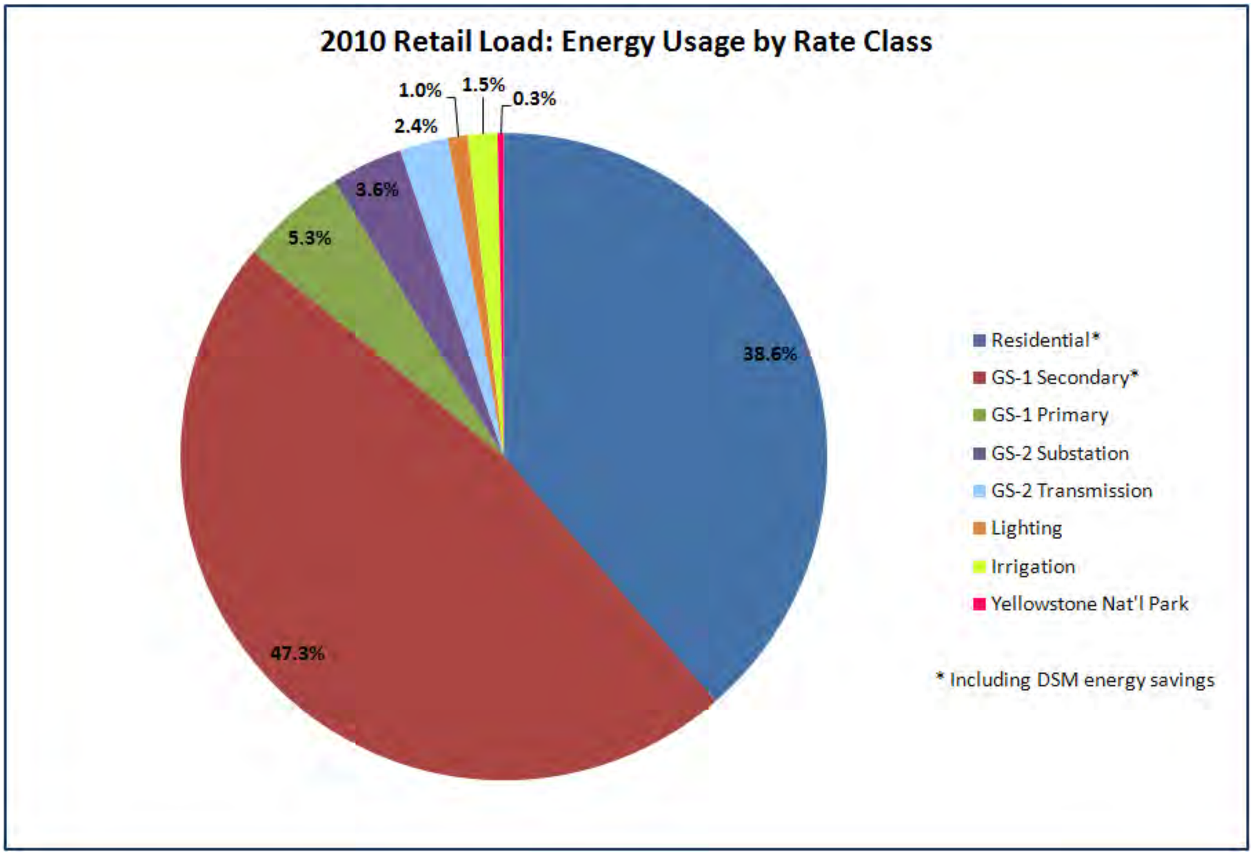
Chapter 6
FORECASTS AND RESOURCE INPUTS

Load Forecast

NorthWestern has prepared a 20-year forecast of load for use in the long-term resource planning process. In addition to the base forecast, high and low load growth scenarios were created for use in the intrinsic evaluations to test the effects of both elevated and depressed growth rates. Loads used in the modeling runs include losses. These losses, applied by individual rate class, must be included in order to determine the total amount of energy needed at the generator or supplier level to serve the needs of retail customers. The forecast was constructed by first evaluating the load history for each rate class followed by the projection of customer count and energy usage.

