from 2002 to 2011. Although the overall demand increases, it does so at a decreasing rate. This is attributed to Energy Efficiency policies, as well as demand response programs. However, the 2007 recession has caused a serious decline in the annual energy demand growth. This is well documented in NERC's 2012 Long Term Reliability Assessment (LRTA). Thus, a long term projection currently is somewhat unreliable. However, the overall demand is expected to grow at the usual rate past the year 2012.

The peak demand is important, not only for electrical system planning purposes, but also because it dictates the price of electricity. Figure 3 shows the price of electricity each year on the horizontal axis, and the change in price from previous year on the vertical axis. The growth of peak demand from 2004 to 2005 has led to drastic increase in average electricity price in 2005. Similarly, the decrease in demand growth from 2006 to 2007 and from 2008 to 2009, the two large arrows in figure 2) drastically reduced the rate of increase in price. The two large arrows in figure 2 are in line with the two dips in figure 3 that occur in the same years. Thus, peak demand and electricity prices are closely related.
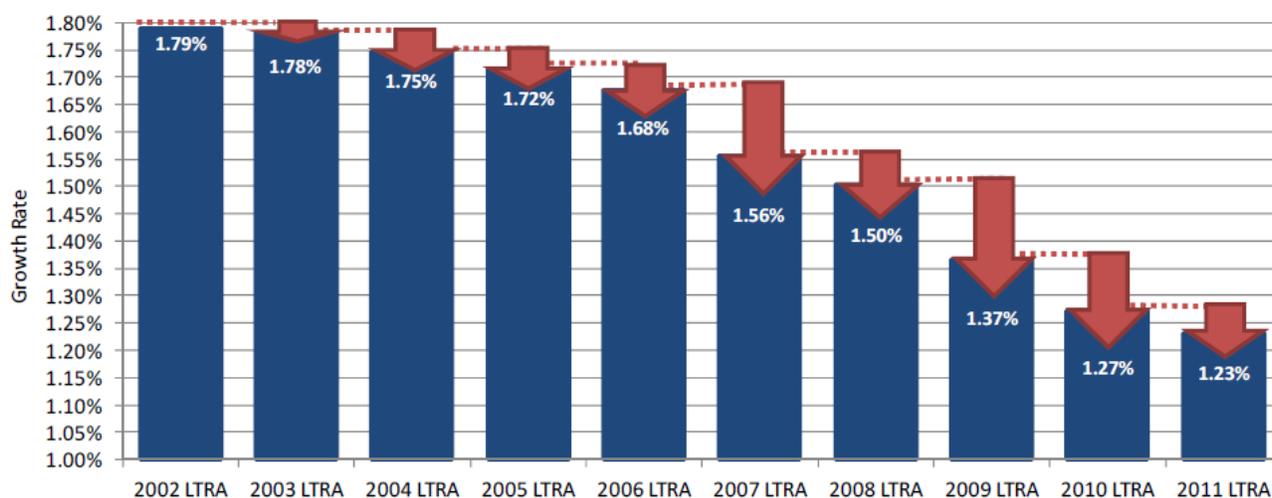
Figure 2: Average annual growth of NERC-wide summer peak demand [3]
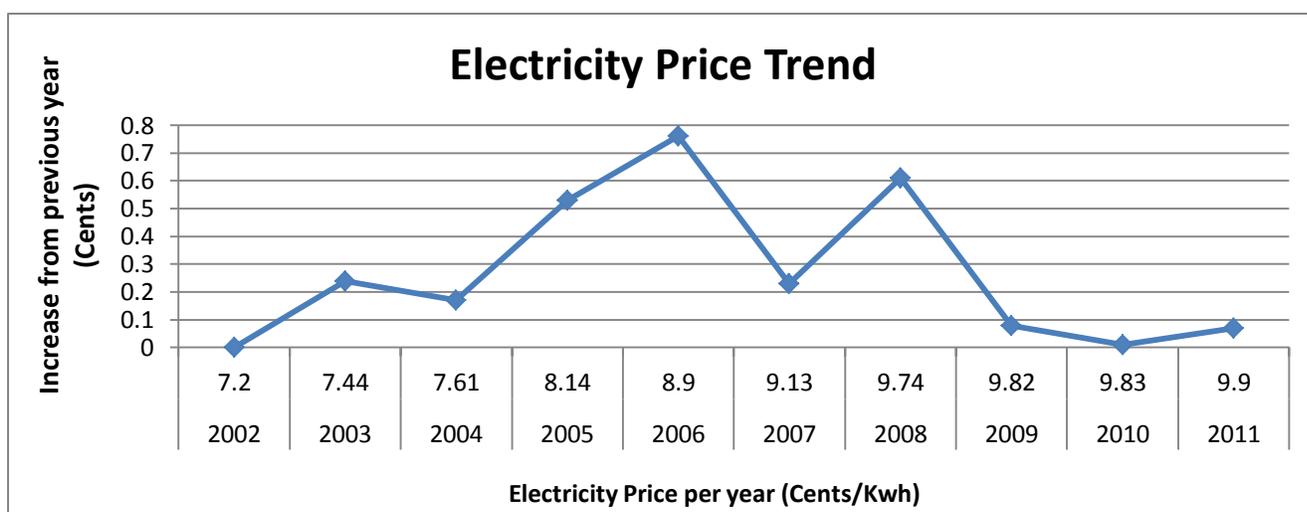
Figure 3: Average price of electricity and change from previous year [4, p. 255]

Until the 1970s, utilities were responsible for generating, transmitting, and distributing electricity to homes and businesses. These companies operated independently of each other and were regulated monopolies. In the early 1990s, Congress and the Federal Energy Regulatory Commission (FERC) started transforming the electric generation and distribution system into a competitive market. They hoped that the market competition would drive the key players to improve the overall system. As a result, ISOs – Independent System Operators were formed to ensure a functioning competitive market across North America. Some of the ISOs are also RTOs – regional Transmission authorities. ISO and RTOs are very similar; typically, RTOs operate at larger areas. The North American Electrical grid is divided into regional entities as shown in Figure 4. These entities account for virtually all the electricity in the United States, Canada, and a portion of Baja California Norte in Mexico. Each region can transmit bulk electricity internally and across regions, making a more flexible and dynamic overall system. Name of these entities are provided in table 4 in appendix. These regions have been redefined over time. For an older map, please refer to Figure 46 in appendix.
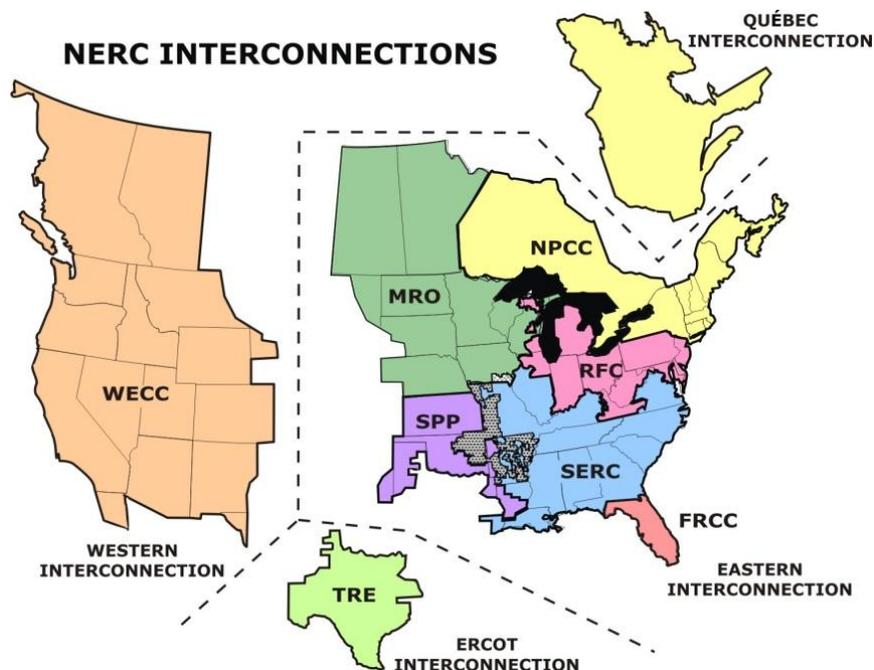
Figure 4: NERC Interconnections between Regional Entities [5]

NERC is a not-for-profit corporation, and it is the central regulatory body that can enforce agendas to ensure the reliable production and distribution of electricity in North America. NERC describes its role as "*NERC develops and enforces Reliability Standards; monitors the bulk power system; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel.*" [6] RTOs and ISOs are in compliance with all applicable NERC and regional reliability standards as well as North American Energy Standards Board (NAESB) business standards and are regulated by the Federal Energy Regulatory Commission (FERC). RTOs are also responsible for the electricity spot market. This hierarchy in the grid system is important to explain how the peak electricity largely affects the electricity price, and to fully realize what demand response is.
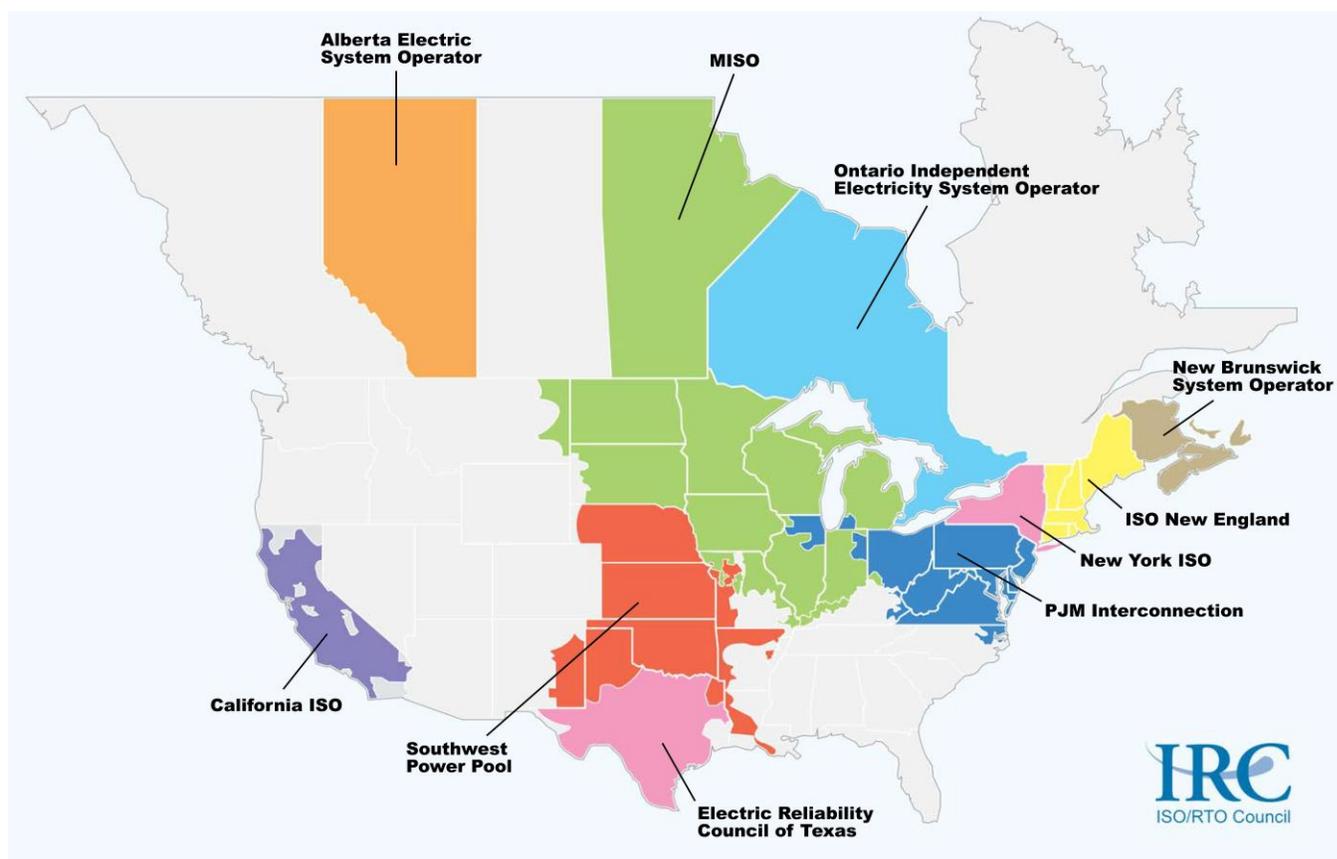
Figure 5: Inter Regional Coordinating Group (IRC) Operating Regions [7]

Contrary to the widespread belief, utilities do not generate all the electricity it provides to the customers, although they are fully responsible for the transmission and distribution to end users. Electricity is bought and sold as commodity in the spot market. Here generators sell, and the customers (including utilities) buy retail electricity. By combining the generating resources, the spot market provides a platform that allows a more efficient method for managing electrical demand, and increases the overall system reliability. It virtually provides the benefits of vertical integration while regulating the monopolistic nature of the business.

Because the electrical load varies in time, and the load determines the cost of delivery to end customers, auctions are held hourly both the day ahead and in real time. Prices are higher during high demand periods and lower in off-peak hours. Although this demand is forecasted, some inaccuracy in forecast, as well as transmission congestion gives rise to uncertainty and volatility in the market. This uncertainty can mostly be attributed to high prices in the spot market during peak demand hours.

Since Electrical demand changes hourly, and even on a minute-to-minute basis, the RTOS/ISOs work together with power generators, utility companies, and other key players to ensure a constant supply of electricity. Figure 6 shows the organizations responsible for managing peak electrical demands in the US.

Electric Systems Selected for Daily Peak Demand
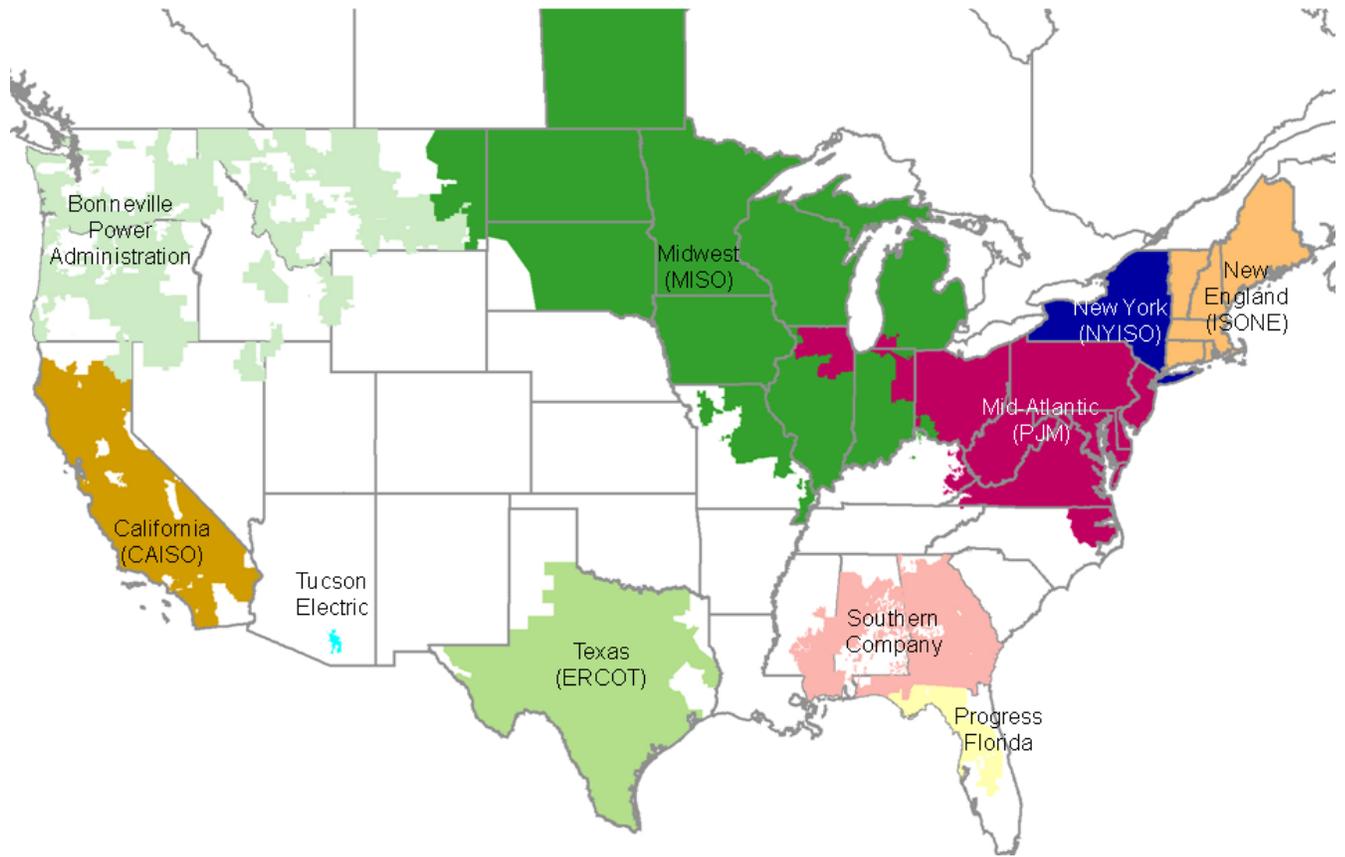
Figure 6: Electric System to mitigate Peak Demand [8]

CHAPTER 1: Demand Response

Demand response can be defined as the ability of customers to reduce electricity consumption during high demand hours. This may be achieved through a request (may be automated) from the utility company or regional transmission organizations, or through variable price rates or financial incentives. Whatever the demand response program may be, its goal is to reduce the electrical load during peak hours to reduce electricity prices, and ensure grid stability. Table 1 shows some of the typical DR programs used by the utilities.

