12 Municipals' Integrated Resource Plan

Barton Village Inc. Electric Department;
Village of Enosburg Falls Water & Light Department;
Town of Hardwick Electric Department;
Village of Hyde Park Electric Department;
Village of Jacksonville Electric Company;
Village of Johnson Water and Light Department;
Village of Ludlow Electric Light Department;
Village of Lyndonville Electric Department;
Village of Morrisville Water & Light Department;
Northfield Electric Department;
Village of Orleans Electric Department;
Swanton Village, Inc. Electric Department;

Integrated Resource Plan
2015-2034

Part 3 - Resource Model & Results

Presented to the Vermont Public Service Board
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Submitted by:
Vermont Public Power Supply Authority

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1. Introduction and Approach

This section of the Integrated Resource Plan ("IRP") describes the municipal systems' resource analytical process that is used to evaluate and assess power portfolios. While the municipal systems seek approval of the IRP, the approval is not being sought for the actual results contained herein or for any explicit resource decision at this time. Rather, the Municipals seek approval of the analytic framework rather than approval of a particular power project or portfolio. The Municipals' IRP results in a plan for meeting future resource needs, but it does not map out with precision what exact action the 12 municipal systems will ultimately take or what single resource mix is best over the course of the next 20 years.

The objective of the integrated resource planning process is to assure consumers are provided with safe and reliable service balanced with the costs and benefits of providing this service. This Integrated Resource Plan outlines the process by which VPPSA equitably considers supply options (electric generation plants or wholesale contracts) when developing strategies to meet its customers' long-term energy and capacity needs. VPPSA's intent is to develop a flexible, cost-effective strategy to serve future power needs for its municipal systems and their customers, recognizing the complex interaction among total resource costs, revenue requirements, reliability, electric rate and environmental impacts, flexibility, diversity and industry restructuring.

To this end, the IRP is a combination of analytics and policy level considerations. For example, the IRP model will produce some specific quantitative numbers, but it does not intend to resolve all resource procurement questions mathematically. Judgment and policy level influences will lead to decisions that are aligned with the consumers of the individual municipal utility systems' desires to the greatest extent possible.

For purposes of this IRP analysis and consistent with past IRPs, all 12 systems were aggregated and treated as one system. It is important to note that the analysis and model, when used in aggregate, does not represent any individual systems' future resource mix. Instead, the IRP provides information on how power supply portfolios will be evaluated and compared in aggregate. Individual resource decisions will be made at the local system level as resource options are presented to the municipal systems. The IRP analysis and associated files have the capability to analyze resources at the individual system level and this will be done as specific power projects are reviewed and assessed. In this way, each utility will have specific information on the impact a project and resource mix will have on their individual system. It provides information that facilitates each utility's determination whether or not a project or resource mix fits with the municipal's goals and customers' preferences.

As part of the IRP process communication and review has been ongoing with the municipal systems. VPPSA staff worked with its member systems to describe the process, seek input, survey utility groups, and develop a power supply tool. VPPSA and the municipal utilities have held substantive discussions on numerous occasions to consider resource options and potential future supply scenarios to meet consumers' needs. VPPSA held regular meetings on future resources at the VPPSA Board level. Resource discussions have been, and will continue to be, an agenda item at all VPPSA Board meetings. Based on direction from the VPPSA Board, resources and combinations of resources are evaluated based their mix of attributes desirable to the members, including diversity, duration, achievability, reliability, credit risk, flexibility, and volatility. These attributes are discussed further in Section 5.1 of Part 3.

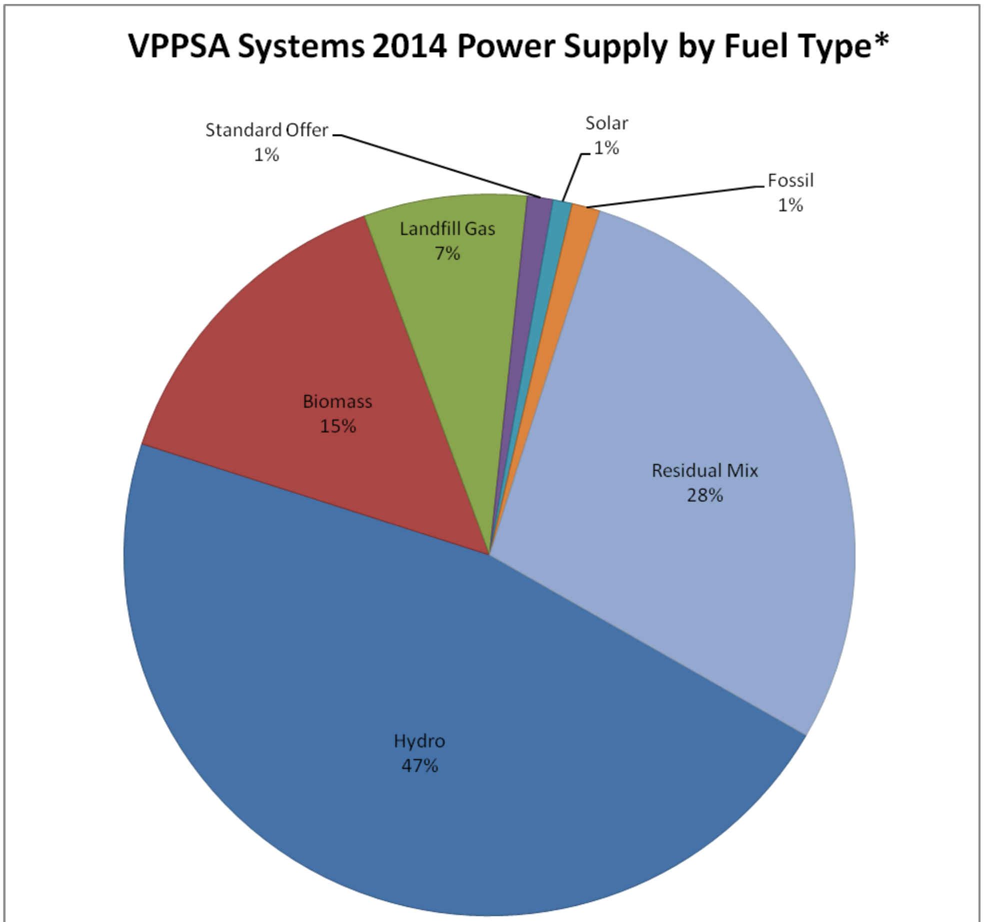
The municipal systems and VPPSA view the IRP planning process as dynamic rather than static; conditions change and planning projections must be updated as necessary to reflect important developments. Therefore, the municipal systems' IRP is just that; a plan that will require continual evolution and further analysis of investment decision paths. This model is the engine driving the analytic framework and is used on a regular basis to help assess and evaluate power project opportunities.

The IRP is written with the goal of ensuring the decision making framework described is understandable and accessible. The IRP model described is provided with the IRP to allow the reader the ability to have an in depth understanding of the impact of key variables on the resource mix. The remainder of this section of the IRP describes VPPSA's existing resources (Section 2), provides an overview of the model (Section 3) and describes key inputs (Section 4) and outputs (Section 5). Section 6 and 7 wrap up with an Action Plan and Conclusion. Appendices include resource and variable assumptions, a detailed description of the operation of the model, and results of the model.

2. Existing Resources

The municipal systems' current power supply portfolio is a combination of long-term contracts, short-term contracts, and generation. The portfolio acts as a diversified means to financially hedge the cost of serving load at the Vermont Zone. The VPPSA systems' current supply mix meets existing energy and demand needs. Figure 2.1 displays the VPPSA utility mix, in aggregate, by fuel type, prior to the sale of any renewable energy attributes. The figure illustrates the diversity of existing fuel sources.

Figure 2-1: VPPSA Systems' 2014 Power Supply by Fuel Type



* Prior to sale of any renewable attributes. Residual Mix are market contracts without a known fuel source.

While current market obligations are being met by existing resources, significant changes to the mix are expected to occur in the near future. Figures 2-2 and 2-3 summarize the position of VPPSA systems (in aggregate) on an energy and capacity basis contrasted to a base-case load forecast for energy and peak demand over a 20-year horizon. It provides an assessment of secured resources as contrasted to load requirements. As shown in the charts, a growing gap in both energy and capacity supply occurs in the near future, especially after 2022.

Figure 2-2: 12 Municipals' Energy Obligation vs. Current Resources

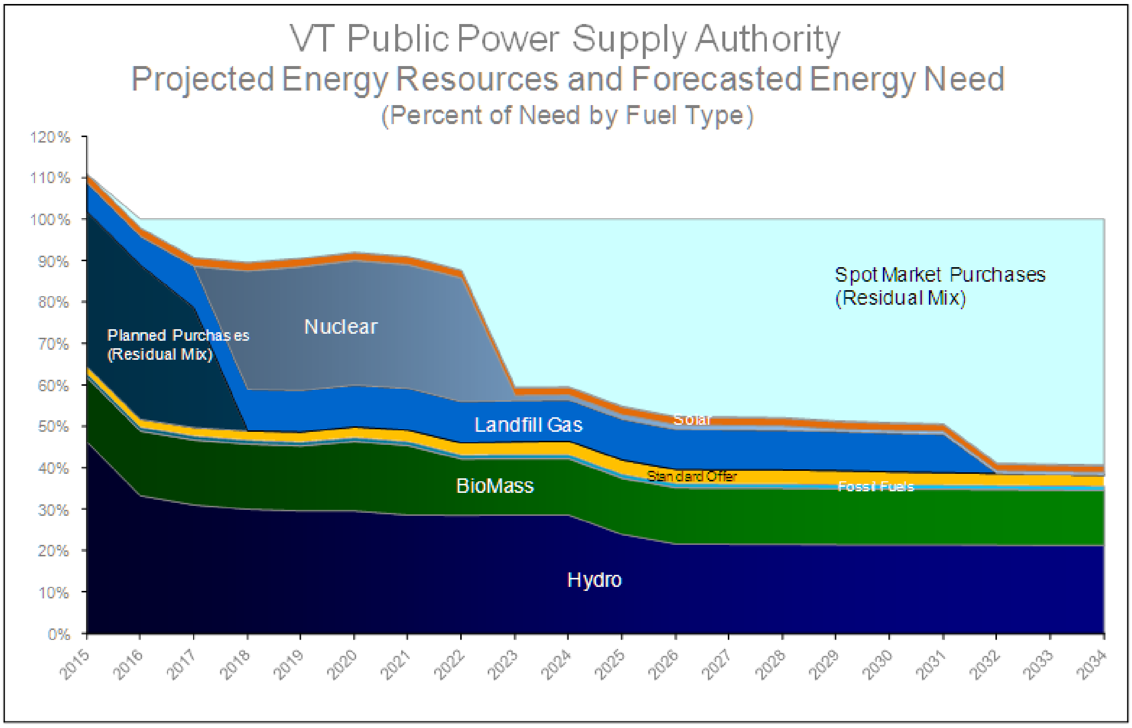
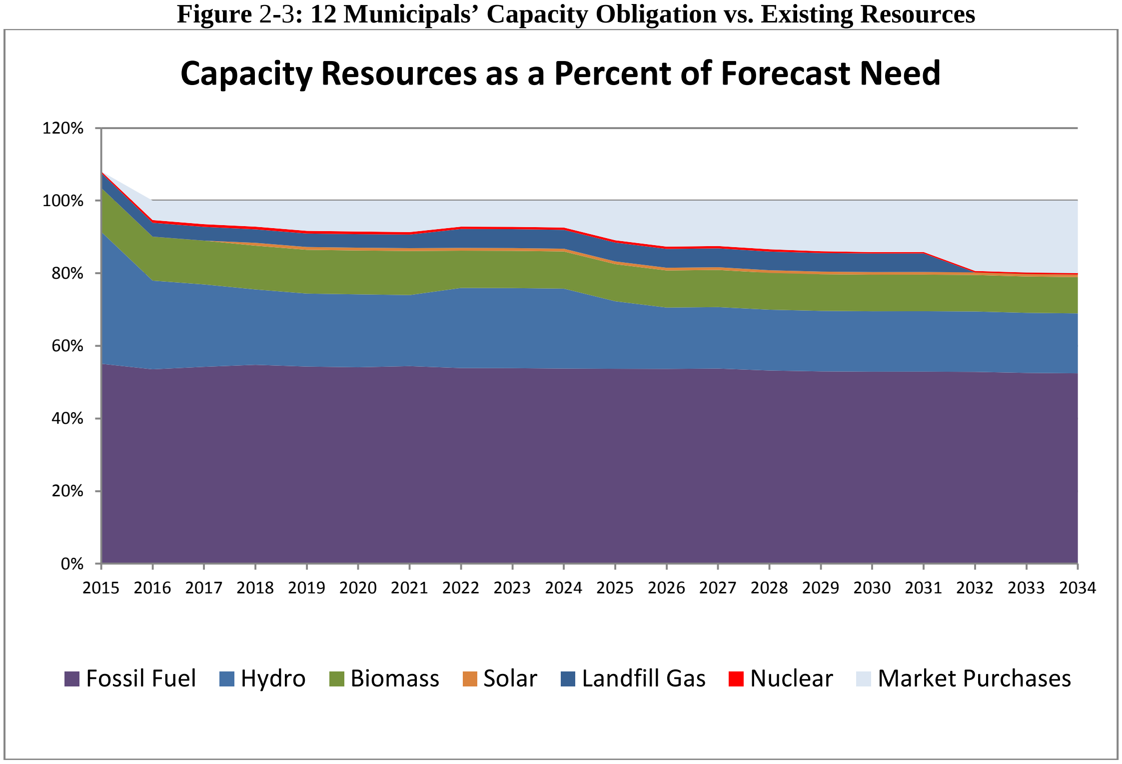


Figure 2-3: 12 Municipals' Capacity Obligation vs. Existing Resources



Major milestones for the supply mix can be summarized as follows:

- Energy Market Contracts expiring in the first one to five years
- Current HQ Contract expirations 2012 through 2016 – 16.4 MW
- Substantial five year energy only contract beginning in 2018
- Capacity resources are expected to be level through 2024 after an initial drop in 2016
- Utility owned hydro facilities will need to undergo FERC relicenseing

Facility Name	Utility Owner	FERC License Expiration Date
Barton Village Hydro	Barton Village	10/1/2043
Enosburg Falls Hydro	Village of Enosburg	04/30/2023
Great Falls Hydro	Village of Lyndonville	5/31/2019
Highgate Falls Hydro	Village of Swanton	04/30/2024
Morrisville Hydro	Village of Morrisville	04/30/2015
Vail Hydro	Village of Lyndonville	02/28/2034

Detail on each municipal system's existing power portfolio and detail on each resource is described in Appendix 1 and included in the individual systems' portions of the IRP.

3. Model Overview

The analytic model that provides the framework for resource decisions is Microsoft Excel based. It consists of three Excel workbooks and a required Microsoft Excel "Add-In". The list below summarizes the primary source files, which are provided with the IRP.

1. "CapEgyCalc5.xlsm"
2. "IRPResults4.xls"
3. "IRP_Run_Assumptions.xlsm"
4. "Sens131s.xla"

"CapEgyCalc5.xlsm" is an input file. All resources in the current supply mix are entered into this file as well as the assumptions of how the resource is to be modeled (costs, capacity factor, on-peak, etc.). Each resource is able to be assigned to member system utilities in full or partial units, in order to model impacts to individuals. The loads that need to be served by multiple utilities are also characterized. Results are generated based upon the chosen inputs in the file and limitations on each resource. Resource and key variable inputs are discussed further in Section 4.

"IRPResults4.xls" captures the output from "CapEgyCalc5.xlsm" and calculates the results, including sensitivity analysis. Variables used to stress test and calculate portfolio Net Present Values (NPV) are included in the "IRPResults4.xls" file and are easily adjusted by the user. This file provides annual summaries, by resource, for the projected output of those resources in capacity, energy, REC, and ancillary product terms as well as projected total power costs and market revenues for resources by year.

"IRP_Run_Assumptions.xlsm" allows for multiple iterations of the model to take place automatically. Up to 25 separate user-defined resource mixes to be run through the model are identified; the file is intended to be the primary user interface for deriving output from the IRP model after all user inputs have been finalized in "CapEgyCalc5.xlsm" and "IRPResults4.xls." The user can define purchase years, capacity factors, and resource lifetimes that will flow into the model. As currently designed, this file allows combinations of hypothetical/generic resources that will meet future load needs to be characterized and makes final modifications to the CapEgyCalc5.xlsm spreadsheet before generating a results file for the case.

"Sens131s.xla" is a required "Add In" for Excel. It needs to be installed as an available "Add In" in order for the model to run correctly. This portion of the model stresses the high, low, and base case of all variables. The file enables the model to produce "tornado" charts outputs after stressing low, base and high case variables and their affects on NPV.

Detailed directions on how to utilize the files above to collectively run the model are provided in Appendix 2.

4. Model Input Description (Resources and Variables)

The model aggregates all 12 VPPSA utility systems' load and resources and treats them as one in order to produce one supply-side resource mix for all 12 systems in aggregate. All resources and supply assumptions are input into the model on a resource-by-resource basis.

Existing generation and contract resources were input into the model including costs, capacity value, energy allotment, and end dates. Figure 4-1 is a list of all resources currently modeled in the IRP analysis and included in the current version of the file "CapEgyCalc5.xlsm". A detailed description of the current supply resources, including the "planned purchase" program (signified below by "PP") is found in each individual member systems' resource inventory.

Figure 4-1: Supply Resources

67 Resources Defined in Spreadsheet's Database		
Supplier ID	***Name***	***Type Code***
NYPA	**NYPA Niagara Project**	Contract Hydro
NYPA	**NYPA St. Lawrence Project**	Contract Hydro
VEPP	**VEPP Inc: Ryegate**	BioMass
VEPP	**Vt Elect Pow Prod Inc: Hydro**	Contract Hydro
MUNI	**Enosburg Falls Hydroelectric**	Internal Hydro

MUNI	**Wolcott Hydro**	Internal Hydro
MUNI	**Vail & Great Falls**	Internal Hydro
MUNI	**Barton Hydroelectric**	Internal Hydro
MUNI	**Morrisville Plant #2**	Internal Hydro
MUNI	**Cadys Falls**	Internal Hydro
MUNI	**H.K. Sanders**	Internal Hydro
MUNI	**Highgate Falls**	Internal Hydro
MUNI	**Unit 5**	Internal Hydro
HQUEB	**Hydro-Quebec Sch. B**	Contract Hydro
HQUEB	**Hydro-Quebec Sch. C3**	Contract Hydro
HQUEB	**Hydro-Quebec Sch. C4A**	Contract Hydro
HQUEB	**Hydro-Quebec Sch. C4B**	Contract Hydro
HQUEB	**Hydro-Quebec ICC**	Contract Hydro
MUNI	**Stonybrook CC Unit 1A**	OIL/GAS
MUNI	**Stonybrook CC Unit 1B**	OIL/GAS
MUNI	**Stonybrook CC Unit 1C**	OIL/GAS
MUNI	**J.C. McNeil**	BioMass
MUNI	**Yarmouth (Wyman) Unit 4**	OIL/GAS
MUNI	**Barton Diesel**	OIL/GAS
VPPSA	**Project 10**	OIL/GAS
VPPSA	**Fitchburg Landfill Gas**	Landfill Gas
SO	**Standard Offer**	Standard Offer
HQUS	**HQUS1**	Contract Hydro
HQUS	**HQUS2**	Contract Hydro
HQUS	**HQUS3**	Contract Hydro
HQUS	**HQUS4**	Contract Hydro
HQUS	**HQUS5**	Contract Hydro
HQUS	**HQUS6**	Contract Hydro
VPPSA	**Seabrook_1**	Nuclear
VPPSA	**Chester Solar**	Solar
VPPSA	**Hardwick Solar**	Solar
VPPSA	**PP6-OnPeak-2015**	Firm System Contract
VPPSA	**PP6-OffPeak-2015**	Firm System Contract
VPPSA	**PP6-OnPeak-15Q4**	Firm System Contract
VPPSA	**PP6-OffPeak-15Q4**	Firm System Contract
VPPSA	**PP7OnPeak2015**	Firm System Contract
VPPSA	**PP7OffPeak2015**	Firm System Contract
VPPSA	**Merr2016OnPeak**	Firm System Contract
VPPSA	**Merr2016OffPeak**	Firm System Contract
VPPSA	**PP8OnPeak2015**	Firm System Contract
VPPSA	**PP8OffPeak2015**	Firm System Contract
VPPSA	**PP8OnPeak2016**	Firm System Contract
VPPSA	**PP8OffPeak2016**	Firm System Contract
VPPSA	**PP8OnPeak2017**	Firm System Contract
VPPSA	**PP8OffPeak2017**	Firm System Contract
VPPSA	**2018-2022 Peak**	Nuclear
VPPSA	**2018-2022 Off Peak**	Nuclear
VPPSA	**Orleans 2014-2016 Peak**	Firm System Contract
VPPSA	**Orleans 2014-2016 Off Peak**	Firm System Contract
VPPSA	**PP10 Peak**	Firm System Contract
VPPSA	**PP10 Off Peak**	Firm System Contract
VPPSA	**Generic OutState Solar**	Solar

VPPSA	**Generic OutState Solar2**	Solar
VPPSA	**Generic InState Solar**	Solar
VPPSA	**Generic InState Solar2**	Solar
VPPSA	**Generic Fixed Price Contract**	Firm System Contract
VPPSA	**Generic Fixed Price Contract2**	Firm System Contract
VPPSA	**Generic Variable Priced Contract**	Firm System Contract
VPPSA	**Generic Variable Priced Contract2**	Firm System Contract
VPPSA	**Generic Wind**	Wind
VPPSA	**Generic Wind2**	Wind
VPPSA	**CT Hydro**	Contract Hydro

Three other resources are also considered in resource planning: Energy Efficiency, Net Metering, and Rate Design. While not explicitly modeled, these policy and/or structural mechanisms fundamentally alter the remaining resource mix necessary to meet consumer's needs. The treatment of each is briefly described in the following sections; the first two are also addressed in the load forecast discussion in section 4.5.

4.1 Energy Efficiency

Efficiency Vermont (EVT) has been delivering energy efficiency services to most utilities in Vermont, including the 12 municipal systems, since 2000. Originally a short-term contract, the Public Service Board has appointed Vermont Energy Investment Corporation (VEIC) to provide services for up to 11 years. This long-term commitment to energy efficiency helps to ensure that all reasonably available cost-effective efficiency resources are procured in the member systems territory, encouraging VEIC's committment to long-term savings for customers rather than simply first-year MWh savings acquisition. The "Order of Appointment", however, does not relieve utilities of their obligation to conduct least cost distributed utility planning, including the consideration of distributed generation, targeted energy efficiency, and demand response.

VPPSA values its relationship with Efficiency Vermont on behalf of its members. It has, and plans to continue to, increased participation in efficiency related Public Service Board dockets to ensure that the framework under which VEIC operates continues to be beneficial to VPPSA members. In addition, VPPSA has and will continue to participate actively in the Vermont System Planning Committee, coordinating forecasting and geographic targeting of efficiency with other Vermont utilities and stakeholders to ensure robust consideration of this indispensible resource.

As discussed in detail below, expected energy efficiency investments over the course of this IRP's timeframe has a significant impact on forecasted demand. The treatment of energy efficiency in the load forecast is discussed in Section 4.5.

4.2 Net Metering

Act 99 of 2014 revised Vermont's net metering program in a number of important ways. Perhaps most significantly, it increased the cumulative capacity cap on net metering from 4% to 15%. This combined with favorable financing and policy incentives, have led to a rapid pace of deployment of net metering systems, particularly solar PV.

At the time the forecast was developed for this IRP, Act 99 had not yet been passed. The forecast used in this model assumes net metering penetration to 4% of the cap, then held constant. VPPSA considered updating the forecast in the IRP document to reflect the 15% cap, however for a number of reasons ultimately determined that this IRP which models net metering penetration at 4% and stresses the forecast in two ways along with other key variables as described below, provided a range of outcomes that demonstrates effective long-term planning methodologies that are employed by VPPSA. The table below shows the current net metering penetration rates by system for each of VPPSA's members. There are large differences in the level of NM penetration across systems, which may be due to a variety of factors that have not yet been studied in detail.

SYSTEM	Net Metering Total Capacity (kw)	PEAK	% PEAK
Barton	85	3,040	2.81%
Enosburg	174	5,740	3.03%
Hardwick	1,166	6,930	16.82%
Hyde Park	341	2,530	13.46%
Jacksonville	26	1,180	2.23%
Johnson	252	2,800	8.99%
Ludlow	150	12,400	1.21%
Lyndonville	749	13,480	5.56%
Morrisville	887	9,170	9.67%
Northfield	137	5,330	2.56%
Orleans	21	3,570	0.59%
Swanton	1,109	10,430	10.63%
TOTAL	**5,097**	**76,600**	**6.65%**

Act 99 called for the Public Service Board to re-design the net metering program, taking into account a number of broad policy goals including consistency with state renewable energy and greenhouse gas goals and notably a focus on cost - both limiting cross-subsidization and ensuring that rates for net metering customers take into account the actual cost to construct those systems. Draft rule revisions are still being finalized, with wide variations between drafts that create significant uncertainty with regard to Net Metering compensation and penetration rates. This IRP models addresses this uncertainty through the load forecast and forecast error variables described in Sections

4.5 and 4.6. Resource decisions will use best available and most current infomration to estimate Net Metering generation and costs, and continue to stress those variables to understand the impacts of variances from the base case. Future IRP's will take into account known Net Metering rules at the time of development for this rapidly evolving State program.

VPPSA supports the continued development of net metering consistent with Vermont statute and Public Service Board rules, and will continue to reflect current understanding of net metering and impacts on its systems in resource planning decisions.

4.3 Vermont Renewable Energy Standard

Act 56 of 2015 established a Renewable Energy Standard (RES) that requires VPPSA utilities to:

- Meet 55% of its retail sales with renewable resource in 2017, increasing to 75% by 2032;
- Meet 1% of its retail sales with in-State "distributed generation" in 2017, increasing to 10% by 2032;
- Meet 2% of its retail sales with as-yet undefined "Energy Transformation Projects" in 2019, increasing to 10.67% by 2032.

Notably, Act 56 gave VPPSA utilities the option of complying with the statute in aggregate or meeting the requirements individually. At the time of filing of this IRP, the RES had just been passed, and proceedings had not yet started to define the parameters within which the goals would need to be met. Given uncertainty surrounding RES, the Vermont Renewable Energy Standard was included as a key variable to be stressed. This variable was stressed at three levels - the base case assuming that resources were acquired that meet the requirements above, at 0%, assuming a political removal of the RES requirements, and at 175%, representing RES requirements 75% above base case.

VPPSA plans to meet the obligations of the RES, and has modeled each scenario as meeting the requirements of RES. Given the timing of Act 56's passage, this modeling was done on an economic basis only -- estimating the cost of compliance through the use of estimated Renewable Energy Credit (REC) value. These varied between Tier I and Tiers II/III. Tier I compliance is based on the cost associated with out-of-state existing facility RECs. Tier II and III compliance rates were based on an estimate of future Massachusetts Class I REC prices. This was used as a proxy under the assumption that in-state developers could have the option of either selling RECs to Vermont utilities and/or selling them out-of-state, effectively making their market price the same. Tier III compliance costs are set to the same as Tier II, becasue Tier II resources are eligible to meet those requirements, and because of the significant uncertainty around the Tier III design at the time of writing. The values are then stressed in two ways, both with regard to the price estimate and with regard to the amount of requirement as described above --

eliminating the compliance costs if there is no longer a Renewable Energy Standard, and increasing the costs 75% to account for more stringent requirments.

VPPSA then examines each supply resource based on cost and benefits, with consideration given to whether it reduces exposure relative to the requirements that a VPPSA member may have. The resulting environmental implications are discussed in Section 5.

4.4 Rate Design and Advanced Metering Infrastructure

Due largely to the small size of the systems, the economies of scale necessary to facilitate a successful business case for Advanced Metering Infrastructure is elusive. That said, VPPSA and its members continue to evaluate its benefits and costs. Billing system upgrades, to handle the data associated with AMI, continue to be evaluated regularly.

AMI has the potential to facilitate more sophisticated rate design. However, this can also be done without AMI. For example, time and value differentiated rate structures could better send signals to customers that increase efficiency and lower costs. Rate structures ranging from Time-of-Use rates to distribution fees that better reflect the costs to serve customers are two possible visions of the future. VPPSA continues to work with its member systems to understand each particular system and their customers, and to recommend effective rate structures for each utility.

4.5 Key Variables

In addition to the existing resource information, key variables and assumptions regarding the expected ranges of those variables are inputs into the model (in the file "IRPResults4.xls").

Figure 4-2 summarizes the key variables VPPSA used in the model. These variables were selected based on power supply staff expertise and judgment following review of a wider range of possible variables, including those modeled in previous iterations of the IRP.

Figure 4-2: Key Variable Ranges

Input Variables	Low NPV $	Base NPV $	High NPV $	Std Dev
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	35.4%
Implied Heat Rate	63.0%	100.0%	137.0%	18.5%
LMP Basis to HUB	97.9%	100.0%	102.1%	1.1%
VT Renewable Energy Standard	0.0%	100.0%	175.0%	
Electric Vehicles	50.0%	100.0%	140.0%	
Regional Network Service Rates	82.3%	100.0%	117.7%	8.9%
Capacity Load Obligation	94.8%	100.0%	110.5%	5.2%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	
FCA Clearing Prices	25.9%	100.0%	211.2%	37.1%
FRM Clearing Prices	42.2%	100.0%	157.8%	28.9%
Renewable Energy Credits	10.0%	100.0%	120.0%	
Load Forecast	-3.7%	0.0%	3.7%	
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	
Inflation	49.3%	100.0%	150.7%	50.7%
Discount rate	84.6%	100.0%	115.4%	0.50%

Each variable has a base-case value which represents current market conditions or the best information available for that variable today. Each variable also has corresponding high and low values which are used to provide sensitivity analysis related to that variable, based on one or two standard deviations away from the base case, depending on the variable. The determination of the standard deviation is based on an examination of fit within the confines of historical data taking into account changes that are not reflected in that data. This allows the cost for the resource mix to be stress tested for the low to high ranges of each variable, providing a range of potential results. The above table shows the degree to which the high and low cases vary from the base case. A complete description of inputs and key variables is provided in the Appendix. Figure 4-3 depicts the first year values of each variable.

Figure 4-3: Key Variable Values in 2017

Input Variables	Low NPV $	Base NPV $	High NPV $
Delivered Natural Gas Prices	$ 1.67	$ 5.73	$ 9.79
Implied Heat Rate	5.26	8.34	11.43
LMP Basis to HUB	-1.18%	-1.20%	-1.23%
VT Renewable Portfolio Standard	$ -	$ 34.04	$ 59.56
Electric Vehicles	56	111	156
Regional Network Service Rates	$ 7.54	$ 9.17	$ 10.79
Capacity Load Obligation	76,808	81,062	89,572
Monthly Peak (Trans)	56,507	62,785	69,064
FCA Clearing Prices	$ 2.14	$ 8.29	$ 17.50
FRM Clearing Prices	$ 1.49	$3.54	$ 5.58
Renewable Energy Credits	$ 5.39	$ 53.89	$ 64.66
Load Forecast	364,637	378,647	392,657
Load Forecast Error Percentage	367,287	378,647	390,006
Inflation	1.06%	2.14%	3.23%
Discount rate	2.8%	3.3%	3.8%

As can be seen in the above figure, the base case estimation for natural gas fuel price is estimated to be $5.73/MMBtu in 2017. The low case is calculated by taking 29.2% (two standard deviations) of the base case, or $1.67/MMBtu. The high case is calculated by taking 170.8% of the base case value (two standard deviations), for a value of $9.79/MMbtu. Each variable is adjusted up and down around the base case value using the percentages identified in figure 4-2. In this way sensitivity to each variable can be calculated in the analysis.

A detailed list of all variables and resource inputs are summarized in the appendix.

4.6 Load Forecast

A critical component of ongoing evaluation of resources relative to need is the load forecast. VPPSA maintains long term energy (monthly resolution) and peak (daily resolution) regression models as an integral part of its strategy of continually reviewing its member system's position, facilitating effective procurement of energy resources to fit projected requirements. These models, originally based on logic from the previously filed IRP, have been substantially revamped in the past few years to better account for emerging trends and fundamental changes to system load. Due to significant progress from statewide energy programs as Energy Efficiency implementation through Efficiency Vermont, Net Metering, and the Standard Offer program, as well as the changing economic climate across Vermont (and nationwide), the models are limited to the use of historical data from the last 10 years. While many member systems are experiencing relatively little annual load variation, a few have seen more significant changes. For these systems, the historical data was limited to a shorter window than 10 years.

Key Drivers: Part of the strategy to develop a set of sustainable, effective models has been to keep them as simple as possible while still including all measures that significantly impact, or are expected to significantly impact load. This involves evaluating a number of potential key drivers and only including those that produce the most significance in a sensible manner. VPPSA has classified three types of variables included in the models to better distinguish their usefulness in this report. **Default variables** that can be found in all models, **system specific long term drivers** and **system specific fundamental change variables**. Each type of variable is discussed, in turn, below.

Default variables include weather drivers (heating and cooling degree days) as well as variables to allow the model to decipher from month to month and, in the case of the peak model, variables to enable the model identify holidays. In the case of weather, a ten year average of normal weather is used moving forward in the energy models and the rank-and-average method[1] has been used in the demand model to better capture the extreme weather conditions that often induce peak demand. These weather variables are transformed to degree days before being utilized in the regression. While these default variables carry significant weight and are able provide a shape to the projected load on a monthly (daily for demand) basis, they do nothing to account for any overall upward or downward trend looking forward. System specific long term drivers are utilized to accomplish this goal.