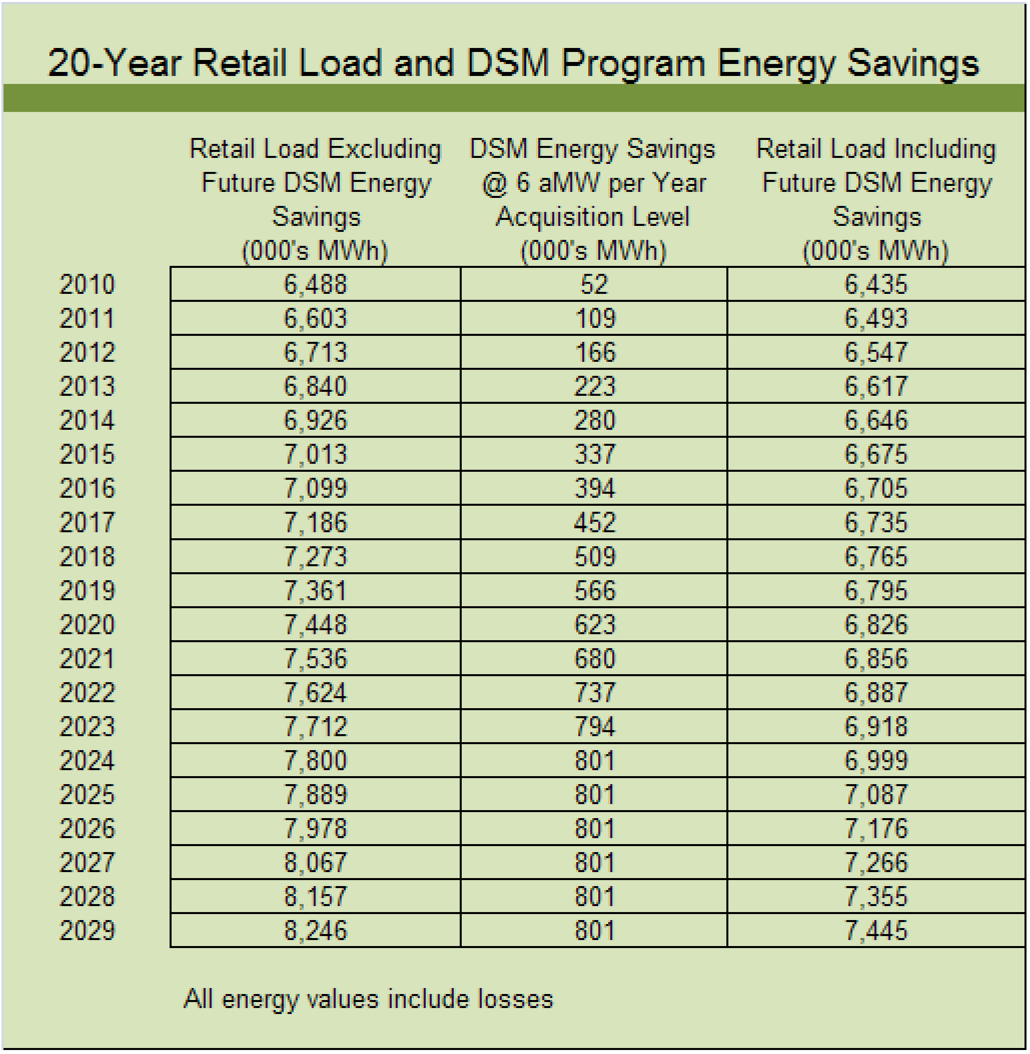
Residential and GS-1 Secondary (small commercial) load represent the majority (approximately 85%) of the retail energy needs in the NorthWestern Montana service territory (see Figure 17). These loads are weather sensitive and exhibit both seasonal and year-to-year variation due to outside air temperature extremes that are typical for the Montana climate. The evaluation of these rate classes includes examining historic usage on a metered usage basis followed by the estimation of usage on a “average” weather basis using load history from the early 1980s to present.

Figure 17



The long-term load forecast is prepared based on estimates of annual energy needs determined for each rate class and aggregated to a single annual value. The basecase estimate of the retail load serving obligation is tabulated and presented in Table 27 to show future loads both excluding and including the impact of the 2009 updated DSM energy savings plan. Additional detailed information on the forecast, forecasting methods, inputs, and assumptions can be found in Volume 3 Chapter 6.

Table 27



20-Year Retail Load and DSM Program Energy Savings

	Retail Load Excluding Future DSM Energy Savings (000's MWh)	DSM Energy Savings @ 6 aMW per Year Acquisition Level (000's MWh)	Retail Load Including Future DSM Energy Savings (000's MWh)
2010	6,488	52	6,435
2011	6,603	109	6,493
2012	6,713	166	6,547
2013	6,840	223	6,617
2014	6,926	280	6,646
2015	7,013	337	6,675
2016	7,099	394	6,705
2017	7,186	452	6,735
2018	7,273	509	6,765
2019	7,361	566	6,795
2020	7,448	623	6,826
2021	7,536	680	6,856
2022	7,624	737	6,887
2023	7,712	794	6,918
2024	7,800	801	6,999
2025	7,889	801	7,087
2026	7,978	801	7,176
2027	8,067	801	7,266
2028	8,157	801	7,355
2029	8,246	801	7,445

All energy values include losses

Load Resource Balance

The Supply load serving obligation specifies the annual energy acquisition target. Load – resource balance is achieved when resources equal the load. To determine needs in the future, the existing supply portfolio is compared against the forecast need to determine the amount and timing of resource acquisition. Resource acquisition planning by NorthWestern must recognize the differences in need between heavy-load and light-load (also referred to as on and off-peak) hours to satisfy load- resource balance. Simple averaging or ignoring the differences in HL and LL would lead to a resource acquisition plan that would not ensure load-resource balance for each of the load serving periods and likely lead to both deficit and surplus energy.