Table 1: Demand Response Programs

Time Based Pricing	Incentive Based Program
Time-of-Use (TOU)	Direct Load Control (DLC)
Critical Peak Rebate (CPR)	Interruptible Load Control (ILC)
Critical Peak Pricing (CPP)	Emergency DR Resource
Day-Ahead Real-Time Pricing (DA-RTP)	

Time Based pricing gives incentives to customers to change his consumption pattern to reduce his electric bill. The customer is not in any contractual obligation to reduce his load in any given time, but is likely to consume less during peak hours due to the high electricity prices.

Direct Load Control (DLC) represents the loads that can be power cycled remotely during periods of peak demand, and the consumer is given financial benefits in return. Common DLC programs include air conditioning units and water pumps connected to devices so that they can be turned on or off remotely. Thus by power cycling a bulk of these loads at intervals, the peak demand can be curbed significantly. Interruptible load Controls usually include larger commercial or industrial customers who can reduce their electricity consumption upon request based on a predetermined price.

1.1 Why demand response?

The amount of power generated and consumed power should be equal for two reasons. Firstly, a balance between the electricity produced and its consumption is needed to maintain power quality. Failure to meet the demand will result in voltage fluctuation, grid instability, and can even lead to a total brownout. Secondly, the electricity produced should not be significantly more than the electricity consumed. As utilities virtually have no means of storing this energy, the wasted electricity will result in an increased cost of production.

A power grid is typically designed to supply the maximum projected demand (including peak demand). Since the peak electricity occurs only for few months, it is a disinvestment to design a grid system with a much higher capacity than needed. Thus reducing the peak demand is financially more feasible.

For residential customers, low electricity price ensures a better life, providing them with affordable heat in winter, and much needed air conditioning in hot summer. For commercial customers it could mean competitive advantage. However, even a slight increase in electricity price will affect the cost of operation and production. Thus, the price of electricity is a determinant factor for economic development.

Figure 7 shows a characteristic graph of load connected to the grid throughout the day. The demand peaks around noontime and starts to drop in the evening. Although the shape of the curve is characteristic to the 24-hour demand on the grid, this graph represents one of the highest demand days in the NEMA zone of the ISO control area. The difference in this case between the lowest and highest demand is 2.5 GW, which is significantly large.
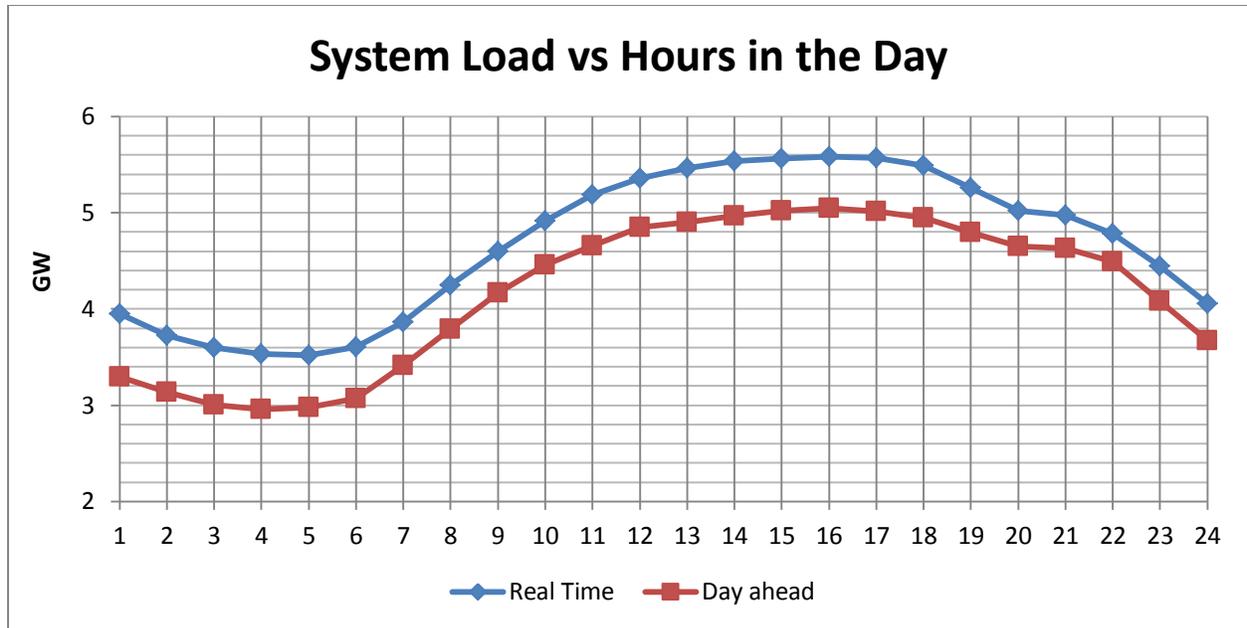
Figure 7: 24 hour load on a very hot day in the NEMABOST Zone within the ISONE region (08/02/06) [9]

1.2 Demand VS Electricity pricing

1.2.1 Price elasticity

In most electric power systems, the consumer pays a fixed price for electricity. Even in markets with variable prices, the unit price itself is fixed for certain times of the day. The utility on the other hand sees a more dynamic and elastic price based on the load on the grid. As shown in figure 8, this price can increase exponentially in the event of very high demands.

Figure 8 shows a small reduction in demand from D1 to D2 causes a larger reduction in electricity price from P1 to P2. The significance of this graph is fully realized in extreme demand scenarios, where this price elasticity can be significant. During the California electricity crisis in 2000-2001, it was reported that a 5% demand reduction could result in a 50% price reduction [10, p. 11]. Thus,

the demand DR program is further preferred by the utility company as it reduces the price volatility in the energy spot market.
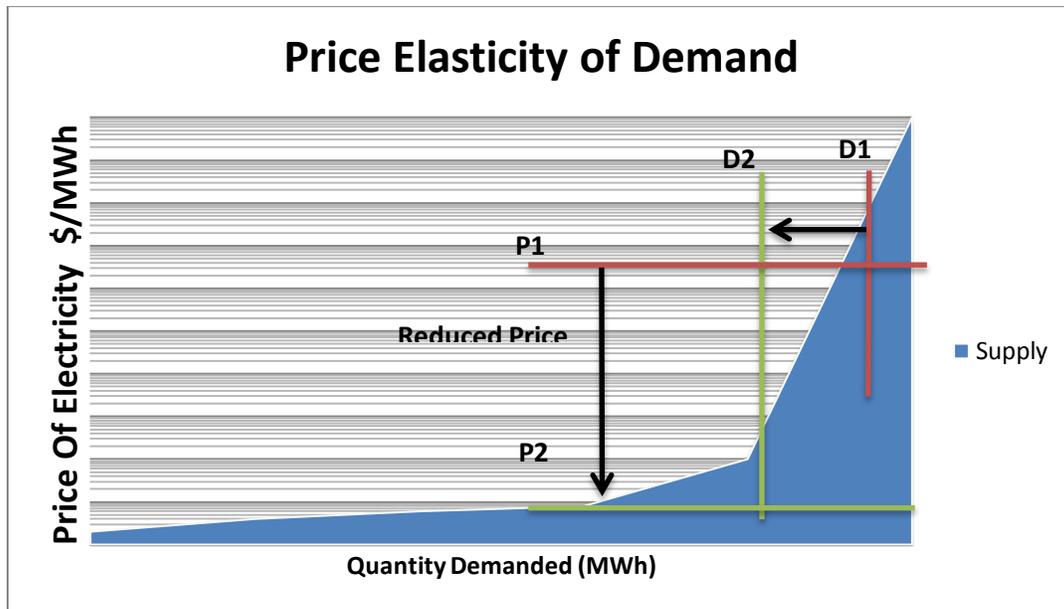
Figure 8: Effect of DR on electricity prices

The wholesale electric price is known as least marginal Price (LMP). It is the least price of electricity that is required to transmit energy to its destination, determined each hour at the electrical spot market. LMPs are determined by day ahead as well in real time auctions. Figure 9 reflects the higher LMP that results from a high demand on the grid. The LMP can grow exponentially during high demand hours.
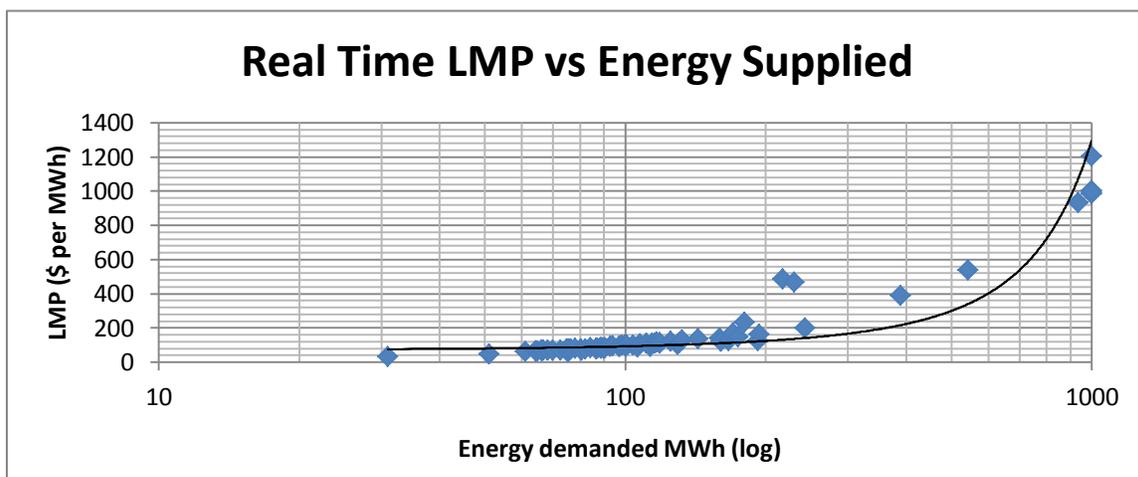
Figure 9: LMP in ISONE spot market for the year for three days 08/01/2006 - 08/03/2006 [9]

Typically, LMPs represent three price components: Energy component, Loss component, and Congestion component. The energy component is the same for every location. The cost of electricity would be the same for all locations within a region without the other two components. The loss component reflects the marginal cost of system losses in a location, while the congestion component is the cost reflected by transmission congestion in a location. Figure 10 shows this relation between congestion and LMP. The dotted line is the hourly energy demand, and the LMP (blue line) follows this demand closely. The spikes in LMP at the 21st and 24th points resulted from higher congestion on the grid, which is represented by the red line. The graph represents 34 highest demand points in three hottest summer days in 2006 in the ISONE region. The same three days data used to construct figure 9.
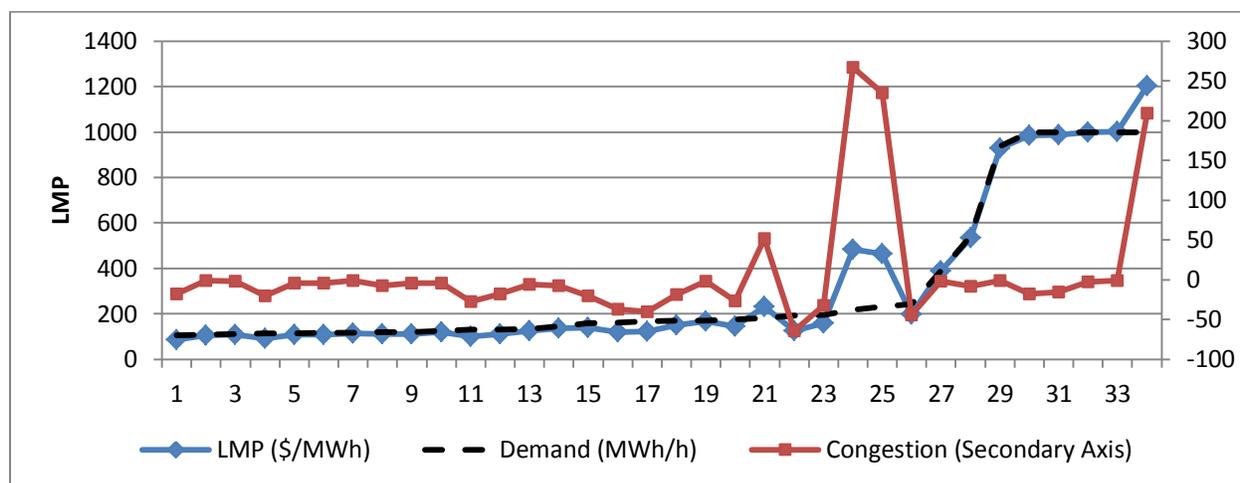
Figure 10: Real Time LMP, demand, and congestion [9]

1.2.2 What Causes the Peak Demand?

The high electric demand is typically driven by extreme weather. The peaks occur in winter, and even higher peaks are experienced in hot summer days. The peaks in winter are lower as the heating systems are not always electrical. The difference between a low demand day and a high demand day could be as much as 10%. Thus, a demand response or "peak shaving" mechanism is highly desirable since it helps to maintain power quality and reduce the electricity price.
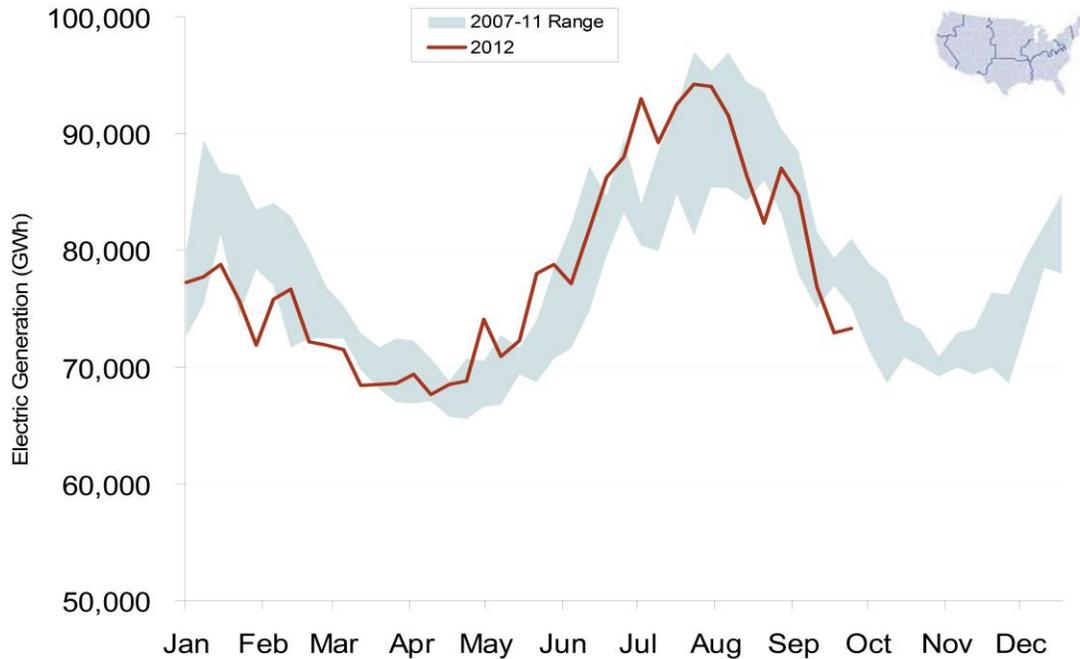
Figure 11: Electricity Generation: US weekly average [11, p. 16]

Figure 11 shows the monthly average of the total electrical energy generated in the US throughout the year. The demand is the greatest between July and September due to the use of air conditioners during summer. The winter usage peaks between December and February. Electricity usage is directly proportional to the extremities of weather. One may note that the 2012 winter electricity usage is much lower than that of the previous years as shown in the graph. This is because the 2012 winter temperature has been the least extreme in the decade.

1.3 Understanding the Power Grid

This section discusses the structure of the grid so that the reader can appreciate the way the grid works and the dynamic nature of power generation that is needed to deliver reliable power at a minimum cost. The overall power on the grid is produced from three different power plants: base load supply, peak supply, and intermediate supply.

1.3.1 Base load supply

In virtually all power systems electricity is produced by the most cost-effective method first. This is called the base load supply. The base load supply meets the demand or load that exists on the grid 24 hours a day. Typically nuclear, hydro, and coal based, these power plants require higher start time and operate 24 hours a day, round the year with the exception of scheduled downtime or repair. Usually base load supply provides most of the electricity used by the grid.