System specific long term drivers are used to drive the model's long term trend, and are based on economic and legislative energy initiatives. VPPSA uses a pool of variables from various sources as described in the table below to provide the model with this long-term vision. Among many systems, the most notable driver of long term load tends to be energy efficiency. The second most significant is generally some type of economic indicator such as unemployment or construction earnings. Energy efficiency appears to be the most significant because loads have historically been fairly flat across member systems, regardless of the health of the economy. Meanwhile, efficiency measures appear to continue to result in a sustained meaningful effect on load. A projection of the impacts of net metering was initially included in the load forecasts, however it had, at best, a minimal impact on the forecast and in many cases the models were unable to latch onto it as a driver. It is believed this is due to the relatively recent uptick in net metering and as more time goes by, the models will find this information increasingly more significant.

System specific fundamental change variables are used to indicate to the model when a fundamental change occurred in a specific utility's energy usage. They are used to indicate an exception to the general trend. This is often due to the addition or removal of

[1] A description of the rank-and-average method can be found at https://www.itron.com/PublishedContent/Defining%20Normal%20Weather%20for%20Energy%20and%20Peak%20Normalization.pdf

a major customer, such as a manufacturing plant, but can also be due to a variety of other reasons including distribution system upgrades/changes. A handful of these exceptions can be found throughout VPPSA member territories. Even after these variables are included, there may still be a reduction to the model's accuracy as a result of the fundamental change; however these variables significantly reduce this impact.

All variables added to the model are tested for their effectiveness. We evaluate the t-stat and coefficient that the model assigns to variables to determine: 1) if the variable is significant/useful and 2) if the variable is significant, is it acting appropriately (e.g. as energy efficiency increases, a reduction in load would be expected. A modeled increase in load would indicate that the variable is not acting appropriately and is not useful). In the case of heating and cooling degree days, the relationship between load and temperature is evaluated to choose the threshold heating/cooling values that capture each individual system's unique relationship to weather. This means that while the model of one system may use, for example, 60°F as a starting point for heating degree days, another may use 50°F. The same goes for cooling degree days.

Data sources: VPPSA uses a several different suppliers to provide much of the data that is ingested by the models and used to predict load. On the next page is a table outlining our main data sources. System specific drivers are then described in more detail.

Figure 4-4: Load Forecast Data Sources

Data Type	Variable(s)	Source	How We Handle Future
Historical Loads	Historical Load – increased by Standard Offer allotment	VELCO	Model Predicted
Net Metering	Net Metering Certificate of Public Good approval MWs	Public Service Department	Set to increase to 4% in 2014 then hold steady.
Electric Cars	Electric Car Saturation Forecasts	Vermont Energy Investment Corporation (Drive Electric Vermont) – VTrans EV Charging Plan (7/11/2013)	Carry trend forward
Weather	Temperature	National Weather Service	Energy Models: 10-year average Demand Models: Rank-and-Average
Energy Efficiency	Accumulated Efficiency Vermont Savings Claims*	Vermont Energy Investment Corporation (Efficiency Vermont)	Use forecast through 2031 then hold savings steady. Accumulated savings used*
Economic Indicators	Construction Earnings Wealth Index Population	Woods and Poole Economics Inc.	Woods and Poole forecast
Economic Indicators	Vermont Unemployment	Modeled from a blend Woods and Poole and Forecast.org data	Regression model using Bureau of Labor Statistics for historical national and Vermont data. Forecasts.org for National Unemployment forecast. Beyond Forecasts.org forecast, national unemployment gradually reverts to the last 10 year average over the following 10 years. Woods and Poole forecast for Vermont Employment (historical and future)

*Note: EVT Savings claims in the models are not allowed to decrease if savings expirations result in a year-over-year decrease in cumulative savings.

System Specific Drivers

<u>ContructionEarnings</u>: Data for this variable is derived from the 2013 Woods and Poole State Profile dataset for Vermont. It represents total statewide construction earnings historically and forecasted forward. This had been used as a long term driver, where it fits, for many of the VPPSA utilities as it is a good indicator of both economic activity and population.

<u>WealthIndex:</u> Data for this variable is derived from the 2013 Woods and Poole State Profile dataset for Vermont. It represents statewide wealth in relation to the remainder of the country. This had been used as a long term driver, where it fits, as it can be used to show how Vermont's economy is performing relative to the rest of the country. The logic is that if Vermont's economy is thriving faster than the rest of the country, it would spur more rapid development. The contrary is a true as well.

<u>VermontUnemployment</u>: Data for this variable is derived from the 2013 Woods and Poole State Profile dataset for Vermont as well as a national unemployment rate. The Woods and Poole dataset used is the statewide employment per person determined by dividing total unemployment by population. This, along with a national unemployment rate is placed into a regression model to come up with a predicted Vermont unemployment rate, which is then used in some load models. The Vermont unemployment rate is considered a reasonable indicator of economic activity in the state.

<u>Population:</u> Data for this variable is derived from the 2013 Woods and Poole State Profile dataset for Vermont. It represents statewide wealth in relation to the remainder of the country. This had been used as a long term driver, where it fits, as it can be used to show how Vermont's population has fluctuated over time and how it is forecast to change in the future.

While nearly all of the forecast models use one of the drivers discussed above, they also almost nearly all use an Energy Efficiency variable called <u>EVT filled</u>. This variable is intended to describe energy efficiency contributions to load reduction and is explained further in the next section. Due to the rapid adoption of energy efficient measures over the years, in some cases this variable in itself becomes the sole long term driver of load for an individual utility. In these instances, drivers mentioned above become insignificant and are not included in the final model.

Energy Efficiency: As energy efficiency (EE) efforts continue to impact the load of utilities across the state, VPPSA revamped the method it uses to incorporate EE into its load forecast. Historically, a simple trending variable was used to "capture" general load trends, including those due to EE programs. VPPSA now examines EE savings data provided by Efficiency Vermont and incorporates both past and expected future savings into nearly all of its energy models. The method involves first looking at claimed EVT savings, per system. This number is divided out by the expected lifetime savings to get a "lifetime" of the savings (typically around 10 or 11 years, but this varies).

Further considerations: While some emerging technologies, such as net metering systems, have historical data to feed into the regression models, there are some where this data is scarce or not yet available due to the newness of the technology. In these cases, the effects of these technologies are not captured directly in the regression models. Forecasts, where available, are used to adjust the modeled load looking forward. VPPSA has recently considered two of these technologies that have the potential to significantly impact energy requirements looking forward: cold climate heat pumps and electric cars.

It is expected that over the next 10-20 years, heat pumps will continue to be installed offsetting the need for resistance and fossil area heat sources. Efficiency Vermont provided information about what it expects to be able to claim as savings for this measure, but this data does not provide a clear picture as to what the total effect on load would be. We have been unable to discover a source for forecast information that we feel comfortable with, however it appears any significant impact to load is still years away. VPPSA expects to include more on this in the future IRP filings. In addition, VPPSA will be watching for further information on the conversion of domestic water heaters, and clothes dryers to heat pump technology as well.

Electric vehicle and plug-in/plug-in hybrid electric (collectively referred to as "EV") vehicle saturation forecasts are starting to become more widely available. VPPSA has obtained some of these forecasts and some information regarding the average impact each electric vehicle has on load.

When predicting the effects electric cars would have on load, VPPSA considered three saturation forecasts, all provided in the VTrans EV Charging Plan (7/1//13), one adjusted for Vermont specific conditions from the Energy Information Administration (EIA), another from the Center for Automotive Research (CAR) and one from the Vermont Air Pollution Control Division. The EIA forecast appears inappropriate in this context as the derivation was substantially underestimating EV ownership in 2013 thus VPPSA focused on the CAR and Vermont Air Pollution Control Division forecasts.. The CAR forecast is an annual forecast that predicts saturation from 2013-2015 and a simple trend was used to continue forward. The Air Pollution Control Division forecast provided a range of ownership projections of 10,000-23,000 by 2023. This is based on legislative regulations requiring manufacturers to produce additional Zero-Emission Vehicles in the future. VPPSA split this forecast into a low forecast (10,000) and high forecast (23,000) case and interpolated each backwards based on the expected ownership counts for 2013 in the CAR forecast. This was done because the CAR projection for the year looks reasonable based on current 2013 trends. This trend was then carried forward for each the high and low cases beyond 2023. These three forecasts were then examined annually through 2034 and averaged to get a saturation that is used in the load forecast.

After the saturation was developed, VPPSA determined the weighted average battery size based on current EV registrations to be 12.5 kWh. It was assumed that each car would be charged fully once per day and that 80% of the battery is available to the user, meaning the battery is not allowed to drop below a 20% charge by the manufacturer due to decreased service life at full discharges. With these assumptions, the average load for each car, on an annual basis, is 365*0.8*12.5 or 3650kWh/year. It can be reasonably expected that battery capacity will increase over time as well as their ability to be depleted lower than 20%, increasing the impact each car will have and thus assuming a 12.5kWh battery is likely a conservative projection of load from electric vehicles. In addition, the forecasts used were trended forward beyond their last forecast year. As with all successful new technologies, adoption is expected to be more exponential in nature and thus more aggressive than we are assuming in this forecast. At the same time, we assumed each EV would be charged daily, a potentially optimistic assumption in the forecast. Considering all of these caveats, we believe the effect on load portrayed by our analysis are likely more conservative than what will actually occur and will need to be reexamined for the 2018 filing as more accurate longer range forecasts hopefully become available. It should also be noted that the impacts of rate design were not considered for this analysis - while rate designs may not affect overall annual consumption appropriately designed rates could impact the shape of the load.

It is important to note that while electric vehicles, net metering, and energy efficiency will continue to have significant impacts on consumption, the framework under which the forecast is developed -- its treatment as a key variable -- allows VPPSA to stress the impacts of changes in load on the resource needs. This stressing (discussed further in the Appendix) ensures that VPPSA and its member utilities will be prepared in the event that any of its forecasts for these emerging technologies are incorrect.

As noted in Figure 4-4, 10 year average historical weather is used to predict energy consumption, while a rank and average method is used for peak demand models. Historical and predicted weather patterns are a key data source in developing the energy forecast. It is important to stress the forecast for this key variable to ensure that the analysis of resources is based upon a robust forecast that encompasses a range of possible futures. The variable range for the Load Forecast is presented in Figure 4-2, while the methodology used to develop this range is presented in Appendix 1. The demand forecast (Capacity Load Obligation or "CLO") is stressed by two standard deviations of the average historical CLO, representing a reasonably wide range of potential outcomes given that the CLO in a given year is based on the utility's load in one hour of the year - a value that could vary widely depending on particular circumstances of the hour.

Figure 4-5 shows the base, high, and low energy forecast. The high and low forecasts are the result of the combination of the Load Forecast and Load Forecast Error key variable ranges. Figure 4-6 presents the high, low, and base forecasts for VPPSA's Capacity Load Obligation.

Figure 4-5: Base, High, and Low Energy Forecast at VT Zone

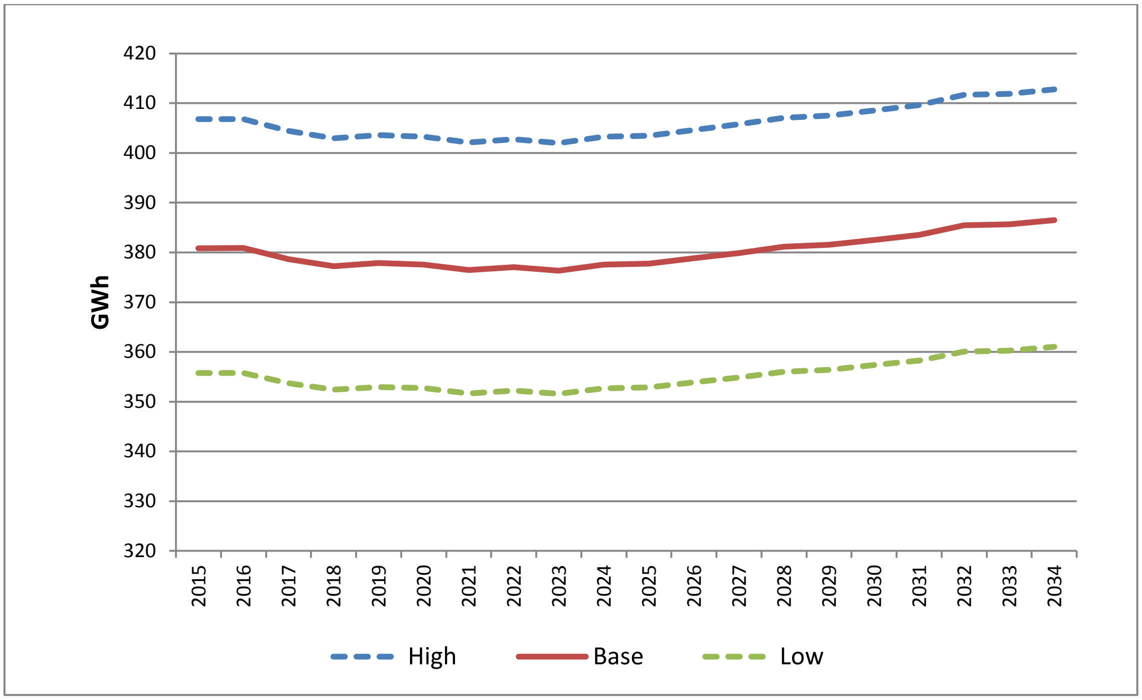
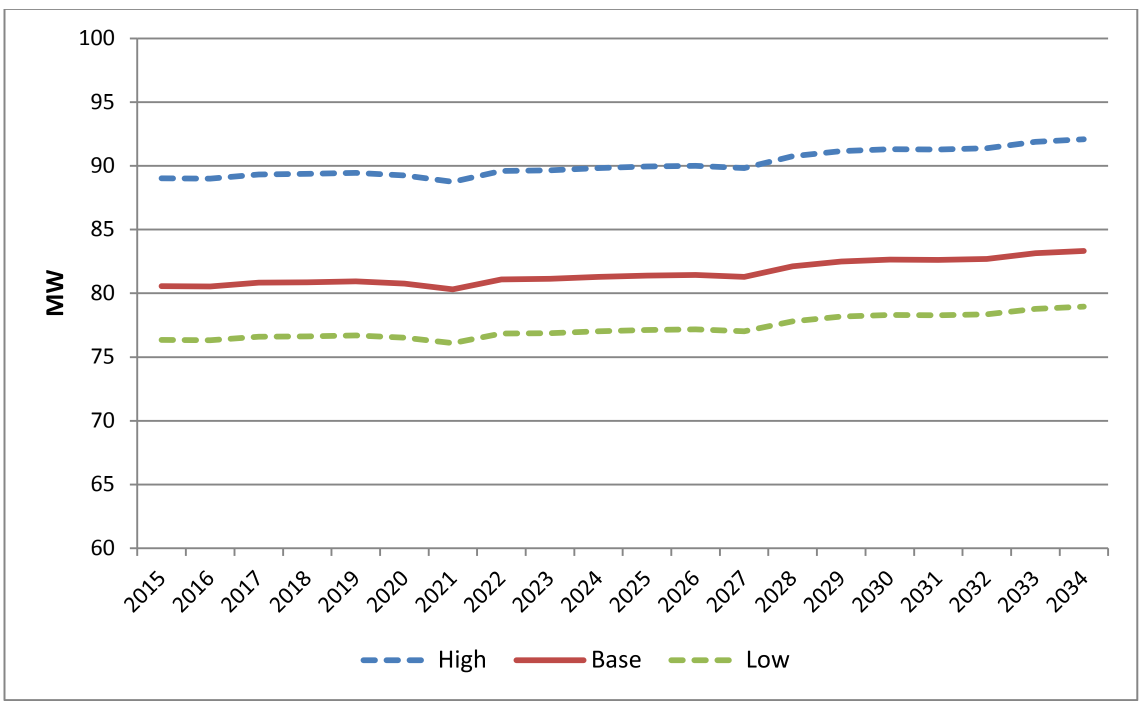


Figure 4-6: Base, High, and Low Capacity Load Obligation



5. Model Output Description

The resource model calculates power costs over a long-term (25-year) future planning period, summarizing results on a net present value ("NPV") basis for each resource mix. The NPV calculation represents the costs or value associated with each resource mix over the 25 year period taking into account inflation and the utility's Weighted Average Cost of Capital (WACC), applied as a discount rate. The lower the NPV value the lower the cost of the portfolio. If all other aspects of an evaluated portfolio (flexibility, diversity, etc.) are equal to alternative resource mixes, then the lower the cost of the portfolio, the more desirable it is.

It is important to note that for VPPSA member municipal utilities, the WACC is low, relative to an investor owned utility. At approximately 3.25%, the WACC is commensurate with that of a societal discount rate of 3% - the general benchmark utilized in Vermont at this time (based on an estimate of the rate long-term federal Treasury bonds). This reflects that the time value of money for municipal utilities is approximately equal to that of society's. Thus, it is not necessary to analyze results from both a societal time value of money perspective and a ratepayer time value of money perspective, as they are effectively the same. The discount rate (the WACC) is still stressed as a key variable and as shown below, and it has a relatively high impact on results.

5.1. *Scenarios and Portfolio Attributes*

VPPSA prepared 25 hypothetical supply scenarios as a reasonable set of options to serve future load needs. By evaluating these various power supply mixes using the IRP model, VPPSA was able to calculate a dollar net present value ("NPV") for the various scenarios. Figure 5-1 describes the scenarios evaluated in this IRP.

Figure 5-1: Supply Scenarios

Supply Scenarios	
All Out-of-State Solar ("SolarOut")	All Variable Contracts ("MktCon")
All In-State Solar ("SolarIn")	All Wind ("Wind")
All Fixed Contracts ("FixCon")	All Spot Market ("Spot")
Combinations of the Above (19 additional sets)	
SolarIn/FixCon	SolarOut/SolarIn/MktCon
SolarOut/SolarIn	SolarOut/SolarIn/Wind
SolarIn/MktCon	SolarIn/MktCon/Wind
SolarIn/Wind	SolarOut/FixCon/MktCon
SolarOut/FixCon	FixCon/MktCon/Wind
FixCon/MktCon	SolarOut/MktCon/Wind
FixCon/Wind	SolarOut/SolarIn/FixCon/MktCon
SolarOut/SolarIn/FixCon	SolarOut/SolarIn/MktCon/Wind
SolarIn/FixCon/MktCon	SolarOut/SolarIn/FixCon/MktCon/Wind
SolarIn/FixCon/Wind	

The list of resources was constructed with a number of resource attributes in mind. Direction from the VPPSA Board of Directors influences greatly the attributes that impact policy selection. Portfolios were designed to evaluate the following attributes (not necessarily listed in order of importance):

> **Diversity.** Increasing fuel diversity, resource diversity, and supplier diversity is considered desirable in a power supply mix, as it reduces risk of being over-reliant on one power source or counterparty. Diversity is especially important given the continued dominance of natural gas a fuel source in New England. In 2013, natural gas accounted for 43% percent of the total electric capacity in the region (and a greater amount of electric energy consumed) in New England. The result of this dependence on natural gas is that wholesale prices are volatile and reliability concerns have developed, especially in winter months when natural gas electric generators compete with space heating for limited natural gas supplies. Diversity in a resource mix mitigates concerns that arise when over-reliant on one fuel source.
>
> **Duration**. The municipal systems' power portfolio has historically provided stable cost power through long-term contracts and resource decisions. As resources expire, acquiring new resources with staggered end dates is an important priority. The goal is to have smaller blocks of resources expiring at regular intervals, rather than large blocks of power ending all at the same time. Duration can also be thought of as diversity in terms of timing of replacement of resources.

Achievability. The resource mix must be considered likely or able to be developed. For example, building a coal power plant was not considered in the analysis due to low likelihood of that option being pursued in Vermont or New England. There may also be practical maximum amounts of some resources if it is determined that those resources should be located in Vermont. This has been done for the solar resources with the annual utility-scale build for VPPSA systems limited to 10 MW.

Reliability. Reliability refers to delivery and availability of the resource. A number of municipal systems have hydro-based power that is considered intermittent. It is important to value how the intermittent source of power delivers energy in relation to consumer energy needs (monthly shapes in particular). Power contracts, even when they have known delivery times and quantities, can be unreliable in the event of default or lack of delivery (see below under Credit Risk). Reliability can also impact owned units in the form of forced outages or fuel availability problems.

Credit Risk. Counterparty credit risk is a very important aspect of doing business in today's power markets. With bankruptcies of major entities such as Enron, Mirant, PGET, and Calpine, understanding credit risk is an essential function in any utility power planning group. The amounts of power provided by any one entity in the power portfolio should be balanced in order to protect against the event of a credit default or bankruptcy. Price alone cannot be used to judge the value of a contract. If the counterparty to a contract does not deliver due to a credit issue, utilities can be left with an unplanned purchase event and be at the mercy of prevailing market conditions. In those cases, the certainty and stability that was sought through contracts may not be realized.

Flexibility. Flexibility in a power portfolio is important in order to take advantage of favorable changes in market conditions. As an example, generation that is dispatchable can be turned off to take advantage of times when the spot market is cheaper. Conversely, by having generation or contracts that are able to turn on when power prices spike, the power portfolio is insulated from significant market price volatility. VPPSA's Peaker Project is a good example of a resource that can insulate a utility against high cost market conditions. In the event of extreme hot or cold temperatures, load levels generally increase dramatically. A peaking unit can ramp up quickly to cover those comparatively few hours of load and insulate a utility from extreme energy price spikes. At the same time, it provides flexibility to the region as reserve capacity available at times of need, in return for this availability the region compensates the facility even when it isn't running.

Another dimension of flexibility to be considered is the flexibility of physical generating assets to respond to market changes. In the example of capacity requirements, VPPSA's Peaker Project can be contrasted to a market contract for the purchase of capacity. A contract for capacity is limited to the product selected and does not adapt readily to changing market rules, and would have little to no additional value in the hypothetical scenario with prevailing high energy prices. However, a generator like the Peaker Project is available if market rules change to realize these high energy values (offsetting charges for consumption).

Volatility – Understanding and mitigating volatility is an important attribute for any power resource portfolio, and a primary focus of VPPSA's member systems. Absent action to remove volatility, the municipal systems' power portfolios are primarily exposed to natural gas and resulting power price volatility due to changing conditions in the wholesale markets. This exposure will increase as existing resources whose price is not natural gas or oil based expire. Future power resources are evaluated for their potential to dampen the effect of volatility.

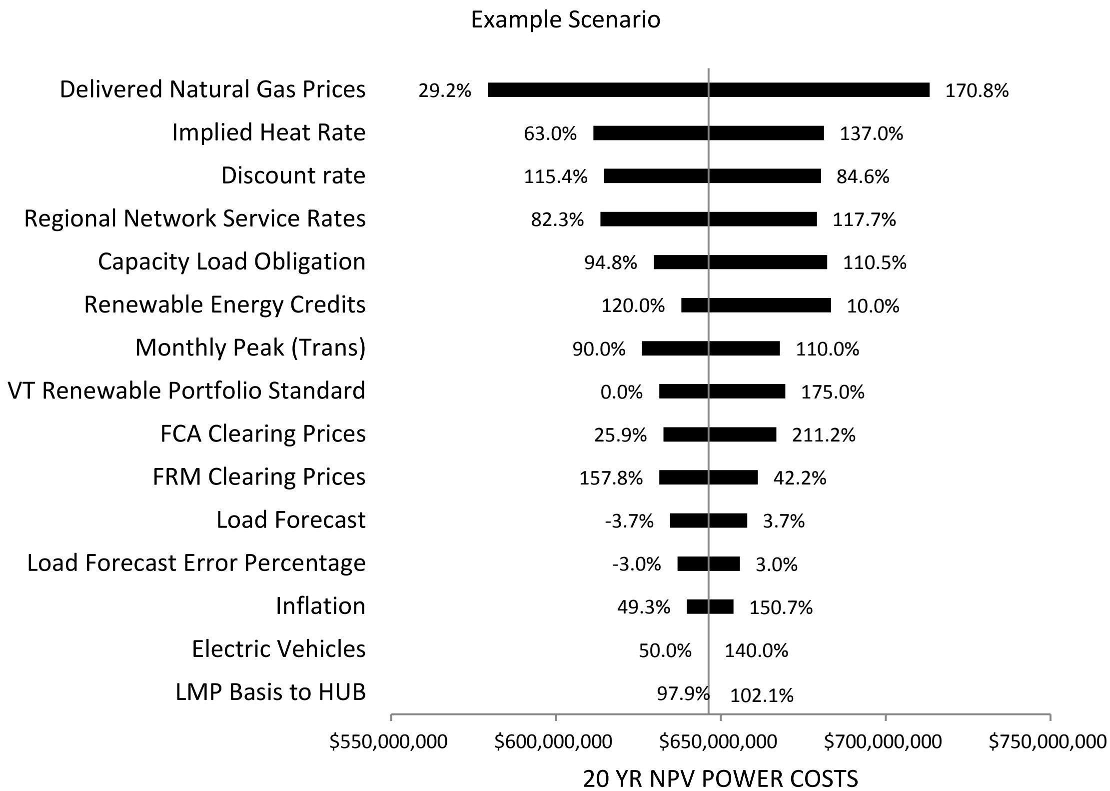
5.2. ***SensIt***

Rather than rely on a simple dollar NPV calculation of base, high, and low forecasts of variable impacts to draw conclusions, the IRP model conducts a sensitivity analysis, using a software package known as "*SensIt*", a sensitivity analysis add-in for Microsoft Excel. It performs sensitivity analysis on a worksheet based on changes in certain inputs and a specified output value (i.e. many inputs – one output) and allows VPPSA to perform "what-if" modeling.

Sensitivity analysis allows VPPSA to determine which inputs or variables are significant (or even critical) cost drivers, thereby leading to a more thorough analysis of scenarios or resource options. This allows VPPSA to identify critical sources of uncertainty and risk associated with a power portfolio, which ultimately become risks to the 12 member utilities and their consumers. Understanding cost drivers allows for a deeper understanding of the amount of volatility or variation they impart to the portfolio. As described above this is an important factor in determining whether or not the portfolio is desirable. For example, assume portfolio A has a 1% lower NPV cost value than portfolio B. On the surface, both portfolios are perceived as roughly equal, with portfolio A being preferred because of its lower price. However, a the sensitivity analysis shows that portfolio A is more likely to fluctuate with changes in the price for natural gas than portfolio B. A risk averse decision maker would opt for portfolio B over A due to portfolio B being less volatile, despite its higher price

SensIt creates "tornado charts" which allow visual identification of the swing or impact a variable has on the end result. For a decision maker trying to understand risk this is a very helpful tool. A tornado chart displays the results of single-factor sensitivity analysis for a specified end result. The chart technique shows how much a variable can change the specified results and therefore provides a measurement of uncertainty for each variable tested. The larger the black rectangle the more sensitive the outcome is to the particular variable (the percentage values for each variable indicate the variable range relative to baseline while the bars indicate the impact on the NPV power supply cost of service).

Figure 5-2: Tornado Chart Example



In the above tornado chart the cost of power over 20 years is most sensitive to changes to the price of natural gas. The largest black rectangle represents the largest dollar change from the low case to high case. In this example, natural gas caused the NPV of the cost of power to be as low as $579 million and as high as $713 million - a potential swing of $134 million. The next largest swing in this example was the variable associated with the value of the implied heat rate of the portfolio. This variable caused the NPV power supply cost to be as low as $611 million and as high as $681 million, a potential swing of $70 million. The smaller the delta between the low case and high case, the smaller the black rectangle area is. Therefore, in this scenario it can be seen that variables such as penetration of electric vehicles and LMP Basis to Hub had very little financial impact on the cost of power.

5.3. *Expected Value Calculations*

VPPSA has included a process in its IRP that gives probability weightings to variables and calculates an expected NPV value. This aspect of the analysis allows decision makers to see the predicted change in costs assuming various probabilities of the variables. This tests the cost conclusions for each scenario by factoring in probability assignments. The probability weightings were used to calculate the expected NPV value of each resource mix. They were developed by the VPPSA power supply team. Each team member individually, without other's knowledge, assigned a probability weighting to the base, high, and low cases based on their individual expertise and projections of the future. Each of these probability weightings were then averaged to determine the probability weighting actually applied to each input variable. For example, collectively, the power supply team believed there would be only a 5% likelihood that the low electric vehicle penetration forecast would occur, with a 60% chance the base case projection was correct, and a 35% chance the high penetration coming to fruition. Figure 5-3 lists the final probability weightings used for each Sensit adjusted input variable used in preparing this filing.

Figure 5-3: Probability Weightings Used for Expected Value Calculation

	Probability of Low	Probability of Base	Probability of High
Delivered Natural Gas Prices	25.00%	55.00%	20.00%
Implied Heat Rate	30.00%	50.00%	20.00%
LMP Basis to HUB	20.00%	40.00%	40.00%
VT Renewable Portfolio Standard	27.50%	55.00%	17.50%
Electric Vehicles	5.00%	60.00%	35.00%
Regional Network Service Rates	10.00%	45.00%	45.00%
Capacity Load Obligation	10.00%	75.00%	15.00%
Monthly Peak (Trans)	15.00%	57.50%	27.50%
FCA Clearing Prices	5.00%	70.00%	25.00%
FRM Clearing Prices	40.00%	41.67%	18.33%
Renewable Energy Credits	36.67%	48.33%	15.00%
Load Forecast	25.00%	50.00%	25.00%
Load Forecast Error Percentage	25.00%	50.00%	25.00%
Inflation	25.00%	35.00%	40.00%
Discount rate	25.00%	35.00%	40.00%

Comparing both NPV and Expected NPV numbers to similar results for other scenarios gives a picture of the variability (around the simple NPV) for all scenarios based on the same key variables and key variable probabilities. As shown in the results, the Expected NPV of every scenario was higher than the NPV - this shows that the power supply team at the time believed there was a greater likelihood of higher costs relative to the base case than lower costs. In this instance, the Expected NPV and NPV differed by roughly the same across scenarios. However, if a scenario's largest variable swing was related to FRM prices (where the VPPSA power supply team expected a higher likelihood of low prices than high), this may have shown a greater difference between Expected NPV and NPV between scenarios. This allows the decision maker to pick a resource portfolio based on more information than would be possible based on just a simple NPV calculation.

5.4. *Results*

By using sensitivity techniques the output of each resource scenario is compared to other scenarios. This allows VPPSA to narrow in on the least cost scenario, and will also allow VPPSA to assess other resource characteristics such as volatility and uncertainty.

Once all of the variables and resources input into the model, all 25 scenarios are characterized, and the model is run. The output from all 25 runs is summarized in Figure 5-4:

Figure 5-4: Summary of Results

Scenario	Scenario	NPV ($)	Expected NPV Value ($)	Largest Variable	Largest Variable Swing ($)	Largest Variable Swing (%)	Second Largest Variable	Second Largest Variable Swing ($)	Second Largest Variable Swing (%)	Probabilistic Departure From Base ($)
1	**Spot**	$646,302,451	$675,381,657	Delivered Natural Gas Prices	$133,966,938	42%	Implied Heat Rate	$69,949,222	11%	$29,079,207
2	**SolarOut**	$637,875,357	$668,388,045	Delivered Natural Gas Prices	$113,727,870	36%	Regional Network Service Rates	$65,635,847	12%	$30,512,689
3	**SolarIn**	$622,557,113	$654,132,624	Delivered Natural Gas Prices	$100,698,133	31%	Regional Network Service Rates	$65,635,847	13%	$31,575,512
4	**FixCon**	$651,829,603	$680,451,996	Discount rate	$66,376,732	21%	Regional Network Service Rates	$65,635,847	20%	$28,622,393
5	**Mkt Cont**	$634,800,132	$661,056,589	Regional Network Service Rates	$65,635,847	23%	Discount rate	$64,185,668	22%	$26,256,457
6	**Wind**	$644,672,738	$677,677,374	Delivered Natural Gas Prices	$100,322,738	30%	Discount rate	$65,778,281	13%	$33,004,636
7	**SolarIn/FixCon**	$625,091,159	$657,321,596	Regional Network Service Rates	$65,635,847	19%	Discount rate	$63,280,848	17%	$32,230,437
8	**SolarOut/SolarIn**	$614,130,019	$643,661,791	Delivered Natural Gas Prices	$80,459,065	23%	Regional Network Service Rates	$65,635,847	15%	$29,531,773
9	**SolarIn/Mkt Cont**	$617,088,712	$646,956,630	Regional Network Service Rates	$65,635,847	19%	Discount rate	$62,253,297	17%	$29,867,917
10	**SolarIn/Wind**	$620,927,400	$652,211,465	Renewable Energy Credits	$77,201,347	21%	Delivered Natural Gas Prices	$67,053,933	16%	$31,284,066
11	**SolarOut/FixCon**	$640,409,403	$668,069,305	Regional Network Service Rates	$65,635,847	18%	Discount rate	$65,066,175	17%	$27,659,902
12	**FixCon/Mkt Cont**	$643,368,097	$671,690,221	Regional Network Service Rates	$65,635,847	22%	Discount rate	$65,295,611	22%	$28,322,124
13	**FixCon/Wind**	$647,206,784	$681,302,906	Discount rate	$66,041,716	18%	Regional Network Service Rates	$65,635,847	18%	$34,096,121
14	**SolarOut/SolarIn/FixCon**	$615,819,383	$646,735,844	Regional Network Service Rates	$65,635,847	19%	Discount rate	$62,199,484	17%	$30,916,461
15	**SolarIn/FixCon/Mkt Cont**	$620,600,877	$650,945,325	Regional Network Service Rates	$65,635,847	20%	Discount rate	$62,683,625	19%	$30,344,448
16	**SolarIn/FixCon/Wind**	$622,616,764	$653,312,075	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,695,311
17	**SolarOut/SolarIn/Mkt Cont**	$610,484,419	$640,031,835	Regional Network Service Rates	$65,635,847	19%	Discount rate	$61,514,451	17%	$29,547,416
18	**SolarOut/SolarIn/Wind**	$612,500,306	$642,397,153	Renewable Energy Credits	$77,201,347	23%	Regional Network Service Rates	$65,635,847	17%	$29,896,847
19	**SolarIn/Mkt Cont/Wind**	$617,281,799	$647,614,439	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,332,640
20	**SolarOut/FixCon/Mkt Cont**	$635,919,121	$663,210,801	Regional Network Service Rates	$65,635,847	21%	Discount rate	$64,468,953	20%	$27,291,680
21	**FixCon/Mkt Cont/Wind**	$642,716,502	$675,764,863	Regional Network Service Rates	$65,635,847	20%	Discount rate	$65,444,494	20%	$33,048,361
22	**SolarOut/Mkt Cont/Wind**	$632,600,044	$663,951,190	Regional Network Service Rates	$65,635,847	19%	Discount rate	$64,275,319	18%	$31,351,146
23	**SolarOut/SolarIn/FixCon/Mkt Cont**	$612,280,241	$642,293,914	Regional Network Service Rates	$65,635,847	21%	Discount rate	$61,718,896	18%	$30,013,672
24	**SolarOut/SolarIn/Mkt Cont/Wind**	$609,420,223	$638,052,989	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$28,632,766
25	**olarOut/SolarIn/FixCon/Mkt Cont/Win**	$611,415,730	$642,206,625	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,790,896

Figure 5-4 does not rank in order of preference at this stage. In the appendix section, details of cost and each scenario's tornado chart are provided for a more detailed review of each resource mix.