To illustrate the load-resource balance for the next 10 years using existing resources and forecast load, Figures 18 and 19 have been prepared. The red forecast load line indicates seasonal swings in energy requirements with values spiking during summer and winter seasons. Below the load line, existing resources have been stacked and summed to demonstrate the volume of resource need as compared to the existing volume of secured resources. Each figure has been created using monthly values and results in a spikey appearance that is reflective of seasonal changes to load and a blended resource shape designed to meet changing load needs.

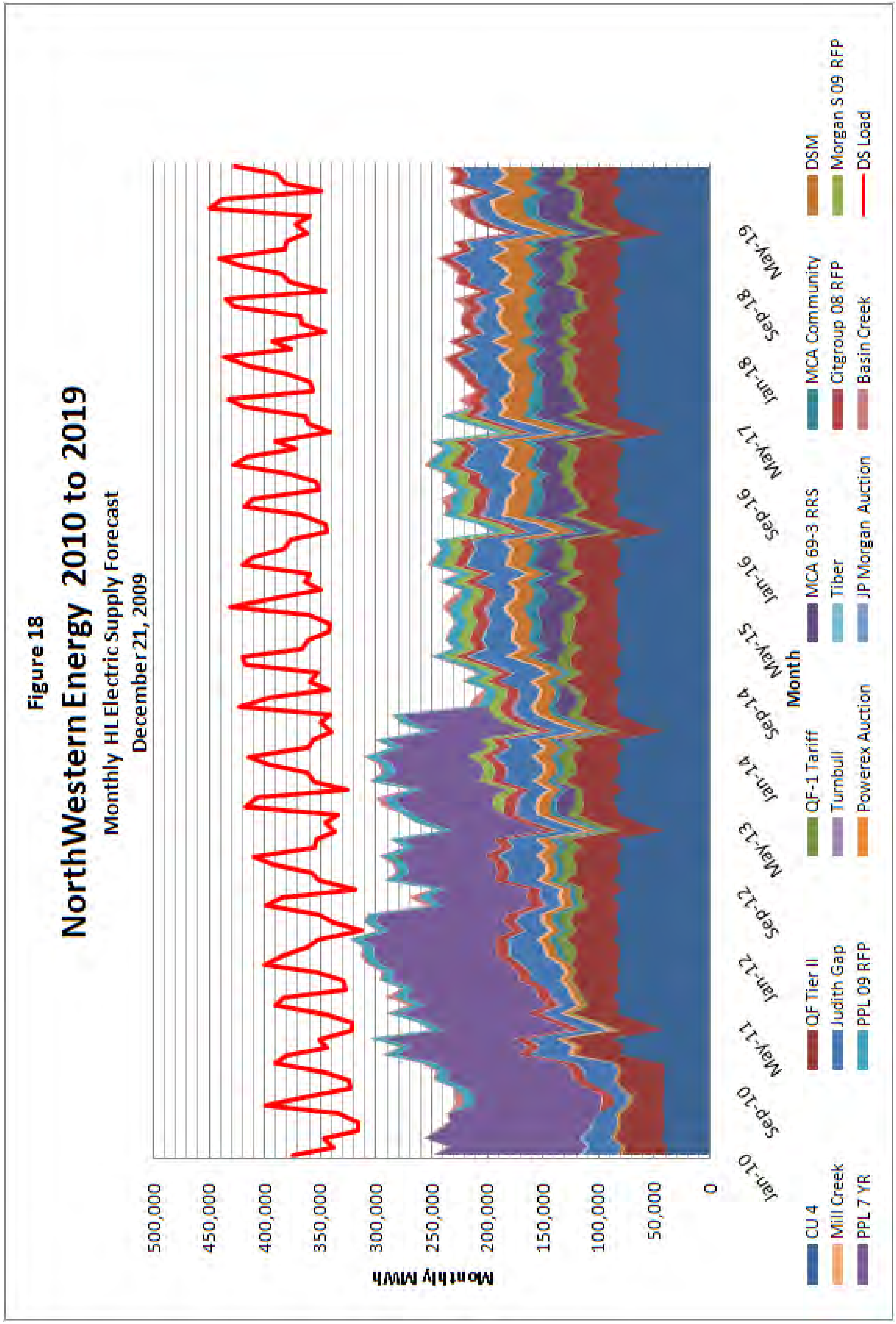


Figure 18

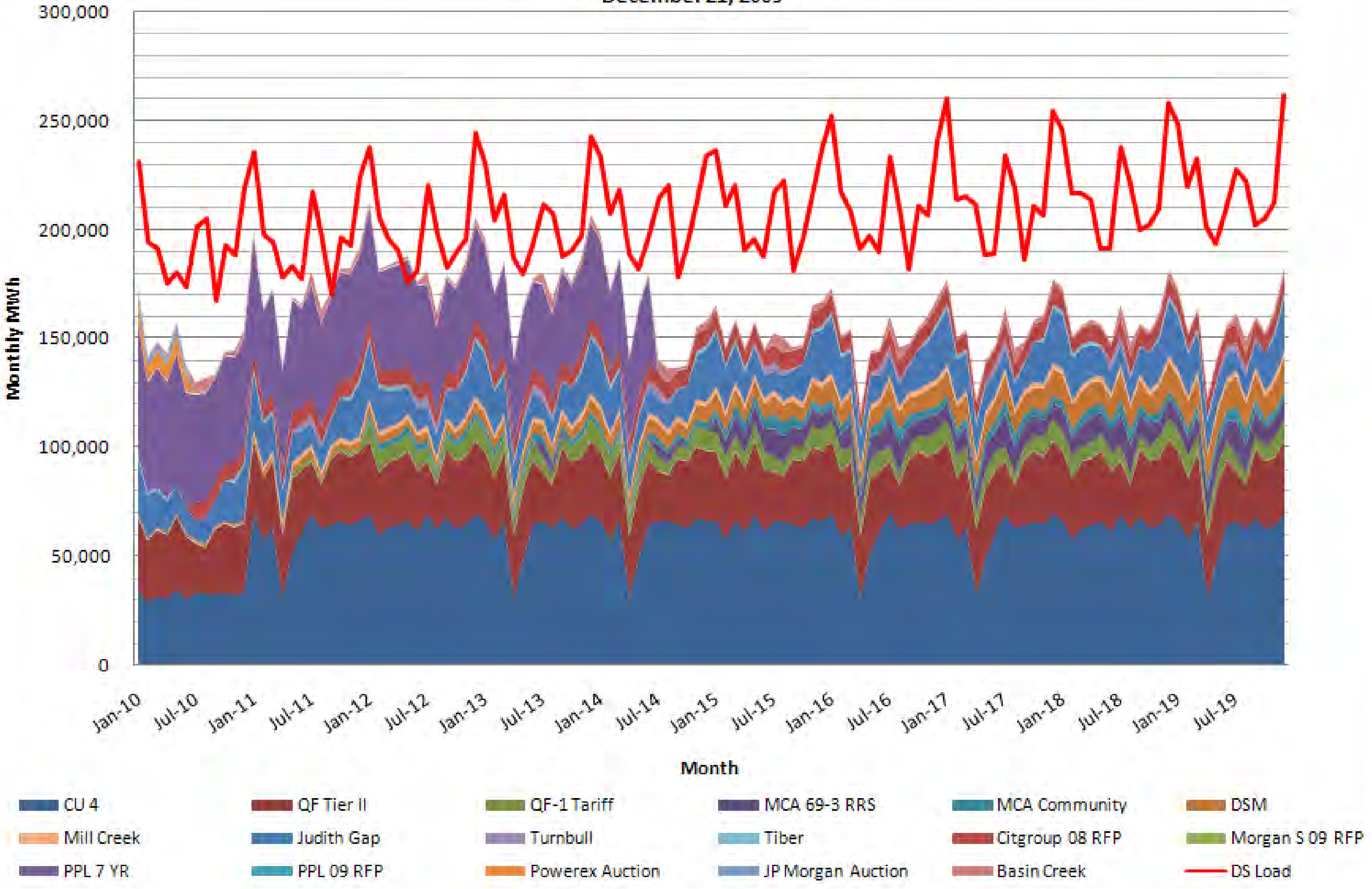
NorthWestern Energy 2010 to 2019
Monthly HL Electric Supply Forecast
December 21, 2009

Figure 19

NorthWestern Energy 2010 to 2019

Monthly LL Electric Supply Forecast

December 21, 2009



Market Price Forecasts

Price Forecasts

As in the 2007 Procurement Plan, NorthWestern acquired energy market price projections from Lands Energy Consulting. The Lands Energy price projection uses current forward market pricing as the starting point and builds upon the market values to arrive at a set of long-term price forecasts. It is important that the price forecasts reflect actual market alternatives the utility faces in the near-term as the market itself is a viable alternative to resource acquisition, at least over periods of time for which long-term market based energy contracts may be secured. While the longer-term price projections will certainly change by the next update to the Procurement Plan, subsequent plans can be updated and inform utility resource decisions at that time.