1.3.2 Peak Supply

As the demand for electricity varies within the day, more costly oil or gas-fired generators are dispatched to mitigate the higher demand. These are known as peak sources. These generators are used as the demand of electricity peaks.
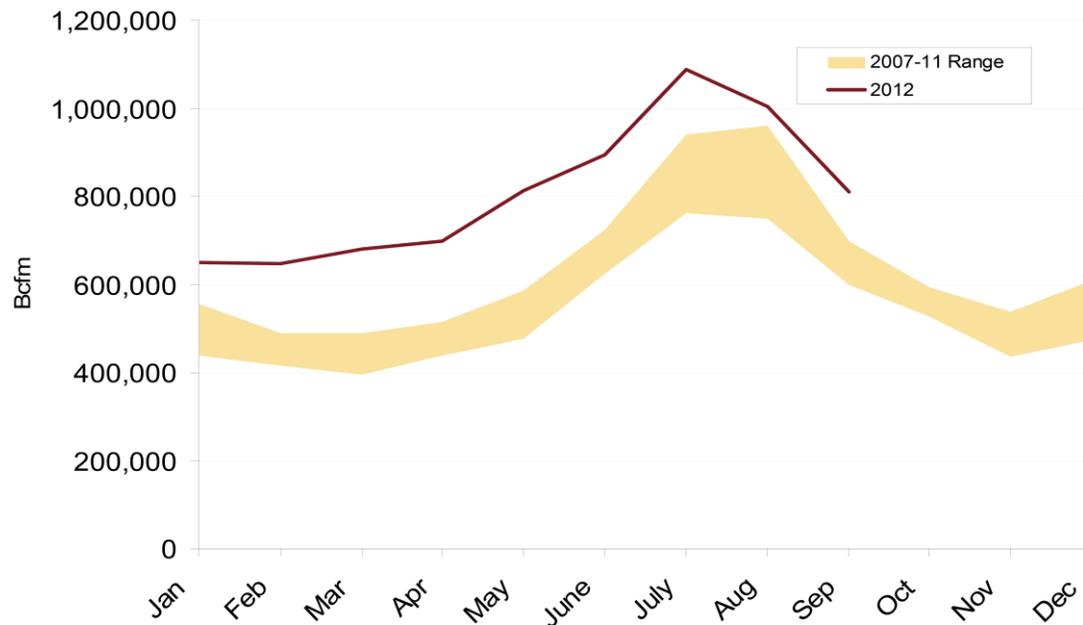
Figure 12: US gas consumption for power generation (monthly average) [11, p. 50]

The use of gas-fired power plants is the greatest in summer as shown in figure 12. Thus, the peak supply, the most expensive source has a predictable demand curve based on temperature or severity of the

weather, and is similar to the overall electricity demand of the country. It is important to understand that Demand response measures are designed to reduce the electricity produced from these sources. The peak supply sources are engaged on a real time basis often depending on projected electricity demands.

1.3.3 Intermediate supply

Intermediate generators are used in between base and peak load. They use the same fuels as peak load generators, but have a higher capacity output. Renewable sources such as wind and solar are also considered intermediate supplies, as their output depends on weather and cannot be relied upon to meet peak demand periods. These sources however help reduce the use of fossil fuels for power generation.
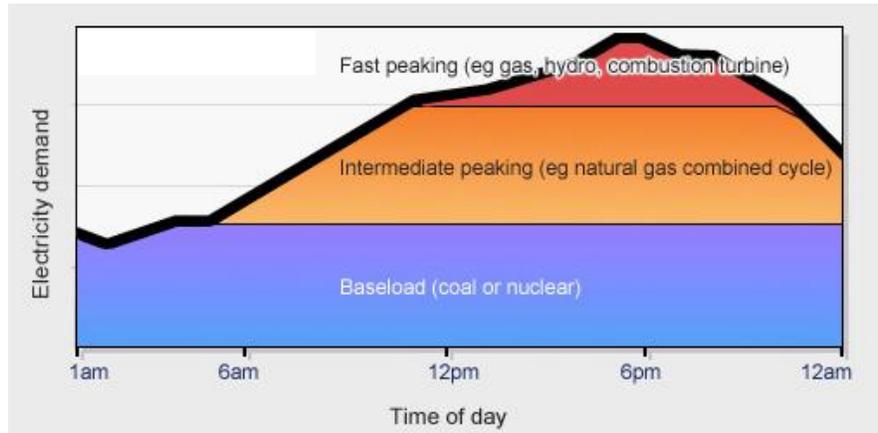
Figure 13: Example of a Conventional Power grid resource deployment [12]

Although PV solar power generation is considered intermediate power source, this study recommends utility scale solar generation as a method to complement demand response. This is because, historically, the solar irradiance has largely been consistent and predictable, and it coincides with the peak demand hours. This is further discussed in chapter 4.

1.4 Grid structure's relation to Marginal Cost

The marginal cost of electricity discussed in 2.2.2 can be fully explained with the method of generating the peak electricity. To visualize how each of the electricity generating sources are dispatched, Figure 14 shows a theoretical curve of generating cost by plant type, and the demand on the grid when

they are dispatched. The lower operating cost sources are dispatched first. This does not reflect an actual power system, but instead provides a hypothetical scenario for visualization purposes.
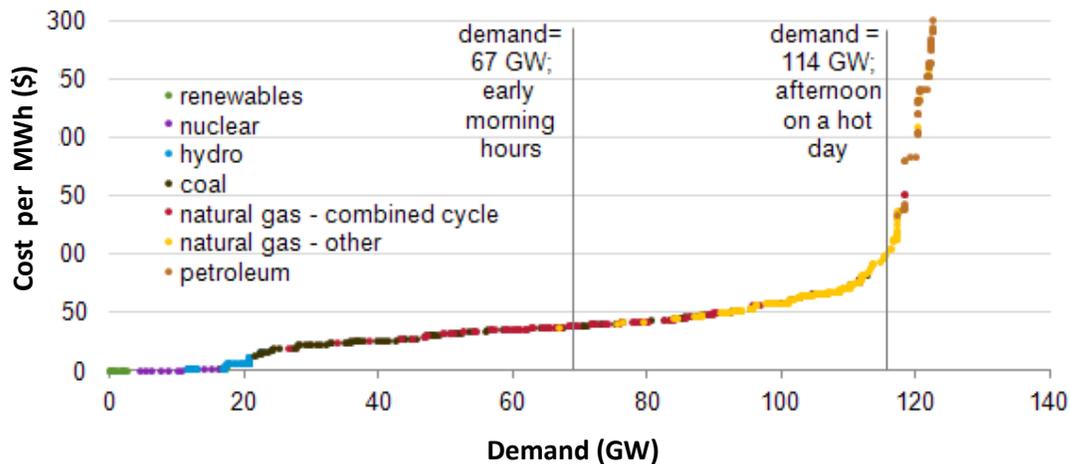
Figure 14: hypothetical Dispatch Curve [13]

The yellow and red dots on in figure 14 shows the gas fired generators that are dispatched during the high demand periods. One reason for these plants to be expensive is the lower energy factor. In other words, it costs them more money to generate the same amounts of electricity that can be generated by a nuclear or a coal plant.

However to fully understand why these "high demand' plants have such high operating costs, the overall annual periods of operation needs to be accounted for. Figure 15 shows the fraction of peak power that each of the three - base, intermediate, and peak supply sources provide plotted against the hours in a year. The peak supply sources provide only a small amount of the overall electrical energy demanded by the grid annually. From an investment standpoint, a power plant that operates only for such a short period is costly, as it would have a longer pay back period. Thus, the cost of producing electricity will be much greater from such a plant.
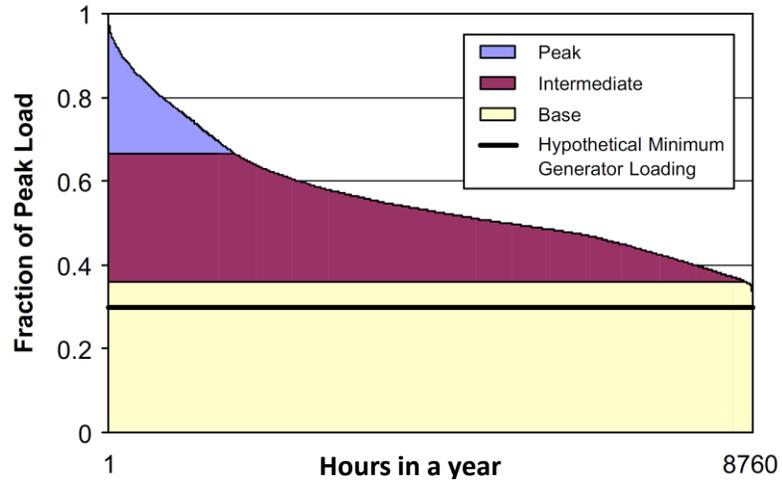
Figure 15: Normalized Load Curve for ERCOT (2000) [14]

Furthermore, to supply the additional power requires grid infrastructure which is also a disinvestment given the short duration they are being used. Since this peak demand increases annually, utilities invest in demand response programs rather than investing large amounts to expand distribution resources.

Chapter 2: Demand Side Management in the US

2.1 History of DSM

The 1973 oil crisis triggered widespread public awareness of energy conservation. In 1978, National Energy Conservation Policy Act (NECPA) was passed. This law required the utility companies to provide on-site energy audits to residential customers. The NECPA is the start of Demand response programs, as we know it.
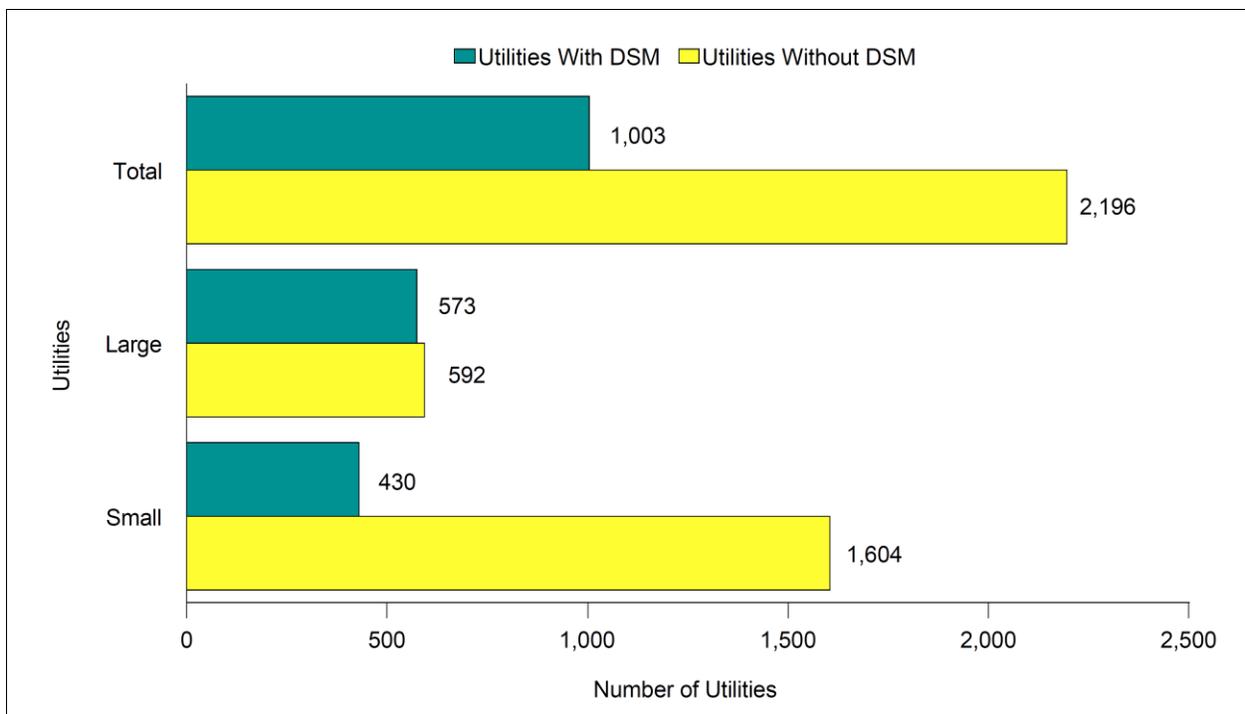
Figure 16: Utilities with and without demand response programs (2006) [15, p. 9]

The electricity production cost led the utilities to experiment with DR programs to reduce operational and capital costs. Electricity wholesale prices were fixed between proceedings, under the rate of return regulation; the utilities would lose money if the marginal cost of generation exceeds this price. At the same time, high interest rates created a problem for utilities to invest in new power plants. Thus,

the utilities initiated a number of load-control programs to reduce consumption during high demand periods, when the marginal cost of generation was high.
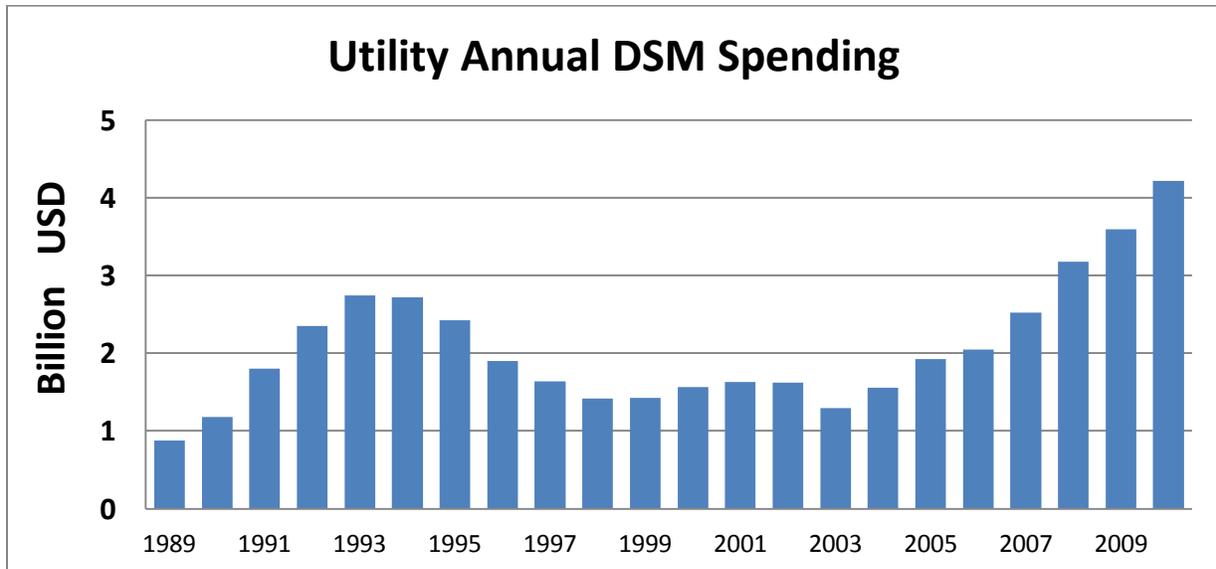
Figure 17: US Annual Spending on DSM [16, p. 267]

Figure 17 shows the annual spending by all US utilities on DSM programs. The prices are not adjusted for inflation. The spending reflects all direct and indirect costs associated with DSM programs. The major categories are customer rebates and incentives, administrative, marketing, training and research costs, and other indirect costs, but does not account for energy efficiency costs. The DSM spending gradually increased from 1989 to 1994. The reduction in spending after 1994 is attributed to utilities cutting back on DSM programs due to industry deregulation.

Actual Load under DSM
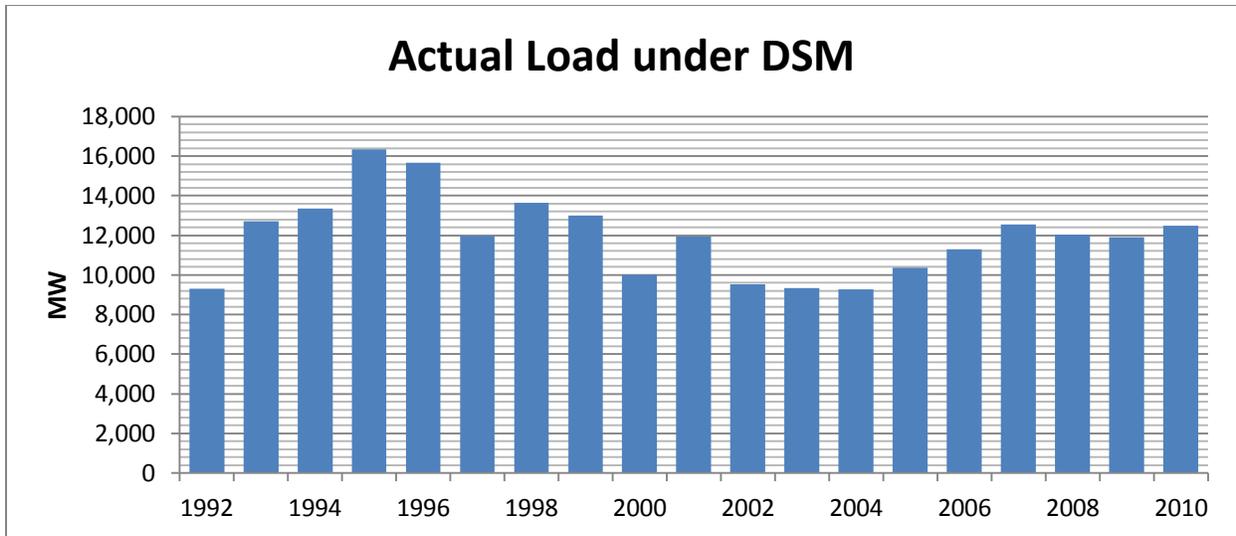
Figure 18: Load under DSM programs [16, p. 267]

The deregulation is also responsible for the decline of overall load under the DSM programs in late 1990s and early 2000 shown in figure 18. Some state governments created new programs that promoted DSM followed this federal deregulation. Examples include the "Energy $mart Loan Fund" initiated by the New York Energy Research and Development Authority and the "Efficiency Vermont" by the Vermont Public Service Board [16, p. 267]. These non-utility costs are not included accounted for in the figure. The actual load under DSM are loads that are enrolled in load management programs through DLC, ILC, or other programs that shift peak loads to off peak periods such as space heating and water heating storage systems.