In interpreting these results, the key values used to evaluate the resource scenarios were:

- NPV Calculation
- Expected NPV Calculation
- Largest Variable Swing (in terms of $)
- Second Largest Variable Swing (in terms of $)

To allow a comparison of multiple variable results, weightings were assigned to each the values as follows:

Figure 5-5: Weighting Values for Ranking Purposes

Value	Weighting
NPV	40%
Expected NPV	45%
Largest Variable Swing ($)	10%
Second Largest Variable Swing ($)	5%

The expected value was given the highest ranking of 45%, followed by the NPV calculation which was given a ranking of 40%. Consistent with least cost planning, these two attributes were weighted the highest as they drive the actual costs for the scenario. The Expected NPV value is weighted slighly more because as described above, it takes into account the expertise of the power supply team, allowing for a more nuanced estimate of cost. The difference, however, is kept minor, recognizing that unpredicatable events could change the course of projections. Volatility and variability are important considerations as well, as they affect the likelihood of achieving the anticipated results. Providing weight to this volatility accounts for each portfolio's risk associated with swings in any one or two variables. These values were given a combined 15% rating in the ranking calculation. While volatility is important, selecting the lowest expected cost resource mix is deemed a higher priority for the municipal systems customers. Figure 5-6 shows the scenarios ranked in order of the weighting values.

Figure 5-6: Scenarios ranked on the basis of NPV, Expected NPV, and Largest Two Variable Swings

Please note that the default sort option for this sheet is on the "Expected NPV ($)" column. When the sheet is opened all values have been sorted by the "Expected NPV ($)."

Scenario	Scenario	NPV ($)	Expected NPV ($)	Largest Variable	Largest Variable Swing ($)	Largest Variable Swing (%)	Second Largest Variable	Second Largest Variable Swing ($)	Second Largest Variable Swing (%)	Probabilistic Departure From Base ($)	Ranking Value
		NPV Sort	E-NPV Sort		LVS Sort	LVS% Sort		SLVS Sort	SLVS% Sort	PDFB Sort	Ranking Sort
24	**SolarOut/SolarIn/Mkt Cont/Wind**	$609,420,223	$638,052,989	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$28,632,766	$541,893,861
17	**SolarOut/SolarIn/Mkt Cont**	$610,484,419	$640,031,835	Regional Network Service Rates	$65,635,847	19%	Discount rate	$61,514,451	17%	$29,547,416	$541,847,400
25	**SolarOut/SolarIn/FixCon/Mkt Cont/Wind**	$611,415,730	$642,206,625	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,790,896	$544,561,200
23	**SolarOut/SolarIn/FixCon/Mkt Cont**	$612,280,241	$642,293,914	Regional Network Service Rates	$65,635,847	21%	Discount rate	$61,718,896	18%	$30,013,672	$543,593,887
18	**SolarOut/SolarIn/Wind**	$612,500,306	$642,397,153	Renewable Energy Credits	$77,201,347	23%	Regional Network Service Rates	$65,635,847	17%	$29,896,847	$545,080,768
8	**SolarOut/SolarIn**	$614,130,019	$643,661,791	Delivered Natural Gas Prices	$80,459,065	23%	Regional Network Service Rates	$65,635,847	15%	$29,531,773	$546,627,512
14	**SolarOut/SolarIn/FixCon**	$615,819,383	$646,735,844	Regional Network Service Rates	$65,635,847	19%	Discount rate	$62,199,484	17%	$30,916,461	$547,032,442
9	**SolarIn/Mkt Cont**	$617,088,712	$646,956,630	Regional Network Service Rates	$65,635,847	19%	Discount rate	$62,253,297	17%	$29,867,917	$547,642,218
19	**SolarIn/Mkt Cont/Wind**	$617,281,799	$647,614,439	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,332,640	$549,341,144
15	**SolarIn/FixCon/Mkt Cont**	$620,600,877	$650,945,325	Regional Network Service Rates	$65,635,847	20%	Discount rate	$62,683,625	19%	$30,344,448	$550,863,513
10	**SolarIn/Wind**	$620,927,400	$652,211,465	Renewable Energy Credits	$77,201,347	21%	Delivered Natural Gas Prices	$67,053,933	16%	$31,284,066	$552,938,951
16	**SolarIn/FixCon/Wind**	$622,616,764	$653,312,075	Renewable Energy Credits	$77,201,347	25%	Regional Network Service Rates	$65,635,847	18%	$30,695,311	$554,039,066
3	**SolarIn**	$622,557,113	$654,132,624	Delivered Natural Gas Prices	$100,698,133	31%	Regional Network Service Rates	$65,635,847	13%	$31,575,512	$556,734,132
7	**SolarIn/FixCon**	$625,091,159	$657,321,596	Regional Network Service Rates	$65,635,847	19%	Discount rate	$63,280,848	17%	$32,230,437	$555,558,809
5	**Mkt Cont**	$634,800,132	$661,056,589	Regional Network Service Rates	$65,635,847	23%	Discount rate	$64,185,668	22%	$26,256,457	$561,168,386
20	**SolarOut/FixCon/Mkt Cont**	$635,919,121	$663,210,801	Regional Network Service Rates	$65,635,847	21%	Discount rate	$64,468,953	20%	$27,291,680	$562,599,541
22	**SolarOut/Mkt Cont/Wind**	$632,600,044	$663,951,190	Regional Network Service Rates	$65,635,847	19%	Discount rate	$64,275,319	18%	$31,351,146	$561,595,403
11	**SolarOut/FixCon**	$640,409,403	$668,069,305	Regional Network Service Rates	$65,635,847	18%	Discount rate	$65,066,175	17%	$27,659,902	$566,611,842
2	**SolarOut**	$637,875,357	$668,388,045	Delivered Natural Gas Prices	$113,727,870	36%	Regional Network Service Rates	$65,635,847	12%	$30,512,689	$570,579,342
12	**FixCon/Mkt Cont**	$643,368,097	$671,690,221	Regional Network Service Rates	$65,635,847	22%	Discount rate	$65,295,611	22%	$28,322,124	$569,436,203
1	**Spot**	$646,302,451	$675,381,657	Delivered Natural Gas Prices	$133,966,938	42%	Implied Heat Rate	$69,949,222	11%	$29,079,207	$579,336,881
21	**FixCon/Mkt Cont/Wind**	$642,716,502	$675,764,863	Regional Network Service Rates	$65,635,847	20%	Discount rate	$65,444,494	20%	$33,048,361	$571,016,598
6	**Wind**	$644,672,738	$677,677,374	Delivered Natural Gas Prices	$100,322,738	30%	Discount rate	$65,778,281	13%	$33,004,636	$576,145,101
4	**FixCon**	$651,829,603	$680,451,996	Discount rate	$66,376,732	21%	Regional Network Service Rates	$65,635,847	20%	$28,622,393	$576,854,705
13	**FixCon/Wind**	$647,206,784	$681,302,906	Discount rate	$66,041,716	18%	Regional Network Service Rates	$65,635,847	18%	$34,096,121	$575,354,985
	Weighted Value	*40%*	*45%*	*NA*	*10%*	*NA*	*NA*	*5%*	*NA*	*0%*	*100%*

As shown in Figure 5-6, portfolios with combinations of solar (both in and out of state) along with market contracts rise to the top of the list with the lowest NPV costs and the least amount of variability. A number of observations are worth noting:

- The six lowest cost scenarios differ on a net present value by less than one percent over twenty years, however the volatility of the largest variables differs between these scenarios.
- Each of the seven lowest cost scenarios have a combination of in- and out-of-state utility scale solar as major components of the portfolio going forward. In addition, the next seven lowest cost scenarios also had in-state solar.
- The value of Renewable Energy Credits (RECs)was the variable with the largest amount of uncertainty for 6 out of the first 12 lowest cost options. Regional Network Service (RNS) charges was the variable with the largest amount of uncertainty for 5 of the first 12 lowest cost options. It was the variable with the first or second largest amount of uncertainty for 22 of the 25 scenarios.
- The addition of wind to the portfolio increased the amount of volatility associated with the portfolio significantly. For example, Scenario 17 with in and out of state solar and Market contracts resulted in RNS rates creating a potential $65 million swing as the largest variable, while Scenario 24 with the same resoruces plus wind generation created a potential $77 million swing in RECs as the largest variable.
- The Spot Market scenario (not locking in any resource and instead riding prevailing market conditions) was the most expensive resource option and had the largest variability (based on potential natural gas price volatility) of all 25 cases.
- Significantly modifying the weighting described in Figure 5-5 would emphasize a need for stability over lowest NPV by reducing the desirability of portfolios with large swings. For example, in this IRP placing a combined 85% weight on the variable swings and 15% combined weight on NPV rather than the original opposite ratios lowers the ranking of those scenarios that rely on wind resources. This highlights that portfolios that depend on the sale of Renewable Energy Credits have the largest first and second variable swings out of all portfolios, and indicates a volatility risk that must be carefully considered.

It is important to evaluate all of the possible scenarios going forward, but more emphasis should be placed on those scenarios that have the characteristics that are desirable to the member systems. It should also be noted that the results above are not dispositive -- updated market, resource cost, capital, and other information is crucial to evaluating resources at the time of availability. With that in mind, figure 5-7 and 5-8 present the results from the second lowest cost scenario (by 0.175%), Scenario 17 - in and out of state solar with market contracts. Scenario 17 also has relatively low key resource variability.

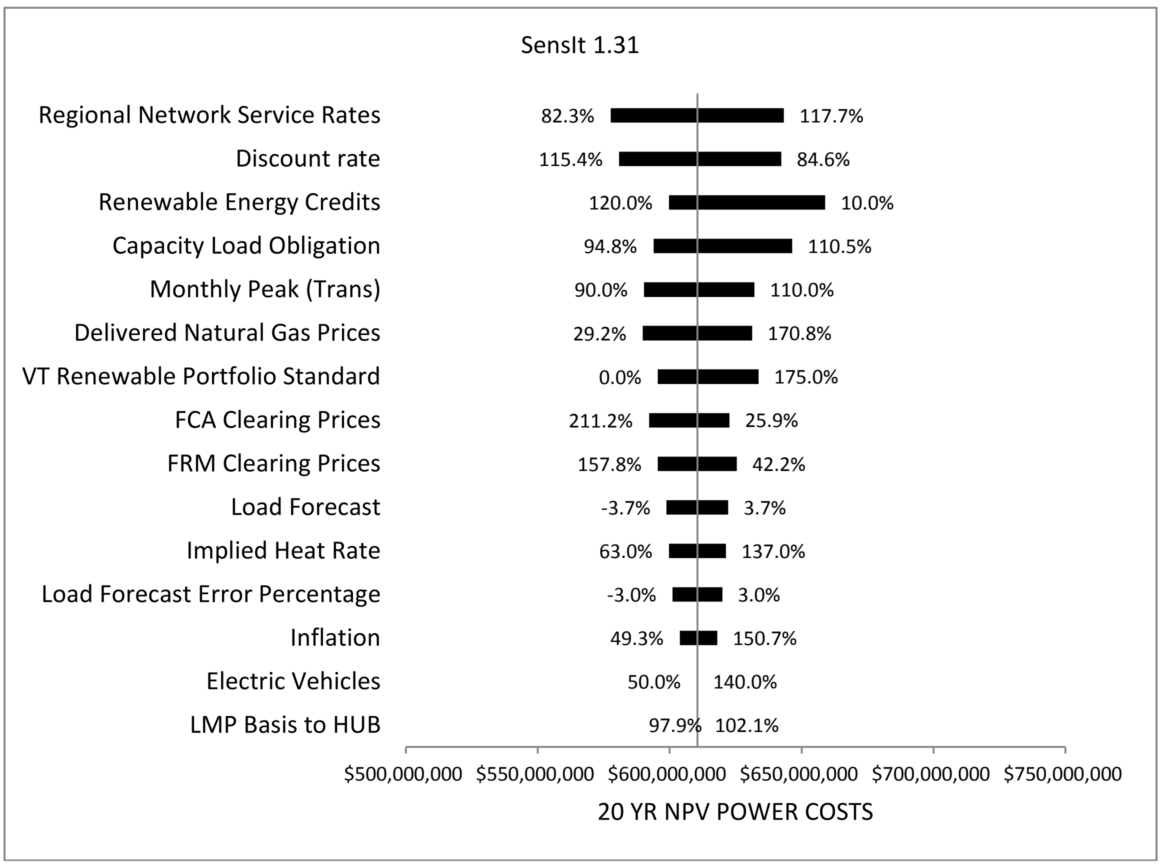
Figure 5-7 is a detailed summary of the resulting NPV calculations for Scenario 17. It shows how much each variable fluctuated relative the base case of $555 million. As described above, The assumed Renewable Energy Credit value is the most significant variable. This variable has a range of $60 million from the low cost case to the high cost case based on the assumptions used in model. The next most significant variable was changes to the expected Regional Network Service rates, followed by changes to the assumed discount rate.

Figure 5-8 provides a summary of the key variables in order of relative importance in the form of a "tornado" chart to show the effect of variables on the cost of power for the scenario.

Figure 5-7: Scenario 17- In-State Solar, Out-of-State Solar, and Market Contract Results

				20 YR NPV POWER COSTS				
	Corresponding Input Value			Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$577,666,499	$610,484,419	$643,302,345	$65,635,847	19.0%
Discount rate	115.4%	100.0%	84.6%	$580,822,128	$610,484,419	$642,336,579	$61,514,451	16.7%
Renewable Energy Credits	120.0%	100.0%	10.0%	$599,717,873	$610,484,419	$658,933,872	$59,215,998	15.5%
Capacity Load Obligation	94.8%	100.0%	110.5%	$593,845,256	$610,484,419	$646,453,367	$52,608,111	12.2%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$590,293,087	$610,484,419	$632,126,785	$41,833,698	7.7%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$589,756,749	$610,484,419	$631,212,088	$41,455,339	7.6%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$595,506,447	$610,484,419	$633,728,911	$38,222,464	6.4%
FCA Clearing Prices	211.2%	100.0%	25.9%	$592,205,484	$610,484,419	$622,670,375	$30,464,892	4.1%
FRM Clearing Prices	157.8%	100.0%	42.2%	$595,529,874	$610,484,419	$625,438,963	$29,909,088	3.9%
Load Forecast	-3.7%	0.0%	3.7%	$598,785,835	$610,484,419	$622,183,002	$23,397,166	2.4%
Implied Heat Rate	63.0%	100.0%	137.0%	$599,661,716	$610,484,419	$621,307,121	$21,645,406	2.1%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$600,999,081	$610,484,419	$619,969,756	$18,970,675	1.6%
Inflation	49.3%	100.0%	150.7%	$603,871,860	$610,484,419	$618,035,758	$14,163,897	0.9%
Electric Vehicles	50.0%	100.0%	140.0%	$610,381,777	$610,484,419	$610,566,531	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$610,484,419	$610,484,419	$610,484,419	$0	0.0%

Figure 5-8: Scenario 17- In-State Solar, Out-of-State Solar, and Market Contract Tornado Chart



30 V.S.A. §218c requires a least cost integrated plan to include "environmental" costs when calculating a "lowest present value life cycle cost." The statute is not clear on how to address these costs. VPPSA has indirectly included costs associated with compliance of certain emissions in the region such as CO_2, NO_x and SO_2 and costs associated with noise pollution, aesthetics, and other quality of life elements are met through the IRP process in a more qualitative way during discussion of the benefits of a particular resource mix.

Direct costs associated with CO_2 (carbon dioxide) emissions are incorporated into forecasts of electricity prices because emissions of the pollutant are regulated by the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort to help reduce greenhouse gas emissions among nine eastern states, with the state of Vermont a founding member. Most electric generators in the RGGI region with a nameplate capacity greater than 25MW are subject to RGGI compliance, which places an annual cap on the amount of collective carbon emissions from these power plants. As such, when the demand for allowances exceeds the supply, carbon emissions from the RGGI states are unlikely to reduce unless the RGGI cap (amount of pollution) is lowered or the CO_2 allowances (right to pollute) are not offered into the auction (retired). VPPSA assumes that those plants that are required to purchase the right to emit CO2 pollution have included those costs into their energy supply offers to the market, influencing the expected costs of energy in the future and is reflected in the forward energy price curve. VPPSA has not assumed an additional cost for carbon should the cost of compliance with RGGI not be reflective of the overall cost to society for the same amount of pollution emitted in the region. Similarly, VPPSA has not included a variable for additional societal costs of carbon for resources that do not use renewable fuels. The net effect of regional carbon emissions from resources that generate electricity from renewable fuel sources and those that generate electricity from fossil fuels is expected to be equal as the total amount of pollution that the region will emit is capped by RGGI. If a renewable resource were to be built in the region, the same amount of carbon allowances would be sold in auctions as would have been sold had a fossil fuel generator been built. The costs for compliance with other regulated emissions such as NOx and SO2 are addressed in a similar way.

The costs associated with compliance of the newly passed Vermont Renewable Energy Standard (Act 56, RES) is also not considered a carbon emissions cost in this Integrated Resource Plan given that such emissions are regulated through RGGI. As discussed in Section 4.3, much of the compliance will be or can be met through the retirement of Renewable Energy Credits (RECs.) VPPSA's understanding is that the RECs associated with the generation used to comply with the VT RES should not be directly associated with carbon reduction for the state of Vermont. It is expected that in the future, the collective efforts of states with an RPS or RES will make it easier for the Governors of the RGGI states to agree to reduce the annual emissions cap as the demand for emissions allowances is expected to be lower as RPS and RES compliance amounts increase.[2]

6. Action Plan

The optimal resource choice from a least cost basis on the current data set was scenario 24 (In-State Solar, Out-of-State Solar, Market Contract, Wind), closely followed by Scenario 17 (In-State Solar, Out-of-State Solar, Market Contract). A number of scenarios containing both In- and Out-of-State solar had similar overall resource costs and volatility. The municipal systems' current portfolio is a mix of long-term contracts, generation, and short-term contracts. VPPSA's overarching strategy, as directed by its members, is to maintain diversity in the municipal systems' power supply portfolios while securing stably priced resources in a cost-effective and environmentally conscious manner. Scenario 17 and Scenario 24 both fit well with the strategy, but as with any resource choice, it is important to use reasonable judgment, updated data, and consider the need to mitigate risk.

From a financial standpoint, understanding risks and potential cost variables is critical. The IRP model, as illustrated in the preceding Sections, is a rigorous planning tool that allows for least cost integrated planning through a robust decision making framework. The analysis undergone for this IRP and for every resource choice provides valuable insight into the impacts of future resource decisions. In particular, the analysis has led us to the following next steps:

- Identify possible solar plant opportunities for partnership and/or development, both In-State and Out-of-State;
- Monitor and pursue regulatory efforts to retire necessary RECs and/or take other necessary actions to meet state targets in the Renewable Energy Standard while preserving the value of REC credits for member systems.
- Keep existing portfolio strengths in mind (diversity, flexibility, stability) when undertaking new purchases
- Pursue resources and actions that lower exposure to Regional Network Service charge rates.
- In the short term, continue to implement the Planned Purchase program. In order to make its members' power costs more predictable, VPPSA implemented a plan to purchase power for future periods using a systematic price hedging technique. The municipal systems participate in planned purchasing in order to avoid uncertainty and volatile swings of spot market purchases. Under this Planned Purchase concept, VPPSA reviews future market exposure (defined as forecasted

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2 This view is not unique. In a discussion about RECs and emissions, Richard Sedano for the Regulatory Assistance Project stated that "Vermont is part of the Regional Greenhouse Gas Initiative and that determines how much carbon the whole region, including Vermont, is going to actually produce. You can only produce a carbon unit if you buy an allowance to do that." Electric Utility Regulation 101, Sedano, Richard, Lindholm, Jane January 21, 2015 (at minute 29:00) http://digital.vpr.net/post/electric-utility-regulation-101#stream/0

need for power, less amounts available through previously secured long-term contracts and generation) every six months.

Twice a year, in the spring and fall, utilities have the opportunity to purchase one quarter of future market energy needs for a two year period. For example, in the spring of 2007, utilities purchased approximately one-fourth of their projected need for market energy for the period January 2009 to December 2010. In the fall of 2007, approximately another one-fourth of the need for the period July 2009 to June 2011 was purchased. By staggering the purchases, at any given time the market needs of a utility are met by contracts purchased at four different price points resulting in less volatile power market prices. This is very similar to the concept of dollar cost averaging which is used in financial investing. The implementation of Planned Purchasing is structured and systematic, but it does not remove the need for continual market monitoring and judgment.

The goal is to use market monitoring and judgment to give the municipal systems the benefit of more favorable resource prices. In the event that market prices are below prices that will cause rates to be stable, additional or longer purchase may be made instead of the normal two year duration. In the event that unusually high prices prevail at the time of a planned purchase, that purchase may be delayed. In general the intent is to avoid trying to “time the market” and so the pre-disposition will be to make each bi-annual purchase unless the prices depart noticeably from expected ranges.

In addition to the above specific actions, VPPSA intends to continue to monitor the penetration of electric vehicles, heat pumps, battery storage, and net metering to understand impacts on energy consumption, load shapes, and rates. VPPSA and its member systems will seek to actively and creatively meet the targets of Vermont's new Renewable Energy Standard.

Finally, VPPSA will continue to monitor and consider the impacts of rate design options on resource planning.

7. Conclusion

The municipal systems’ IRP is intended to act as a plan for meeting future power needs, but it does not map out with precision what action will be taken or an explicit outcome. VPPSA continually updates data and re-evaluates supply alternatives (particularly when considering investment in or contracting for a specific long-term resource). The results of this IRP indicate to VPPSA and its members the areas in which there is more work to be done and what critical paths are necessary to reach a least-cost outcome. The IRP is a planning process and is a dynamic, rather than a static, one. As conditions change, planning assumptions, and even the model itself, will need to be updated to reflect important developments.

Any specific resource option will generally be evaluated in the same way as the planning or generic resources in the IRP model. When considering a specific proposed resource, updating all assumptions and probability estimates with the best available information at that time will be necessary. Also, if a specific proposal is of the same type as a planning or generic resource (e.g. an in-state solar resource) it will be important to consider differences between the characteristics of the specific proposal and the generic assumptions for that resource type in order to insure that the planning assumptions are still relevant (e.g. the tilt and azimuth of a solar resource could affect its value).

As indicated earlier, the decision-making framework illustrated by this IRP is applied at the individual system level; this is done as specific power projects are reviewed and assessed in the future. In this way each utility has specific information on the impact a project and resource mix will have on their individual system. Each utility can then determine if a project or resource mix fits with the municipal's goals and customers' preferences.

Appendix 1: Resource and Variable Assumptions

RESOURCES

Resource Name	**NYPA - Niagara**
Expiration:	The Niagara contract is modeled as being renewed for the duration of the IRP analysis.
Dispatch:	Cap+Niag**.** The percent of energy on and off peak was determined based on average values. The contract provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	NH000. NYPA hydro with no REC properties.
Black Start?	No
Forward Reserve?	No
Nominal kW:	4,050 kW. The historical Niagara entitlement was used
Capacity Cost:	The contract is subject to cost-of-service treatment and so changes are not known. For IRP modeling purposes historical capacity costs (and related cost net of NYPA re-bills) were escalated by inflation to derive forecasted capacity costs.
Market Cap kW:	The nominal kW are adjusted by the ISO-NE Pool Reserve Margin rate to arrive at UCAP kW for the contract. The historical monthly reserve margins were used as a proxy for future years and combined with the nominal kW assumptions to arrive at market capacity kW.
Capacity Factor:	A historical average monthly capacity factor was used for future months.
Energy Price:	The contract is subject to cost-of-service treatment and so changes are not known. For IRP modeling purposes assumed energy costs were escalated by inflation to derive forecasted energy costs per MWh.

Resource Name **NYPA – St Lawrence**

Expiration: The St Lawrence contract is modeled as being renewed for the duration of the IRP analysis.

Dispatch: Cap+StLa**.** The percent of energy on and off peak was determined based on average values. The contract provides market capacity.

EforD: No longer used with new Forward Capacity Market rules

Type: NH000. NYPA hydro with no REC properties.

Black Start? No

Forward Reserve? No

Nominal kW: **87 kW** The historical St Lawrence entitlement was used.

Capacity Cost: The contract is subject to cost-of-service treatment and so changes are not known. For IRP modeling purposes historical capacity costs (and related cost net of NYPA re-bills) were escalated by inflation to derive forecasted capacity costs.

Market Cap kW: No change from historical market capacity values was assumed.

Capacity Factor: A historical average monthly capacity factor was used for future months.

Energy Price: The contract is subject to cost-of-service treatment and so changes are not known. For IRP modeling purposes historical energy costs were escalated by inflation to derive forecasted energy costs per MWh.

Resource Name	**Hydro Quebec ICC**
Expiration:	VPPSA's members have an ownership (life of asset) interest in the Phase I / II transmission path. For the purposes of this draft of the IRP model, and given the long lifespan of such assets, this resource has not been treated as expiring.
Dispatch:	Not applicable
EforD:	No longer used with new Forward Capacity Market rules
Type:	HQ000
Black Start?	No
Forward Reserve?	No
Nominal kW:	Based on market capacity value given the nature of the use of the asset.
Capacity Cost:	Currently included in the IRP model is a two year average actual average cost per market kW, escalated by inflation.
Market Cap kW:	The asset generally receives a market capacity credit during the months of March to November.
Capacity Factor:	Not applicable
Energy Price:	Not applicable

Resource Name	**VEPP Inc. BIOMASS (RYEGATE)**
Expiration:	October 2021
Dispatch:	Cap+7x24. The unit operates as base load. The unit provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	VB000
Black Start?	No
Forward Reserve?	No
Nominal kW:	The unit is rated at 20,500 kW and the current allocation for the utilities included in VPPSA's ISO-NE asset ID is 8.08% for an entitlement of 1,6579 kW.
Capacity Cost:	The unit is modeled with no capacity cost.
Market Cap kW:	An average of 17,686 kW was used based on FCM obligations.
Capacity Factor:	The monthly CF% in the model is based on assumptions from Engie
Energy Price:	Energy price assumptions (by year) are from the statewide contract document.

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Resource Name VEPP Inc. Hydro Units

Expiration: Varies. Unit contract expirations are calculated via a schedule and reflected in declining VEPP Inc. hydro nominal kW.

Dispatch: Cap+MorHyd Morrisville's multiple hydros were used as a proxy for the on and off peak hour proportions for the VEPP Inc. units. The units all provide market capacity.

EforD: No longer used with new Forward Capacity Market rules

Type: VH000

Black Start? No

Forward Reserve? No

Nominal kW: VPPSA has used the nominal ratings for the VEPP Inc. hydro ratings posted on the VEPP inc. web site. VPPSA's current share is 7.59%. VPPSA entitlement share of 40,652 kW is assumed as continuing and decreases as contracts retire.

Capacity Cost: The VEPP Inc. hydro units are not modeled as having a capacity cost.

Market Cap kW: The market capacity provided by the VEPP Inc. hydro units is based the intermittent hydro ratings registered for the VEPP Inc. hydro units in the Forward Capacity Market. All market capacity has been calculated through the use of a table to reflect VEPP Inc. contract expirations over time.

Capacity Factor: The monthly VEPP Inc. capacity factor was provided by the VEPP Inc

Energy Price: The energy price by month was calculated based on information provided by VEPP Inc.

Resource Name	**McNeil**
Expiration:	Life of unit
Dispatch:	Monthly capacity factor based on past 3 year average actual run pattern for plant by month. Assumed dispatch would model historic run pattern. Dispatch tied to variable energy costs (wood. ash, rail, etc) and compared to projected LMP. McNeil also provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	BM100 – 100% of REC values due to CT Class I qualification.
Black Start?	No
Forward Reserve?	No
Nominal kW:	50,000 kW VPPSA's 16% entitlement is 8,000 kW
Capacity Cost:	Demand value consists of debt service schedule and fixed demand charges for the plant. Debt service ends June 2015. Fixed costs based on 5 year budget of operations, maintenance, transmission, A&G, insurance, taxes, and other fixed costs.
Market Cap kW:	The McNeil plant has a summer claimed capability of 52,000 kW and a winter rating of 54,000 kW. VPPSA has an entitlement of 16% or 8,640 kW.
Capacity Factor:	Monthly average capacity factors are based on a 3 year monthly average. If sensitivity to assumption changes are being tested, McNeil's capacity factor is adjusted by the same adjustment as is used for natural gas (up to a maximum capacity factor of 75%). This adjustment is made under the assumptions that natural gas (vs. heat rate) changes have the largest effect on market prices and McNeil's fuel is not equally volatile. Significant changes in market energy prices should result in increase in McNeil operations up to limitations imposed by fuel delivery restrictions.
Energy Price:	Assumed based on existing variable costs.

Resource Name	**Hydro Quebec**	
Expiration:	By Schedule:	
	Schedule B	October 31, 2015
	Schedule C3	December 31, 2015
	Schedule C4a	October 31, 2016
	Schedule C4b	October 31, 2020
Dispatch:	Special (Cap+HyQu) – assumed to be present in all on peak hours of specified months with residual energy up to scheduled CF occurring in off-peak hours. Resource provides market capacity.	
EforD:	No longer used with new Forward Capacity Market rules	
Type:	HQ000 – Unique (HQ) with no REC properties	
Black Start?	No	
Forward Reserve?	No	
Nominal kW:	Per contract / schedule	
Capacity Cost:	Assumed constant at current contract levels. The capacity for each contract schedule can be adjusted every five years (on a staggered schedule – i.e. all contracts do not change on the same years). History has shown that upward and downward adjustments are possible under the adjustment formula so no change has been assumed.	
Market Cap kW:	The HQ schedules are assumed to provide their full entitlement as market capacity under the current and proposed rules.	
Capacity Factor:	The most recent submitted monthly CF% schedule has been used and assumed to continue.	
Energy Price:	Contract rates are subject to adjustment annually. HQ energy rates for the IRP have been assumed to inflate from current contract rates by the inflation rate every contract year (November to October).	

Resource Name	**Stony Brook Intermediate Units 1A, 1B, 1C**
Expiration:	The contracts are life of unit.
Dispatch:	Cap+5x16. Stony Brook is assumed to generate energy only during on-peak periods. Stony Brook provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	OG000
Black Start?	Yes
Forward Reserve?	No
Nominal kW:	The combined rating of the three identical units is approximately 350 MW nominal. VPPSA's members hold entitlement to 2.201% of each unit through a combination of purchase power agreements and ownership interest. Accordingly a nominal kW (VPPSA) of approximately 2,600 kW per unit was used in the IRP model.
Capacity Cost:	VPPSA has used an average (post bond retirement) capacity cost increased annually for inflation from MMWEC's most recent budget for the IRP model.
Market Cap kW:	The average claimed capability for each of the three units has been normalized to average monthly values.
Capacity Factor:	A historical average capacity factor for the units was used. The period selected for the average was all monthly values after March 2003. The extreme minimum and maximum values for each month were excluded from the averages.
Energy Price:	The energy price included in the IRP model for Stony Brook is that used in the 2015-19 VPPSA budget. It was derived using the CME Groups natural gas price forecast and Stony Brook's planning heat rate of 8,800. These monthly price forecasts for natural gas were multiplied by the assumed heat rate of 8,800 to derive a base case energy price forecast (monthly) for Stony Brook.

Resource Name	**Yarmouth (Wyman)**
Expiration:	The contract is life of unit.
Dispatch:	Cap+5x16. Yarmouth is assumed to generate energy only during on-peak periods. Yarmouth provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	OG000
Black Start?	No
Forward Reserve?	No
Nominal kW:	618 MW. VPPSA's entitlement of the total capacity is 0.033%.
Capacity Cost:	No capacity costs were assumed. Unit is modeled on its energy rate due to limited information contained in FPL invoices detailing variable vs. non-variable costs. This information is being researched to obtain greater detail on this resource.
Market Cap kW:	The Claimed Capability for the unit runs very close to its nominal rating so the same value is used
Capacity Factor:	The unit was modeled as having a similar capacity factor to the Stony Brook unit due to limited information and its similar nature as a marginal unit in the pool. The capacity factor for Stony Brook is very similar to planning capacity factors for Yarmouth.
Energy Price:	Historical pricing was used inflated each year by the inflation rate in the model.

Resource Name: Swanton Hydro (Highgate)

Expiration: Life of unit

Dispatch: Cap+SwaH The percent of energy on and off peak was determined based on average values. The units provide market capacity.