The price forecast uses as inputs the NyMex monthly forward price strip for natural gas through September 2013 and the forward price strip for electricity through March 2011. Since the natural gas markets are more liquid and transparent, the electricity prices are computed for the period April 2011 through September 2013 by applying the first year market heat rates to the gas prices. The market heat rate is the observed relationship between electricity and natural gas prices and is computed by dividing the electricity price by the natural gas price. The units for market heat rate are MMBtu/MWh, the same units that are used to quantify the operating efficiency of natural gas plants. In this way, the economic dispatch of natural gas units can be determined by comparing a specific unit's effective heat rate with the market heat rate. If the unit's heat rate is lower than the market heat rate, the unit is economic at prevailing markets and should run. Since the marginal natural gas unit operating at any given time drives the market relationship between natural gas and electricity, it is reasonable to expect that the market heat rate should be elevated under higher market conditions. Prices beyond September 2013 were determined by applying a simple annual escalation factor of 2.7569%. The annual escalation was computed using a 3-year average of the GDP Implicit Price Deflator.1

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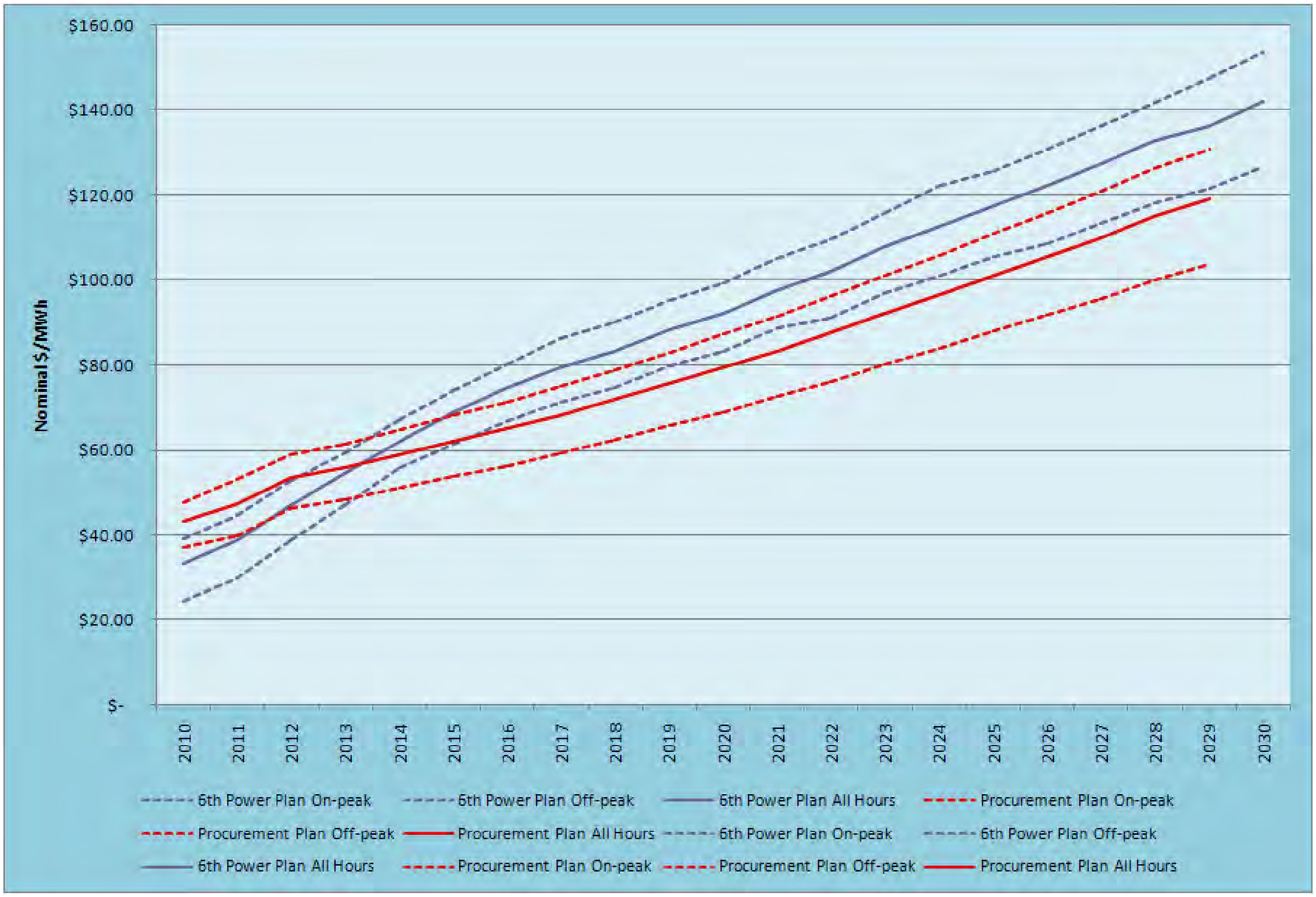
[1] Table showing the GDP Implicit Price Deflator included in Appendix XXX