Peak Load Reduction from Energy Efficeincy
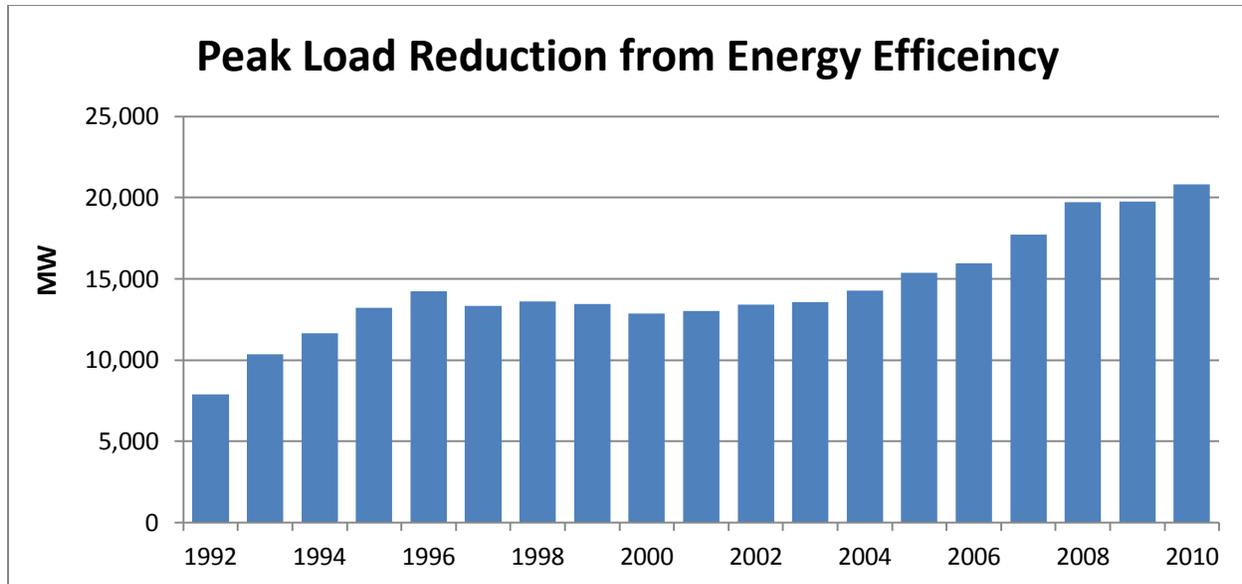
Figure 19: Peak demand reduction from energy efficiency [16, p. 267]

Energy Efficiency in figure 20 accounts for the reduction in electricity use by specific end-used devices and systems, typically without affecting productivity or services provided by the devices or systems. These generally include the substitution of older devices connected to the grid with more advanced and energy efficient versions. Examples include high efficient appliances such as air conditioner, lighting, heating, refrigerators, or control system, building design, and heat recovery systems.

Total Peak load Reduction
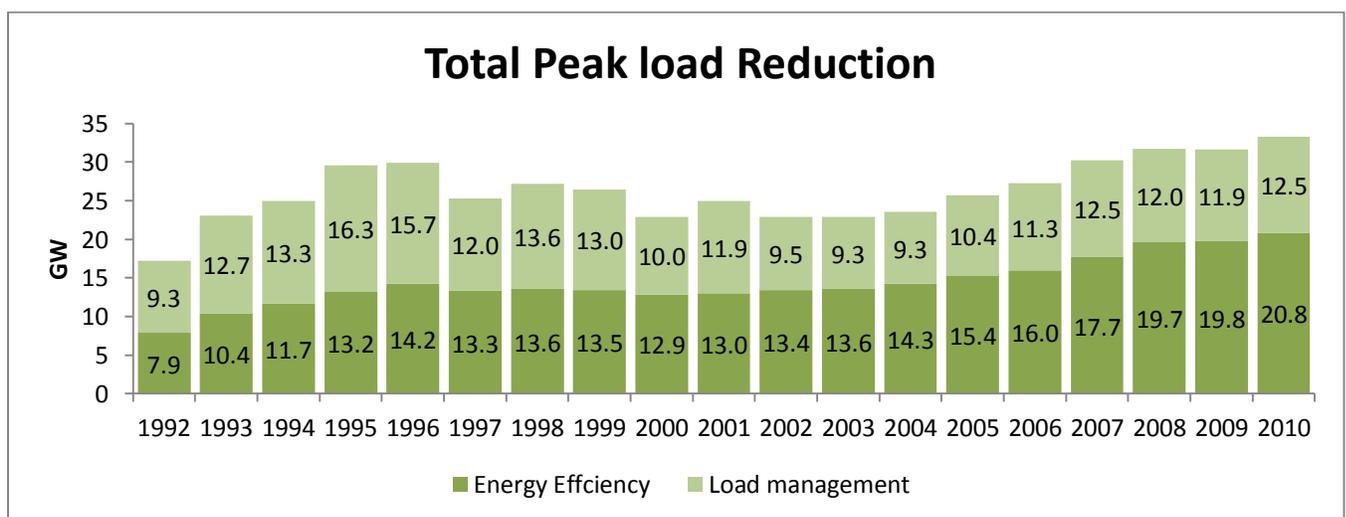
Figure 20: Total Peak Load Reduction [16, p. 267]

2.2 Demand Response Projections

The role of DSM programs in the US is projected to play a larger role in mitigating peak electrical demands. IEA estimates peak demand reduction of up to 5% by the year 2019 [17]. The projected peak demand reductions are shown in figure 21. The DR programs only include programs that allow system operators to control loads directly, and does not account for programs where customers have control such as Time of Use (TOU). The energy efficiency in figure 21 refers to reduction of peak load resulting from using more energy efficient appliances and lighting. These DSM programs have significant impact on peak demand, as NERC's 2010 LRTA reported that increasing participation in DR programs is contributing to reducing the overall growth of peak demand [17]. Both DR programs and effects of incremental energy efficiency are likely to increase through 2019.
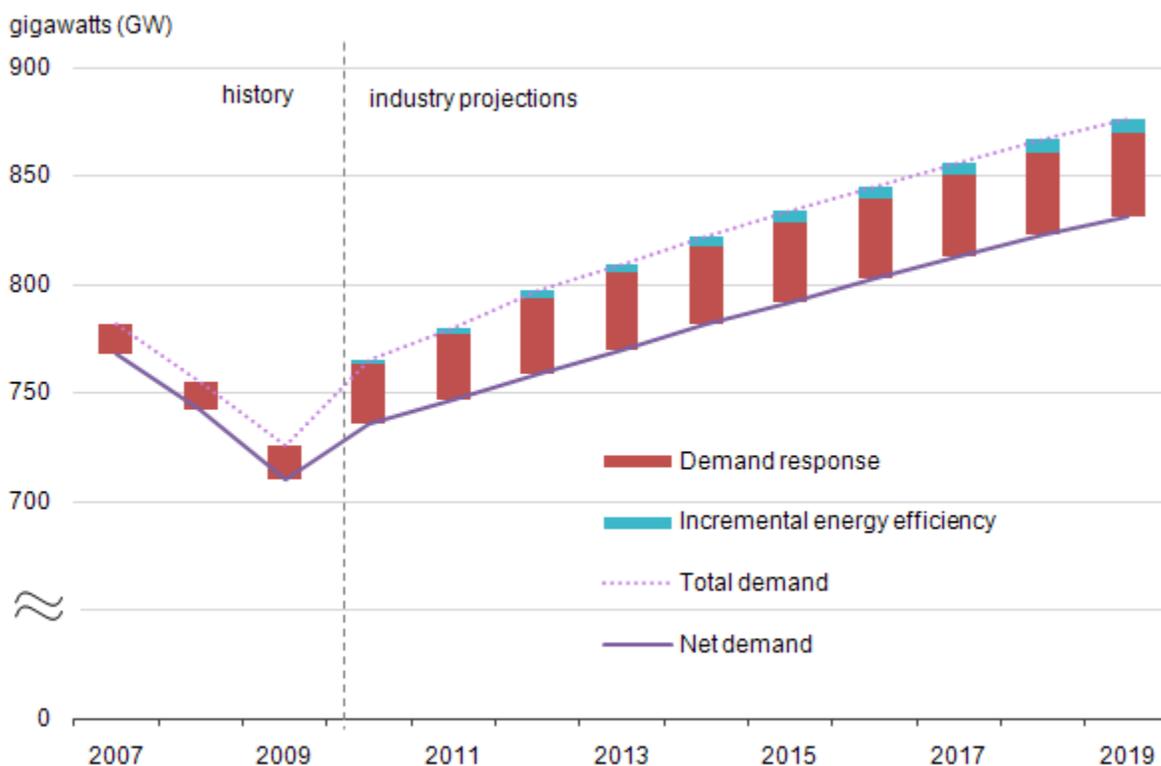
Figure: 21. Peak Reduction through Energy efficiency and Demand Response [18]

CHAPTER 3: Target Region: New England

3.1 Price of electricity

Electricity price has been gradually rising in the US for the past decade. As of Sept 2012, the New England region, New York, and California has some of the highest prices in the nation. On a macro scale, the cost of generating electricity varies depending on the market price, cost of fuel, type of fuel, government subsidies, regulations, and even weather. While only so much can be done about these factors, on a micro-scale, peak electricity largely affects the electricity cost as discussed in chapter 1. Thus to study DSM programs, regions with high electricity prices were looked at.

This IQP has found that a key driving factor between various regions is the type of fuel used. Average annual electricity price and fuel source data was taken from the EIA database for the six geographical regions: New England, Mid Atlantic, East North Central, West North Central, South Atlantic, East South Central, Mountain, Pacific Contiguous, and Pacific Noncontiguous. For a list of all states in each region, please refer to table 6 in appendix. Ten-year average of price and energy generated from different sources were calculated. The percentage of electricity generated from natural gas (NG), and from coal and hydro combined is shown in figure 22, starting with the region with highest electricity price at the left. The regions that produce the most electricity from coal and hydro have the cheapest electricity.

Percentage of total Electricity Generation
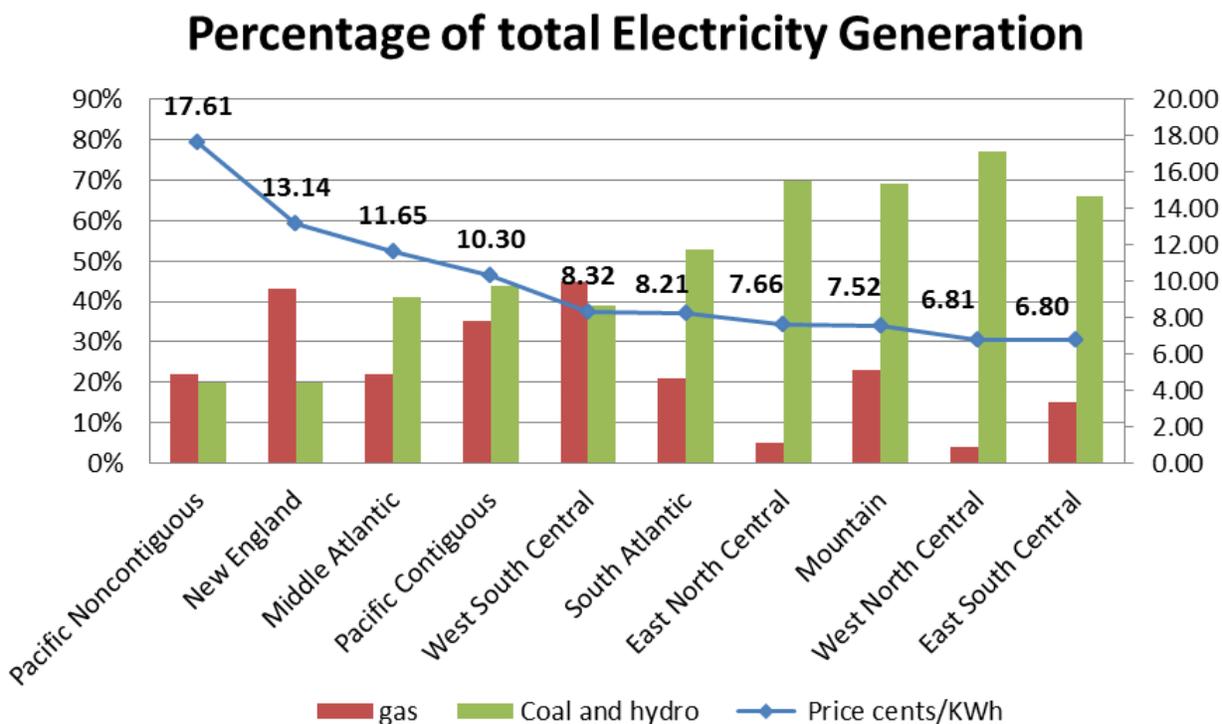
Figure 22: Percentage of Electricity generated by source

New England and the New York region have the highest electricity price in the Nation. The high electricity costs in the New England region is mostly because of their extensive use of gas generators. In 2010, 45% of New England's electricity was generated form natural gas generators [19, p. 7].

Ten year average of natural gas used of total electric generation in Rhode Island is 98% and Massachusetts is 56% During the late nineties when gas prices were low, almost 100% of the power generators installed in the region were gas fired, totaling to almost 10 GW of installation between 1994 and 2004 [19, p. 9]. This had the advantage of improved air quality from replacing coal power plants. However, the gas price hike has drastically raised the price of electricity in this region. This correlation between NG price and electricity price is the most apparent in the NY region. Figure 23 shows the average annual cost of NG and electricity in the state between 2000 and 2011. The high cost of NG from 2005-2008, also drove the electricity prices.

Figure 23: Gas and Electricity Price in New York [20, p. 15]

The high electricity price has made the New England and New York region good potential targets for further study. The NG price is not likely to decrease in the near future; in fact, it is likely to increase gradually in the next two decades as shown in figure 24.
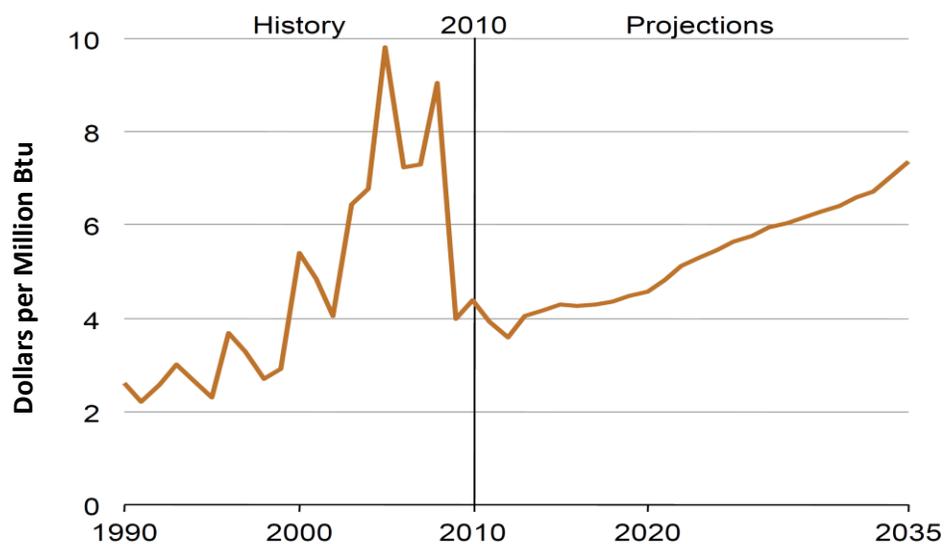
Figure 24: Projected gas price (Henry Hub spot prices) [21, p. 91]

The NYISO 2010 summer peak demand forecast shows an annual average growth rate of 0.85% for the years 2012 through 2022 [22, p. 5] compared to 1.5% projected by ISONE for the NE region [1, p. 5]. Furthermore, New England is projected to see tremendous growth in PV solar installation, totaling almost 800 MW of added nameplate capacity in the next 11 years, out of which 400 MW will be in the state of Massachusetts. Since this IQP proposes utility scale solar as a means to complement DSM programs, ISONE seems more suitable for the case study. To summarize, it is the high electricity cost, the annual growth of summer peak demand, and the prospective growth of PV installation that lead this study to select this region.
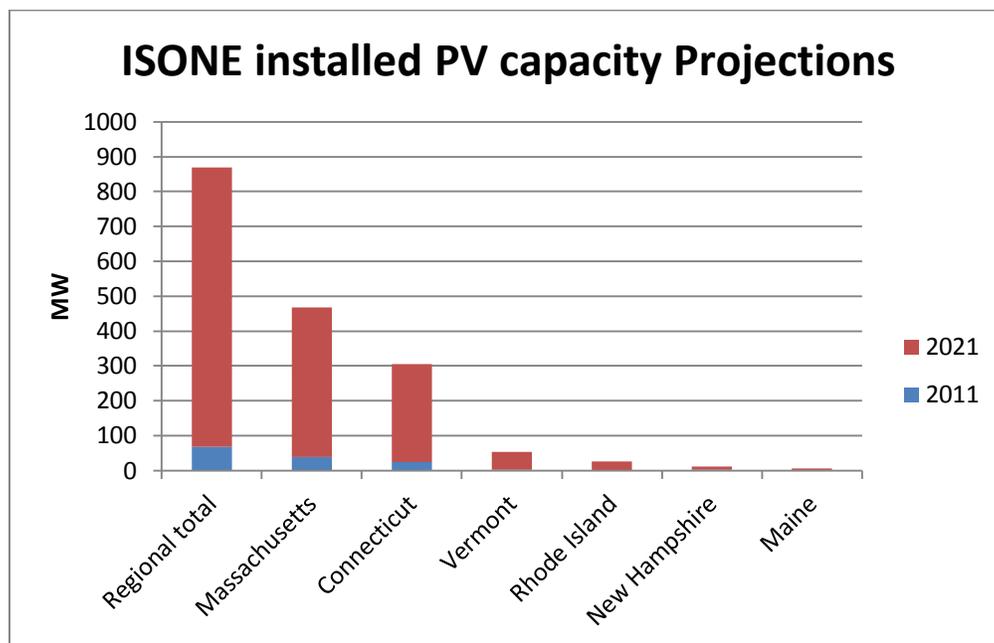
Figure 25: Prospective expansion of PV in New England [1, p. 148]

3.2 ISONE Load and Capacity Forecast

ISO New England is responsible for the state of CT, MA, NH, RI, VT, and ME. ISO New England describes its role as: *"ISO New England meets its obligation in three ways: by ensuring the day-to-day reliable operation of New England's bulk power generation and transmission system, by overseeing and ensuring the fair administration of the region's wholesale electricity markets, and by managing comprehensive, regional planning processes"* [23].