EforD: No longer used with new Forward Capacity Market rules

Type: IH100 – 100% of Hydro Class II REC value. Note: At this time, VPPSA is assigning low-value Class II REC's to all existing hydros. In the event that a new hydro became available, or an existing unit needed to model increased output that would qualify for Class I REC status, the forecast price for REC's would be set to Class I values and the amount of output qualifying for REC treatment from existing resources would be modeled in a manner similar to that used in McNeil.

FERC licence Expiration: 4/30/2024

Black Start? No

Forward Reserve? No

Nominal kW: 11,392 kW

Capacity Cost: Not modeled in IRP

Market Cap kW: Under the Forward Capacity Market, the unit's winter and summer FCM intermittent values are used.

Capacity Factor: Monthly average capacity factors based on 10 year average monthly generation and the nominal unit kW.

Energy Price: Not modeled in IRP

Resource Name	**Morrisville Hydro Units** HK Sanders (Green River) Cady's Falls Morrisville Plant #2
Expiration:	Life of units
Dispatch:	Cap+MorH The percent of energy on and off peak was determined based on average values for the units. The units provide market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	IH100
FERC licence Expiration:	
Black Start?	No
Forward Reserve?	No
Nominal kW:	HK Sanders 1,800 kW Cady's Falls 1,400 kW Morrisville Plant #2 1,800 kW
Capacity Cost:	Not modeled in IRP
Market Cap kW:	The units' value is based on their Forward Capacity Market obligation through 2018. The June 2017-May2018 values are carried forward into the future.
Capacity Factor:	Monthly average capacity factors based on 5-10 year averages, depending on plant, of monthly generation and the nominal unit kW.
Energy Price:	Not modeled in IRP

Resource Name: Barton Hydro

Expiration:	Life of unit
Dispatch:	Cap+BarH The percent of energy on and off peak was based on average values for the unit. The units provide market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	IH100
FERC licence Expiration:	10/1/2043
Black Start?	No
Forward Reserve?	No
Nominal kW:	1,400 kW
Capacity Cost:	Not modeled in IRP
Market Cap kW:	The unit's winter and summer FCM intermittent values are based on FCM obligation through 2018, carried forward throughout the life of the unit.
Capacity Factor:	Monthly average capacity factors based on 10 year average monthly generation and the nominal unit kW.
Energy Price:	Not modeled in IRP

Resource Name: Lyndonville Hydro (Vail & Great Falls)

Expiration:	Life of unit
Dispatch:	Cap+LynH The percent of energy on and off peak was determined based on average values for the unit. The unit provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	IH100
FERC licence Expiration:	02/28/2034 and 05/31/2019
Black Start?	No
Forward Reserve?	No
Nominal kW:	2,400 kW
Capacity Cost:	Not modeled in IRP
Market Cap kW:	The unit's winter and summer FCM intermittent values are based on FCM obligation through 2018, carried forward throughout the life of the unit.
Capacity Factor:	Monthly average capacity factors based on 10 year average monthly generation and the nominal unit kW.
Energy Price:	Not modeled in IRP

Resource Name:	**Wolcott Hydro (Hardwick)**
Expiration:	Life of unit
Dispatch:	Cap+HarH The percent of energy on and off peak was determined based on average values for the units. The units provide market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	IH100
Black Start?	No
Forward Reserve?	No
Nominal kW:	815 kW
Capacity Cost:	Not modeled in IRP
Market Cap kW:	The unit's winter and summer FCM intermittent values are based on FCM obligation through 2018, carried forward throughout the life of the unit.
Capacity Factor:	Monthly average capacity factors based on 10 year average monthly generation and the nominal unit kW.
Energy Price:	Not modeled in IRP

Resource Name	**Barton Diesels**
Expiration:	These units are no longer operational. However, the unit continues to receive capacity benefits as they retain a forward capacity obligation through the 2018-19 capacity year.
Dispatch:	Cap+5x16. The resource only receives capacity benefits.
EforD:	No longer used with new Forward Capacity Market rules
Type:	OG000
Black Start?	No
Forward Reserve?	No
Nominal kW:	The two units were rated at 350 kW each (700 kW combined).
Capacity Cost:	Not modeled in IRP
Market Cap kW:	FCA Obligation through 2018-2019.
Capacity Factor:	The capacity factor is set to zero because the units are no longer opertaional.
Energy Price:	The energy price is set to zero because the units are no longer operational.

Resource Name: Enosburg Falls Hydro

Expiration:	Life of unit
Dispatch:	Cap+EnoH The percent of energy on and off peak was determined based on average values for the unit. The units provide market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	IH100
FERC licence Expiration:	04/30/2023
Black Start?	No
Forward Reserve?	No
Nominal kW:	975 kW (600 kW Village Plant#1, 375 kW Kendall)
Capacity Cost:	Not modeled in IRP
Market Cap kW:	The unit's winter and summer FCM intermittent values are based on FCM obligation through 2018, carried forward throughout the life of the unit.
Capacity Factor:	Monthly average capacity factors based on 10 year average monthly generation and the nominal unit kW.
Energy Price:	Not modeled in IRP

Resource Name	**MARKET ENERGY CONTRACTS**
Expiration:	By contract terms.
Dispatch:	By contract terms.
EforD:	No longer used with new Forward Capacity Market rules
Type:	FS000
Black Start?	No
Forward Reserve?	No
Nominal kW:	By contract terms.
Capacity Cost:	By contract terms.
Market Cap kW:	Market energy contracts do not provide market capacity.
Capacity Factor:	By contract terms.
Energy Price:	By contract terms.

Resource Name	**Project 10**
Expiration:	Life of unit and runs through the modeling period.
Dispatch:	Cap+5x16 The unit is assumed to operate only during on peak hours. The unit provides market capacity.
EforD:	No longer used with new Forward Capacity Market rules
Type:	OG000
Black Start?	Yes
Forward Reserve?	Yes
Nominal kW:	40,000 kW.
Capacity Cost:	$7.00 kW-mo beginning in 2015.
Market Cap kW:	39,163 kW, based on FCM obligation through 2017-18, then held constant.
Capacity Factor:	Assumed nearly zero CF thereby limiting contribution to energy outlook.
Energy Price:	Limited dispatch, only at very high energy prices.

Resource Name HQUS

Expiration: 6 different MW expirations. Contract runs from November 1, 2012 – October 31, 2018. Total contract (prior to VPPSA allocation model as):

- 25,000 kW from November 1, 2012 to October 31, 2015
- 187,000 kW from November 1, 2015 to October 31, 2016
- 212,000 kW from November 1, 2016 to October 31, 2020
- 218,000 kW from November 1, 2020 to October 31, 2030
- 218,000 kW from November 1, 2030 to October 31, 2035
- 56,000 kW from November 1, 2035 to October 31, 2038

Dispatch: 7X16. The contract does not provide market capacity.

EforD: No longer used with new Forward Capacity Market rules

Type: FS000

Black Start? Yes

Forward Reserve? Yes

Nominal kW: Variable.

Capacity Cost: Not applicable.

Market Cap kW: Not Applicable

Capacity Factor: 66.67%.

Energy Price: This is a market following contract with a variable energy price.

Resource Name	**Chester Solar**
Expiration:	This contract is life of unit (2039)
Dispatch:	Cap+Solar.
EforD:	No longer used with new Forward Capacity Market rules
Type:	SL000
Black Start?	No
Forward Reserve?	No
Nominal kW:	4.408
Capacity Cost:	Not applicable.
Market Cap kW:	Beginning in 2018, 1,904 kW based on FCA obligation, summer only. Declines by .5% per year for assumed panel degradation.
Capacity Factor:	Varies by month based on estimated production.
Energy Price:	Beginning in 2015, $76.66/MWh, declining in 2024 to $72.62/MWh

Resource Name	**Seabrook 1**
Expiration:	2034.
Dispatch:	Cap+7X24
EforD:	No longer used with new Forward Capacity Market rules
Type:	NU000
Black Start?	No
Forward Reserve?	No
Nominal kW:	600kW 2019-2020; 520 kW 2021-2028; 320kW 2029-2034
Capacity Cost:	Starts at $3.24 in 2015, increasing by inflation.
Market Cap kW:	Same as Nominal.
Capacity Factor:	100%
Energy Price:	Market price forecast with applicable shaping factors as set forth in the PPA.

Resource Name	**Fitchburg Landfill Gas**
Expiration:	2031
Dispatch:	Cap+7x24
EforD:	No longer used with new Forward Capacity Market rules
Type:	LG000
Black Start?	No
Forward Reserve?	No
Nominal kW:	3,000kW through 2016, then 4.5MW
Capacity Cost:	Not applicable.
Market Cap kW:	Uses FCA obligation through CP 2017-18, then holds capacity value constant through the 10th year of the contract (2021). Starting 2022 this value reflects the most recent Qualified Capacity
Capacity Factor:	Declines starting in 2017 on assumption of reduced output.
Energy Price:	$90/MWh through 2021, $85/MWh 2022-2026, $95/MWh 2027-2031

Resource Name	**Standard Offer**
Expiration:	Varies. This is the aggregation of the state standard offer projects.
Dispatch:	7x24
EforD:	No longer used with new Forward Capacity Market rules
Type:	SO000
Black Start?	No
Forward Reserve?	No
Nominal kW:	Varies, starting at 46,435 kW in 2015 rising to 124,486 by 2030 before beginning to decline as projects reach the end of their useful life.
Capacity Cost:	Not applicable.
Market Cap kW:	Not applicable.
Capacity Factor:	Varies due to timing of unit end of life and degradation of generation.
Energy Price:	Varies.

KEY VARIABLE ASSUMPTIONS

This section describes the base case sources for key variables examined, along with the assumed value, description of the justification for sensitivity parameters, and provides any appropriate discussion. The method for estimating the probability of a sensitivity occurring was described in Section 5.3.

Variable Name: **Natural Gas – New England**

Base Case Source: CME Group NYMEX market published market prices.

Assumed Value: Ranging from $4.22 per MMbtu in 2015 to $6.69 per MMbtu in 2024. After 2024 the forecast of natural gas was held constant (in terms of 2014 dollars). VPPSA has inflated the nominal gas prices for 2022 on by the inflation index in use in the IRP model to mirror this treatment.

Entry Area: "Price Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: Assumed ± two standard deviations.

Discussion: The relationship between spot market electricity prices in New England and wholesale natural gas prices is strong. In addition price volatility has been a major concern in the wholesale power markets as well. Therefore, relying on wholesale power markets to replace significant portions of expiring resources can be seen as problematic.

Variable Name: **<u>Pool Implied Heat Rate</u>**

Base Case Source: Calculated from JP Morgan historical Mass hub energy prices and historical Algonquin City-gates energy prices

Assumed Value: Ranging from 8.68 in 2015 to 6.67 in 2024

Entry Area: "Price Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: Assumed ± two standard deviations.

Variable Name: **<u>VT Renewable Energy Standard</u>**

Base Case Source: Vermont Renewable Energy Standard Total Energy, Distributed Generation, and Energy Transformation requirements (referred to in the model as Class I, II, and III) have a base case equivalent to that included in Act 56 of 2015.

Assumed Value: Class I assumes 55% in 2017 increasing to 75% requirement in 2032. Class II assumes 1% in 2017 increasing to 10% in 2032, with Class II being a subset of Class I. Class III assumes 2% in 2019 increasing to 12% in 2034.

Entry Area: "Load Forecast" Sheet of IRPResults4 spreadsheet.

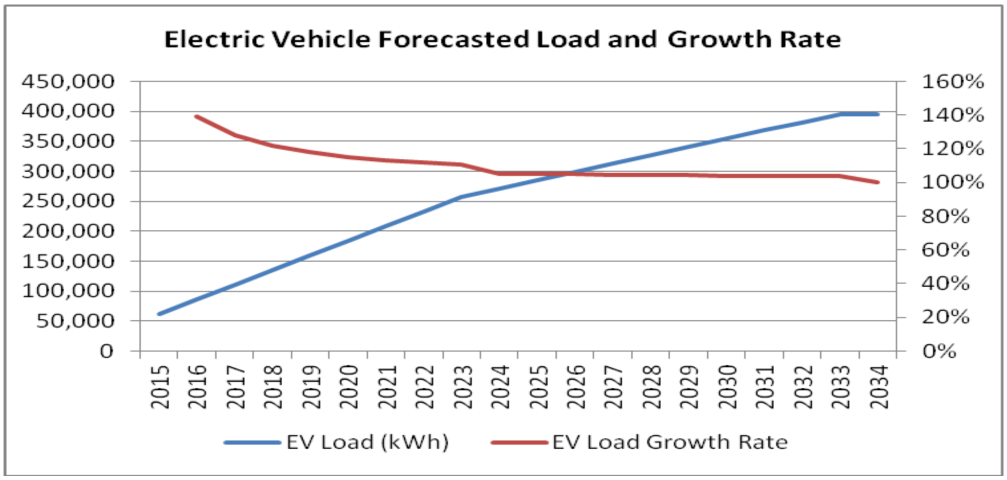
Sensitivity: The sensitivity applied was a political removal of the Renewable Energy Standard (0% requirement) and a stiffening of the requirement by 75%.

Discussion: Given the political nature of a Renewable Energy Standard, it is prudent to examine a wide range of potential changes to the requirements.

Variable Name: **<u>Electric Vehicles</u>**

Base Case Source: Vermont Energy Investment Corporation (Drive Electric Vermont) - VTrans EV Charging Plan (7/11/2013)

Assumed Value: Forecast load begins at 63MWh in 2015, increasing dramatically for the first 10 years as electric vehicle penetration increases. The load from electric vehicles levels off as the market becomes more saturated and battery technology is assumed to improve.



Entry Area: "Load Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: Low sensitivity set to 50% of expected load, high set at 140% of expected load from electric vehicles.

Variable Name: **<u>RNS Rates</u>**

Base Case Source: Published ISO-NE estimated RNS rates from 2015-18, escalated by the average rate of increase from 2015-2018. (5.84%)

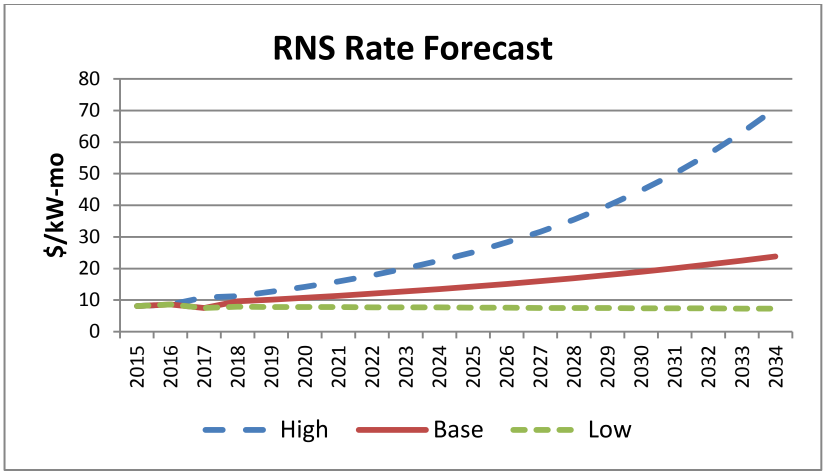
Assumed Value: $8.08 per kW-month increasing to $23.77 per kW-month in 2034.

Entry Area: "Price Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: **+/-** 2 standard deviations from historical 2000-2014 RNS Rates linear line of best fit.

Discussion: The past 5-10 years have seen significant regional investments in transmission infrastructure in New England. According to the ISO-NE 2014 Regional System Plan, there was $6 billion of transmission investment since 2002, with another $4.5 billion planned in the near future, a near doubling of in-service value of regional transmission. Instead of having a significant jump in rate followed by a small increase, the forecast smoothed the increase in RNS charges based on the average annual rate of increase over a number of years.

In order to determine the high and low cases, RNS rates were graphed relative to a linear line of best fit. The standard deviation was calcluated bsed on the annual difference between this line of best fits and the actual RNS rate. The below chart shows the resulting base, high, and low cases. While the high case appears to be extreme in this analysis, it was determined that it was a reasonable outcome considering that the RNS rate has increased by a multiple of 7 since 2000. With the potential for RNS rate to cover non-electric infrastructure (such as gas pipelines) and/or "public policy" transmission along with traditional load growth and asset condition related investments, another 7x increase within 20 years is within the realm of possibility.


RNS Rate Forecast
$/kW-mo
80
70
60
50
40
30
20
10
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
High
Base
Low

Variable Name: **Capacity Load Obligation**

Base Case Source: Load forecast (see forecast description for details on its creation) increased by the objective capability adjustment of 29.11%. This is the basis on which ISO-NE issues capacity charges for load.

Assumed Value: Just over 80MW increasing to 82.5MW in 2034.

Entry Area: "Load Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: **+/-** 2 standard deviations

Variable Name: **<u>Monthly Peak (Trans.)</u>**

Base Case Source: The monthly peak value is developed in the forecast as described in Section 4.5. This value is multiplied by the assumed Transmission, Regional Network Service Charge, and other appropriate rates to create a value for these Non-Energy Charges.

Assumed Value: Varies by month.

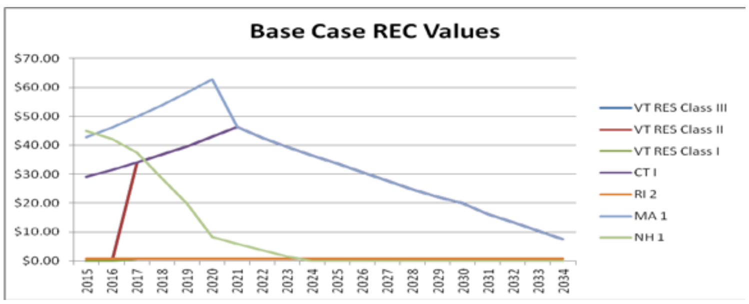
Entry Area: "Load Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: **+/- 10%**

Variable Name: **<u>Renewable Energy Credits</u>**

Base Case Source: Bloomberg New Energy Finance H1 2015 US REC Market Outlook for CT and MA REC prices. Vermont "Class II" (Distributed Generation Requirement) and "Class III" were assumed to be equivalent to Connecticut Tier I Renewable Energy Credits. Vermont Class I ("Total Energy") Tier assumed to be consistent with Rhode Island Tier 2.

Assumed Value: The chart below illustrates the assumed base case values for REC prices.



Entry Area: “Price Fcsts Pre Sensit" tab of IRPResults4 spreadsheet

Sensitivity: The low sensitivity is set at 10% of the base case price. It is prudent to consider the possibility of REC prices dropping significantly either through market mechanics or political operation. This possibility was illustrated by Maine Class 1 prices. In 2014, Bloomberg New Energy Finance predicted that Maine Class 1 prices would be $16.20/MWh. Less than one year later, they were trading at $1.50, a 90% reduction relative to the forecast.

The high sensitivity was set recognizing that REC prices are unlikely to rise materially above the Alternative Compliance Payment.

Discussion: In general, REC market prices are intended to settle at the difference between the levelized cost of new entry for a qualifying resource and the energy and capacity market payments that the resource could get from participating in regional marketplace. As technology costs continue to decline (particularly for solar PV) while energy prices stay constant or rise, the REC value should decline over time. However, the IRP model fixes the base case price as political change and market imperfections are expected to continue.

Variable Name: **<u>LMP Basis to Hub</u>**

Base Case Source: Jan 2010-May 2015 historical Hub price data relative to relevant nodes, by month.

Assumed Value: Varies by node.

Entry Area: “Basis Variance” Sheet of IRPResults4 spreadsheet.

Sensitivity: +/- two standard deviations of the difference between the Hub (4000) and VT zones (4003).

Discussion: Rates associated with energy resources adjusted depending on appropriate node where unit is located.

Variable Name: **FCM Clearing Prices**

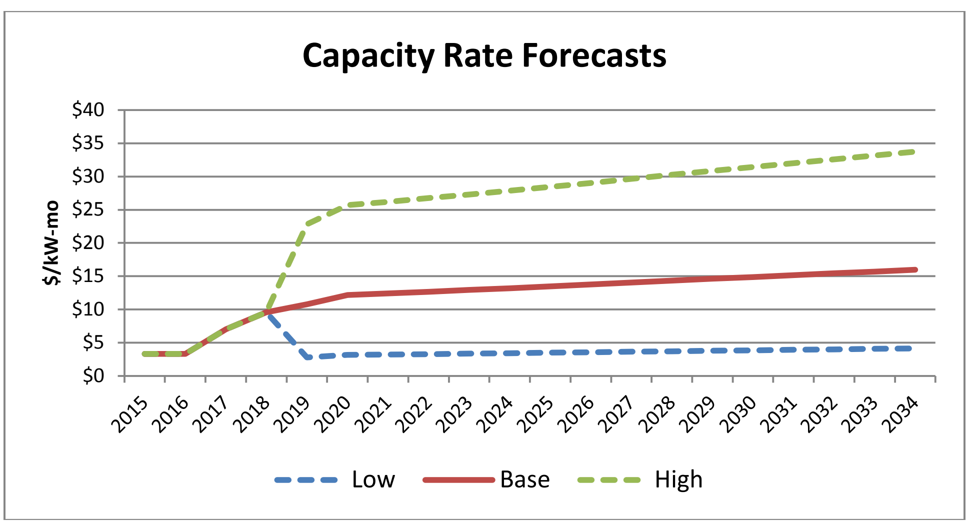
Base Case Source: Price set by auction through May 2019 according to the below table. The base price beyond 2019 was set consistent with the Avoided Costs approved by the Public Service Board in Docket 8010.

Assumed Value:

Auction Year	Capacity Rate ($/kW-mo.)
2015-16	$3.43
2016-17	$3.15
2017-18	$7.03
2018-19	$9.55

Entry Area: "Price Forecasts Pre Sensit" Sheet of IRPResults4 spreadsheet.

Sensitivity: + Three standard deviations, - two standard deviations. Calculated by historical deviation as percentage of the mean for the first 8 forward capacity auctions. This sensitivity represents a very wide variance from the base forecast, capturing on the upside the possibility of significant retirements from fossil units combined with higher than expected costs for new capacity, and capturing on the downside the extreme oversupply of capacity that could result from annual over purchase of capacity by ISO-NE. Notably, even with this significant variance, capacity rate forecasts were not the variable that caused the first or second larges swing in NPV for any scenario.



Variable Name: **Forward Reserve Market Projection**

Base Case Source: Expected FRM prices for 2015 and 2016, increased by inflation.

Assumed Value: $4.34/kW-month declining to $3.39/kW-month in 2016, then increasing by inflation.

Entry Area: "Price Fcsts Pre Sensit" Sheet of IRPResults4 spreadsheet.

Sensitivity: +/- two standard deviations, using historic standard deviation as a percentage of the mean for FRM auction clearing prices starting winter of 2006-7.

Variable Name: **Load Forecast**

Base Case Source: Base case forecasts are prepared by VPPSA.

Assumed Value: See Load Forecast section of this IRP.

Entry Area: “Load Forecast” Sheet of IRPResults4 spreadsheet.

Sensitivity: The Load Forecast variable is structured to stress the reaction of the load forecast to extreme weather conditions that may result from Climate Change. This variable is independent from the "Load Forecast Error" variable, which is distinguished in that the latter is intended to address structural changes in load due to the changing nature of customer's relationship with electricity and energy choices in general.

To develop the high Load Forecast case, the base case forecast models were modified by increasing the temperature 5° during the warmer 6 months of the year and decreasing the temperature 5° during the cooler 6 months of the year. We then determined the average annual percent increase in load that this resulted in among all systems (currently 3.7%). Because the model treats increases in CDDs/HDDs the same as decreases in CDDs/HDDs, theoretically a low case should have nearly the same percent departure as the high case, just in the opposite direction. Therefore we used that same percentage to stress the model to a low case as well (currently -3.7%).

Variable Name: **Load Forecast Error**

Base Case Source: Base case forecasts are prepared by VPPSA.

Assumed Value: See Load Forecast section of this IRP.

Entry Area: "Load Forecast" Sheet of IRPResults4 spreadsheet.

Sensitivity: A variance of 3% on both sides of the base case values were used for variance / sensitivity testing.

Discussion: The Load Forecast Error variable is intended to stress the forecast due to possible changes in the fundamental drivers in demand. As described in Section 4.6, continued energy efficiency programs, rapid net metering deployment, and the standard offer program have significantly changed the trajetory of consumption. As those transformations continue to materialize, other near term technologies and load management tools such as heat pumps or advanced rate design could further change the fundamental drivers of the load forecast. The load forecast is stressed to account for these potential changes that would affect load. See system descriptions for discussions on individual load forecasts.

Variable Name: <u>**Discount Rate**</u>

Base Case Source: Current cost of capital for VPPSA members.

Assumed Value: 3.25%

Entry Area: "Sensit Input Table" of IRPResults4 spreadsheet.

Sensitivity: **+- .5%.** This is within the expected range that VPPSA members may pay for capital.

Discussion: Testing variance on discount rate is intended to reveal if any potential resource configurations are more sensitive to discount rate assumptions (due to timing of benefits and costs) than others. The theory is that a large variance would indicate a plan where resource configuration's benefits (or costs) are heavily front end weighted.

Variable Name: <u>**Inflation**</u>

Base Case Source: Fifteen year average from January 2000 to Dec 2014.

Assumed Value: 2.145%

Entry Area: "Inflation" Sheet of IRPResults4 spreadsheet.

Sensitivity: The sensitivity was developed by using the standard deviation of inflation 1983 to 2014, divided by the mean. The range is set such that the low case assumes 1.06% inflation, while the high case assumes 3.23% inflation.

Discussion: Inflation is generally used in the VPPSA IRP model to provide future forecasts of variables that do not have specific projections but are expected to increase over time.

Appendix 2: Model Directions

CapEgyCalc5.xlsm – INPUT TEMPLATE

<u>Preliminary Steps / Setup</u>

1. Save the CapEgyCalc5.xlsm Spreadsheet and the IRPResults4.xls Spreadsheet into the same directory as each other.

<u>Global Information (Sheet "Initial")</u>

1. Select the Utility to be evaluated using the command button labeled "Select Utility". The model's default value is "VT Public Power Supply Authority."

2. Define the first and last years to be evaluated. 2015 is currently being used as the lead year.

3. Enter allowable types (generally fuel based) into the types table in cells J20:L30 of the "Initial" sheet.

4. Enter allowable suppliers into the suppliers table in cells J59:P89 of the "Initial" sheet. A supplier may provide multiple resources but totals by supplier will be provided in the output spreadsheet.

<u>Resource Data Inputs (Sheets "ResDef1" and "ResDef2")</u>

Supplier: Textual – must match a choice entered into the supplier list on cells J59:P89 of the "Initial" sheet.

Resource Name: Textual / Descriptive

ID(#): A short ***<u>unique</u>*** textual identifier for each resource.

Dispatch: Resource output must be characterized in terms of whether or not the resource provides capacity deliveries and how its energy deliveries are distributed on to off peak. This is done by selecting one (or a combination of) the following identifiers:

Cap: For capacity only
5x16 Energy deliveries weekdays HE8-HE23
7x16 Energy deliveries all days HE8-HE23
7x24 Energy delivery all days – all hours
OfPk Energy deliveries not included in 5x16

7x08 Energy deliveries all days HE1-HE7 and HE23
2x16 Energy deliveries weekends HE8-HE23
5x08 Energy deliveries weekdays HE1-HE7 and HE23
6733 Energy deliveries 2/3 on peak – balance off peak
6040 Energy deliveries 60% on peak – balance off peak
7030 Energy deliveries 70% on peak – balance off peak
BarH Energy deliveries based on historical Barton hydro data
EnoH Energy deliveries based on historical Enosburg hydro data
HarH Energy deliveries based on historical Hardwick hydro data
LynH Energy deliveries based on historical Lyndonville hydro data
MorH Energy deliveries based on historical Morrisville hydro data
SwaH Energy deliveries based on historical Swanton hydro data
HyQu Maximizes on peak deliveries – balance (to contract CF) to off peak
McNe Maximizes on peak deliveries – balance (to normal CF) to off peak
Niag Energy deliveries based on historical Niagara hydro data
StLa Energy deliveries based on historical St Lawrence hydro data
Pkr Energy deliveries weekdays HE8-HE23
Sola Energy deliveries based on a solar profile using PV watts
Wind Energy deliveries based on a past wind project contemplated for East Mountain

For units providing both capacity and energy the identifier would be combined as shown in the following example:

Cap+5x16 For a unit providing capacity and energy during the ISO-NE peak period

EforD: The Equivalent Forced Outage Rate "EforD" is used to de-rate the market capacity value for a unit. This is no longer used.

Type: Textual – must match a choice entered into the types listed in cells J20:L30 of the "Initial" sheet. As part of the type a three numeral designation indicating the percent of Renewable Energy Credits "RECS" should be indicated. For example:

BM050 Would indicate a biomass facility with 50% of its output qualifying for REC treatment.

Black Start? Yes/No depending on whether or not the unit is expected to be accepted into, to receive payments from, the ISO-NE system restoration tariff.

Forward Reserve? Yes/No depending on whether or not the unit is expected to participate in and receive payments from the ISO-NE Forward Reserve auction process.

Nominal kW: The nominal capacity by month/year should be entered. It is this capacity that will be used in combination with the capacity charge per kW to determine capacity costs by resource, and in combination with the capacity factor by month to determine energy deliveries.

Capacity Cost: Should be in nominal dollars by year (as opposed to constant year costs) and is used in combination with the Nominal kW to determine annual capacity costs.

Market Cap kW: The units market capacity value. Under the Forward Capacity Market "FCM", the ratings are the summer and winter qualified capacity by month.

Capacity Factor: The expected monthly capacity factor the unit will provide in terms of energy delivered in proportion to its Nominal kW rating and the hours in the month.

Energy Price: Should be in nominal dollars by year (as opposed to constant year costs) and is used in combination with the Nominal kW and Capacity Factor to determine annual energy costs.

Resource Data Inputs (Sheet "UAP")

This table allows the aggregate results for any scenario to be recreated for a specific utility as long as all resources have been allocated to utilities. For each resource enter the following information:

ID(#) Must match (exactly) the same information for one of the resources on either sheets ResDef1 or ResDef2.

Utility Identifier: A unique 3 letter code for each utility

Utility Name: A detailed name for each utility. At this time, generic (or planning) resources are treated as belonging to a fictional VPPSA utility (PLA) with this fictional utility possessing 100% of the entitlement to these resources. This allows planning resources to be quickly "turned on" or "turned off" by entering 0% allocation to PLA.

Utility Number: A unique numeric identifier for each utility. Currently these are set to the VELCO utility ID's.

VPPSA: Each utility can be identified as belonging to VPPSA or not. In the block below the utility name, enter "VPPSA" or leave the field blank.

Allocation percent: For each resource – utility – month combination an entitlement (in percent) should be entered. Allocations should total to 100% on the rows labeled "All" (Rows 10-21). The combined VPPSA entitlement (Rows 22-33) need not total to 100% if there are non-VPPSA utilities entered in the model as there are now.

Energy Delivery / Dispatch (Sheet "OnOffHr")

Seven standard dispatch shapes (allocations of energy to on and off peak hours) are provided and fifteen more custom shapes may be defined. Each dispatch shape must have a unique identifier that is the entered on the ResDef1 and ResDef2 sheets for appropriate resources.

Other Purchased Power Expenses (Sheet "NonEgyChgs")

In order to provide as complete a picture as possible of purchase power expenses and the relative effects of decisions, costs for non-modeled items such as:

Ancillary Markets
Transmission Charges
Other Charges

The projected costs for these items are entered from VPPSA's most recent detailed budgets. This information will be exported to the results spreadsheet where it is converted into average costs per kWh of load and increased by inflation to extended it into the future.

Load Forecasts (Sheet "Load")

For each utility the following information is entered:

Utility Name: Must match a utility name from the "UAP" sheet.

Utility ID: Must match a 3 letter code from the "UAP" sheet.

Demand: Annual peak demand at the system inlet.

Energy: Annual total system load at the system inlet (this includes loads served by generating resources internal to the system).

Sub-transmission Losses: Losses between the system inlet and the VELCO transmission system in percent. Generally defined in the transmission providers applicable tariff. Sub-transmission losses are utility specific.

On Pk Energy: The percent of the forecast load expected to occur in the ISO-NE defined on peak hours. Percent of load on peak is utility specific.

VELCO Losses: VELCO transmission losses (TNL) are entered as a percent. Due to somewhat unusual accounting for low voltage PTF losses these can be negative. These losses are applied to all utilities.

Other Losses: Two other entry areas are allowed for transmission losses but are not currently in use. These losses would be applied to all utilities.

Objective Capability Adjustment: This is used to convert forecast system peak to UCAP obligation. .

Exporting Data To The Results Spreadsheet

1. Check that all of the user input data (shown in blue) on the Initial Worksheet as well as the other worksheets is as you wish. Make any necessary changes.

2. Select the desired utility (or group) you wish to calculate. Use the command button at Cell "I7" to provide a list of candidates for selection. The utility identification information is entered via the user's selection from this list.

3. Push the "Resources Defined" command button to populate the list and the "Get Resource Data" command button on the Initial Worksheet to initiate the calculation of the IRP Results Spreadsheet. The results, based on the data in the CapEgyCalc5 Spreadsheet, the user's selections, and the minimal data recorded on the blue tab worksheets of the IRP Results Spreadsheet, will be automatically presented to the user for review.