Figure 20: Price Forecast Compared to NWPCC 6th Power Plan



Comparison to 6th Power Plan

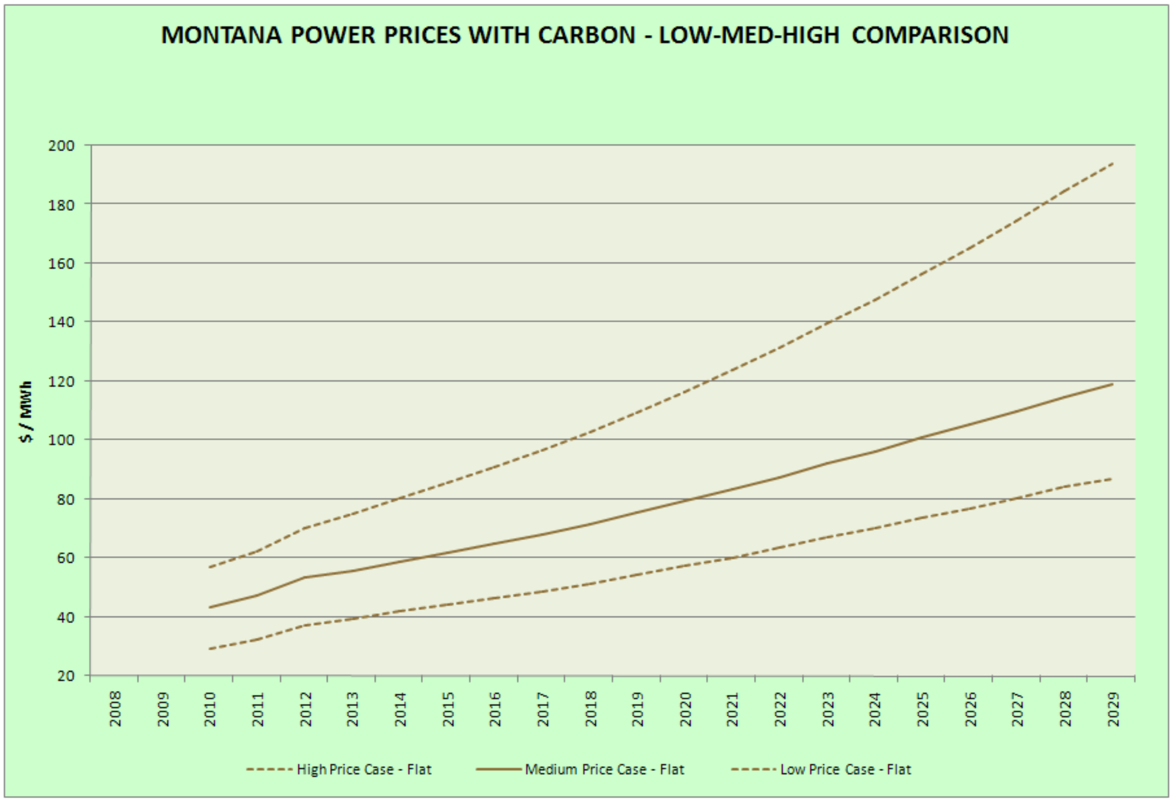
The NWPCC price forecast compares favorably with the Lands Energy forecast. The Lands Energy forecast is a little higher in the first few years, but the NWPCC forecast overtakes it and is somewhat higher in the latter years.

High And Low Case Price Forecasts

It is important within the context of Procurement Plan analysis to model price forecast variations to understand the sensitivity of results – and ultimately resource decisions – in light of significant changes in the long-term price of power. It is important to note that the long-term sensitivity is different from short-term market volatility. The short-term market volatility is analyzed thorough the use of stochastic modeling using the GenTrader® model and is applied to all of the long-term market price forecasts.

The High Price Case was computed by applying a 30% upward adjustment to the first two years of the Medium Case forecast and using a 5.0% annual escalation thereafter. The Low Price Case was computed by applying a 30% downward adjustment to the first two years of the Medium Case forecast and using a 2.0% annual escalation thereafter. These cases bracket a reasonable range of potential long-term shifts in market prices.

Figure 21: Low, Medium and High Price Forecasts for Flat Power (all hours)



Carbon Adjustment

The market forecasts represent the cost of the highest cost unit needed to serve regional load – the marginal unit. Currently, there are no cost adders to these different units based on their CO2 emissions. Since the modeling will incorporate carbon emissions adders to the different resource procurement options, it is important to make a similar adjustment to the market reflecting the impact carbon cost adders will have on the marginal unit. This adjustment to the price curves was accomplished by applying various carbon cost projections to the market using the computed market heat rate to determined the implied heat rate of the marginal operating unit and adjusting the adder based on an assumption that the CO2 emission rate will be similar to a combined cycle combustion turbine, which emits .429 tons CO2 for every Megawatt-hour produced. The carbon projections that were used as inputs for this adjustment are shown in the figure below. Please refer also to Chapter 4, Table 18 Carbon Scenarios. By making this adjustment, the market curves should reflect the market price forecast with and without carbon penalty impacts is displayed in the following two tables.