"The ISO forecasts the 10-year growth rate to be 1.5% per year for the summer peak demand, 0.6% per year for the winter peak demand, and 0.9% per year for the annual use of electric energy. The annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load) continues to decline from 57.5% in 2012 to 54.9% in 2021" [1, p. 5].

According to NERC 2011 LRTA, no significant issues were raised for the ISONE region. ISONE has adequate reserve margin currently as shown in figure 26; the target reserve margin set by NERC is 15%. This is a measure of generating capacity available to meet expected demand. It is calculated by equation 1.

$$Reserve\ margin = \frac{Available\ capacity - Net\ internal\ demand}{Net\ internal\ demand}\ X\ 100\% \qquad [1]$$

Net internal demand defined by NERC is the Total Internal Demand less dispatchable, controllable, Capacity Demand Response used to reduce load [24]. The projected demand is based on a 50/50 forecast, which means that the peak loads have a 50% chance of being exceeded because of weather conditions.
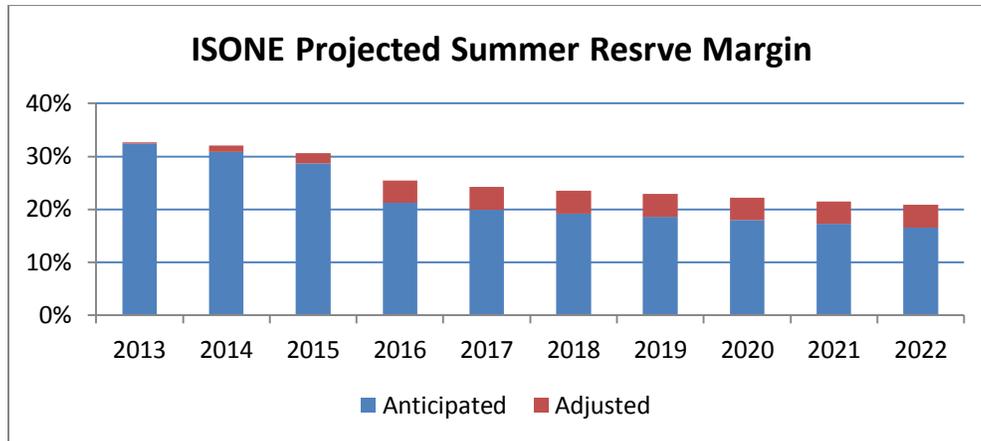
Figure 26: ISONE reserve margin planning [25, p. 10]

Although ISONE has adequate of reserve margin, it has been experiencing a declining load factor in the past decade. Load factor is a measure of how "peaky" the load on the grid is. It is calculated by using equation 1.

$$Load\ Factor = \frac{Avergare\ Load}{Peak\ Load} \qquad [2]$$

As discussed earlier in this paper, peak electricity is expensive, because it is costly to generate, and the uncertainty causes a higher LMP at the spot market. Thus to reduce the cost of electricity and avoid expenses related to expanding grid infrastructure, ISONE needs to improve their load factor.
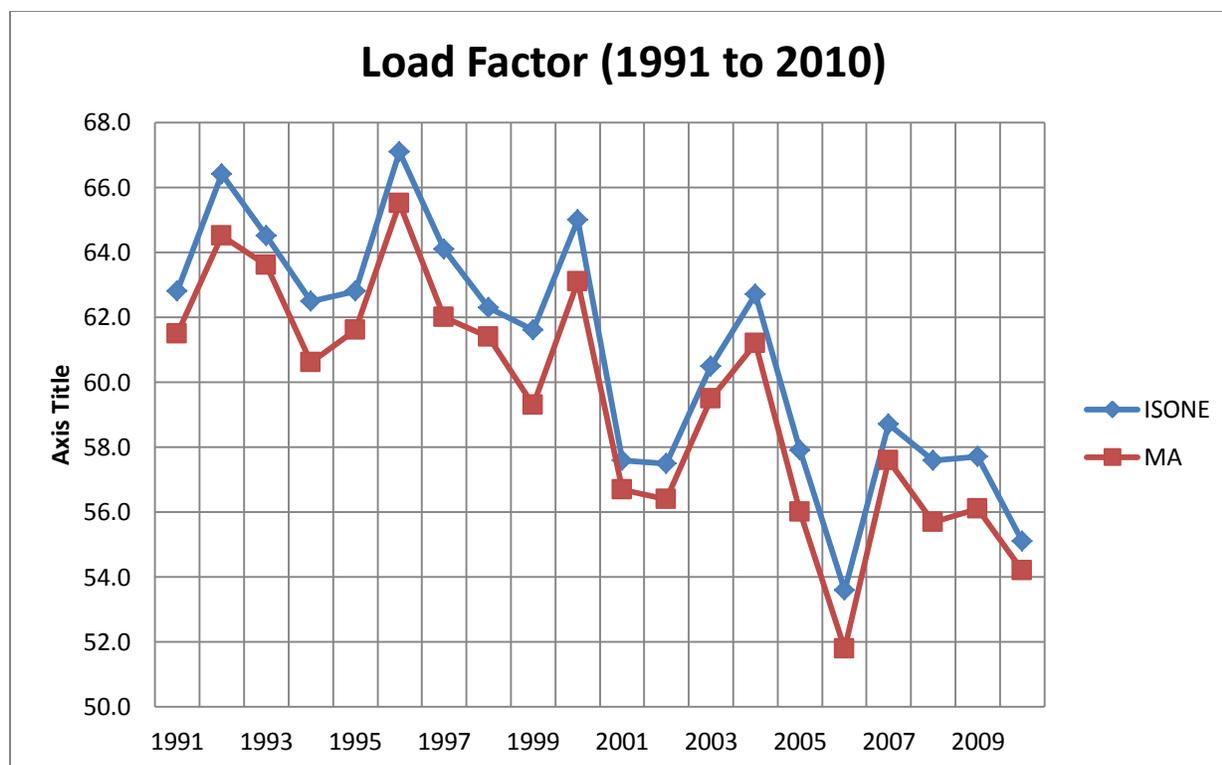
Figure 27: Actual load factor ISONE [26]

Since 2004, ISONE has run successful DSM programs to improve its load factor. However due to a rising peak demand during summer, the summer load factor still declined, and is expected to do so (although at a much slower rate) till 2015. The 2006 load factor was the lowest in its 10-year history because of the extreme summer temperatures experienced in the region. As discussed earlier in this report, the increased number installed of Air-conditioning units is largely responsible for the disparity between rising summer and winter demands. While the winter load factors have significantly increased because of successful DSM programs, the summer load factor continues to decline as shown in figure 27. The load factors discussed in here refers to actual load factors experienced annually, and does not account for DSM measures OP4 (Operating procedure 4) and PDR (Passive Demand Response).
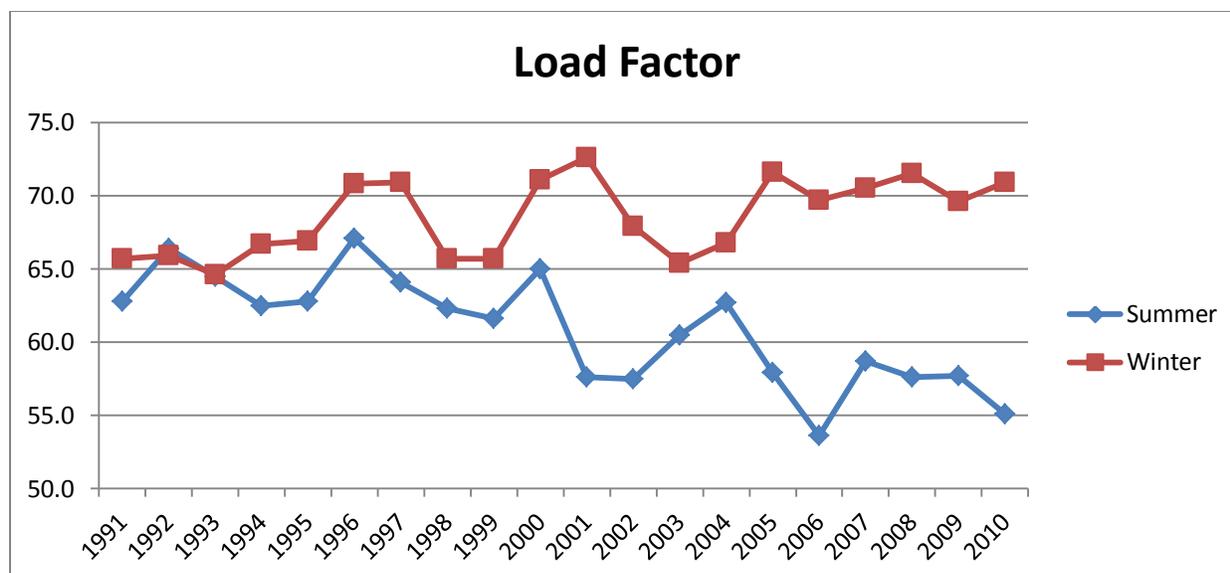
Figure 28: ISONE Load factor (actual) [26]

3.3 ISONE Overview

ISONE is divided into 8 Load zones (refer to figure 31). Load zones are aggregation of nodes within an area, and are used for wholesale billing. These eight load zones are Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

The pricing points on the system include individual generating units, load nodes, load zones and the Hub. Load zones are accumulation of load nodes within an area, while the Hub is a collection of locations that represents an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace [1, p. 26]. In the ISONE region, generators are paid the LMP for electric energy at their respective nodes, and the participants serving demand pay the price at their respective load zones [1, p. 26].

- 6.5 million households and businesses; population 14 million
- Over 300 generators
- 32,000 MW of total generation
- Over 8,000 miles of transmission lines
- 13 interconnections to electricity systems in New York and Canada
- Approximately 2,100 MW of demand resources for 2012
- All-time peak demand of 28,130 MW, set on August 2, 2006
- Approximately 500 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)
- $7.63 billion total market value— $6.17 billion energy market, $1.35 billion capacity market, and approximately $0.11 billion for ancillary services
- Approximately $5.0 billion in transmission investment since 2002; approximately $6 billion planned over the next 10 years

Figure 29: New England Demographics [1, p. 24]

Additionally, the region is divided into 19 demand resource dispatch zones, as shown in figure 30. These DR dispatch zones are groups of nodes used to dispatch real-time demand-response resources or real-time emergency generation (RTEG) resources [1, p. 24]. "These allow for a more granular dispatch of active demand resources at times, locations, and quantities needed to address potential system problems without unnecessarily calling on other active demand resources" [1, p. 24].
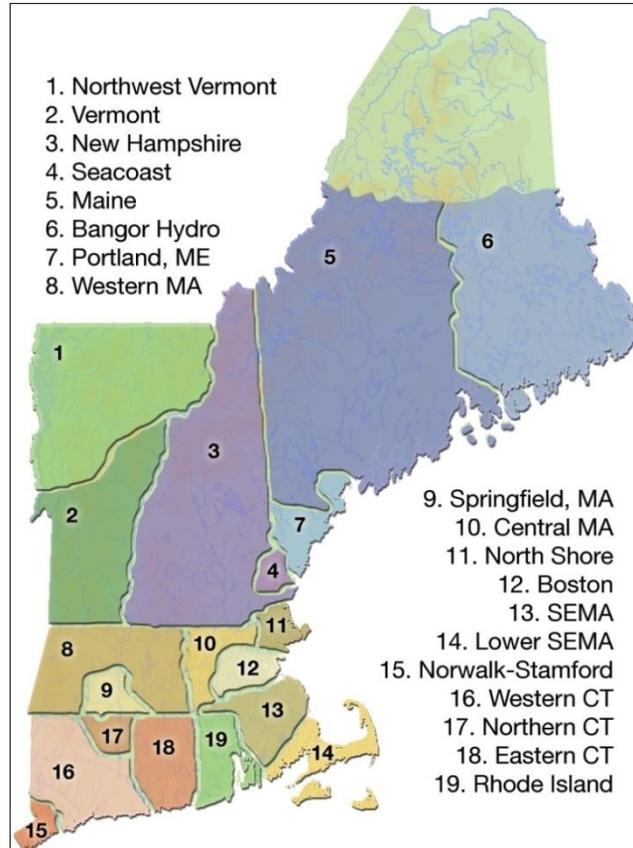
Figure 30: ISONE DR dispatch zones [1, p. 27]

3.4 Target Load Zone: NEMABOSS
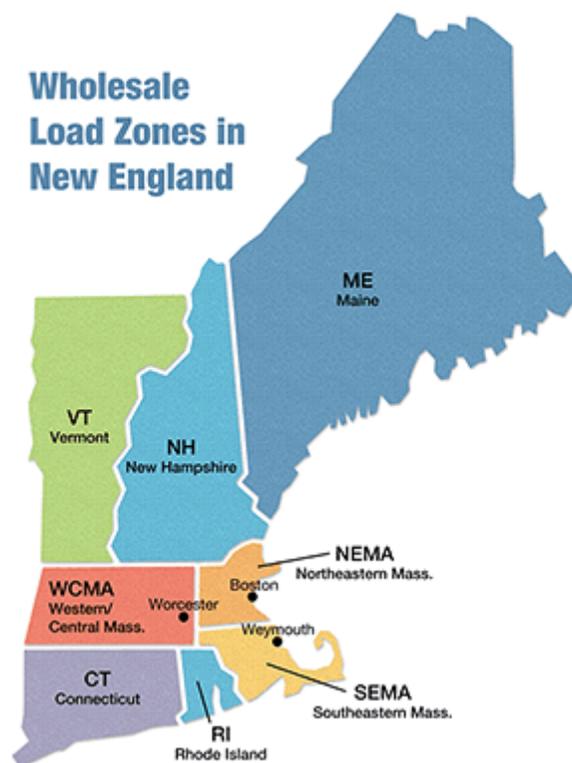
Figure 31: ISONE Load Zones [27]

In the Northeast Massachusetts (NEMA)/Boston capacity zone, the amount of capacity resources is projected to marginally meet the resource adequacy requirements for that area. In the near future, Salem Harbor units #1, #2, #3, and #4 (near Boston) will retire decreasing the generating capacity of nearly 750 MW. In Forward Capacity Auction 6 (FCA 6), the local sourcing requirement (LSR) for NEMA/Boston was 3,289 MW, and the resources in that area totaled 3,348 MW. [1, p. 7] Thus, any additional retirements in NEMA/Boston region may create the need to develop new generating resources. Furthermore, recent developments in NEMA/Boston associated with reduced liquefied natural gas (LNG) supplies further highlighted reliability concerns in this zone. [1, p. 7] Figure 32 shows the top 100 hourly demand for the ISONE region for the year 2011. The NEMA zone has a higher overall system load, and the peak demand is significantly higher than the average demand compared to other load zones.
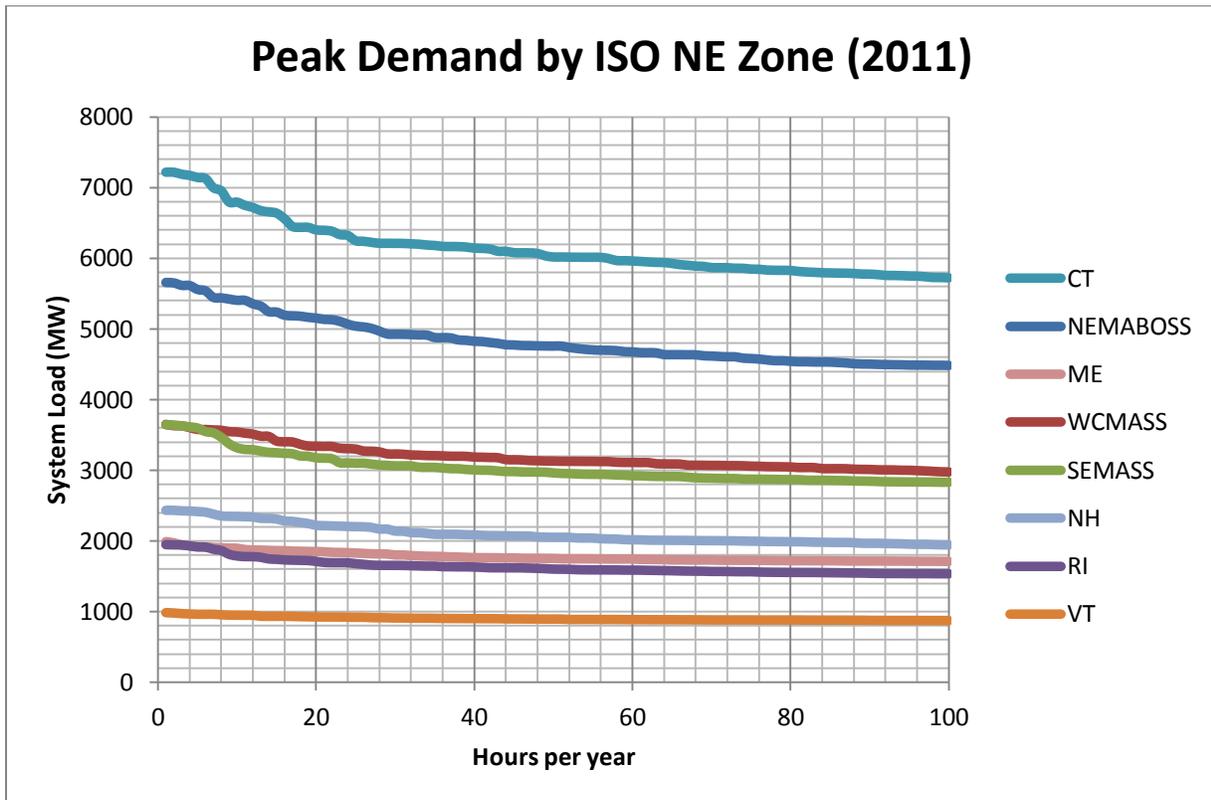
Figure 32: Top 100 load hours ISONE for the Year 2011 [28]

CHAPTER 4: Utility Scale Solar PV Projects

This chapter discusses the potential of PV to complement DSM programs. This IQP advocates for PV solar projects to complement DSM programs. The trends in the solar PV market are discussed and a detail financial model and is presented for a prospective utility scale PV project in Massachusetts. Although This IQP advocates expansion of PV in general, larger scale is preferred to smaller residential one because of economies of scale as well as well as design flexibility, which allows for increased output for the same nameplate capacity. In addition, non-residential solar expansion distributes the financial risks from homeowners to other energy investors.