<u>REMINDERS:</u>

a. The IRPResults4.xls Spreadsheet must be an existing file. The CapEgyCalc5.xlsm Spreadsheet will not create, from scratch, a results spreadsheet. Make the information changes you require on the blue tab worksheets of the IRPResults4.xls Spreadsheet, which is of a generic nature (i.e., REC values, inflation information, projected market capacity and energy prices), before you run the CapEgyCalc5 Spreadsheet. Note, all of the results contained on the IRPResults4.xls Spreadsheet are calculated from the user defined data/choices selected on the CapEgyCalc5.xlsm Spreadsheet each time the spreadsheet is run. An existing IRPResults4.xls Spreadsheet is required as it is used in formatting the results and certain calculations are based on spreadsheet formulas rather than code calculations. (An expedient to keep programming costs down.)

b. Before running the CapEgyCalc5.xlsm Spreadsheet (i.e., "pushing" the "Get Resource Data" button), make sure that the IRPResults4.xls Spreadsheet that will be calculated (i.e., that indicated in Cell "E10") is closed. An error will occur otherwise.

IRPRESULTS4.xls– OUTPUT TEMPLATE

This spreadsheet does not possess macros. Once the data is input from the CapEgyCalc5 spreadsheet, the base case results are available. Performing Sensitivity analysis requires an inexpensive add-in called ***SensIt*** that tests the base case results for sensitivity to changes in identified key variables.

General Notes:

SensIt (an inexpensive Excel add-in) is required to perform sensitivity analysis but is not required for interim results and base case power costs by year.

1. Table of Contents Sheet

This sheet lists the sheets (tabs) of the IRPResults4 spreadsheet in the order that they appear. Command buttons allowing quick navigation to important sheets (and sheets "buried" deep in the workbook) are provided and if clicked will take the user directly to the sheet in question.

2. Inflation Estimate (Based on Consumer Price Index)

This sheet only requires periodic update. Currently inflation is set at 2.145% and based on the average change annually between January 2000 and January 2014.

2. *SensIt* Variable Ranges

If *SensIt* (an Excel add-in) is installed, this table allows the user to input sensitivity ranges around the base case for each variable and to output the "swings" or changes in base case results from increasing and decreasing the key variable from base case to each extreme.

3. Price Forecasts Pre *SensIt* Adjustment

This page contains the inputs prior to any adjustments from the *SensIt* add-in and requires extensive data entry in the form of forecasts for:

- Natural Gas Prices
- New England Effective Heat Rates
- Forecasts of market capacity prices,
- Forecasts of Forward Reserves auction values
- Forecasts of Transmission Benefit payments (Blackstart)
- REC credit values by type
- Forecasts of Regional Network Service rates

4. Price Forecasts

This page is in an identical format to the Price Forecasts Pre *SensIt* Adjustment but incorporates any *SensIt* driven changes to the cells highlighted in olive green.

5. Load Forecast

Imports (and *SensIt* adjusts) the energy forecast for the system identified in the CapEgyCalc5 spreadsheet. Also converts the peak demand forecast to a UCAP obligation forecast using the Objective Capability Adjustment. This tab also includes the new Vermont Renewable Energy Standard Assumptions

6. Basis Variance

This sheet shows the average difference in prices between nodes where resources are credited and the Massachusetts Hub price. This allows for different pricing for resources while using a single forecasted price provided by CME Group and modified by VPPSA for outer years.

7. Resource Entitlements (kW)

This sheet shows, by resource and year, the entitlement in each resource for energy purposes only. This is used in combination with the CF% to arrive at energy by resource and year. The kW entitlements shown here do NOT represent market capacity. For example, an energy-only market contract would show a nominal entitlement on this spreadsheet while a market capacity-only contract would not.

8. Annual Energy Availability/Capacity Factor (%)

This sheet is used to derive annual energy from each resource.

9. Energy Availability Adjustments

Allows wholesale changes to the availability of a resource by turning it off (0%). The default is 100%.

10. Energy Rates ($/MWh)

This sheet is used to derive annual energy costs by resource by year.

11. Energy Rate Adjustments

Identifies and incorporates any *SensIt* based adjustments to Energy Charges. Cells currently subject to such changes are shaded in olive green. A value of 100% represents no change from base case assumptions.

12. Capacity Rates ($/kW-Year)

This sheet is used to derive annual capacity costs by resource by year.

13. Capacity Rate Adjustments

Identifies and incorporates any *SensIt* based adjustments to Energy Charges. Cells currently subject to such changes are shaded in olive green. A value of 100% represents no change from base case assumptions.

14. Market Capacity (kW)

This sheet shows the gross (before EforD) market capacity entitlement for the peak month (currently August) by resource by year.

15. Capacity eFOR'D UCAP Value Factor (%)

This sheet summarizes the EforD (which serves to reduce available capacity from resources) for each resource and is no longer relevant

16. Capacity Entitlement/UCAP (kW)

This sheet shows the market capacity entitlement by resource by year as reduced to account for EforD.

17. Forward Reserve Entitlement (kW)

This sheet shows the kW value of any resource identified as providing Forward Reserve service.

18. Black Start Entitlement (kW)

This sheet shows the kW value of any resource identified as providing System Restoration (Black Start) service.

19. Energy Entitlements (kWh)

This sheet shows the summary of the on and off peak deliveries from the next sheet

20. Allocation of Energy Entitlements to On/Off-Peak Periods (kWh)

This sheet shows the deliveries by resource and year into the on and off peak periods (based on the ISO-NE definition of these periods).

21. Energy Charges ($)

This sheet shows the cost for energy by resource and year.

22. Energy Credits ($)

This sheet shows the payments for energy deliveries (at LMP) by resource by year.

23. Capacity Charges ($)

This sheet shows the cost for capacity by resource and year.

24. Capacity Credits ($)

This sheet shows the payments for deliveries of capacity (at the forecast market capacity price) by resource by year.

25. Forward Reserve Credits ($)

This sheet shows any forecasted resource payments for participation in the Forward Reserve markets.

26. Trans Credits) ($)

This sheet shows any projected payments for resources providing system restoration service.

27. Renewable Credits by Category (REC)

This sheet shows any projected resource revenues for sales of REC's.

28. Non-Energy Costs ($ or $/kWh)

This sheet shows the estimated non-resource purchase power costs (such as transmission, ancillary markets etc.)

29. Power Costs ($)

This is the main output for the model and provides total forecast of Purchase Power costs. Note that costs for units owned and operated by the VPPSA utilities do not appear in the Purchase Power FERC account and are not modeled here.

30. Energy t by Category (kWh & %)

This sheet provides an annual summary of energy by type (generally fuel) and assumed spot market energy purchases. This sheet is useful for monitoring fuel diversity.

31. Energy by Supplier (kWh & %)

This sheet provides an annual summary of energy by supplier and is useful for monitoring supplier diversity.

32. Resources by Category

Chart of this data.

33. UCAP by Source / Capacity Obligations vs. Resources

Chart of this data.

34. *SensIt* 1.31 Probabilistic Results

This is an output of the *SensIt* analysis and a conversion of that output to probabilistic results.

IRP_Run_Assumptions.xlsm – OUTPUT AUTOMATION TEMPLATE

This workbook was created to allow for the user to perform multiple iterations of resource mixes with summarization worksheets created to quickly view the results. This workbook is intended to be the starting point for a user wishing to obtain output from the IRP model once all adjustments have been made to the source files "CapEgyCalc5.xlsm" and "IRPResults4.xls." The details of the workbook are described below on a sheet by sheet basis.

General Notes:

- This workbook requires that the locations of the files "CapEgyCalc5.xlsm" and "IRPReults4.xls" are in the same directory as IRP_Run_Assumptions.xlsm.

1. Assumptions

This worksheet is the main worksheet for this workbook. The large button titled "Run Scenarios and Summarize" is what is used to create up to 25 different scenarios. The user must change only the box directly to the left of the button (Cell "H18") with the desired number of scenarios. The routine will create a file titled "IRP_Run_Assumptions_MM_DD_YYYY.xls" in the scenarios output folder. This file will contain summary information on all the runs as well as their corresponding tornado charts. In addition to this summary file, A full scenario detail file will be saved in the same "Scenarios" directory as "IRPResults4_Scenario_ MM_DD_YYYY _X.xls" for every scenario, where "X" stands for the Scenario number. This process will take on average 1 - 2 minutes for every scenario chosen, so for large runs of 25 scenarios be prepared to wait while the routine chugs along. The following descriptions explain the worksheet in more detail. Cell ranges that do not require user input have been put in italics.

a. CapEgyCalc5 and IRPResults4 must be in the same folder as this file

b. The output will be in a Scenarios folder within the folder this file is in. This folder will be created if it does not exist.

c. Cell range "A3:U12" are values that are the current forecasted resource needs for VPPSA. These values come from cell range "C68:AZ68" in the "Energy by Category" tab of "IRPResults4.xls." The values are titled "Market energy Purchases."

d. If the user changes the capacity factors for each resource in the cell range "C16:C21" then the required megawatts needed to fulfill the chosen years resource shortage will change accordingly and update the resource definition located on tab "ResDef1" and "ResDef2" in "CapEgyCalc5.xls."

e. Cell range "D16:D21" can be adjusted to represent the assumed lifetime of a particular resource type. These cells are linked to "CapEgyCalc5.xls", under the "ResDef1" and "ResDef2" tab.

f. Cell range “C24:AA29” can be adjusted to represent the “mix” of resources listed in cell range “B24:B29”, “Resources”. The total resources percentages must add up to 100% on line 20.

g. Two separate years have been set up as “Purchase Years.” These years can be changed in cells “A33”and “A40.” Formulas will fill in the required amounts of each resource based on its percentage to fill the entire need for the chosen year.

h. Cells “C33:AA45” are calculation cells that determine the necessary Megawatts needed to fulfill the chosen purchase years Megawatt requirement, based on the percentage of resources chosen in cell range “C24:AA29.”

i. Cells below row 46 are used as the linking cells to “CapEgyCalc5.xls” and should not be altered.

2. <u>Summary:</u>

This worksheet summarizes the scenario outputs. The worksheet will be populated and saved in a new workbook titled “IRP_Run_Assumptions_MM_DD_YYYY.xls.” in the directory chosen for “Scenarios” on the “Assumption” worksheet.

a. Cell range “B2:G26” contains the text identification for the scenarios corresponding to their resource mix percentage shown in cell range “M2:R26.”

b. Column “C” summarizes the Net Present Value (NPV) dollar amount for each scenario.

c. Column “D” summarizes the Expected Net Present Value dollar amount based on the probabilities chosen in “IRPResults4.xls.”

d. Column “E” Identifies the Largest Swing variable for the scenario’s resource mix.

e. Column “F” Identifies the Largest Swing variable dollar amount for the scenario’s resource mix.

f. Column “G” Identifies the Largest Swing variable percentage for the scenario’s resource mix.

g. Column “H” Identifies the Second Largest Swing variable for the scenario’s resource mix.

h. Column “I” Identifies the Second Largest Swing variable dollar amount for the scenario’s resource mix.

i. Column “J” Identifies the Second Largest Swing variable percentage for the scenario’s resource mix.

j. Column “K” Identifies the Probabilistic departure from the base case scenario dollar amount for the scenario’s resource mix based on the probabilities chosen in “IRPResults4.xls.”

k. Cell range “A29:N39” (“Lowest Values” heading) identifies the scenarios with the lowest values from the above summaries.

l. Cell range “A42:N50” (“Highest Values” heading) contain the highest values from the above summaries.

3. Summary Sorted:

This worksheet has the exact same format as the "Summary" worksheet with the exception of an additional column titled "Ranking Value.". The main difference is that the summarized data from the "Summary" worksheet is sorted by default on the "Expected NPV ($)" from lowest value to highest value. The user can press any of the buttons above the various column headings to resort the data based on the chosen column. For example if the button "LVS Sort" was pressed the information would be re-sorted from lowest to highest value based on the "Largest Variable Swing ($)." In addition to the "Summary" worksheet a "Ranking Value" column has been added to aid in "weighting" the outputs to help identify top performing scenarios. The ranking percentage for each output is located within row 27 and can be changed by the user. A "Ranking Sort" button allows for a sort from lowest to highest value and will need to be activated if ranking values are altered.

4. Generation

This tab is used for data manipulation only. The purpose is to format resource generation needs into monthly values.

5. Expiration_1

This tab is used for data manipulation only. The purpose is to calculate the length in months of a resources lifetime and to stop the benefit of that resource once the lifetime has been met. This worksheet is concerned with the first year of purchases.

6. Expiration_2

This tab is used for data manipulation only. The purpose is to calculate the length in months of a resources lifetime and to stop the benefit of that resource once the lifetime has been met. This worksheet is concerned with the second year of purchases.

7. Expiration_3

This tab is used for data manipulation only. The purpose is to calculate the length in months of a resources lifetime and to stop the benefit of that resource once the lifetime has been met. This worksheet is concerned with the third year of purchases if applicable.

8. Resource Total

This tab is used for data manipulation only. The purpose is to calculate the length in months of a resources lifetime and to stop the benefit of that resource once the lifetime has been met. This worksheet is concerned with the total value for all purchase years.

9. <u>LMP</u>

This tab is used for data manipulation only. The purpose is to format LMP information into monthly values. The result was used to forecast LMP's monthly for the "GenCont" and "Generic VY" resources formerly in the "ResDef2" worksheet in "CapEgyCalc5.xls"

Sens131s.xla – *SensIt* 1.31 Sensitivity Analysis ADD IN REQUIREMENT

The "VPPSA IRP Model" requires the inclusion of the "*SensIt* 1.31 Sensitivity Analysis" add-in in order to function properly. This add-in has been included in the portable model files, but the user must still install the add-in so that Microsoft Excel knows where to find the module when called in the automation routine if the add-in has not already installed. The step by step instructions on how to do this are below.

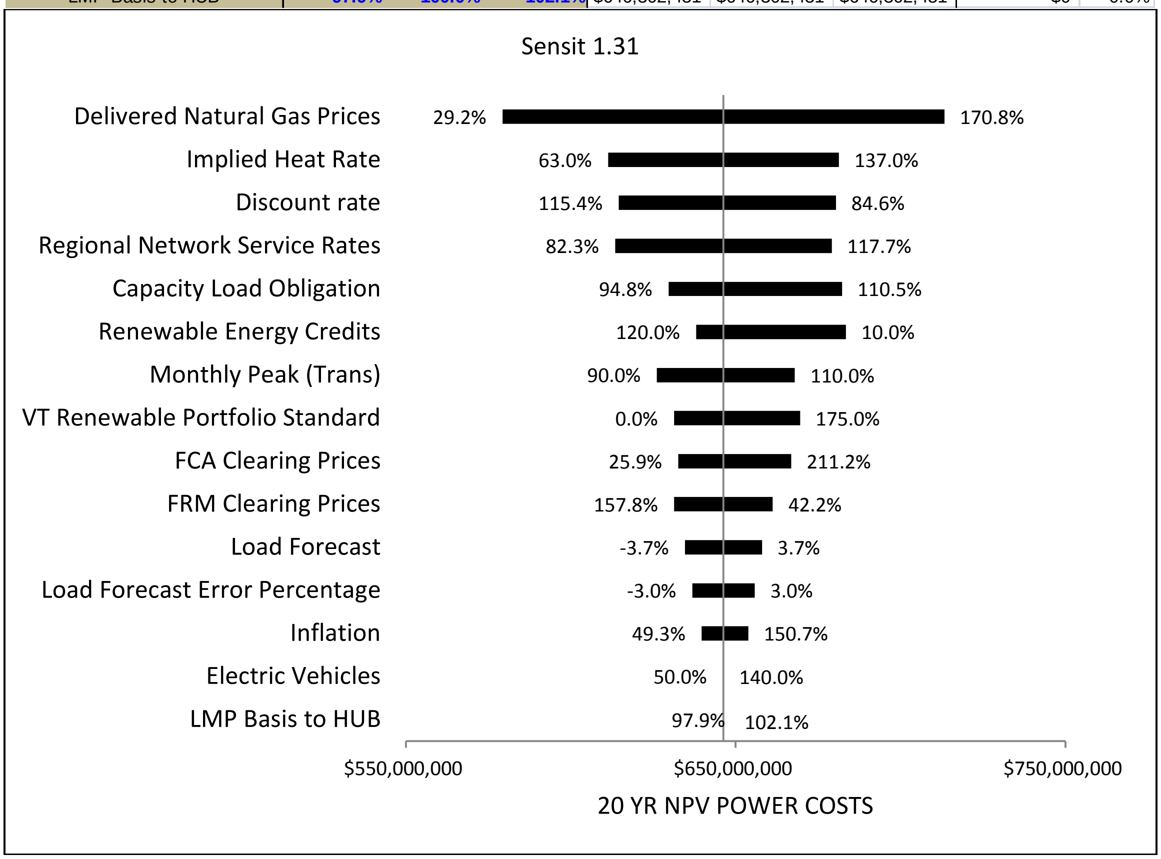
<u>How To</u>

1. Open up the file "IRP_Run_Assumptions.xls"
2. Select File/Options
3. Click Add-Ins
4. Click the Go button next to Manage Add-Ins
5. Browse the file finder to the directory where "Sens131s.xla" is located. By default, it is in the same directory as this document.
6. All Done! The user should notice that the "SensIt 1.31 Sensitivity Analysis" add-in is now listed in the "Add-Ins available" list box with a check mark next to it. If it is not checked then be sure to place a check mark next to it.

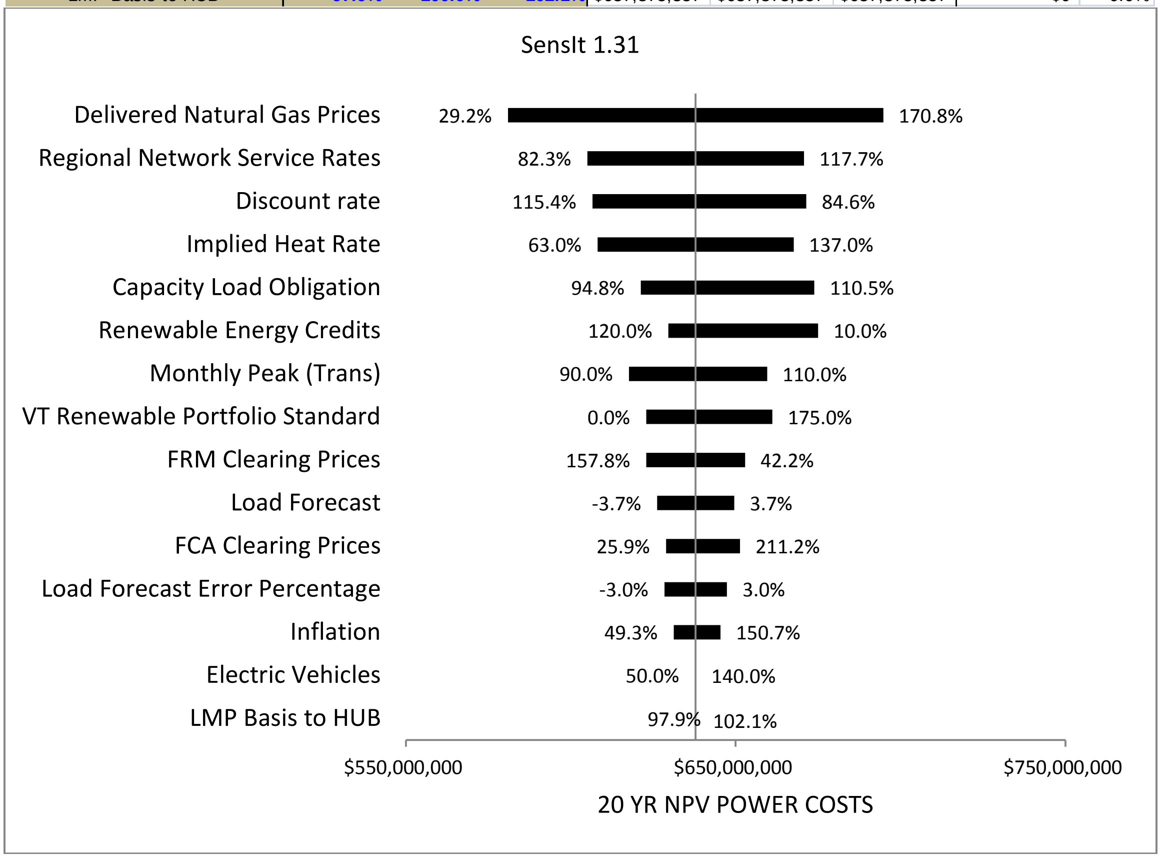
Appendix 3: Resource Scenario Results

The following tables and charts illustrate the results of each of the 25 scenarios examined.

Sensit 1.31			**Scenario 1: Spot**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:08 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$579,318,982	$646,302,451	$713,285,919	$133,966,938	42.0%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$611,327,840	$646,302,451	$681,277,061	$69,949,222	11.5%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$614,577,736	$646,302,451	$680,374,027	$65,796,292	10.1%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$613,484,531	$646,302,451	$679,120,377	$65,635,847	10.1%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$629,663,288	$646,302,451	$682,271,399	$52,608,111	6.5%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$638,054,906	$646,302,451	$683,416,401	$45,361,495	4.8%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$626,111,119	$646,302,451	$667,944,817	$41,833,698	4.1%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$631,324,479	$646,302,451	$669,546,943	$38,222,464	3.4%
FCA Clearing Prices	**25.9%**	**100.0%**	**211.2%**	$632,608,759	$646,302,451	$666,842,988	$34,234,229	2.7%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$631,347,906	$646,302,451	$661,256,995	$29,909,088	2.1%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$634,603,867	$646,302,451	$658,001,034	$23,397,166	1.3%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$636,817,113	$646,302,451	$655,787,788	$18,970,675	0.8%
Inflation	**49.3%**	**100.0%**	**150.7%**	$639,689,892	$646,302,451	$653,853,789	$14,163,897	0.5%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$646,199,809	$646,302,451	$646,384,563	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$646,302,451	$646,302,451	$646,302,451	$0	0.0%



SensIt 1.31			**Scenario 2: SolarOut**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:11 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value			Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$581,011,422	$637,875,357	$694,739,292	$113,727,870	36.4%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$605,057,437	$637,875,357	$670,693,283	$65,635,847	12.1%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$606,629,167	$637,875,357	$671,431,908	$64,802,740	11.8%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$608,184,539	$637,875,357	$667,566,175	$59,381,636	9.9%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$621,236,194	$637,875,357	$673,844,305	$52,608,111	7.8%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$629,627,812	$637,875,357	$674,989,307	$45,361,495	5.8%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$617,684,025	$637,875,357	$659,517,724	$41,833,698	4.9%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$622,897,385	$637,875,357	$661,119,849	$38,222,464	4.1%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$622,920,813	$637,875,357	$652,829,901	$29,909,088	2.5%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$626,176,774	$637,875,357	$649,573,940	$23,397,166	1.5%
FCA Clearing Prices	**25.9%**	**100.0%**	**211.2%**	$628,902,328	$637,875,357	$651,334,900	$22,432,572	1.4%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$628,390,019	$637,875,357	$647,360,694	$18,970,675	1.0%
Inflation	**49.3%**	**100.0%**	**150.7%**	$631,262,799	$637,875,357	$645,426,696	$14,163,897	0.6%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$637,772,716	$637,875,357	$637,957,470	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$637,875,357	$637,875,357	$637,875,357	$0	0.0%



SensIt 1.31

Many Inputs, One Output

Single-Factor Sensitivity Analysis

Scenario 3: SolarIn

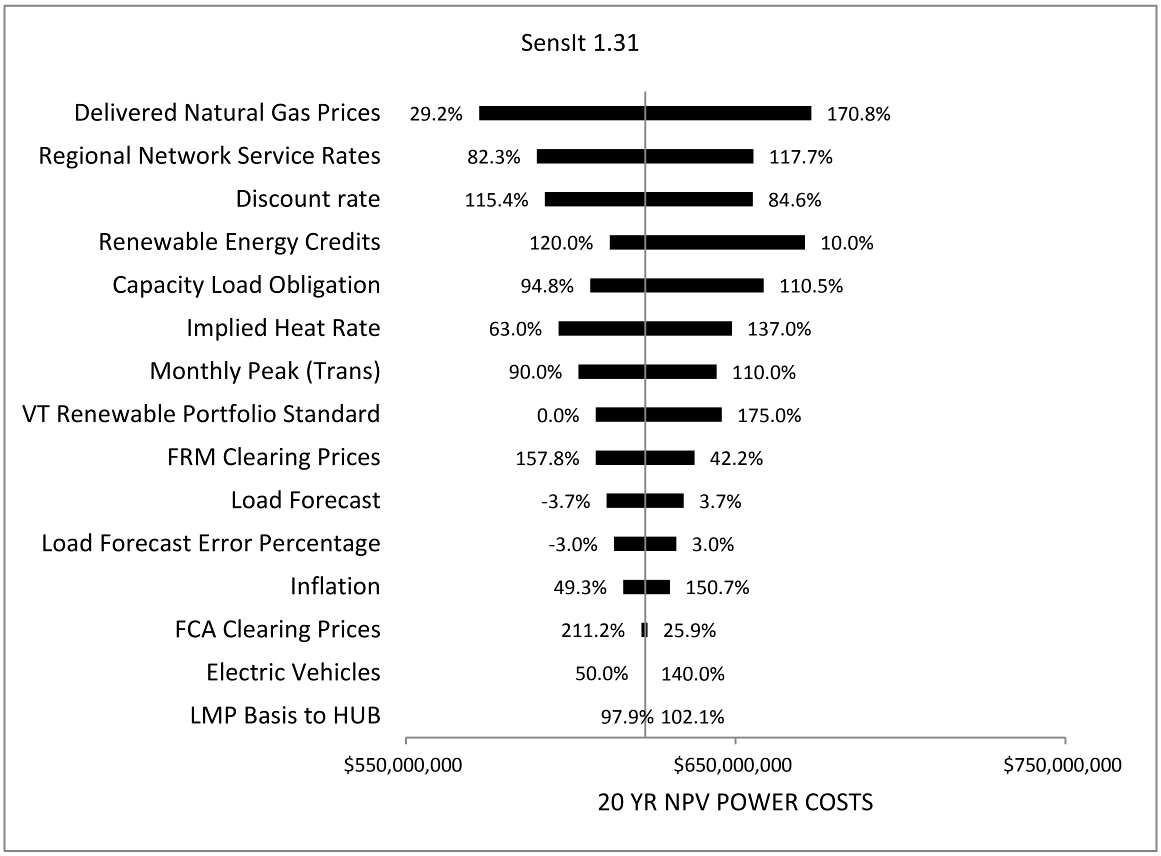
Date 15-Jul-15

Time 5:13 PM

Workbook IRPResults4.xls

Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$572,208,046	$622,557,113	$672,906,179	$100,698,133	31.0%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$589,739,193	$622,557,113	$655,375,039	$65,635,847	13.2%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$592,171,769	$622,557,113	$655,189,181	$63,017,412	12.2%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$611,790,567	$622,557,113	$671,006,566	$59,215,998	10.7%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$605,917,950	$622,557,113	$658,526,061	$52,608,111	8.5%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$596,267,954	$622,557,113	$648,846,271	$52,578,316	8.5%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$602,365,781	$622,557,113	$644,199,479	$41,833,698	5.4%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$607,579,141	$622,557,113	$645,801,605	$38,222,464	4.5%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$607,602,568	$622,557,113	$637,511,657	$29,909,088	2.7%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$610,858,529	$622,557,113	$634,255,696	$23,397,166	1.7%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$613,071,775	$622,557,113	$632,042,450	$18,970,675	1.1%
Inflation	**49.3%**	**100.0%**	**150.7%**	$615,944,554	$622,557,113	$630,108,452	$14,163,897	0.6%
FCA Clearing Prices	**211.2%**	**100.0%**	**25.9%**	$621,441,865	$622,557,113	$623,300,611	$1,858,746	0.0%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$622,454,471	$622,557,113	$622,639,225	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$622,557,113	$622,557,113	$622,557,113	$0	0.0%



SensIt 1.31 | **Scenario 4: FixCon**

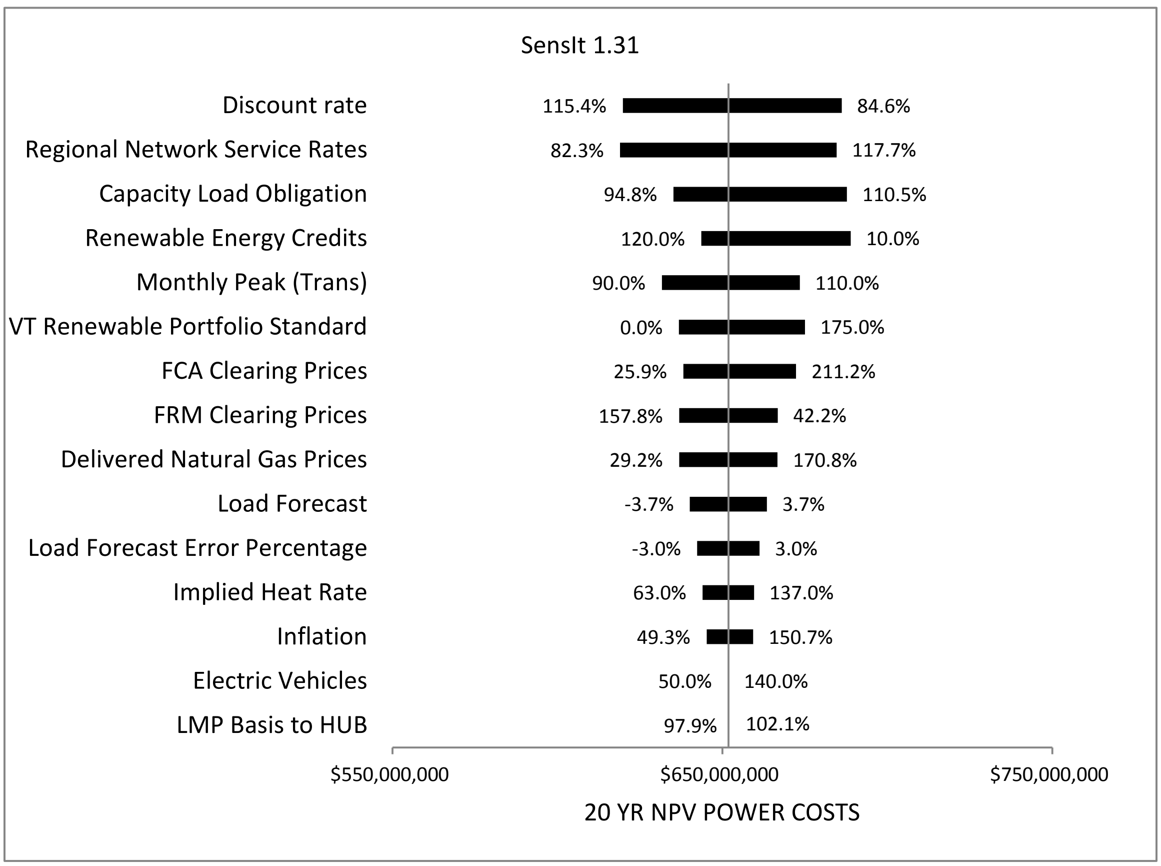
Many Inputs, One Output

Single-Factor Sensitivity Analysis

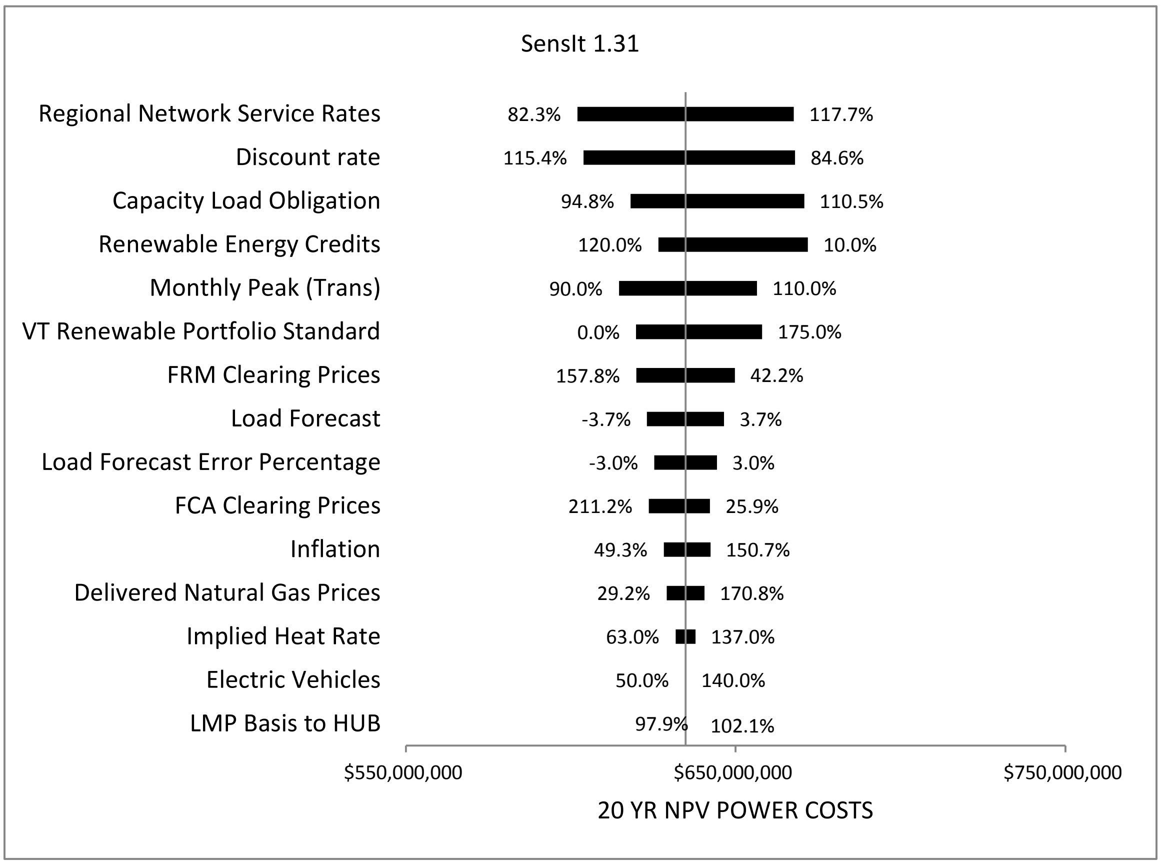
Date 15-Jul-15 | Workbook IRPResults4.xls