Figure 22

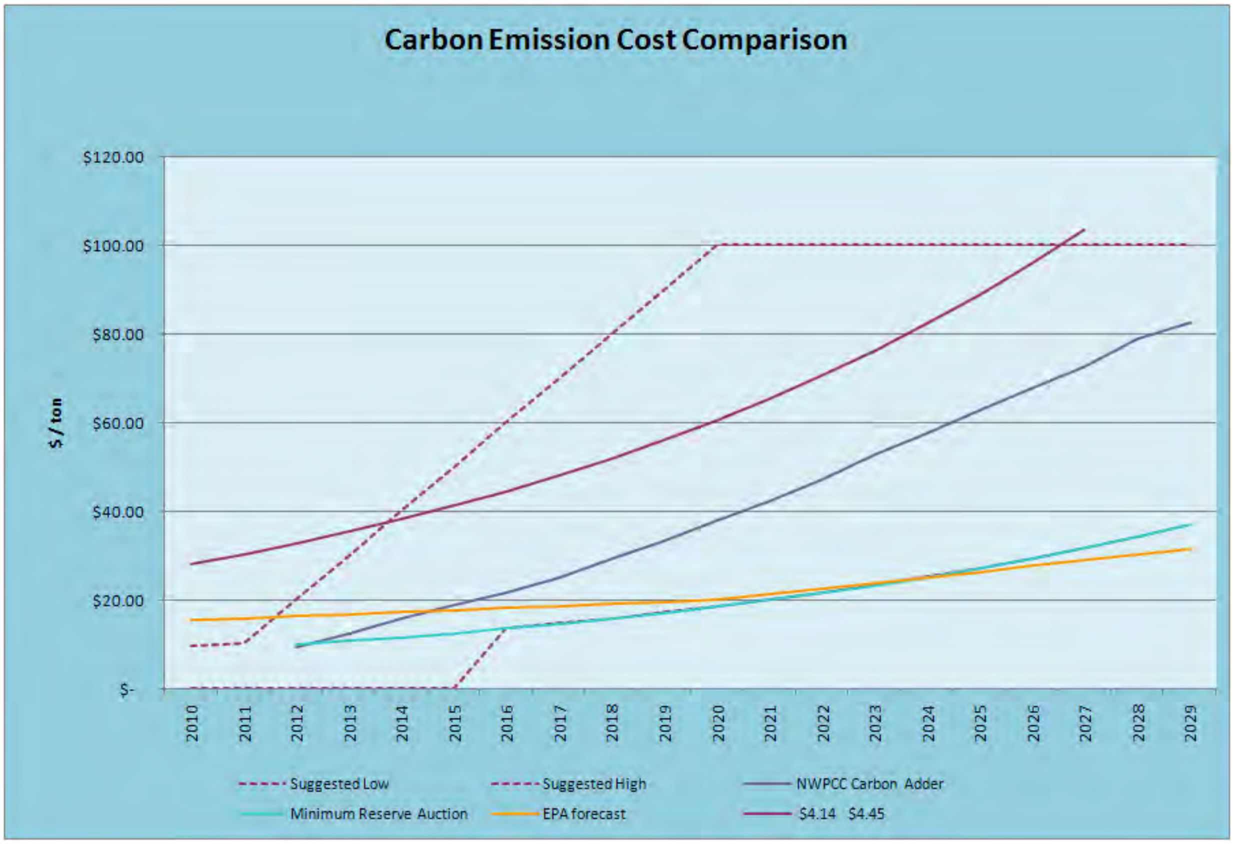


Table 28

Base Case
Power Price Forecast

Montana Delivery

Year	HL On-Peak	LL Off-Peak	Flat
2010	$47.86	$37.25	$43.19
2011	$53.06	$39.78	$47.22
2012	$53.94	$42.48	$48.90
2013	$60.00	$47.13	$54.34
2014	$63.25	$49.90	$57.38
2015	$66.81	$52.74	$60.62
2016	$70.18	$55.43	$63.69
2017	$73.43	$58.02	$66.65
2018	$77.11	$60.95	$70.00
2019	$81.17	$64.19	$73.70
2020	$85.37	$67.53	$77.52
2021	$89.72	$71.00	$81.49
2022	$94.13	$74.52	$85.50
2023	$98.90	$78.32	$89.84
2024	$103.99	$82.38	$94.48
2025	$108.80	$86.21	$98.86
2026	$113.97	$90.33	$103.57
2027	$118.82	$94.21	$107.99
2028	$124.00	$98.33	$112.70
2029	$129.64	$102.83	$117.84
20-Year Lev	$74.94	$58.99	$67.92