4.1 Why Solar

The growth of solar PV systems in the past 5 years has been tremendous all over the world. PV systems have grown annually at 60% globally and 53% the United States. In the year 2011 alone, the US has installed about 2 GW of the 21 GW of PV installed globally. This was a 109% increase over from the previous year [29, p. 1]. The increase in state and federal incentives as well as the decline in PV system cost is causing this rapid expansion of PV installation across the US. As discussed later in this chapter, the PV power output period partially coincides with the peak electricity demands of the day. Furthermore, more than half of the annual electricity from PV is generated in three summer months, which makes solar a better investment to mitigate peak electricity compared to other renewables.

4.1.1 PV output pattern

This IQP has found that PV output peak hours largely coincide with peak electrical Demand periods both during the 24-hour period of the day as well as summer peak months. AS discussed earlier in this report, summer peaks are significantly higher than winter peaks both throughout the US (figure 1), as well as in New England. Consequently, summer capacity margin is generally less than that of winter. Thus from an electricity generation and distribution standpoint, summer peaks drive the capacity

expansion cost.   Furthermore, summer load factors are lower and electricity prices are higher compared to that of winter. For example in the New England region, the 2011 winter load factor was 70.9%, which is 15.8% more than the 55.1% summer load factor (figure 28).

4.1.1.1   Monthly Output

To study the monthly solar to electrical energy pattern, 10 years data of monthly total electricity generated from solar resources was taken from EIA database. Each month's contribution to the total energy generated was plotted for 9 years as shown in figure 33.

Electricity Generation from Solar (US)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	7.19	30.44	78.11	99.42	110.4	103.4	121.2	116.3	94.99	68.1	40.4	21.21
2008	16.29	35.84	74.6	94.14	98.74	128.2	110.9	105.3	92.6	60.24	28.85	18.69
2007	12.84	19.24	48.49	54.46	84.19	84.46	85.79	75.16	68.21	49.23	24.3	5.402
2006	12.94	19.53	33.4	52.07	70.74	69.7	61.66	82.99	53.99	32.28	15.69	2.713
2005	8.668	13.08	38.16	58.26	81.15	88.48	72.33	75.85	61.11	37.67	12.76	2.793
2004	12.61	10.86	52.93	56.9	81.78	87.88	82.1	72.85	60.63	33.52	15.34	7.758
2003	13.22	17.83	50.03	60.31	67.96	90.68	62.41	61.99	55.86	35.44	14.03	4.251
2002	11.32	23.57	44.4	45.86	57.64	95.54	85.54	74.93	52.61	30.96	28.18	4.307
2001	6.5	12.57	31.5	38.76	81.05	91.14	91.99	85.3	64.8	20.81	14.29	4.036

Figure 33: Total PV solar output in the US by month

While the peak energy month varied each year, in all 10 years they occurred between May-August. The month of June has produced the most energy in the 10 years total, followed by July, August, and May. Another significance of this plot is that the Monthly output for each year was highest during the hottest month of that year. For example in 2006, the highest summer temperatures were observed in August, the month when solar energy produced was also the highest for that year. This is important because the hottest days tend to show higher energy consumption as well as peak demand.

The total energy generated was highest in summer months. The four summer months- May, June, July, August accounted for more than half of the total energy produced as shown in figure 34.
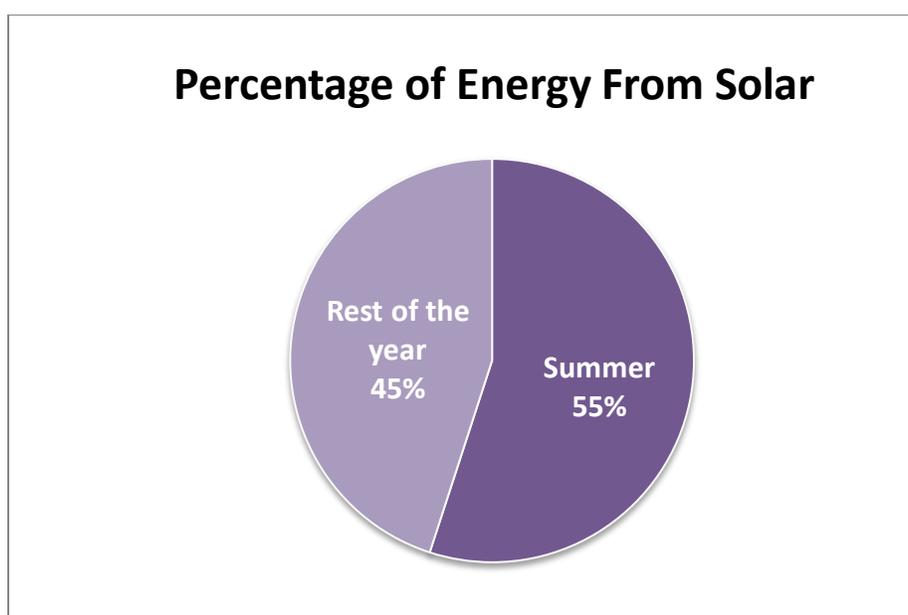
Figure 34: Summer PV energy accounts for more than half of annual

Since this IQP proposes the use of PV solar technology, especially in the state of Massachusetts, a similar analysis was done based on reported electricity generation data to IEA from three solar projects located in Massachusetts. Since large-scale PV projects are new in Massachusetts, only three of facilities have recorded data in the IEA database, and complete data for 12 months was found only for the year 2011. The two projects: NEDC Solar Site and Haverhill Solar Power Project both have nameplate

capacities of 983 KW, and are rooftop PV systems located at municipality buildings. The Silver Lake Photovoltaic Facility has a nameplate capacity of 1.8 MW. It is a ground mount system located in Pittsfield MA.

The electricity production pattern of all three PV sites is very similar, and this pattern is consistent with the US annual energy production from all solar sources (figure 33). All three sites produce approximately half of its annual energy in the four months between May and August as shown in figure 36. Since summer electrical demands are more concerning than winter demands, the higher energy produced from PV during this period makes it suitable for mitigating the summer peak demands.
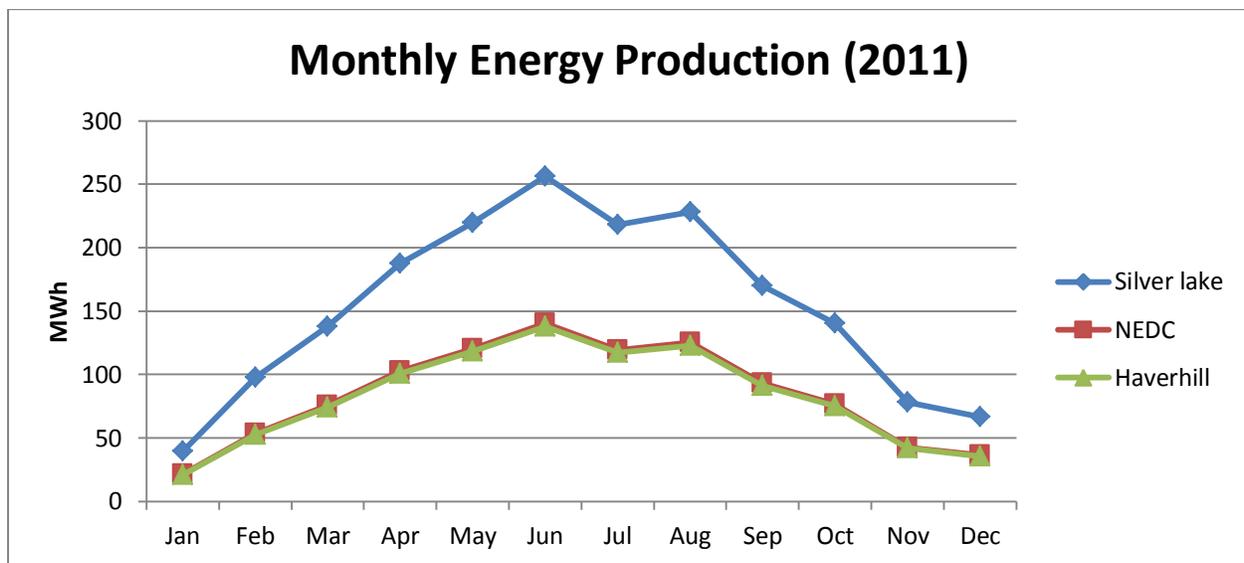
Figure 35: Actual electricity produced for the year 2011
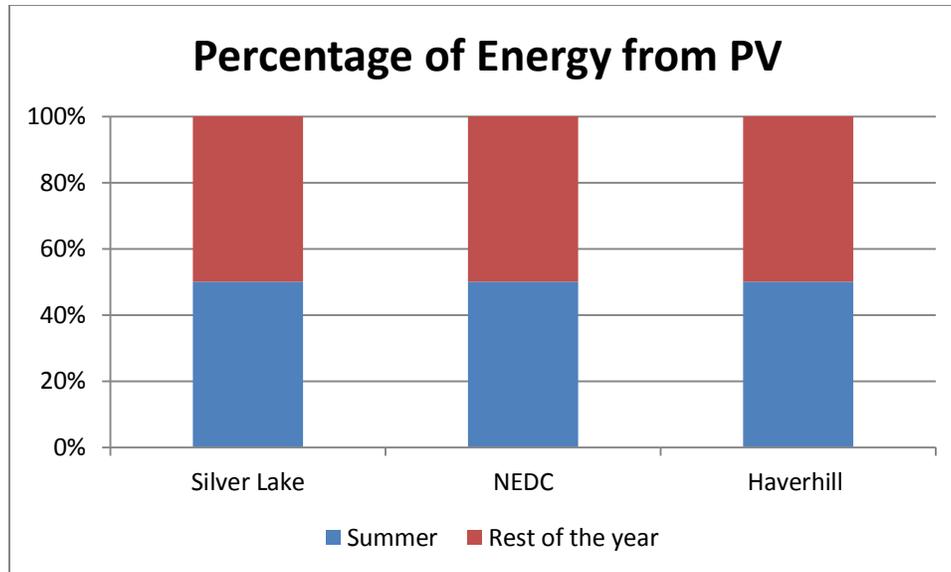
Figure 36: Energy from PV in summer vs. rest of the year

4.1.1.2 *24-Hour PV output*

To study how PV output coincides with hourly peak electricity demands, simulated hourly data was used for the Boston area. The data was generated by NREL's "PV watts v.1" using typical meteorological year (TMY) weather data. Since weather patterns vary from year to year, the values plotted here are better indicators of long-term performance than for a particular month or year. Compared to long-term performance, the data shown is accurate within 10% to 12% margin [30]. The data also accounts for PV cell temperature. The parameters used for simulation is shown in table 2. The DC rating or the nameplate capacity is chosen to be 1000 KW, as this value is later used in the financial analysis in the next chapter.

Table 2: Simulation Parameters

City: BOSTON
State: Massachusetts
Latitude (deg N): 42.37
Longitude (deg W): 71.03
Elevation (m): 5
Array Type: Fixed Tilt
Array Tilt (deg): 35
Array Azimuth (deg): 178
DC Rating (kW): 1000
DC to AC Derate Factor: 0.770
AC Rating (kW): 770.9

The AC rating shown on the table is calculated by multiplying the DC rating with the derating factor, to account for inversion loss. Thus, the maximum output power (AC power) that can be produced is 770 KW. The array tilt is chosen 35 degrees, based on optimum tilt angle calculated from solar insolation data from Solmetric Corporation (figure 43 in appendix). An annual average of the 24-hour output power is shown in figure figure 37. The PV output is the highest at noontime, reaching about 65% of the rated output. The output power is over 52% for hours between 10:00 am and 2:00 pm.
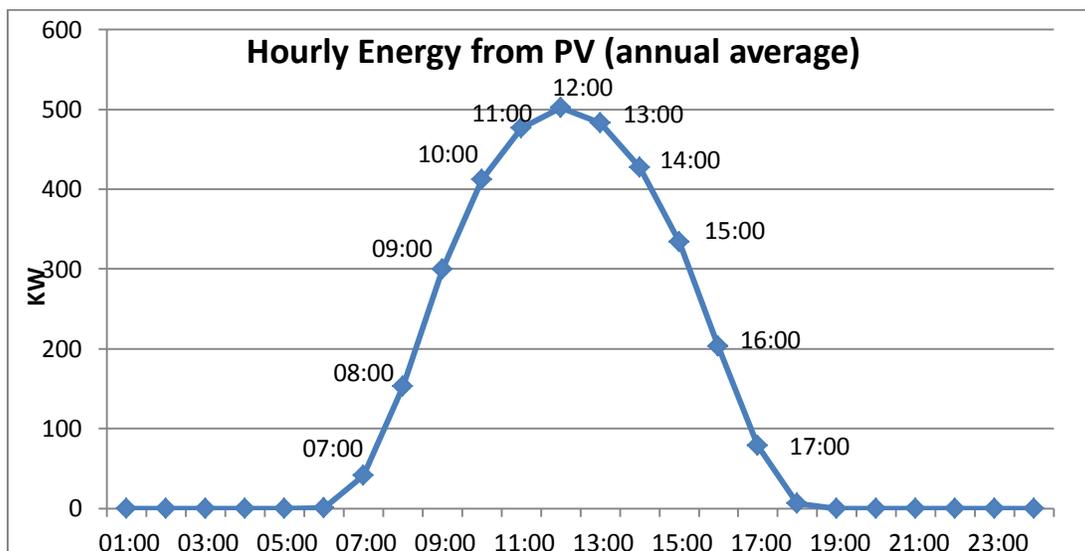
Figure 37: Simulated hourly PV output (KW)

While the capacity factor of PV is generally much lower than other renewable resources, most of the energy is produced during peak electrical demand hours[1]. Thus, this IQP recommends the use of PV technology as a peak electrical demand management strategy. Figure 36 compares the simulated average hourly to the annual average hourly electrical load in the NEMABOST load zone. The simulated PV output follows the load curve, producing the maximum energy during high demand hours.
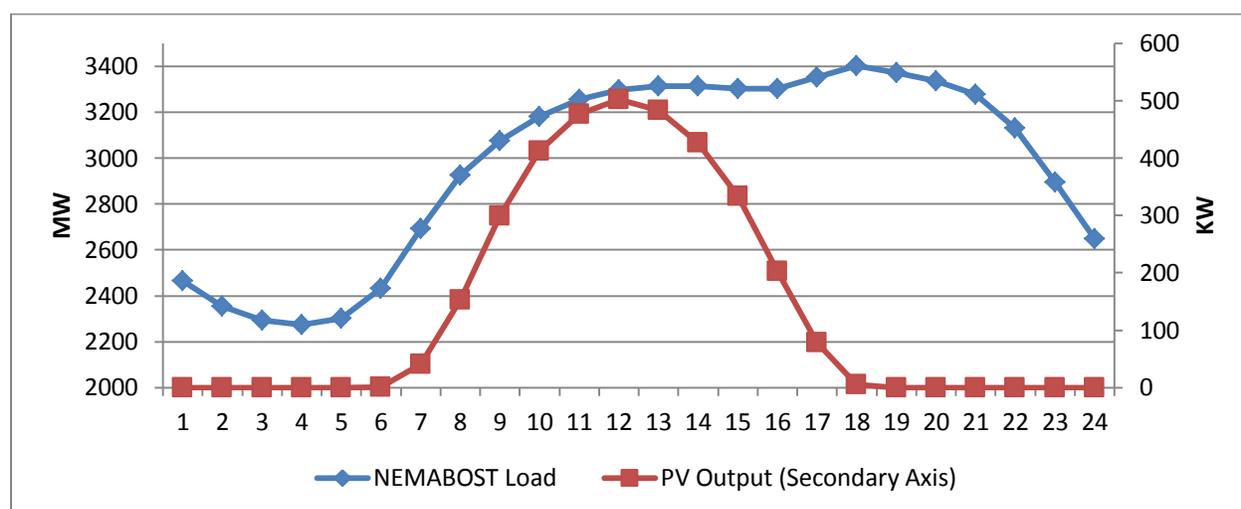
Figure 38: 24-Hour PV output (Boston) and ISONE Annual Average Hourly Load Curve (2011)

4.2 Scale and Technology

From a peak demand standpoint, residential PV systems are promising since they typically come with batteries. This can be especially helpful as the batteries could be discharged during peak hours by a signal from the utility companies. However, from an end consumer standpoint owning, maintaining, and financing a PV system can be difficult. The residential PV systems also pose a financial risk on homeowners that they should not have to take, and currently the IRR on smaller residential PV

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[1] Capacity factor is the ratio of actual output of power compared to nameplate capacity over a period. Over a 24-hour period, PV technologies have relatively low capacity factors as they only produce energy during the day when sunlight is present. Refer to figure 48 in appendix for Capacity factor of various renewable sources.

systems(<10KW) is much lower than bigger commercial or utility projects. Furthermore, the integration of small residential systems in different locations across the grid has added reliability issues that need to studied and addressed if done in a larger scale. Thus, this IQP proposes commercial and utility scale PV projects.