Time 5:16 PM | Output Cell 'Sensit Input Table'!$C$25

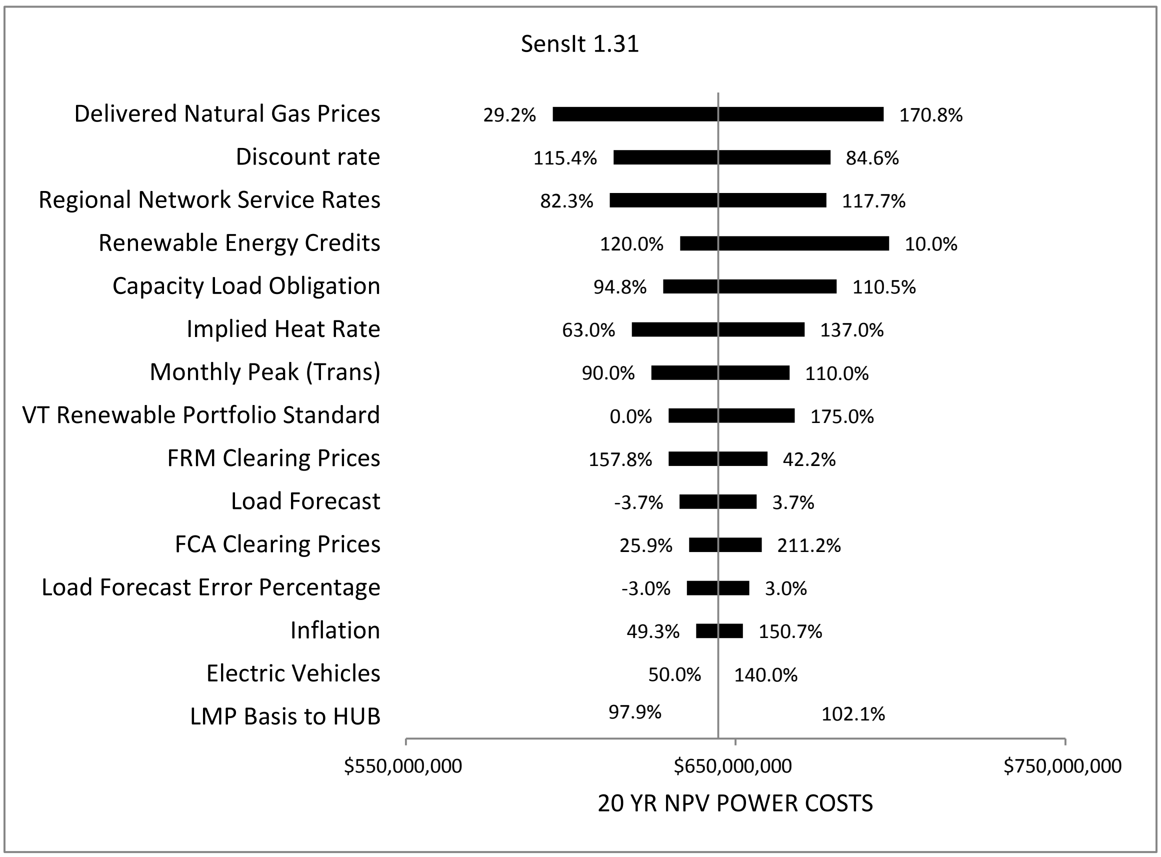
	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Discount rate	**115.4%**	**100.0%**	**84.6%**	$619,822,908	$651,829,603	$686,199,640	$66,376,732	20.9%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$619,011,683	$651,829,603	$684,647,529	$65,635,847	20.5%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$635,190,440	$651,829,603	$687,798,551	$52,608,111	13.1%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$643,582,058	$651,829,603	$688,943,553	$45,361,495	9.8%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$631,638,271	$651,829,603	$673,471,970	$41,833,698	8.3%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$636,851,631	$651,829,603	$675,074,095	$38,222,464	6.9%
FCA Clearing Prices	**25.9%**	**100.0%**	**211.2%**	$638,135,911	$651,829,603	$672,370,140	$34,234,229	5.6%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$636,875,059	$651,829,603	$666,784,147	$29,909,088	4.2%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$636,906,149	$651,829,603	$666,753,056	$29,846,907	4.2%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$640,131,020	$651,829,603	$663,528,186	$23,397,166	2.6%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$642,344,265	$651,829,603	$661,314,940	$18,970,675	1.7%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$644,037,501	$651,829,603	$659,621,704	$15,584,203	1.2%
Inflation	**49.3%**	**100.0%**	**150.7%**	$645,217,044	$651,829,603	$659,380,942	$14,163,897	1.0%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$651,726,962	$651,829,603	$651,911,716	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$651,829,603	$651,829,603	$651,829,603	$0	0.0%



SensIt 1.31			**Scenario 5: Mkt Cont**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:19 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value			Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$601,982,212	$634,800,132	$667,618,059	$65,635,847	22.7%
Discount rate	115.4%	100.0%	84.6%	$603,848,526	$634,800,132	$668,034,194	$64,185,668	21.7%
Capacity Load Obligation	94.8%	100.0%	110.5%	$618,160,970	$634,800,132	$670,769,080	$52,608,111	14.6%
Renewable Energy Credits	120.0%	100.0%	10.0%	$626,552,588	$634,800,132	$671,914,083	$45,361,495	10.8%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$614,608,801	$634,800,132	$656,442,499	$41,833,698	9.2%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$619,822,161	$634,800,132	$658,044,625	$38,222,464	7.7%
FRM Clearing Prices	157.8%	100.0%	42.2%	$619,845,588	$634,800,132	$649,754,676	$29,909,088	4.7%
Load Forecast	-3.7%	0.0%	3.7%	$623,101,549	$634,800,132	$646,498,715	$23,397,166	2.9%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$625,314,795	$634,800,132	$644,285,470	$18,970,675	1.9%
FCA Clearing Prices	211.2%	100.0%	25.9%	$623,638,416	$634,800,132	$642,241,277	$18,602,861	1.8%
Inflation	49.3%	100.0%	150.7%	$628,187,574	$634,800,132	$642,351,471	$14,163,897	1.1%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$629,062,253	$634,800,132	$640,538,012	$11,475,759	0.7%
Implied Heat Rate	63.0%	100.0%	137.0%	$631,804,168	$634,800,132	$637,796,097	$5,991,929	0.2%
Electric Vehicles	50.0%	100.0%	140.0%	$634,697,491	$634,800,132	$634,882,245	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$634,800,132	$634,800,132	$634,800,132	$0	0.0%



SensIt 1.31			**Scenario 6: Wind**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:22 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$594,511,369	$644,672,738	$694,834,107	$100,322,738	29.7%
Discount rate	115.4%	100.0%	84.6%	$612,958,816	$644,672,738	$678,737,097	$65,778,281	12.8%
Regional Network Service Rates	82.3%	100.0%	117.7%	$611,854,818	$644,672,738	$677,490,664	$65,635,847	12.7%
Renewable Energy Credits	120.0%	100.0%	10.0%	$633,155,130	$644,672,738	$696,501,973	$63,346,844	11.8%
Capacity Load Obligation	94.8%	100.0%	110.5%	$628,033,575	$644,672,738	$680,641,686	$52,608,111	8.2%
Implied Heat Rate	63.0%	100.0%	137.0%	$618,481,584	$644,672,738	$670,863,892	$52,382,308	8.1%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$624,481,406	$644,672,738	$666,315,105	$41,833,698	5.2%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$629,694,766	$644,672,738	$667,917,230	$38,222,464	4.3%
FRM Clearing Prices	157.8%	100.0%	42.2%	$629,718,194	$644,672,738	$659,627,282	$29,909,088	2.6%
Load Forecast	-3.7%	0.0%	3.7%	$632,974,155	$644,672,738	$656,371,321	$23,397,166	1.6%
FCA Clearing Prices	25.9%	100.0%	211.2%	$635,868,361	$644,672,738	$657,879,303	$22,010,942	1.4%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$635,187,400	$644,672,738	$654,158,075	$18,970,675	1.1%
Inflation	49.3%	100.0%	150.7%	$638,060,180	$644,672,738	$652,224,077	$14,163,897	0.6%
Electric Vehicles	50.0%	100.0%	140.0%	$644,570,097	$644,672,738	$644,754,851	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$644,672,738	$644,672,738	$644,672,738	$0	0.0%

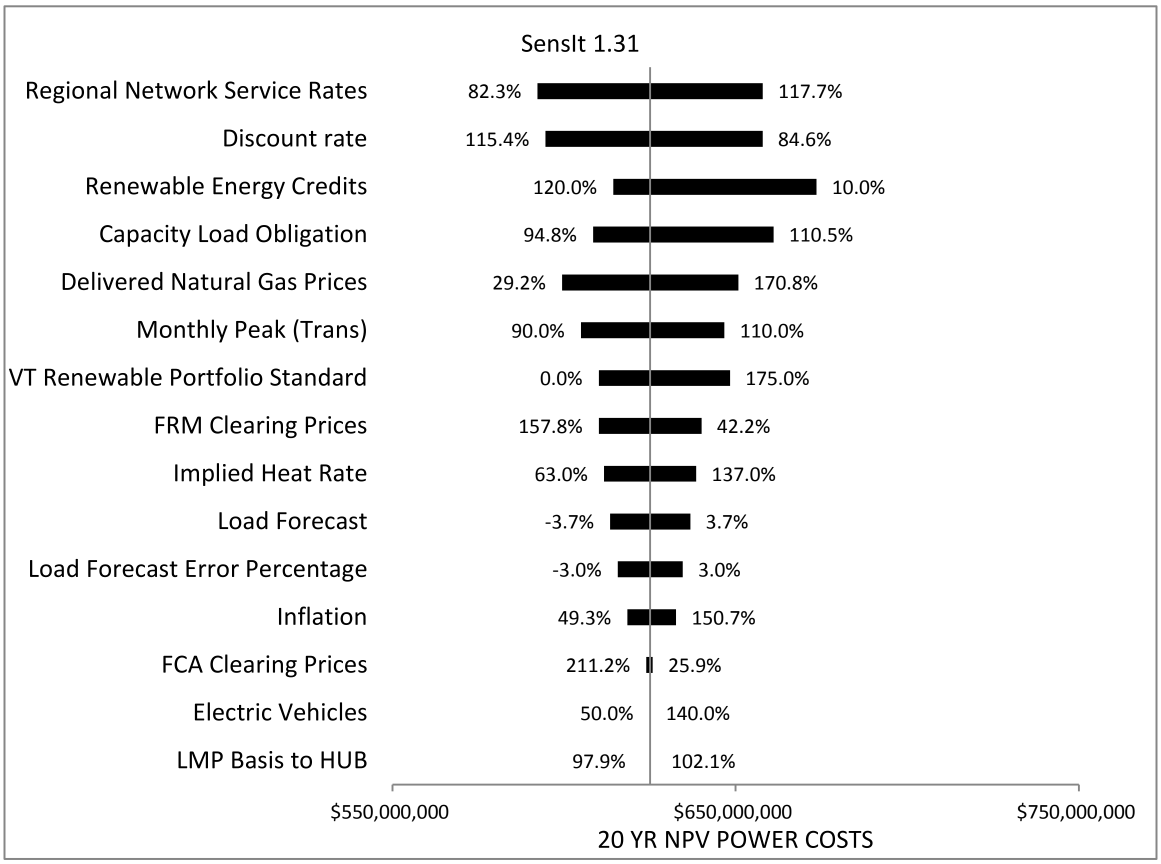


SensIt 1.31 **Scenario 7: SolarIn/FixCon**

Many Inputs, One Output

Single-Factor Sensitivity Analysis

Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:25 PM			Output Cell	'Sensit Input Table'!$C$25			
					20 YR NPV POWER COSTS			
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$592,273,239	$625,091,159	$657,909,086	$65,635,847	18.6%
Discount rate	115.4%	100.0%	84.6%	$594,577,779	$625,091,159	$657,858,626	$63,280,848	17.3%
Renewable Energy Credits	120.0%	100.0%	10.0%	$614,324,614	$625,091,159	$673,540,612	$59,215,998	15.1%
Capacity Load Obligation	94.8%	100.0%	110.5%	$608,451,997	$625,091,159	$661,060,107	$52,608,111	11.9%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$599,402,100	$625,091,159	$650,780,218	$51,378,119	11.4%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$604,899,828	$625,091,159	$646,733,526	$41,833,698	7.6%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$610,113,188	$625,091,159	$648,335,652	$38,222,464	6.3%
FRM Clearing Prices	157.8%	100.0%	42.2%	$610,136,615	$625,091,159	$640,045,703	$29,909,088	3.9%
Implied Heat Rate	63.0%	100.0%	137.0%	$611,677,927	$625,091,159	$638,504,392	$26,826,465	3.1%
Load Forecast	-3.7%	0.0%	3.7%	$613,392,576	$625,091,159	$636,789,742	$23,397,166	2.4%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$615,605,822	$625,091,159	$634,576,497	$18,970,675	1.6%
Inflation	49.3%	100.0%	150.7%	$618,478,601	$625,091,159	$632,642,498	$14,163,897	0.9%
FCA Clearing Prices	211.2%	100.0%	25.9%	$623,975,912	$625,091,159	$625,834,657	$1,858,746	0.0%
Electric Vehicles	50.0%	100.0%	140.0%	$624,988,518	$625,091,159	$625,173,272	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$625,091,159	$625,091,159	$625,091,159	$0	0.0%



SensIt 1.31 **Scenario 8: SolarOut/SolarIn**

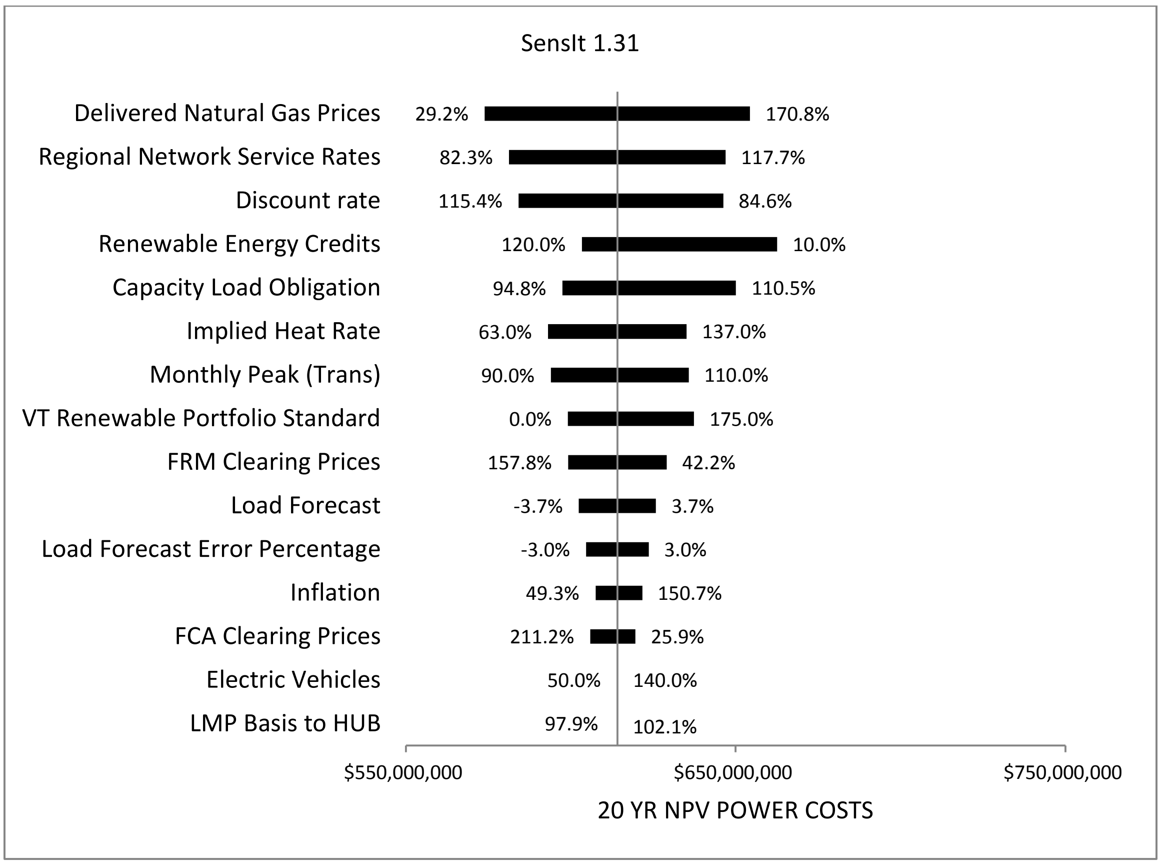
Many Inputs, One Output

Single-Factor Sensitivity Analysis

Date 15-Jul-15 Workbook IRPResults4.xls

Time 5:28 PM Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$573,900,486	$614,130,019	$654,359,551	$80,459,065	23.1%
Regional Network Service Rates	82.3%	100.0%	117.7%	$581,312,099	$614,130,019	$646,947,945	$65,635,847	15.3%
Discount rate	115.4%	100.0%	84.6%	$584,223,200	$614,130,019	$646,247,061	$62,023,861	13.7%
Renewable Energy Credits	120.0%	100.0%	10.0%	$603,363,474	$614,130,019	$662,579,472	$59,215,998	12.5%
Capacity Load Obligation	94.8%	100.0%	110.5%	$597,490,856	$614,130,019	$650,098,967	$52,608,111	9.9%
Implied Heat Rate	63.0%	100.0%	137.0%	$593,124,653	$614,130,019	$635,135,384	$42,010,731	6.3%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$593,938,688	$614,130,019	$635,772,386	$41,833,698	6.2%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$599,152,047	$614,130,019	$637,374,511	$38,222,464	5.2%
FRM Clearing Prices	157.8%	100.0%	42.2%	$599,175,475	$614,130,019	$629,084,563	$29,909,088	3.2%
Load Forecast	-3.7%	0.0%	3.7%	$602,431,436	$614,130,019	$625,828,602	$23,397,166	2.0%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$604,644,681	$614,130,019	$623,615,356	$18,970,675	1.3%
Inflation	49.3%	100.0%	150.7%	$607,517,461	$614,130,019	$621,681,358	$14,163,897	0.7%
FCA Clearing Prices	211.2%	100.0%	25.9%	$605,933,777	$614,130,019	$619,594,180	$13,660,403	0.7%
Electric Vehicles	50.0%	100.0%	140.0%	$614,027,378	$614,130,019	$614,212,132	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$614,130,019	$614,130,019	$614,130,019	$0	0.0%



SensIt 1.31 | **Scenario 9: SolarIn/Mkt Cont**

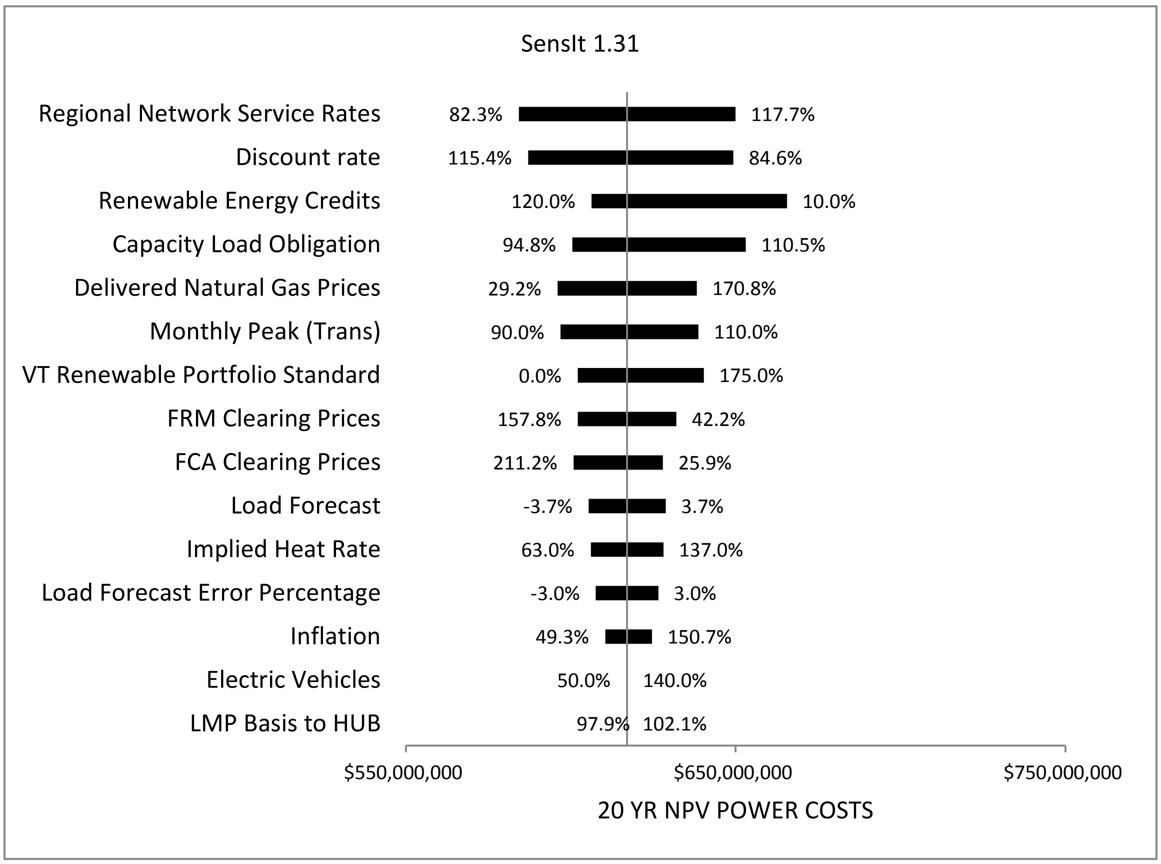
Many Inputs, One Output

Single-Factor Sensitivity Analysis

Date 15-Jul-15 | Workbook IRPResults4.xls

Time 5:31 PM | Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$584,270,792	$617,088,712	$649,906,639	$65,635,847	19.0%
Discount rate	115.4%	100.0%	84.6%	$587,070,161	$617,088,712	$649,323,457	$62,253,297	17.1%
Renewable Energy Credits	120.0%	100.0%	10.0%	$606,322,167	$617,088,712	$665,538,165	$59,215,998	15.5%
Capacity Load Obligation	94.8%	100.0%	110.5%	$600,449,550	$617,088,712	$653,057,660	$52,608,111	12.2%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$595,992,440	$617,088,712	$638,184,984	$42,192,544	7.9%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$596,897,381	$617,088,712	$638,731,079	$41,833,698	7.7%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$602,110,741	$617,088,712	$640,333,205	$38,222,464	6.4%
FRM Clearing Prices	157.8%	100.0%	42.2%	$602,134,168	$617,088,712	$632,043,256	$29,909,088	3.9%
FCA Clearing Prices	211.2%	100.0%	25.9%	$600,849,425	$617,088,712	$627,914,903	$27,065,478	3.2%
Load Forecast	-3.7%	0.0%	3.7%	$605,390,129	$617,088,712	$628,787,295	$23,397,166	2.4%
Implied Heat Rate	63.0%	100.0%	137.0%	$606,073,548	$617,088,712	$628,103,876	$22,030,328	2.1%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$607,603,374	$617,088,712	$626,574,050	$18,970,675	1.6%
Inflation	49.3%	100.0%	150.7%	$610,476,154	$617,088,712	$624,640,051	$14,163,897	0.9%
Electric Vehicles	50.0%	100.0%	140.0%	$616,986,071	$617,088,712	$617,170,825	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$617,088,712	$617,088,712	$617,088,712	$0	0.0%



SensIt 1.31 | **Scenario 10: SolarIn/Wind**

Many Inputs, One Output

Single-Factor Sensitivity Analysis

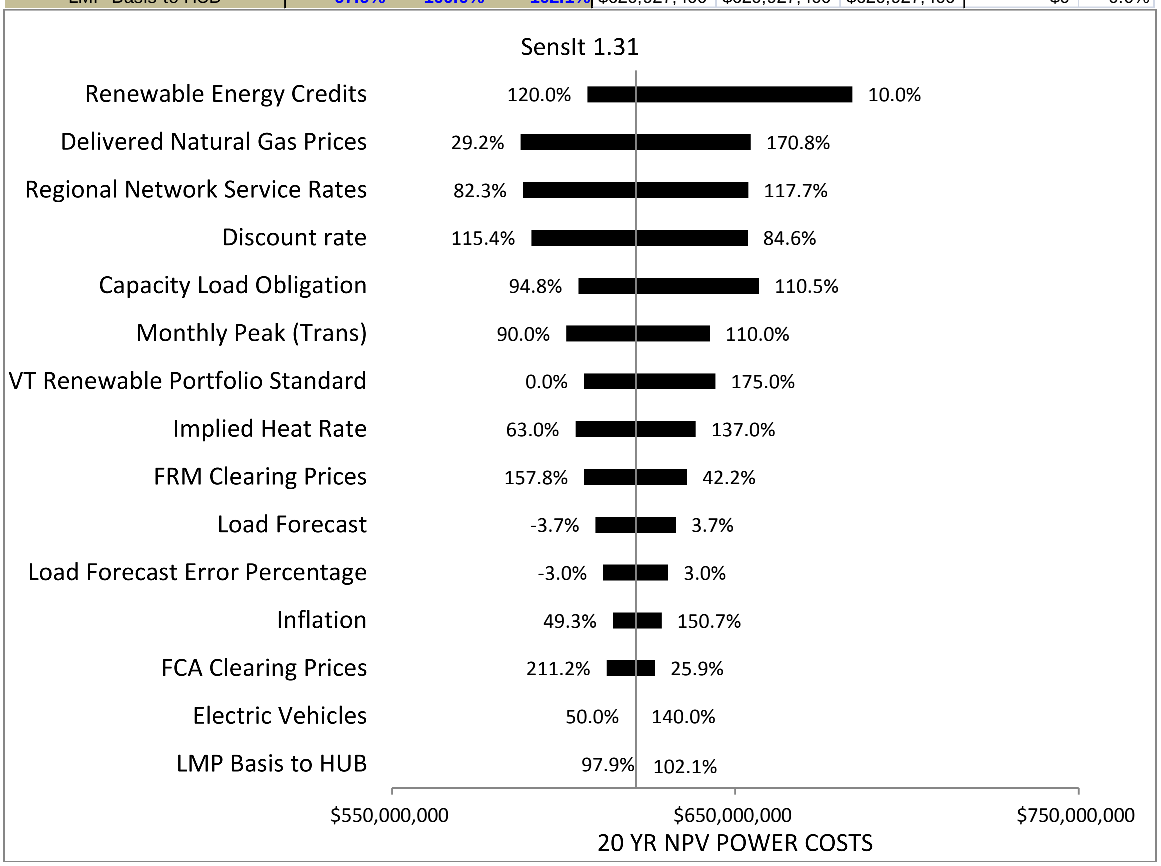
Date 15-Jul-15

Time 5:34 PM

Workbook IRPResults4.xls

Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	120.0%	100.0%	10.0%	$606,890,791	$620,927,400	$684,092,138	$77,201,347	21.2%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$587,400,433	$620,927,400	$654,454,366	$67,053,933	16.0%
Regional Network Service Rates	82.3%	100.0%	117.7%	$588,109,480	$620,927,400	$653,745,326	$65,635,847	15.3%
Discount rate	115.4%	100.0%	84.6%	$590,552,848	$620,927,400	$653,552,250	$62,999,402	14.1%
Capacity Load Obligation	94.8%	100.0%	110.5%	$604,288,237	$620,927,400	$656,896,348	$52,608,111	9.8%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$600,736,068	$620,927,400	$642,569,767	$41,833,698	6.2%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$605,949,428	$620,927,400	$644,171,892	$38,222,464	5.2%
Implied Heat Rate	63.0%	100.0%	137.0%	$603,421,698	$620,927,400	$638,433,101	$35,011,403	4.4%
FRM Clearing Prices	157.8%	100.0%	42.2%	$605,972,856	$620,927,400	$635,881,944	$29,909,088	3.2%
Load Forecast	-3.7%	0.0%	3.7%	$609,228,817	$620,927,400	$632,625,983	$23,397,166	1.9%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$611,442,062	$620,927,400	$630,412,737	$18,970,675	1.3%
Inflation	49.3%	100.0%	150.7%	$614,314,842	$620,927,400	$628,478,739	$14,163,897	0.7%
FCA Clearing Prices	211.2%	100.0%	25.9%	$612,478,180	$620,927,400	$626,560,213	$14,082,033	0.7%
Electric Vehicles	50.0%	100.0%	140.0%	$620,824,759	$620,927,400	$621,009,513	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$620,927,400	$620,927,400	$620,927,400	$0	0.0%



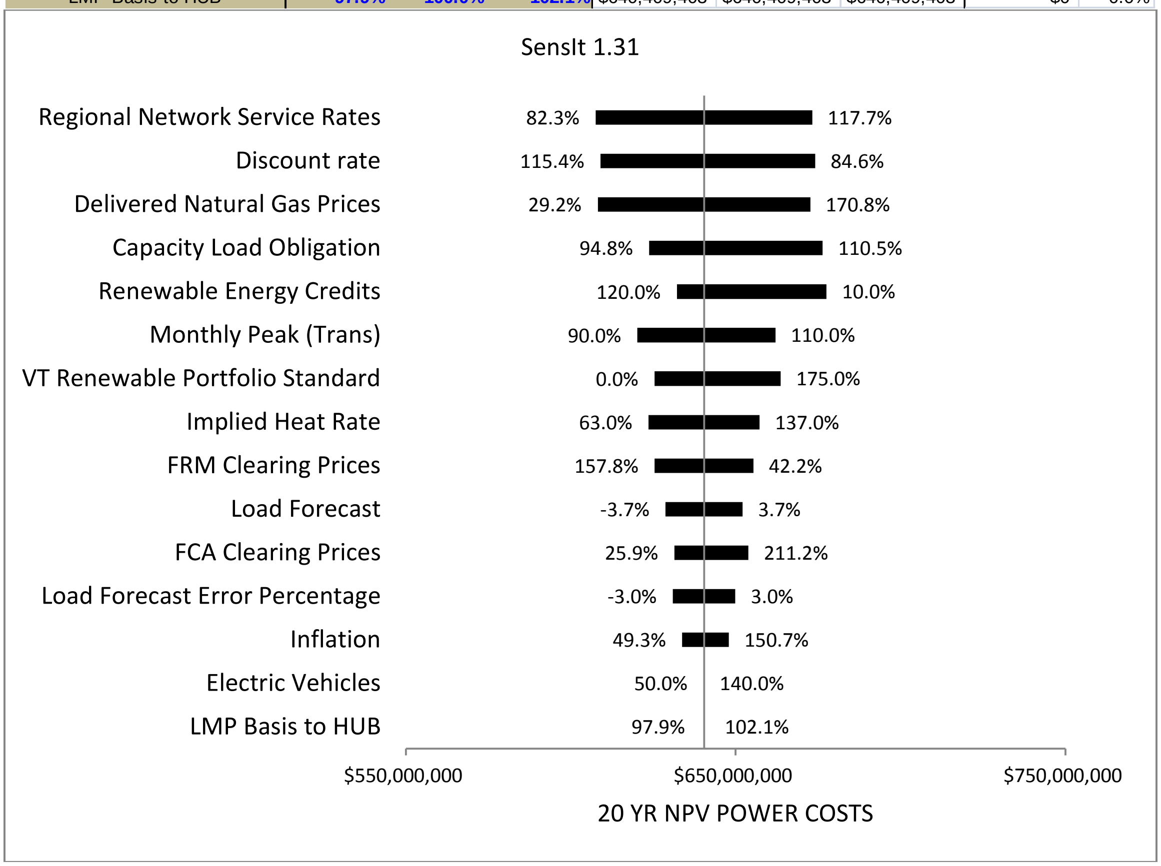
SensIt 1.31 | **Scenario 11: SolarOut/FixCon**

Many Inputs, One Output

Single-Factor Sensitivity Analysis

Date	15-Jul-15		Workbook	IRPResults4.xls
Time	5:36 PM		Output Cell	'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$607,591,483	$640,409,403	$673,227,330	$65,635,847	17.7%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$609,035,177	$640,409,403	$674,101,353	$65,066,175	17.4%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$608,205,476	$640,409,403	$672,613,331	$64,407,855	17.0%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$623,770,241	$640,409,403	$676,378,351	$52,608,111	11.4%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$632,161,859	$640,409,403	$677,523,354	$45,361,495	8.4%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$620,218,072	$640,409,403	$662,051,770	$41,833,698	7.2%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$625,431,432	$640,409,403	$663,653,896	$38,222,464	6.0%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$623,594,511	$640,409,403	$657,224,296	$33,629,785	4.6%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$625,454,859	$640,409,403	$655,363,948	$29,909,088	3.7%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$628,710,820	$640,409,403	$652,107,987	$23,397,166	2.2%
FCA Clearing Prices	**25.9%**	**100.0%**	**211.2%**	$631,436,375	$640,409,403	$653,868,946	$22,432,572	2.1%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$630,924,066	$640,409,403	$649,894,741	$18,970,675	1.5%
Inflation	**49.3%**	**100.0%**	**150.7%**	$633,796,845	$640,409,403	$647,960,742	$14,163,897	0.8%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$640,306,762	$640,409,403	$640,491,516	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$640,409,403	$640,409,403	$640,409,403	$0	0.0%



SensIt 1.31 | **Scenario 12: FixCon/Mkt Cont**

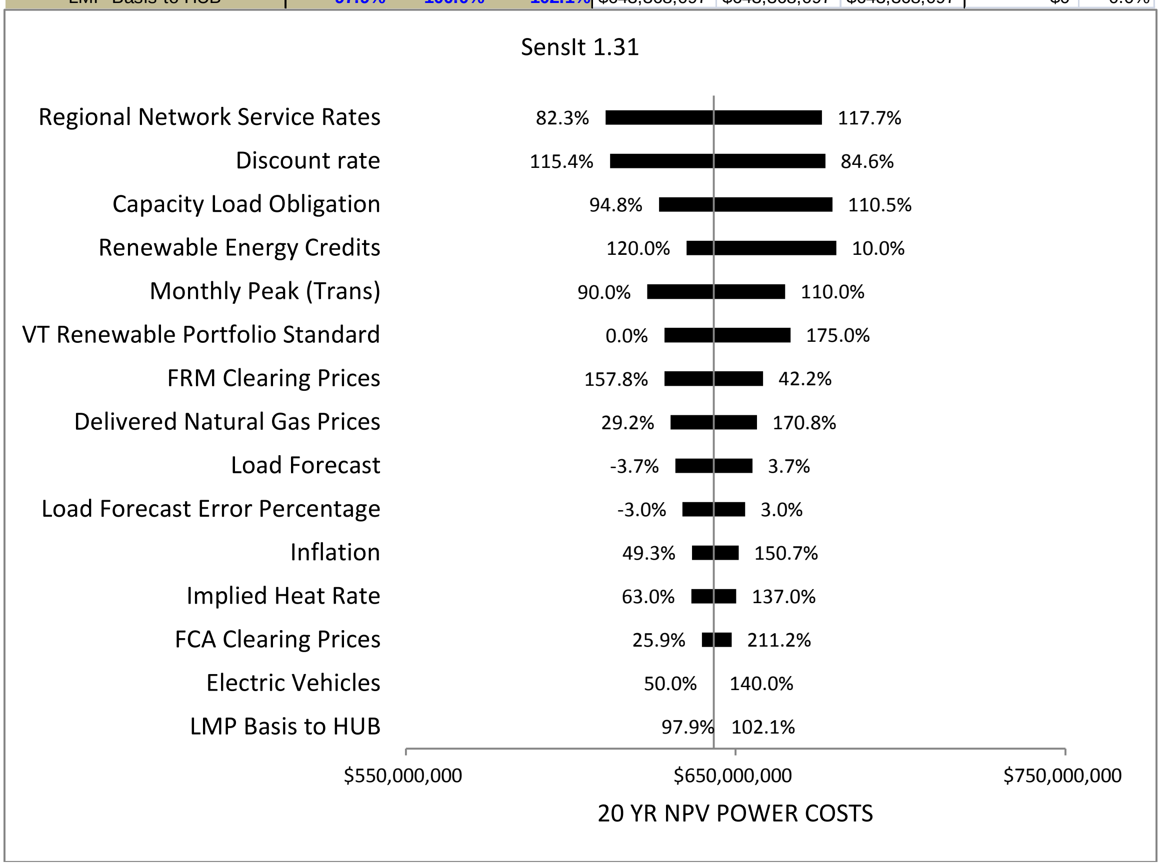
Many Inputs, One Output

Single-Factor Sensitivity Analysis

Date 15-Jul-15 | Workbook IRPResults4.xls

Time 5:39 PM | Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$610,550,177	$643,368,097	$676,186,023	$65,635,847	22.0%
Discount rate	115.4%	100.0%	84.6%	$611,882,138	$643,368,097	$677,177,749	$65,295,611	21.8%
Capacity Load Obligation	94.8%	100.0%	110.5%	$626,728,934	$643,368,097	$679,337,045	$52,608,111	14.1%
Renewable Energy Credits	120.0%	100.0%	10.0%	$635,120,552	$643,368,097	$680,482,047	$45,361,495	10.5%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$623,176,765	$643,368,097	$665,010,464	$41,833,698	8.9%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$628,390,125	$643,368,097	$666,612,589	$38,222,464	7.5%
FRM Clearing Prices	157.8%	100.0%	42.2%	$628,413,553	$643,368,097	$658,322,641	$29,909,088	4.6%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$630,297,429	$643,368,097	$656,438,764	$26,141,335	3.5%
Load Forecast	-3.7%	0.0%	3.7%	$631,669,514	$643,368,097	$655,066,680	$23,397,166	2.8%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$633,882,759	$643,368,097	$652,853,434	$18,970,675	1.8%
Inflation	49.3%	100.0%	150.7%	$636,755,539	$643,368,097	$650,919,436	$14,163,897	1.0%
Implied Heat Rate	63.0%	100.0%	137.0%	$636,543,405	$643,368,097	$650,192,788	$13,649,383	1.0%
FCA Clearing Prices	25.9%	100.0%	211.2%	$639,757,098	$643,368,097	$648,784,595	$9,027,497	0.4%
Electric Vehicles	50.0%	100.0%	140.0%	$643,265,456	$643,368,097	$643,450,210	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$643,368,097	$643,368,097	$643,368,097	$0	0.0%



SensIt 1.31 | **Scenario 13: FixCon/Wind**

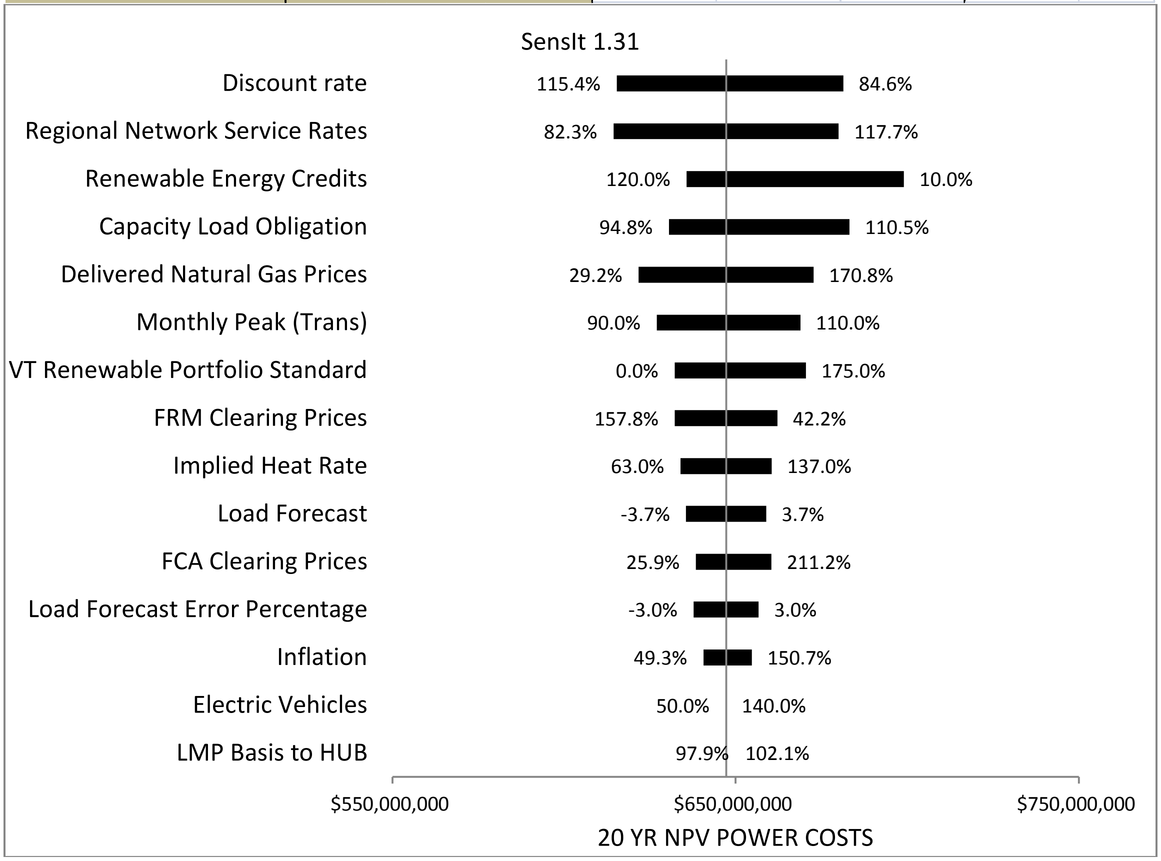
Many Inputs, One Output

Single-Factor Sensitivity Analysis

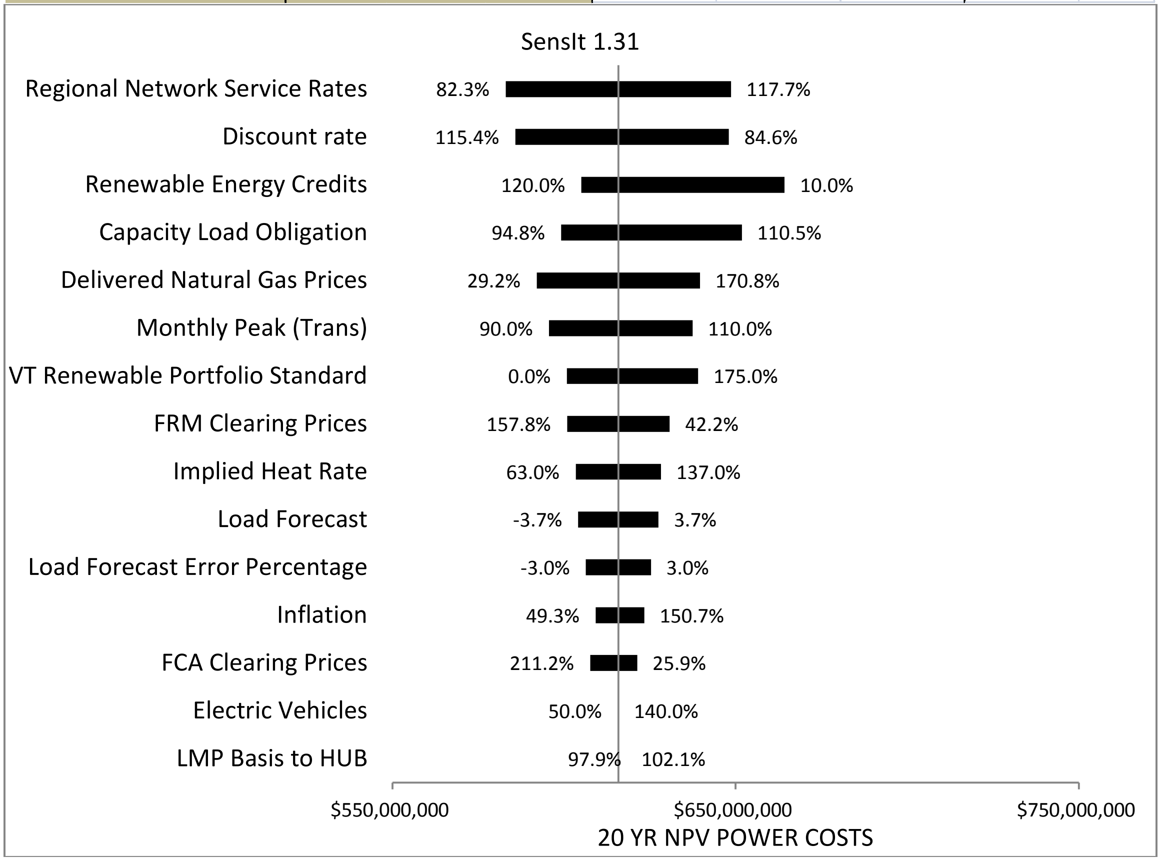
Date 15-Jul-15 | Workbook IRPResults4.xls

Time 5:42 PM | Output Cell 'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Discount rate	115.4%	100.0%	84.6%	$615,364,826	$647,206,784	$681,406,542	$66,041,716	17.8%
Regional Network Service Rates	82.3%	100.0%	117.7%	$614,388,864	$647,206,784	$680,024,711	$65,635,847	17.6%
Renewable Energy Credits	120.0%	100.0%	10.0%	$635,689,176	$647,206,784	$699,036,020	$63,346,844	16.4%
Capacity Load Obligation	94.8%	100.0%	110.5%	$630,567,622	$647,206,784	$683,175,732	$52,608,111	11.3%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$621,705,423	$647,206,784	$672,708,146	$51,002,724	10.6%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$627,015,453	$647,206,784	$668,849,151	$41,833,698	7.2%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$632,228,813	$647,206,784	$670,451,277	$38,222,464	6.0%
FRM Clearing Prices	157.8%	100.0%	42.2%	$632,252,240	$647,206,784	$662,161,329	$29,909,088	3.7%
Implied Heat Rate	63.0%	100.0%	137.0%	$633,891,556	$647,206,784	$660,522,013	$26,630,457	2.9%
Load Forecast	-3.7%	0.0%	3.7%	$635,508,201	$647,206,784	$658,905,368	$23,397,166	2.2%
FCA Clearing Prices	25.9%	100.0%	211.2%	$638,402,408	$647,206,784	$660,413,350	$22,010,942	2.0%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$637,721,447	$647,206,784	$656,692,122	$18,970,675	1.5%
Inflation	49.3%	100.0%	150.7%	$640,594,226	$647,206,784	$654,758,123	$14,163,897	0.8%
Electric Vehicles	50.0%	100.0%	140.0%	$647,104,143	$647,206,784	$647,288,897	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$647,206,784	$647,206,784	$647,206,784	$0	0.0%



Sensit 1.31			Scenario 14: SolarOut/SolarIn/FixCon					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:45 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$583,001,463	$615,819,383	$648,637,310	$65,635,847	19.0%
Discount rate	115.4%	100.0%	84.6%	$585,827,207	$615,819,383	$648,026,691	$62,199,484	17.0%
Renewable Energy Credits	120.0%	100.0%	10.0%	$605,052,838	$615,819,383	$664,268,836	$59,215,998	15.4%
Capacity Load Obligation	94.8%	100.0%	110.5%	$599,180,221	$615,819,383	$651,788,331	$52,608,111	12.2%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$592,029,856	$615,819,383	$639,608,911	$47,579,055	10.0%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$595,628,052	$615,819,383	$637,461,750	$41,833,698	7.7%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$600,841,412	$615,819,383	$639,063,876	$38,222,464	6.4%
FRM Clearing Prices	157.8%	100.0%	42.2%	$600,864,839	$615,819,383	$630,773,927	$29,909,088	3.9%
Implied Heat Rate	63.0%	100.0%	137.0%	$603,397,968	$615,819,383	$628,240,798	$24,842,830	2.7%
Load Forecast	-3.7%	0.0%	3.7%	$604,120,800	$615,819,383	$627,517,966	$23,397,166	2.4%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$606,334,046	$615,819,383	$625,304,721	$18,970,675	1.6%
Inflation	49.3%	100.0%	150.7%	$609,206,825	$615,819,383	$623,370,722	$14,163,897	0.9%
FCA Clearing Prices	211.2%	100.0%	25.9%	$607,623,141	$615,819,383	$621,283,545	$13,660,403	0.8%
Electric Vehicles	50.0%	100.0%	140.0%	$615,716,742	$615,819,383	$615,901,496	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$615,819,383	$615,819,383	$615,819,383	$0	0.0%



SensIt 1.31 **Scenario 15: SolarIn/FixCon/Mkt Cont**

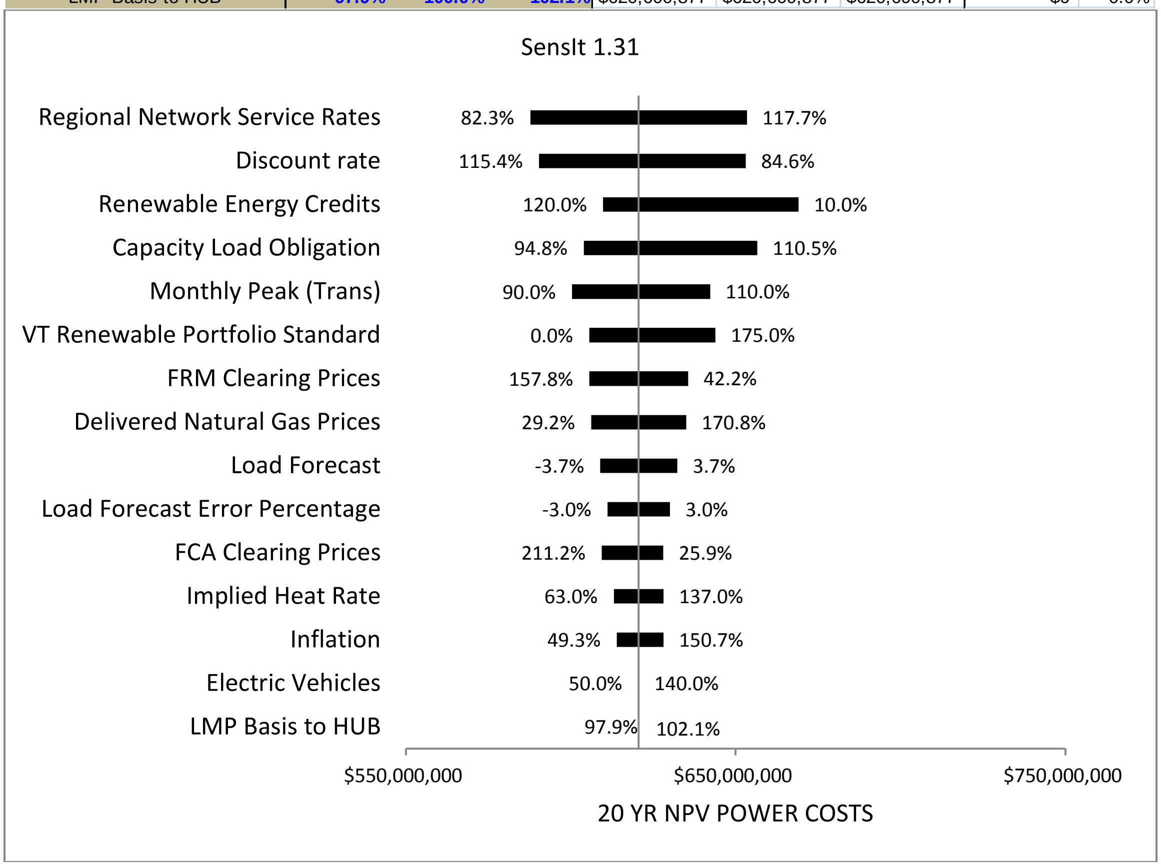
Many Inputs, One Output

Single-Factor Sensitivity Analysis

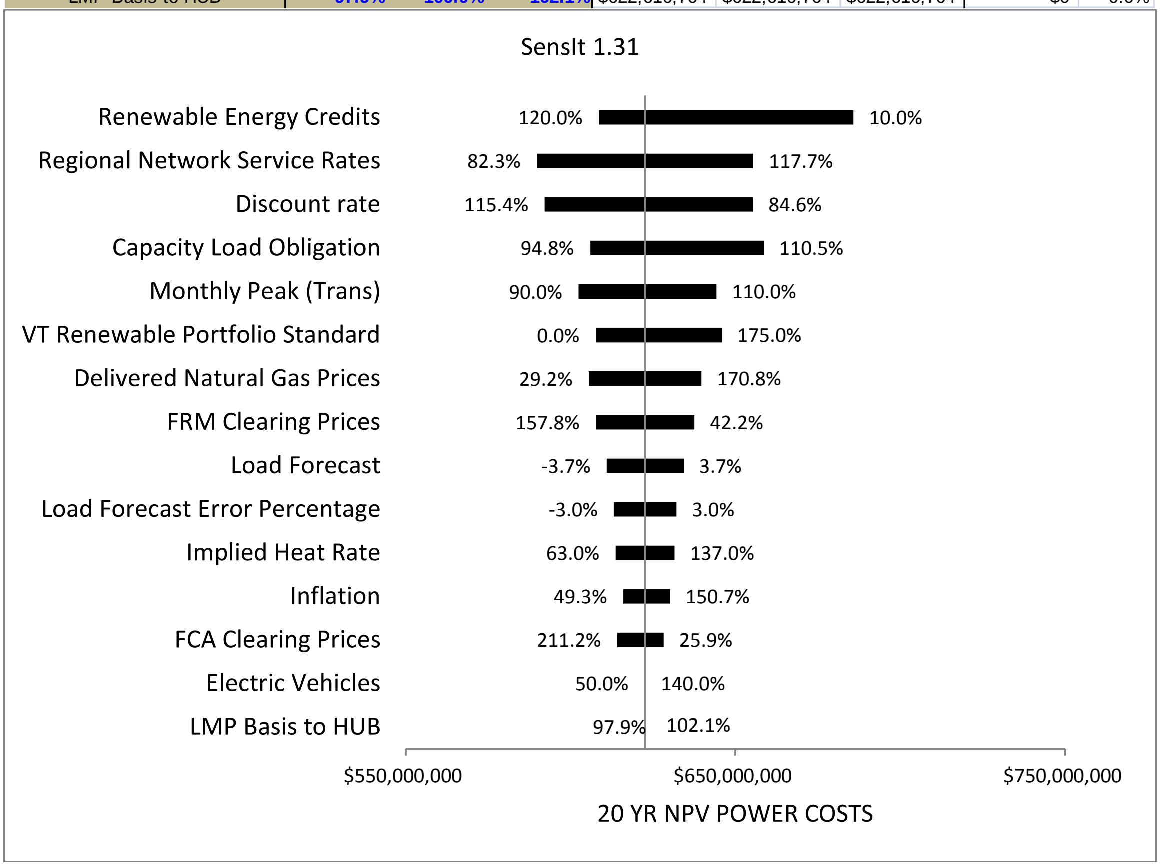
Date 15-Jul-15 Workbook IRPResults4.xls

Time 5:48 PM Output Cell 'Sensit Input Table'!$C$25

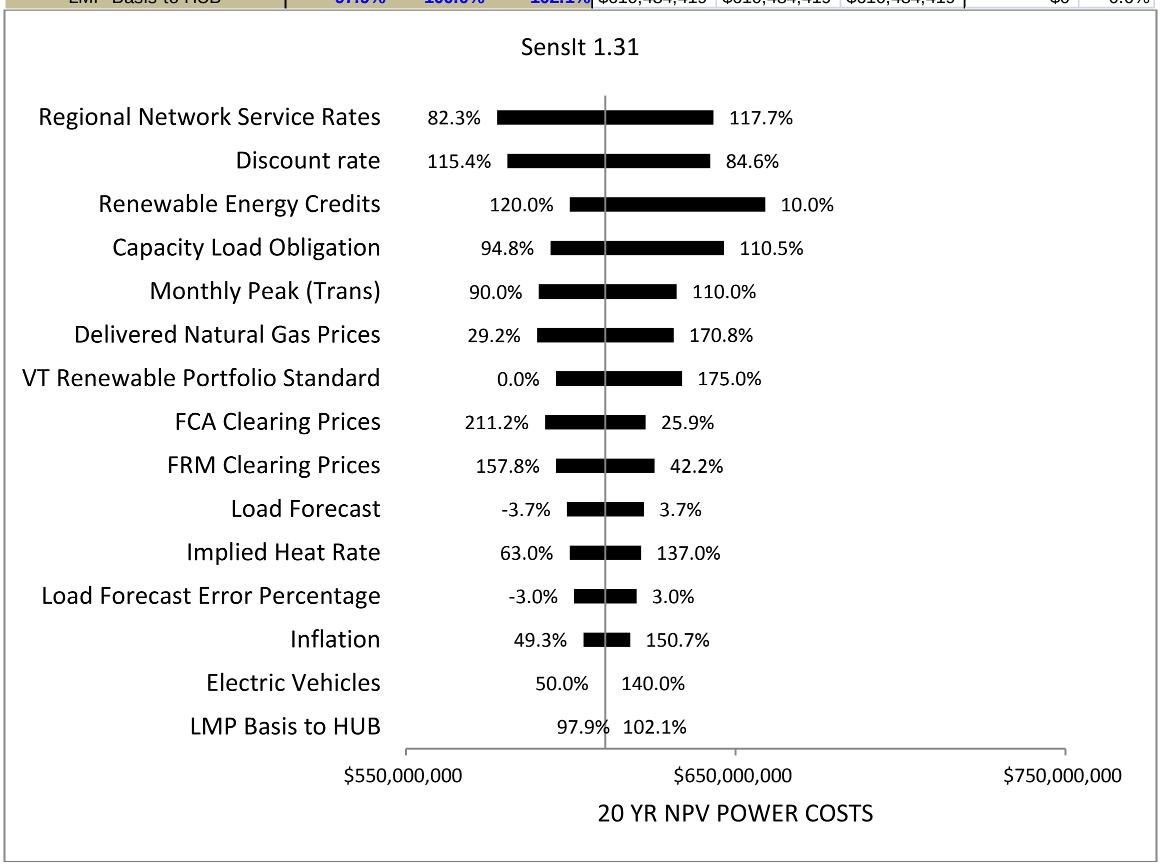
	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$587,782,957	$620,600,877	$653,418,803	$65,635,847	20.4%
Discount rate	115.4%	100.0%	84.6%	$590,374,703	$620,600,877	$653,058,329	$62,683,625	18.6%
Renewable Energy Credits	120.0%	100.0%	10.0%	$609,834,332	$620,600,877	$669,050,330	$59,215,998	16.6%
Capacity Load Obligation	94.8%	100.0%	110.5%	$603,961,714	$620,600,877	$656,569,825	$52,608,111	13.1%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$600,409,545	$620,600,877	$642,243,244	$41,833,698	8.3%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$605,622,905	$620,600,877	$643,845,369	$38,222,464	6.9%
FRM Clearing Prices	157.8%	100.0%	42.2%	$605,646,333	$620,600,877	$635,555,421	$29,909,088	4.2%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$606,193,678	$620,600,877	$635,008,076	$28,814,398	3.9%
Load Forecast	-3.7%	0.0%	3.7%	$608,902,294	$620,600,877	$632,299,460	$23,397,166	2.6%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$611,115,539	$620,600,877	$630,086,214	$18,970,675	1.7%
FCA Clearing Prices	211.2%	100.0%	25.9%	$609,402,936	$620,600,877	$628,066,170	$18,663,234	1.6%
Implied Heat Rate	63.0%	100.0%	137.0%	$613,078,331	$620,600,877	$628,123,422	$15,045,090	1.1%
Inflation	49.3%	100.0%	150.7%	$613,988,318	$620,600,877	$628,152,216	$14,163,897	0.9%
Electric Vehicles	50.0%	100.0%	140.0%	$620,498,236	$620,600,877	$620,682,990	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$620,600,877	$620,600,877	$620,600,877	$0	0.0%



SensIt 1.31			**Scenario 16: SolarIn/FixCon/Wind**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:51 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value			Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$608,580,156	$622,616,764	$685,781,503	$77,201,347	24.9%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$589,798,844	$622,616,764	$655,434,691	$65,635,847	18.0%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$592,156,855	$622,616,764	$655,331,880	$63,175,025	16.7%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$605,977,602	$622,616,764	$658,585,712	$52,608,111	11.6%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$602,425,433	$622,616,764	$644,259,131	$41,833,698	7.3%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$607,638,793	$622,616,764	$645,861,257	$38,222,464	6.1%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$605,529,802	$622,616,764	$639,703,726	$34,173,924	4.9%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$607,662,220	$622,616,764	$637,571,308	$29,909,088	3.7%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$610,918,181	$622,616,764	$634,315,347	$23,397,166	2.3%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$613,131,427	$622,616,764	$632,102,102	$18,970,675	1.5%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$613,695,013	$622,616,764	$631,538,515	$17,843,502	1.3%
Inflation	**49.3%**	**100.0%**	**150.7%**	$616,004,206	$622,616,764	$630,168,103	$14,163,897	0.8%
FCA Clearing Prices	**211.2%**	**100.0%**	**25.9%**	$614,167,545	$622,616,764	$628,249,577	$14,082,033	0.8%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$622,514,123	$622,616,764	$622,698,877	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$622,616,764	$622,616,764	$622,616,764	$0	0.0%



SensIt 1.31			**Scenario 17: SolarOut/SolarIn/Mkt Cont**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:53 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$577,666,499	$610,484,419	$643,302,345	$65,635,847	19.0%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$580,822,128	$610,484,419	$642,336,579	$61,514,451	16.7%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$599,717,873	$610,484,419	$658,933,872	$59,215,998	15.5%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$593,845,256	$610,484,419	$646,453,367	$52,608,111	12.2%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$590,293,087	$610,484,419	$632,126,785	$41,833,698	7.7%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$589,756,749	$610,484,419	$631,212,088	$41,455,339	7.6%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$595,506,447	$610,484,419	$633,728,911	$38,222,464	6.4%
FCA Clearing Prices	**211.2%**	**100.0%**	**25.9%**	$592,205,484	$610,484,419	$622,670,375	$30,464,892	4.1%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$595,529,874	$610,484,419	$625,438,963	$29,909,088	3.9%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$598,785,835	$610,484,419	$622,183,002	$23,397,166	2.4%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$599,661,716	$610,484,419	$621,307,121	$21,645,406	2.1%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$600,999,081	$610,484,419	$619,969,756	$18,970,675	1.6%
Inflation	**49.3%**	**100.0%**	**150.7%**	$603,871,860	$610,484,419	$618,035,758	$14,163,897	0.9%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$610,381,777	$610,484,419	$610,566,531	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$610,484,419	$610,484,419	$610,484,419	$0	0.0%



SensIt 1.31

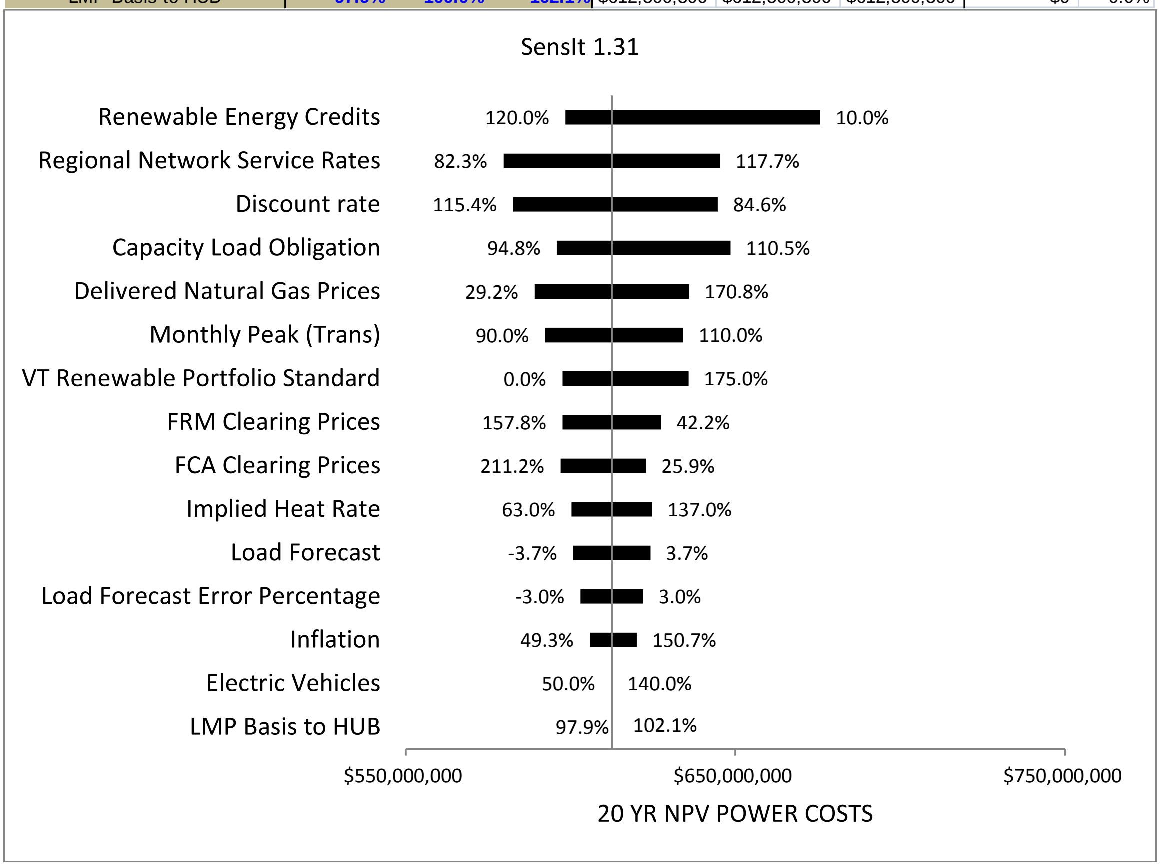
Scenario 18: SolarOut/SolarIn/Wind

Many Inputs, One Output

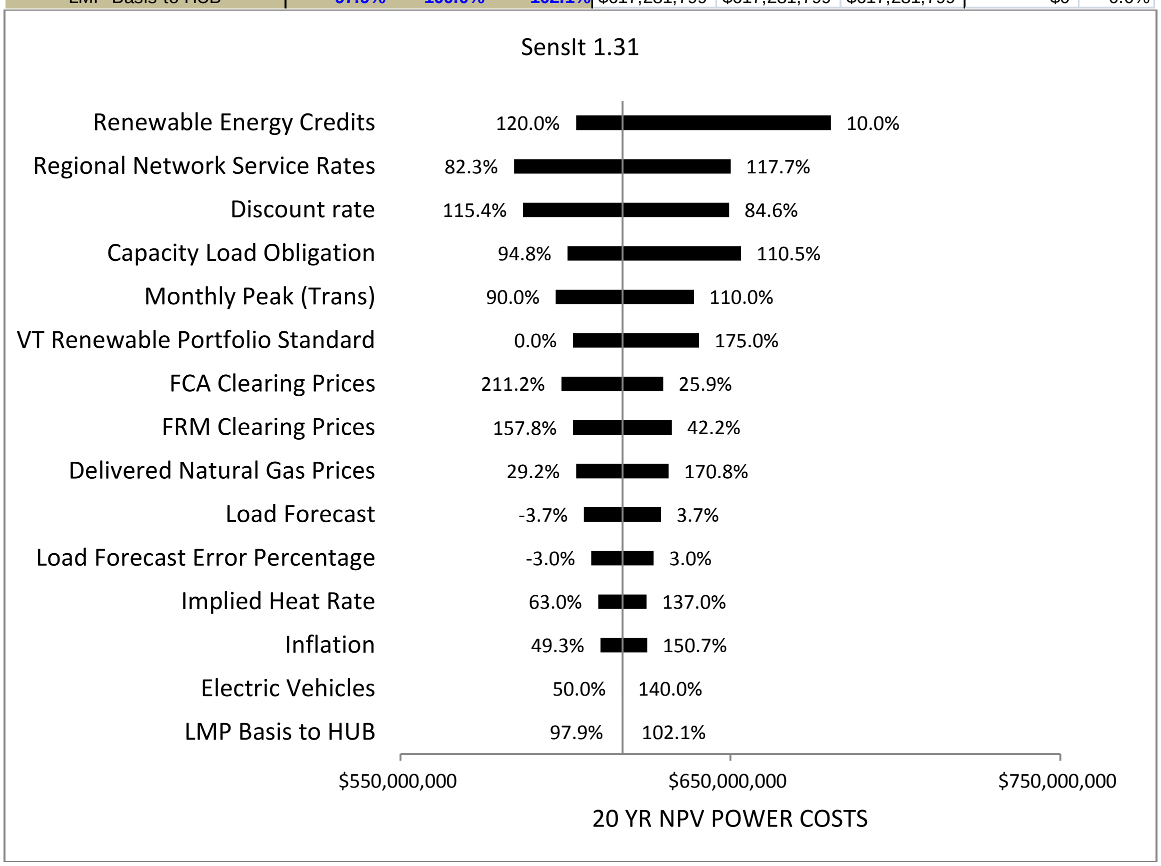
Single-Factor Sensitivity Analysis

Date	15-Jul-15		Workbook	IRPResults4.xls
Time	5:56 PM		Output Cell	'Sensit Input Table'!$C$25