4.2.1 Residential, Commercial and Utility

Small (residential) PV systems are more expensive than the larger systems due to economies of scale, as well as the added battery cost. From 2011 Q4 reported data shown in figure 39, the mean price for systems <5KW was can range between $5/W to $6/W, compared to $3/W to $4/W for larger commercial systems > 1,00KW. Although the price varies across states, the price was significantly higher for smaller systems everywhere in the US. This added cost can significantly affect the payback period, and the return on investment.

Small residential systems have a much higher cost than larger systems. Commercial projects greater than 100 KW are much cheaper due to the economies of scale. While utility scale projects have the same economies of scale as commercial projects, they have added construction cost for preparing the site for PV installation. This extra cost makes utility PV projects less profitable than commercial PV projects for the same nameplate capacity. Thus, the most profitable project for the least startup cost would be a commercial project close to 1MW of nameplate capacity.
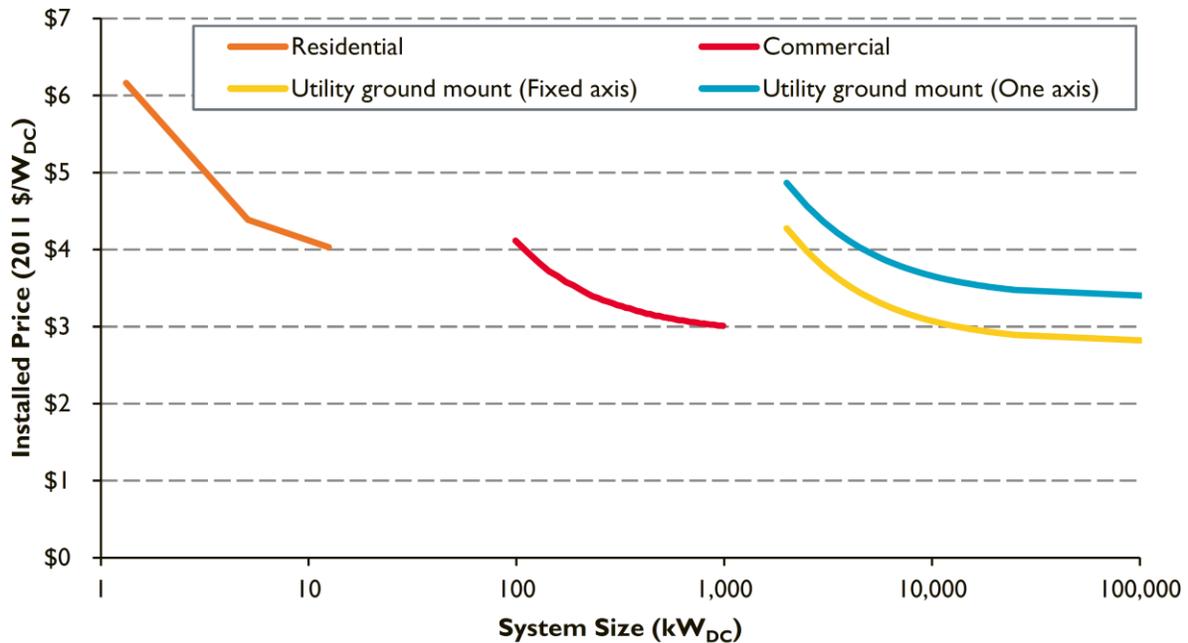
Figure 39: PV system cost [29, p. 12]

In 2011, most Utility scale projects larger than 10 MW ranged from $2.80/W to $3.50/W, while projects smaller than 10 MW span a broader range, with most projects priced between $3.50/W and $5.00/W. [29, p. 8] The reduced costs of larger utility scale projects undoubtedly reflect economies of scale. However, other factors may be at play. Site characteristics typical of smaller versus larger projects could affect this cost. Furthermore, large projects are more likely to be developed by more experienced and/or vertically integrated entities, thus further reducing the cost.

4.2.2 PV technology

The relationship between PV technology and installed is less discernible. Figure 9 shows reported installation cost of several utility scale projects between 2 MW to 40 MW. Among projects less than 10 MW, the five thin film projects are at the low end of the spectrum. All the five thin film projects are owned by a single southwestern utility. Among projects larger than 10 MW, however, no clear differences in installed prices are observable either between the crystalline and thin-film systems or between the systems with and without tracking [29, p. 9]. The absence of visible trend does not mean that PV technology has no impact on price. The impact on price is simply lost in the small sample size because of various other factors such as regulatory compliance cost, public versus private land, leased versus owned land, and design requirement due to specific climate conditions [29, p. 9].
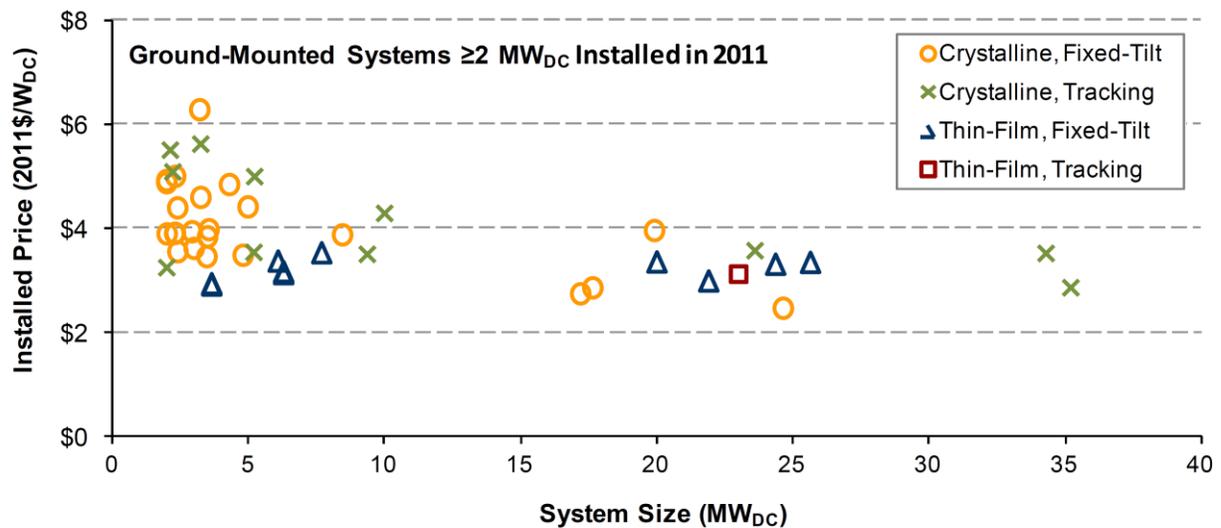
Figure 40: PV Technology and System Cost [29, p. 9]

Chapter 5: PV Solar Project study in Massachusetts

This IQP advocates the use of solar PV to complement DSM programs. ISONE region was chosen for further studies because of the high electricity cost, the annual growth of summer peak demand, and the prospective growth of PV in the region. Among the ISONE states, Massachusetts is expected to have the largest growth, an additional 400 MW PV capacity expansion through 2021. Thus, this chapter provides financial analysis of a prospective PV project

5.1 Financial Analysis

This section provides a simple financial analysis for a 1MW commercial PV project in the Boston area. The simulation was run using NREL's System Advisor Model (SAM) software version 2.3.3. Instead of using any specific model of PV technology, the PVWatts system model within SAM was used. Table 3 shows the parameters that were used in the simulation.

For simplification, it is assumed that the solar project is owned and maintained by a single entity, and all the electricity produced is sold through a power purchase agreement (PPA). Two analyses were performed. The first analysis used a fixed IRR of 15% to calculate levelized cost of electricity (LCOE) for variable system cost and SREC prices. The second analysis provides an estimate of required PPA price to achieve expected IRRs.

Table 3 shows the parameters used for the financial analysis. For a 1MW commercial project, a total system cost (including construction, permit, and other initial costs) is expected to be $3 to $4 per watt. For a utility scale (ground mounted), the same nameplate capacity will cost between $4 to $6 per watt, due to added construction costs for site preparation. Thus, the simulation includes a system cost of $3 to $6 per Watt to allow the simulation to be used for analysis of both ground mount systems (utility) and rooftop (commercial) projects. The tilt angle of 35 degree results in an annual energy production of 1,247 MWh annually, calculated by SAM using TMY-2 data. The assumed capacity factor was calculated

to be 14.2%. The project life expectancy is assumed 25 years as most PV manufacturers provide a 25-year warranty, while the inverters need to be replaced once during this period. A debt fraction of 50% is assumed, although smaller companies with weak financial history should expect a lower debt fraction. A high interest rate of 9% is assumed.

Table 3: PV project simulation parameters

Parameters	Values used for Analysis
Size	1 MW
Capacity factor	14.2%
Energy produced (annual)	1,246,529 KWh
Cost	$3-6/W
O&M costs	Fixed at $8.50/kW
Inverter replacement	$300,000 once during project lifetime
PV system degradation	0.5%/year
Inflation rate	2%
Debt fraction	50%
Loan rate	9%
Minimum required IRR	15%
Real discount rate	12%
DSCR	No minimum DSCR
PPA escalation rate	1%/year
Loan term	25 years
Analysis period	25 years
System lifetime	25 years
Financial incentives	Federal 30% ITC
SREC Prices	$(250-600)/MWh/year for 10 years, taxable
Federal, state, property tax	35%, 8%, 2%, (annual)
Depreciation	MACRS 5 years

5.1.1 Sensitivity Analysis

A simple sensitivity analysis was simulated by varying each input parameter by 10% as shown in figure 39. For the base case, the parameters were used from table 3, with a conservative SREC price of $0.3/KWh and $5/W system cost. LCOE was found to be most sensitive to the total system cost, annual energy produced, debt fraction, and SREC. Albeit small, the loan interest rate also affected the LCOE. While project owner cannot control the annual energy output or the SREC, this analysis provides insights into the debt fraction and loan interest rate. Since the LCOE is more sensitive to debt fraction than loan

interest rate, prospective project owner will profit more by negotiating a slightly higher interest rate than a lower debt fraction. This is further discussed in the next section.
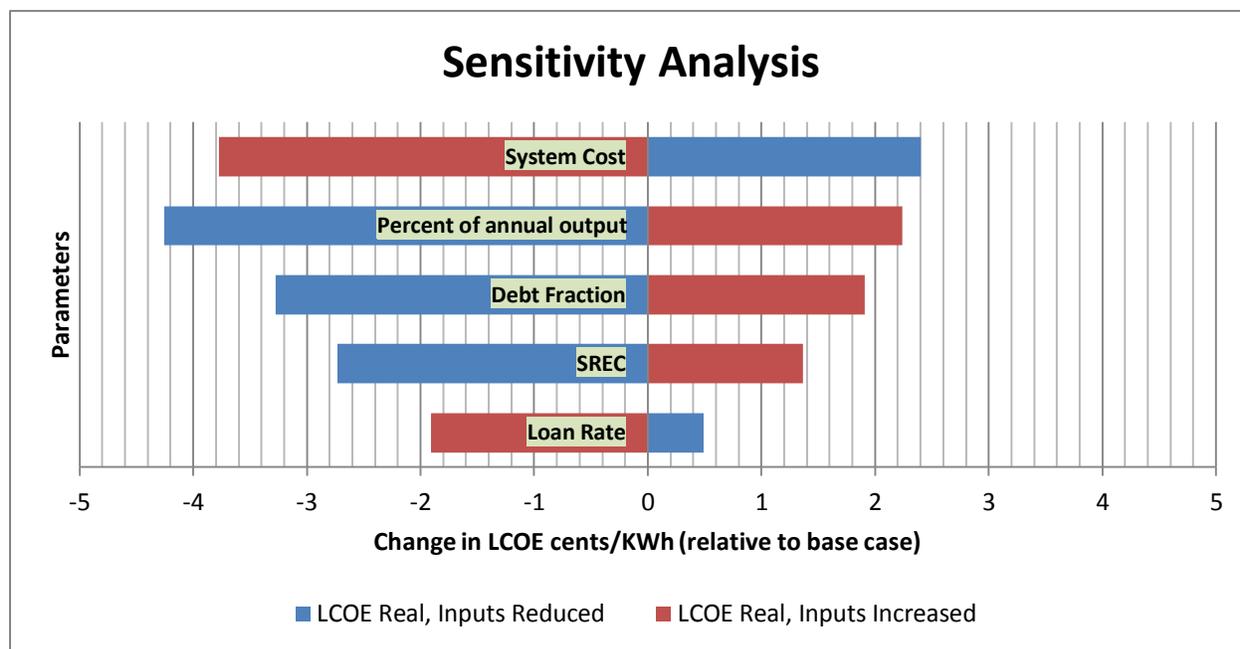
Figure 41: Sensitivity Analysis (Inputs varied by 10%)

5.1.2 Worst Case Sensitivity Analysis

For the base case, the parameters were used from table 3, with a conservative SREC price of $0.3/KWh and $5/W system cost. These are the same parameters used to calculate LCOE in figure 39. The calculated base case LCOE was found to be 11.68 cents/KWh. The worst-case LCOE was simulated by changing each parameter to a reasonable worst-case scenario as shown in figure 40. In this analysis, LCOE was found to be the most sensitive to debt fraction, as realistically the debt fraction could be as low as 35%, while the system price is not likely to be more than $6/W. An increased interest rate of 11% caused LCOE to increase to 12.7 cents/KWh, while a debt fraction of 35% increases the LCOE well above the average electricity market price of 15 cents/KWh. Thus, the prospective project owner should negotiate a less than 50% debt ratio with the financing institution, even if it is at a higher interest rate.
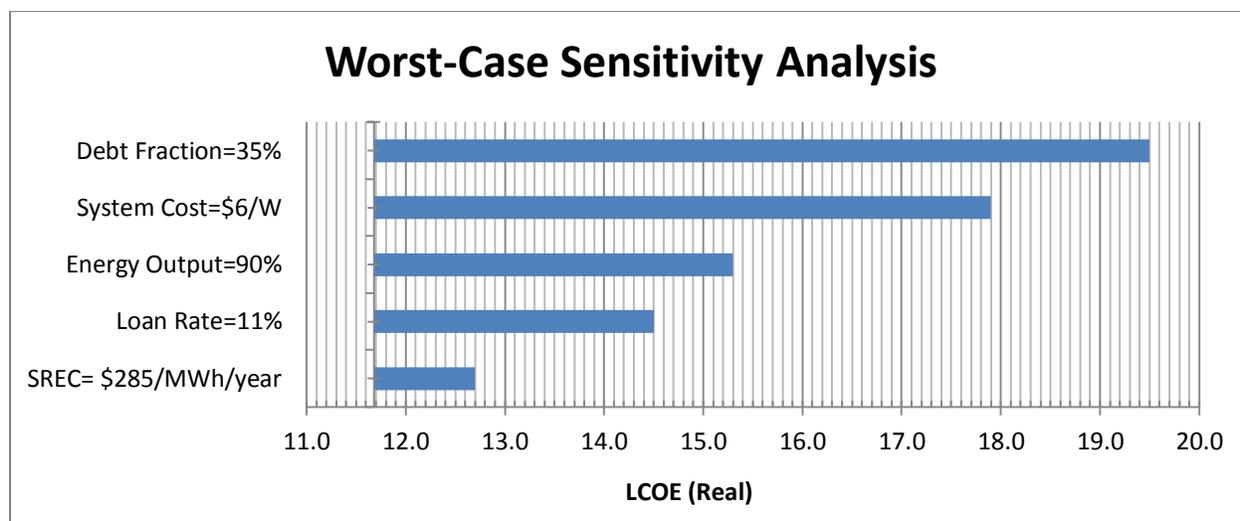
Figure 42: Worst-case Sensitivity Analysis

The SREC floor price for the state of Massachusetts is guaranteed to be $285/MWh/year. The state ensures this price by controlling the allocation of additional renewable generation each year. Thus, this floor price is used in this analysis as the lowest SREC price.

A likely worst-case scenario is a project with $5/W system cost, and 50% debt fraction but with an increased loan interest rate of 11% and the lowest SREC price of $285/MWh/year. In this case, the calculated LCOE was found to be 15.48 cents/KWh, which is slightly higher than the current average electricity price. For the given worst-case SREC price, the project could be viable with a lower system cost or a lower interest rate. For roof top projects, system cost of less than $5/W is easily achievable.