	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$598,463,697	$612,500,306	$675,665,045	$77,201,347	23.3%
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$579,682,386	$612,500,306	$645,318,233	$65,635,847	16.9%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$582,604,280	$612,500,306	$644,610,130	$62,005,850	15.0%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$595,861,143	$612,500,306	$648,469,254	$52,608,111	10.8%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$589,092,873	$612,500,306	$635,907,739	$46,814,865	8.6%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$592,308,975	$612,500,306	$634,142,673	$41,833,698	6.8%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$597,522,335	$612,500,306	$635,744,798	$38,222,464	5.7%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$597,545,762	$612,500,306	$627,454,850	$29,909,088	3.5%
FCA Clearing Prices	**211.2%**	**100.0%**	**25.9%**	$596,970,092	$612,500,306	$622,853,782	$25,883,690	2.6%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$600,278,397	$612,500,306	$624,722,215	$24,443,818	2.3%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$600,801,723	$612,500,306	$624,198,889	$23,397,166	2.1%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$603,014,968	$612,500,306	$621,985,644	$18,970,675	1.4%
Inflation	**49.3%**	**100.0%**	**150.7%**	$605,887,748	$612,500,306	$620,051,645	$14,163,897	0.8%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$612,397,665	$612,500,306	$612,582,419	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$612,500,306	$612,500,306	$612,500,306	$0	0.0%

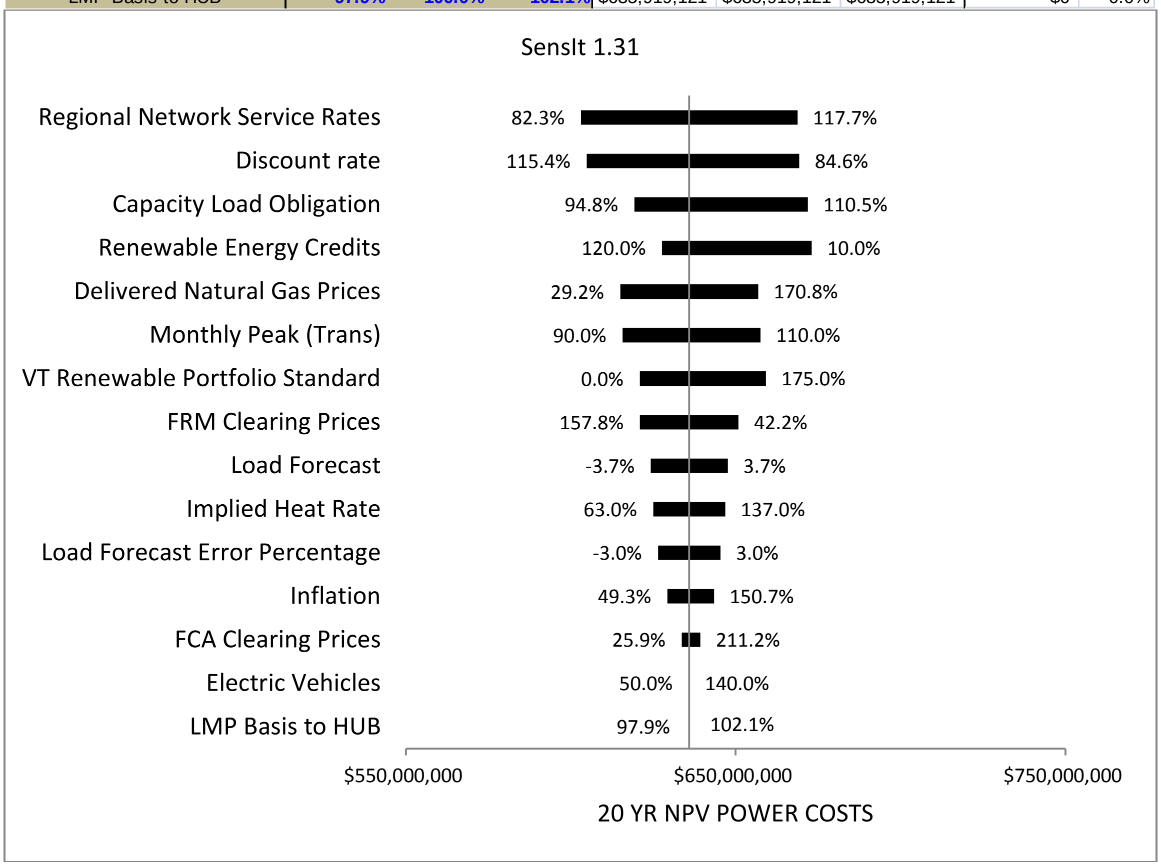


SensIt 1.31			**Scenario 19: SolarIn/Mkt Cont/Wind**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	5:59 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	120.0%	100.0%	10.0%	$603,245,191	$617,281,799	$680,446,538	$77,201,347	24.7%
Regional Network Service Rates	82.3%	100.0%	117.7%	$584,463,880	$617,281,799	$650,099,726	$65,635,847	17.9%
Discount rate	115.4%	100.0%	84.6%	$587,151,777	$617,281,799	$649,641,768	$62,489,991	16.2%
Capacity Load Obligation	94.8%	100.0%	110.5%	$600,642,637	$617,281,799	$653,250,748	$52,608,111	11.5%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$597,090,468	$617,281,799	$638,924,166	$41,833,698	7.3%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$602,303,828	$617,281,799	$640,526,292	$38,222,464	6.1%
FCA Clearing Prices	211.2%	100.0%	25.9%	$598,749,887	$617,281,799	$629,636,408	$30,886,521	4.0%
FRM Clearing Prices	157.8%	100.0%	42.2%	$602,327,255	$617,281,799	$632,236,344	$29,909,088	3.7%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$603,256,696	$617,281,799	$631,306,903	$28,050,208	3.3%
Load Forecast	-3.7%	0.0%	3.7%	$605,583,216	$617,281,799	$628,980,383	$23,397,166	2.3%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$607,796,462	$617,281,799	$626,767,137	$18,970,675	1.5%
Implied Heat Rate	63.0%	100.0%	137.0%	$609,958,761	$617,281,799	$624,604,838	$14,646,078	0.9%
Inflation	49.3%	100.0%	150.7%	$610,669,241	$617,281,799	$624,833,138	$14,163,897	0.8%
Electric Vehicles	50.0%	100.0%	140.0%	$617,179,158	$617,281,799	$617,363,912	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$617,281,799	$617,281,799	$617,281,799	$0	0.0%



SensIt 1.31			**Scenario 20: SolarOut/FixCon/Mkt Cont**				
Many Inputs, One Output							
Single-Factor Sensitivity Analysis							
Date	15-Jul-15			Workbook	IRPResults4.xls		
Time	6:02 PM			Output Cell	'Sensit Input Table'!$C$25		
				20 YR NPV POWER COSTS			
	Corresponding Input Value			Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2

Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Percent Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$603,101,201	$635,919,121	$668,737,048	$65,635,847	20.7%
Discount rate	115.4%	100.0%	84.6%	$604,832,102	$635,919,121	$669,301,055	$64,468,953	20.0%
Capacity Load Obligation	94.8%	100.0%	110.5%	$619,279,958	$635,919,121	$671,888,069	$52,608,111	13.3%
Renewable Energy Credits	120.0%	100.0%	10.0%	$627,671,576	$635,919,121	$673,033,071	$45,361,495	9.9%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$614,997,054	$635,919,121	$656,841,188	$41,844,134	8.4%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$615,727,790	$635,919,121	$657,561,488	$41,833,698	8.4%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$620,941,150	$635,919,121	$659,163,613	$38,222,464	7.0%
FRM Clearing Prices	157.8%	100.0%	42.2%	$620,964,577	$635,919,121	$650,873,665	$29,909,088	4.3%
Load Forecast	-3.7%	0.0%	3.7%	$624,220,538	$635,919,121	$647,617,704	$23,397,166	2.6%
Implied Heat Rate	63.0%	100.0%	137.0%	$624,994,916	$635,919,121	$646,843,326	$21,848,410	2.3%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$626,433,783	$635,919,121	$645,404,459	$18,970,675	1.7%
Inflation	49.3%	100.0%	150.7%	$629,306,563	$635,919,121	$643,470,460	$14,163,897	1.0%
FCA Clearing Prices	25.9%	100.0%	211.2%	$633,667,888	$635,919,121	$639,295,971	$5,628,083	0.2%
Electric Vehicles	50.0%	100.0%	140.0%	$635,816,480	$635,919,121	$636,001,234	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$635,919,121	$635,919,121	$635,919,121	$0	0.0%



SensIt 1.31

Many Inputs, One Output

Single-Factor Sensitivity Analysis

Scenario 21: FixCon/Mkt Cont/Wind

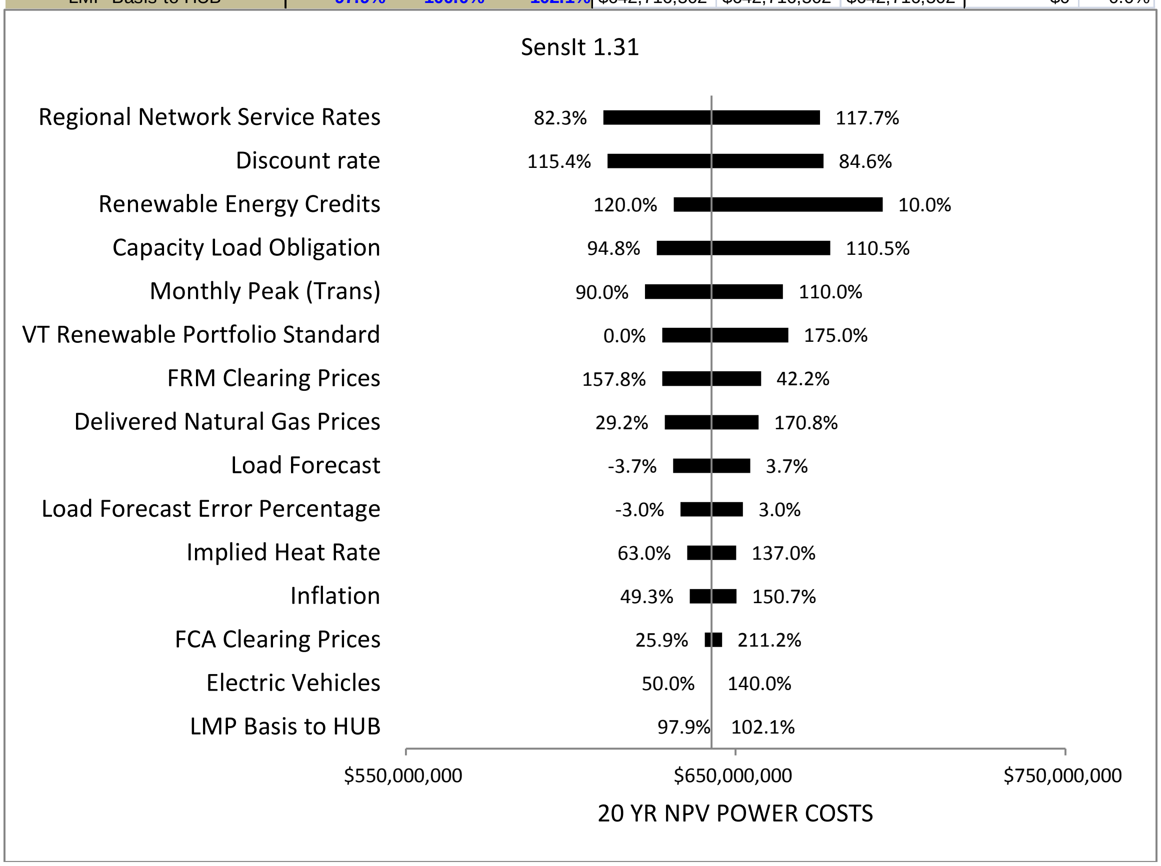
Date 15-Jul-15

Time 6:05 PM

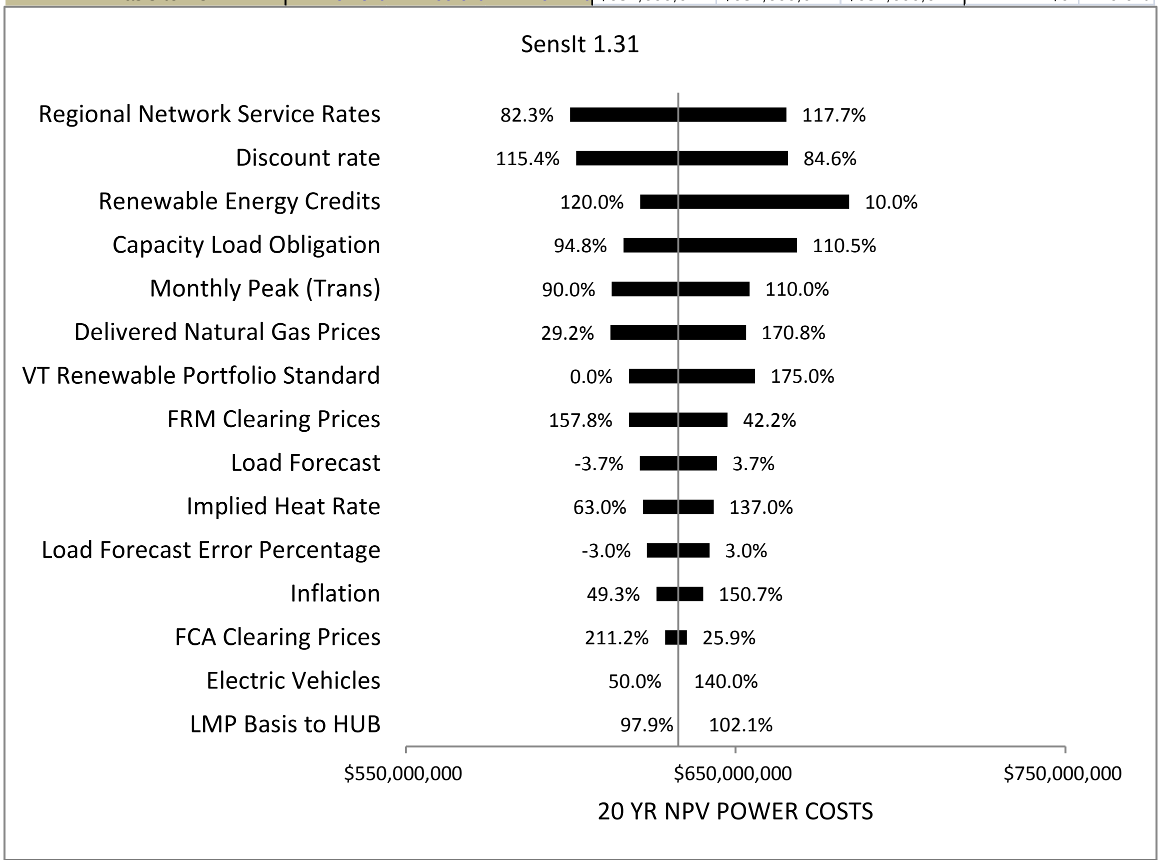
Workbook IRPResults4.xls

Output Cell 'Sensit Input Table'!$C$25

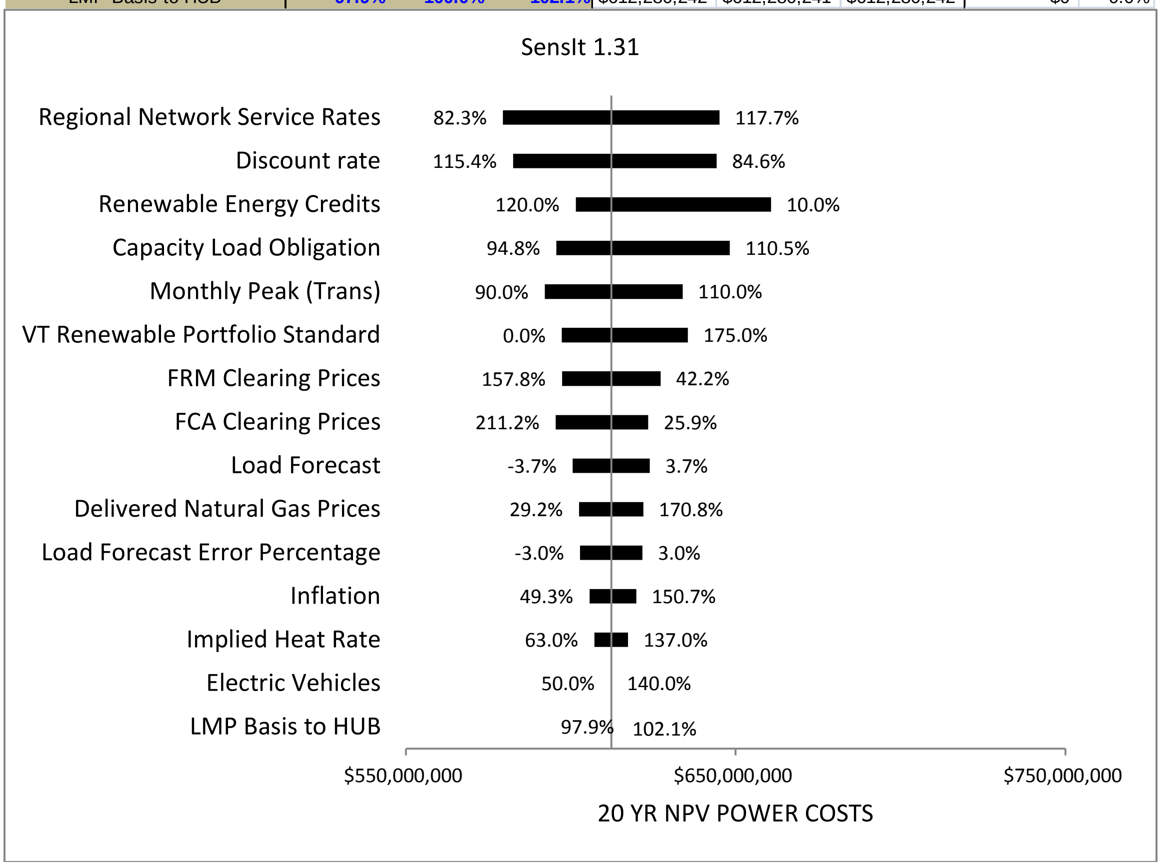
	Corresponding Input Value			20 YR NPV POWER COSTS Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$609,898,582	$642,716,502	$675,534,429	$65,635,847	19.9%
Discount rate	115.4%	100.0%	84.6%	$611,161,750	$642,716,502	$676,606,245	$65,444,494	19.8%
Renewable Energy Credits	120.0%	100.0%	10.0%	$631,198,894	$642,716,502	$694,545,738	$63,346,844	18.5%
Capacity Load Obligation	94.8%	100.0%	110.5%	$626,077,339	$642,716,502	$678,685,450	$52,608,111	12.8%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$622,525,171	$642,716,502	$664,358,869	$41,833,698	8.1%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$627,738,531	$642,716,502	$665,960,994	$38,222,464	6.8%
FRM Clearing Prices	157.8%	100.0%	42.2%	$627,761,958	$642,716,502	$657,671,046	$29,909,088	4.1%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$628,497,001	$642,716,502	$656,936,003	$28,439,003	3.7%
Load Forecast	-3.7%	0.0%	3.7%	$631,017,919	$642,716,502	$654,415,085	$23,397,166	2.5%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$633,231,164	$642,716,502	$652,201,840	$18,970,675	1.7%
Implied Heat Rate	63.0%	100.0%	137.0%	$635,291,961	$642,716,502	$650,141,043	$14,849,083	1.0%
Inflation	49.3%	100.0%	150.7%	$636,103,944	$642,716,502	$650,267,841	$14,163,897	0.9%
FCA Clearing Prices	25.9%	100.0%	211.2%	$640,633,920	$642,716,502	$645,840,374	$5,206,454	0.1%
Electric Vehicles	50.0%	100.0%	140.0%	$642,613,861	$642,716,502	$642,798,615	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$642,716,502	$642,716,502	$642,716,502	$0	0.0%



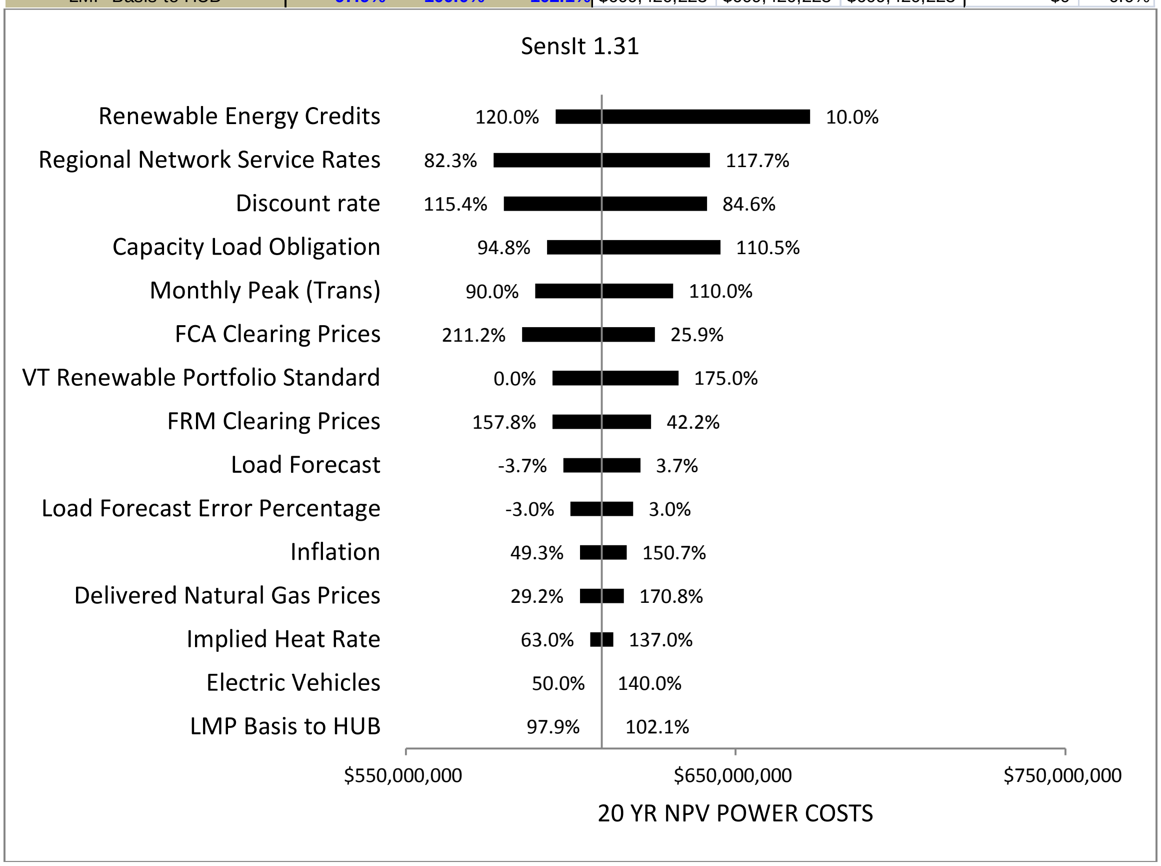
SensIt 1.31			**Scenario 22: SolarOut/Mkt Cont/Wind**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	6:08 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	**82.3%**	**100.0%**	**117.7%**	$599,782,124	$632,600,044	$665,417,970	$65,635,847	19.0%
Discount rate	**115.4%**	**100.0%**	**84.6%**	$601,609,175	$632,600,044	$665,884,495	$64,275,319	18.3%
Renewable Energy Credits	**120.0%**	**100.0%**	**10.0%**	$621,082,436	$632,600,044	$684,429,279	$63,346,844	17.7%
Capacity Load Obligation	**94.8%**	**100.0%**	**110.5%**	$615,960,881	$632,600,044	$668,568,992	$52,608,111	12.2%
Monthly Peak (Trans)	**90.0%**	**100.0%**	**110.0%**	$612,408,712	$632,600,044	$654,242,411	$41,833,698	7.7%
Delivered Natural Gas Prices	**29.2%**	**100.0%**	**170.8%**	$612,060,072	$632,600,044	$653,140,016	$41,079,944	7.5%
VT Renewable Portfolio Standard	**0.0%**	**100.0%**	**175.0%**	$617,622,072	$632,600,044	$655,844,536	$38,222,464	6.5%
FRM Clearing Prices	**157.8%**	**100.0%**	**42.2%**	$617,645,500	$632,600,044	$647,554,588	$29,909,088	4.0%
Load Forecast	**-3.7%**	**0.0%**	**3.7%**	$620,901,461	$632,600,044	$644,298,627	$23,397,166	2.4%
Implied Heat Rate	**63.0%**	**100.0%**	**137.0%**	$621,875,345	$632,600,044	$643,324,743	$21,449,398	2.0%
Load Forecast Error Percentage	**-3.0%**	**0.0%**	**3.0%**	$623,114,706	$632,600,044	$642,085,381	$18,970,675	1.6%
Inflation	**49.3%**	**100.0%**	**150.7%**	$625,987,486	$632,600,044	$640,151,383	$14,163,897	0.9%
FCA Clearing Prices	**211.2%**	**100.0%**	**25.9%**	$628,642,922	$632,600,044	$635,238,125	$6,595,204	0.2%
Electric Vehicles	**50.0%**	**100.0%**	**140.0%**	$632,497,403	$632,600,044	$632,682,157	$184,754	0.0%
LMP Basis to HUB	**97.9%**	**100.0%**	**102.1%**	$632,600,044	$632,600,044	$632,600,044	$0	0.0%



SensIt 1.31			**Scenario 23: SolarOut/SolarIn/FixCon/Mkt Cont**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	6:11 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Regional Network Service Rates	82.3%	100.0%	117.7%	$579,462,322	$612,280,241	$645,098,168	$65,635,847	20.6%
Discount rate	115.4%	100.0%	84.6%	$582,518,977	$612,280,241	$644,237,874	$61,718,896	18.2%
Renewable Energy Credits	120.0%	100.0%	10.0%	$601,513,696	$612,280,241	$660,729,695	$59,215,998	16.8%
Capacity Load Obligation	94.8%	100.0%	110.5%	$595,641,079	$612,280,241	$648,249,190	$52,608,111	13.3%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$592,088,910	$612,280,241	$633,922,608	$41,833,698	8.4%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$597,302,270	$612,280,241	$635,524,734	$38,222,464	7.0%
FRM Clearing Prices	157.8%	100.0%	42.2%	$597,325,697	$612,280,241	$627,234,786	$29,909,088	4.3%
FCA Clearing Prices	211.2%	100.0%	25.9%	$595,455,482	$612,280,241	$623,496,748	$28,041,267	3.8%
Load Forecast	-3.7%	0.0%	3.7%	$600,581,658	$612,280,241	$623,978,825	$23,397,166	2.6%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$602,512,575	$612,280,241	$622,047,908	$19,535,333	1.8%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$602,794,904	$612,280,241	$621,765,579	$18,970,675	1.7%
Inflation	49.3%	100.0%	150.7%	$605,667,683	$612,280,241	$619,831,580	$14,163,897	1.0%
Implied Heat Rate	63.0%	100.0%	137.0%	$607,180,172	$612,280,241	$617,380,311	$10,200,138	0.5%
Electric Vehicles	50.0%	100.0%	140.0%	$612,177,600	$612,280,241	$612,362,354	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$612,280,242	$612,280,241	$612,280,242	$0	0.0%



SensIt 1.31			Scenario 24: SolarOut/SolarIn/Mkt Cont/Wind					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	6:14 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value			Output Value				Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	120.0%	100.0%	10.0%	$595,383,615	$609,420,223	$672,584,962	$77,201,347	25.0%
Regional Network Service Rates	82.3%	100.0%	117.7%	$576,602,303	$609,420,223	$642,238,150	$65,635,847	18.0%
Discount rate	115.4%	100.0%	84.6%	$579,729,202	$609,420,223	$641,308,035	$61,578,833	15.9%
Capacity Load Obligation	94.8%	100.0%	110.5%	$592,781,061	$609,420,223	$645,389,171	$52,608,111	11.6%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$589,228,892	$609,420,223	$631,062,590	$41,833,698	7.3%
FCA Clearing Prices	211.2%	100.0%	25.9%	$585,261,491	$609,420,223	$625,526,045	$40,264,554	6.8%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$594,442,252	$609,420,223	$632,664,716	$38,222,464	6.1%
FRM Clearing Prices	157.8%	100.0%	42.2%	$594,465,679	$609,420,223	$624,374,767	$29,909,088	3.7%
Load Forecast	-3.7%	0.0%	3.7%	$597,721,640	$609,420,223	$621,118,806	$23,397,166	2.3%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$599,934,886	$609,420,223	$618,905,561	$18,970,675	1.5%
Inflation	49.3%	100.0%	150.7%	$602,807,665	$609,420,223	$616,971,562	$14,163,897	0.8%
Delivered Natural Gas Prices	29.2%	100.0%	170.8%	$602,774,653	$609,420,223	$616,065,794	$13,291,141	0.7%
Implied Heat Rate	63.0%	100.0%	137.0%	$605,950,319	$609,420,223	$612,890,128	$6,939,809	0.2%
Electric Vehicles	50.0%	100.0%	140.0%	$609,317,582	$609,420,223	$609,502,336	$184,754	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$609,420,223	$609,420,223	$609,420,223	$0	0.0%



SensIt 1.31			**Scenario 25: SolarOut/SolarIn/FixCon/Mkt Cont/Wind**					
Many Inputs, One Output								
Single-Factor Sensitivity Analysis								
Date	15-Jul-15			Workbook	IRPResults4.xls			
Time	6:17 PM			Output Cell	'Sensit Input Table'!$C$25			
				20 YR NPV POWER COSTS				
	Corresponding Input Value				Output Value			Percent
Input Variable	Low Output	Base Case	High Output	Low	Base	High	Swing	Swing^2
Renewable Energy Credits	120.0%	100.0%	10.0%	$597,379,121	$611,415,730	$674,580,468	$77,201,347	25.5%
Regional Network Service Rates	82.3%	100.0%	117.7%	$578,597,810	$611,415,730	$644,233,656	$65,635,847	18.4%
Discount rate	115.4%	100.0%	84.6%	$581,612,905	$611,415,730	$643,423,039	$61,810,135	16.3%
Capacity Load Obligation	94.8%	100.0%	110.5%	$594,776,567	$611,415,730	$647,384,678	$52,608,111	11.8%
Monthly Peak (Trans)	90.0%	100.0%	110.0%	$591,224,398	$611,415,730	$633,058,096	$41,833,698	7.5%
VT Renewable Portfolio Standard	0.0%	100.0%	175.0%	$596,437,758	$611,415,730	$634,660,222	$38,222,464	6.2%
FCA Clearing Prices	211.2%	100.0%	25.9%	$589,389,994	$611,415,730	$626,099,553	$36,709,559	5.8%
FRM Clearing Prices	157.8%	100.0%	42.2%	$596,461,185	$611,415,730	$626,370,274	$29,909,088	3.8%
Load Forecast	-3.7%	0.0%	3.7%	$599,717,146	$611,415,730	$623,114,313	$23,397,166	2.3%
Load Forecast Error Percentage	-3.0%	0.0%	3.0%	$601,930,392	$611,415,730	$620,901,067	$18,970,675	1.5%
Inflation	49.3%	100.0%	150.7%	$604,803,171	$611,415,730	$618,967,069	$14,163,897	0.9%
Electric Vehicles	50.0%	100.0%	140.0%	$611,313,088	$611,415,730	$611,497,842	$184,754	0.0%
Delivered Natural Gas Prices	170.8%	100.0%	29.2%	$611,372,227	$611,415,730	$611,459,232	$87,006	0.0%
Implied Heat Rate	137.0%	100.0%	63.0%	$611,393,015	$611,415,730	$611,438,444	$45,429	0.0%
LMP Basis to HUB	97.9%	100.0%	102.1%	$611,415,730	$611,415,730	$611,415,730	$0	0.0%