5.1.3 Base case analysis

From the sensitivity analysis, it was determined that system cost, debt fraction, and SREC prices mostly dictated the LCOE. For the base case analysis, the parameters in table 3 are used. Assuming that the project debt ratio of 50% is acquired, the LCOE was plotted for a range of SREC prices and system cost as shown in figure 41. The system cost in figure 41 is the total project capital cost in dollars for each watt of nameplate capacity. The LCOE was calculated for a fixed IRR of 15%. The SREC range used in the simulation was from $250/MWh to $500/MWh.
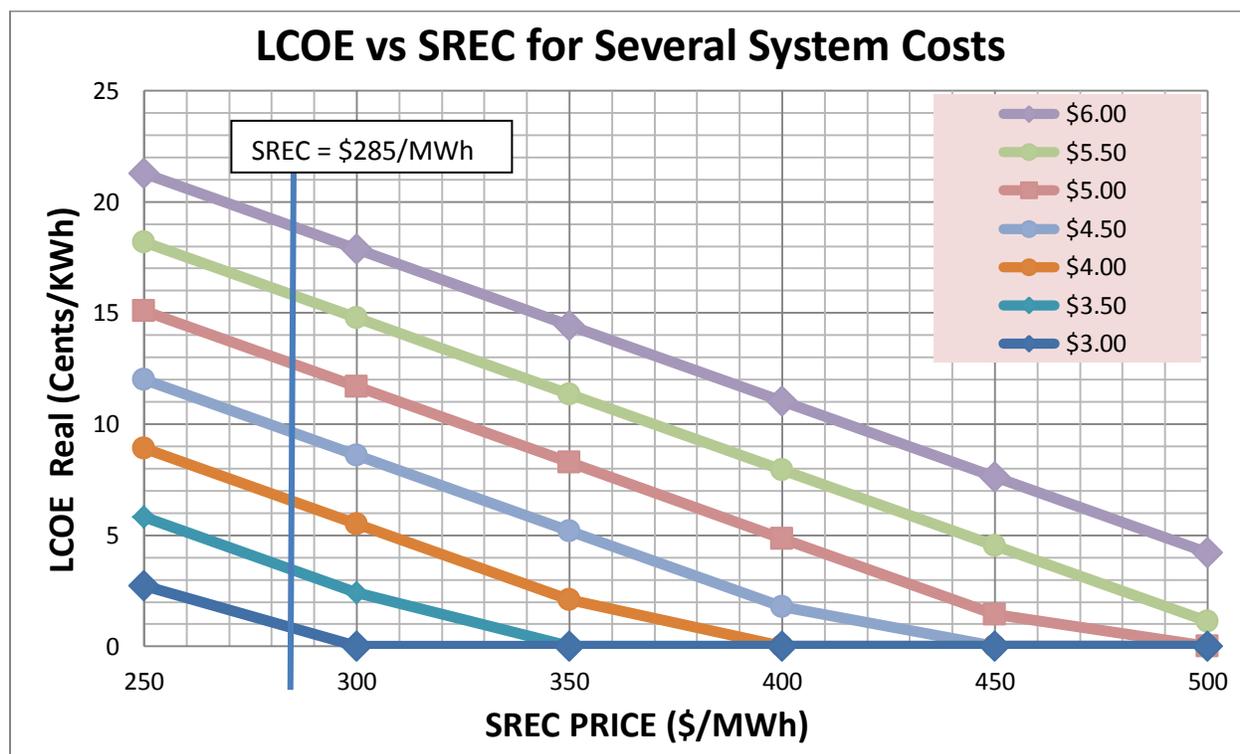
Figure 43: LCOE vs. SREC

For a very low SREC price of $250/MWh, the system cost would have to be less than $4.5/W for the project to be financially feasible. If the state guaranteed minimum SREC is observed in the market, projects costing $5/W may be financially viable. Since residential systems <5KW can cost between $5/W to $6/W, residential PV projects are marginally viable, and the investment may not get a minimum 15% IRR, if the state fails to maintain its SREC floor price. Thus, this IQP recommends larger scale PV systems as opposed to smaller ones.

For the base case for a larger (>1MW) commercial project costing $5/W system cost and assuming a fixed $300/MWh SREC price, the LCOE is calculated 11.68 cents/KWh. Such a project can expect a 15% IRR with a PPA of 12.7 cents/KWh. The system cost is an overestimation, and a typical 1MW project is likely to cost between $3/W to $4/W in the year 2013.

5.1.4   Return on Investment

In the previous analysis, the LCOE was calculated for different SREC and System costs to study project feasibiiltiy. In his subsection, the SREC price is fixed at $300/MWh, and the PPA price was calculated by varying the system cost for several sets of IRR as shown in figure 42. This figure allows the project owner to estimate the required PPA price that has to be negotiated with the buyer to achieve a requuired IRR. The IRR values assume The PPA escalation is assumed to be 1% annually.
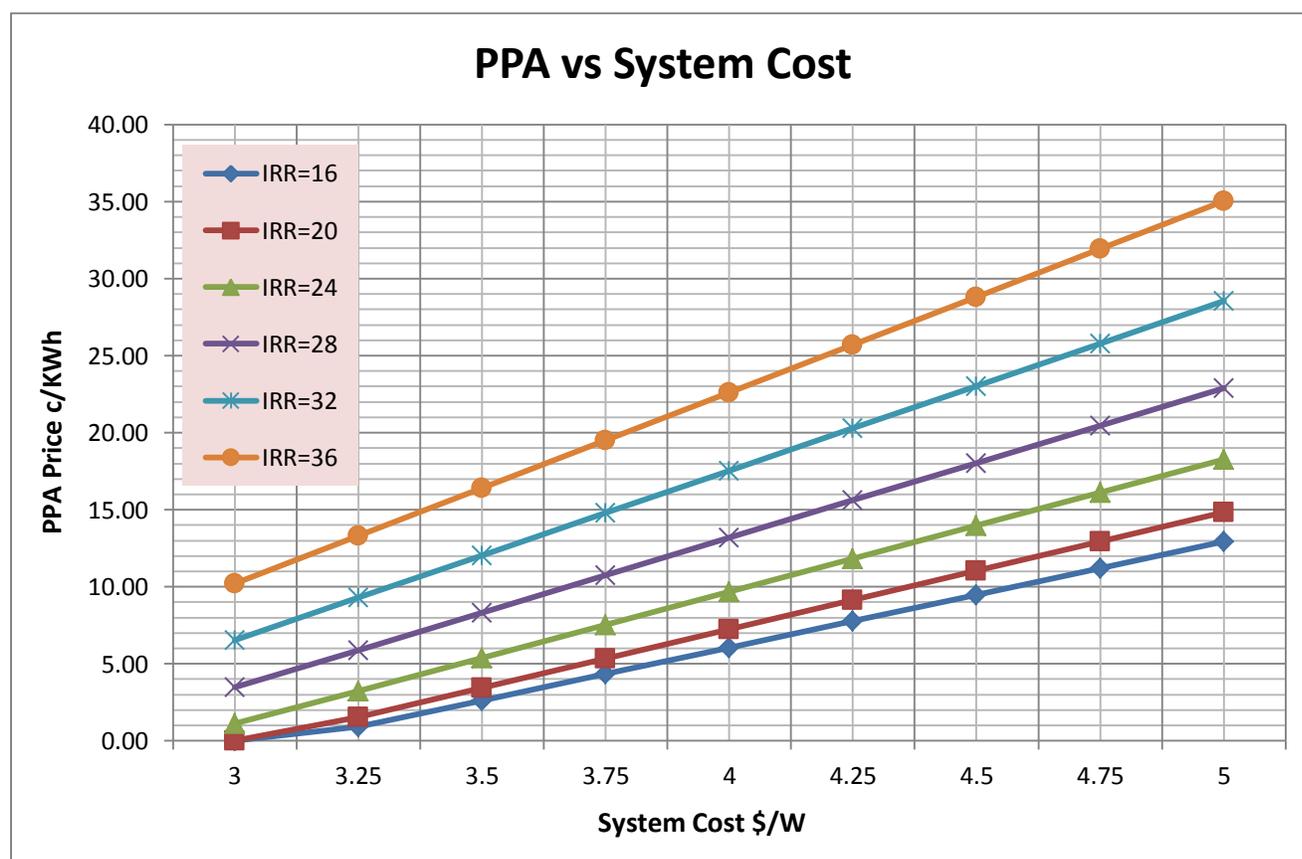
Figure 44: PPA price required to meet expected IRR

Based on data from figure 42, PPA less than the market electricity price of 15 c/KWh, could yeild an IRR of 24% for projects costing $4.5/W, and as high as 36% for projects costing $3.3/W. Although, typically the PPA is likely to be at least 3 c/KWh to 5 c/KWh lower than the market price. Thus

considering a PPA of atleast 10 c/KWh, projects costing $4.5/W can expect a n IRR of 16% while projects costing $3.3/W can expect 30% IRR.

As PV system prices drop in the year 2013, vertically integrated developers could have system costs as low as $3/W, wchich would yeild an impressive 36% IRR. For a smaller and/or less experienced developer, system cost is likely to be as low as $3.3/W yeailding a 30% IRR and as high as $4/W resulting in 24% IRR. Projects can expect an even higher IRR depending on the decline of PV system and balance of system (BOS) costs.

Conclusion

Peak electrical demand is projected to increase in the forseeable future, despite the innovation of more energy efficient appliances, and an increase in DSM programs. Summer peak demands are cosiderably higher than winter peaks due to the use of air conditioning. According to a 2009 EIA census, over 80% of US homes in the south, the midwest, and the northeast region are air conditioned, totaling to nearly a million homes throughout the country [31]. Peak eelctricity can considerably affect the price of electricity, which in turn can affect the economy, as well as quality of life.

Since solar power generation patterns largely coincide with peak electrical demand hours during the day, and almost half the energy is produced between May and August (summer), PV projects should be prefered over other renewable sources such as wind. Currently the IRR in the state of Massachusetts range between 16% to 30%. As the cost of PV solar systems decrease in the future, PV solar projects, especially larger commerical or utility scale projects will become more profitable. If the electricity price in Massachusetts keeps escalating at the current rate or higher, eventually a much lower PV system cost could return a 12% IRR wihtout the state incentives.

Appendix

Table 4 List of present regional entities

ERCOT	ERCOT ISO				
FRCC	Florida Power & Light				
TE	Hydro Quebec, TransEnergie				
ICTE	Independent Coordinator Transmission - Entergy				
ISONE	ISO New England Inc.				
MISO	Midwest ISO				
NBSO	New Brunswick System Operator				
NYIS	New York Independent System Operator				
ONT	Ontario - Independent Electricity System Operator				
PJM	PJM Interconnection				
SPC	SaskPower				
SOCO	Southern Company Services, Inc.				
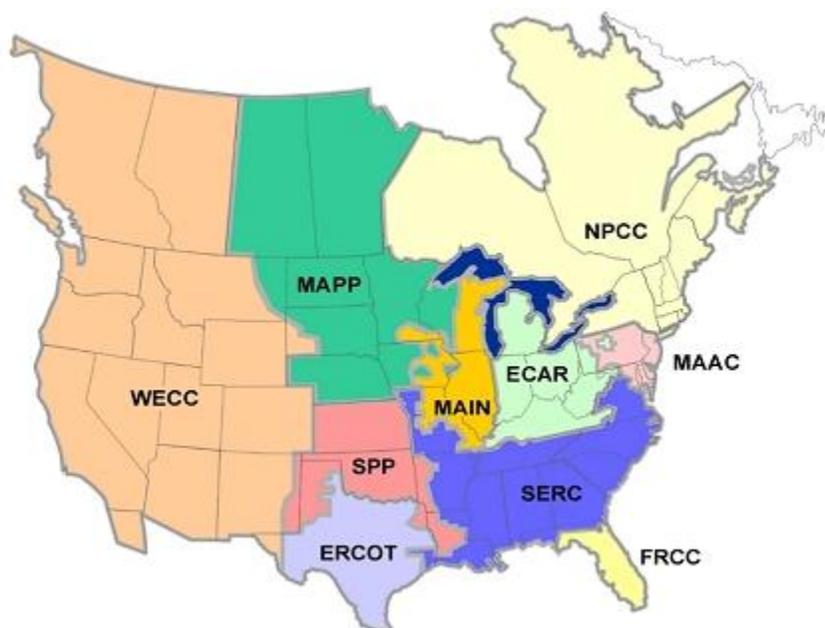
Figure 45 Historic Map of NERC Regional Council (Ending Dec 2005) [32]

Table 5 List of historic regional entites

ECAR	East Central Area Reliability Coordination Agreement
ERCOT	Electric Reliability Council of Texas
FRCC	Florida Reliability Coordinating Council
MACC	Mid-Atlantic Area Council (MAAC)
MAIN	Mid-America Interconnected Network (MAIN)
MAAP	Mid-Continent Area Power Pool (MAPP)
NPCC	Northeast Power Coordinating Council (NPCC)
SERC	Southeastern Electric Reliability Council (SERC)
SPP	Southwest Power Pool (SPP)
WECC	Western Energy Coordinating Council (WECC)
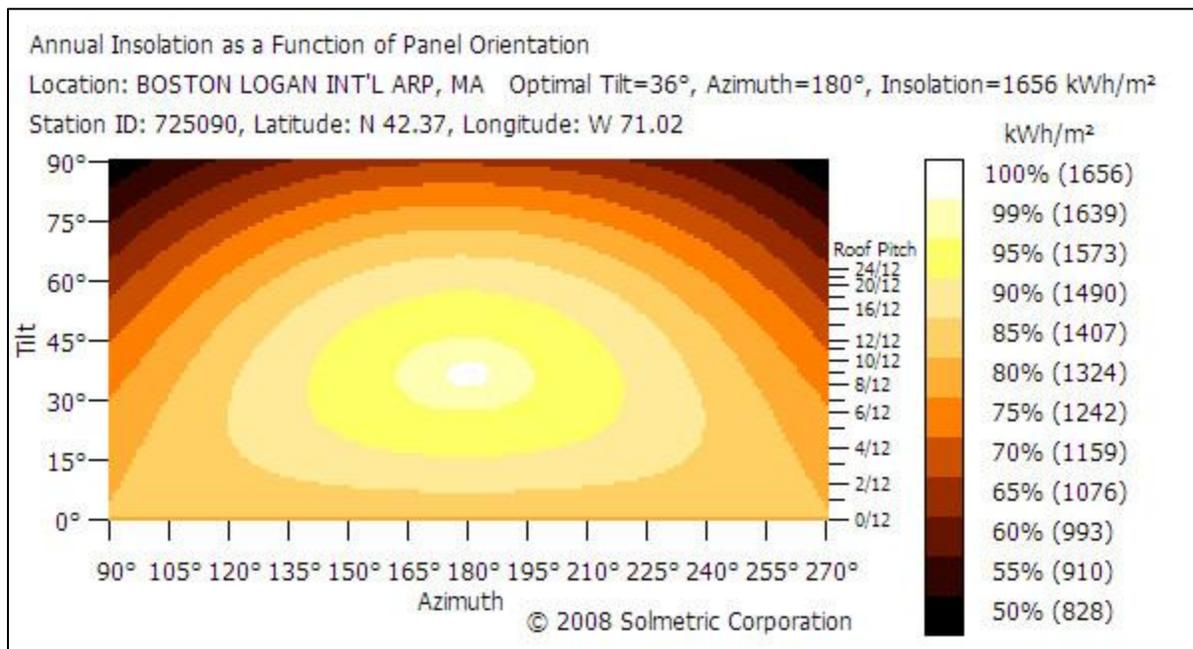
Figure 46: Solar Insolation data [33]
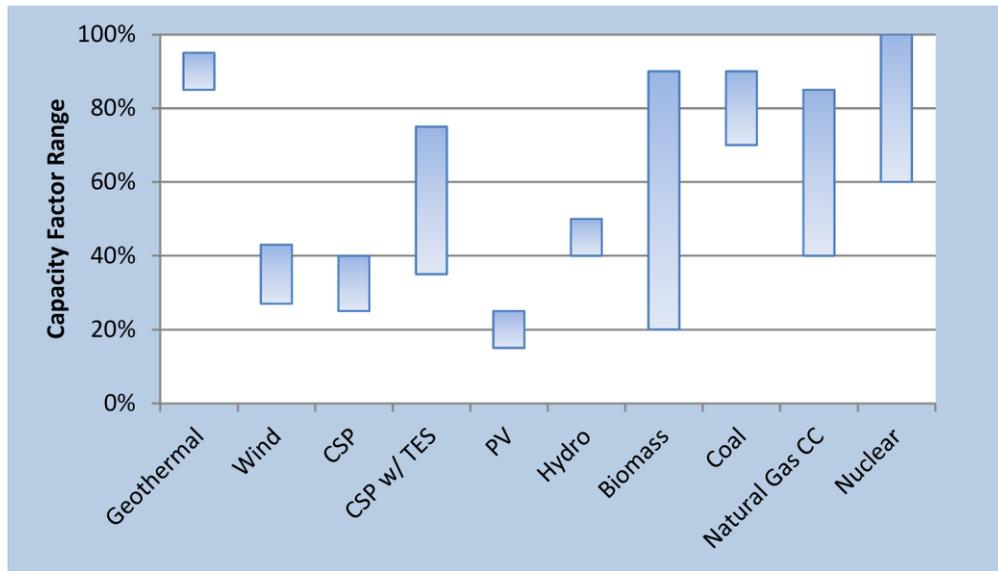
Figure 47: capacity factor of renewable energy technologies [34, p. 17]

Table 6

New England
Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont
Middle Atlantic
New Jersey
New York
Pennsylvania
East North Central
Illinois
Indiana
Michigan
Ohio
Wisconsin
West North Central
Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota
South Atlantic
Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia
East South Central
Alabama
Kentucky
Mississippi
Tennessee
West South Central
Arkansas
Louisiana
Oklahoma
Texas
Mountain
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming
Pacific Contiguous
California
Oregon
Washington
Pacific Noncontiguous
Alaska
Hawaii

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