Table 29

No Carbon Penalty Case
Power Price Forecast
Montana Delivery

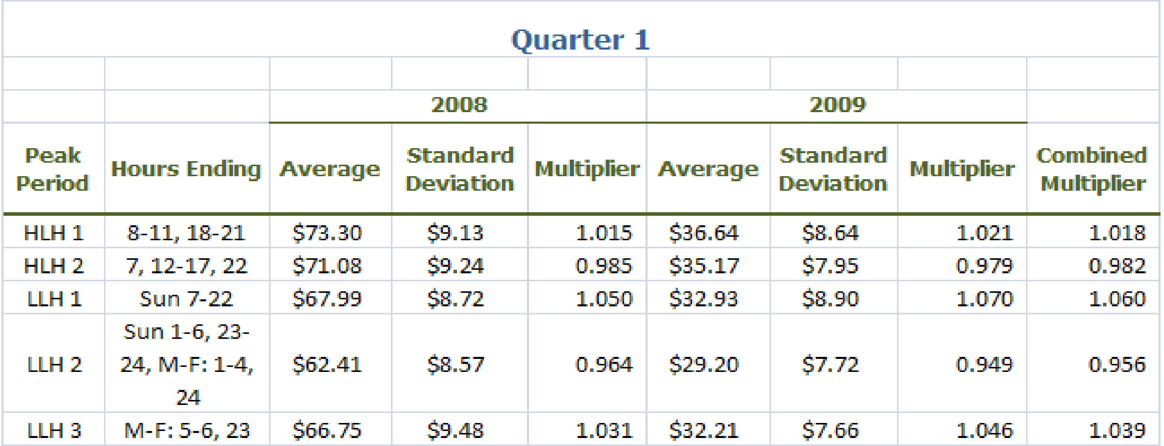
Year	HL On-Peak	LL Off-Peak	Flat
2010	$47.86	$37.25	$43.19
2011	$53.06	$39.78	$47.22
2012	$53.94	$42.48	$48.90
2013	$54.86	$43.22	$49.74
2014	$56.46	$44.49	$51.19
2015	$58.10	$45.80	$52.69
2016	$59.78	$47.15	$54.22
2017	$61.51	$48.53	$55.80
2018	$63.29	$49.95	$57.42
2019	$65.12	$51.41	$59.09
2020	$67.00	$52.91	$60.80
2021	$68.93	$54.45	$62.56
2022	$70.91	$56.04	$64.37
2023	$72.95	$57.66	$66.22
2024	$75.04	$59.34	$68.13
2025	$77.19	$61.06	$70.09
2026	$79.40	$62.82	$72.11
2027	$81.68	$64.64	$74.18
2028	$84.01	$66.50	$76.31
2029	$86.41	$68.42	$78.49
20-Year Lev	$62.00	$48.71	$56.15

Peak Period Definitions

One aspect of the modeling is that NorthWestern’s loads and resources are not necessarily easily grouped into the same On-Peak and Off-Peak periods that the electricity markets use for trading purposes. In particular, the utility operation tends to experience peaks within the HL period and can also experience extreme valleys in prices during the daily LL period. In addition, the LL period also includes hours ending 0700-2200 on Sundays. This daytime Sunday period proves to be anomalous to the remainder of the weekly LL period. Also, the daytime peak periods tend to shift seasonally, with the super-peak periods during the winter reflecting the higher loads in the morning and the evening when customers are active and it is dark due to the shorter days and the temperatures lower. The summer super-peak reflects the predominant afternoon loads needed for cooling and air handling.

In order to determine the peak periods and the price adjustment, hourly price data was examined for 2008 and 2009. For each complete quarter, the hours within HL and LL periods were ranked by weekday from highest observed average price to the lowest. In addition, the averages for the hours were computed as well as the normal change in price between hours. These data summaries were then used to break the HL and LL periods into logical groupings for each of the quarters. The observed prices were also used to determine a multiplier to transform the period average price into separate prices for each of the peak periods. The results of this analysis are summarized in the tables below:

Table 30



Quarter 1

		2008			2009			
Peak Period	Hours Ending	Average	Standard Deviation	Multiplier	Average	Standard Deviation	Multiplier	Combined Multiplier
HLH 1	8-11, 18-21	$73.30	$9.13	1.015	$36.64	$8.64	1.021	1.018
HLH 2	7, 12-17, 22	$71.08	$9.24	0.985	$35.17	$7.95	0.979	0.982
LLH 1	Sun 7-22	$67.99	$8.72	1.050	$32.93	$8.90	1.070	1.060
LLH 2	Sun 1-6, 23-24, M-F: 1-4, 24	$62.41	$8.57	0.964	$29.20	$7.72	0.949	0.956
LLH 3	M-F: 5-6, 23	$66.75	$9.48	1.031	$32.21	$7.66	1.046	1.039

Table 31

Quarter 2

		2008			2009			
Peak Period	**Hours Ending**	**Average**	**Standard Deviation**	**Multiplier**	**Average**	**Standard Deviation**	**Multiplier**	**Combined Multiplier**
HLH 1	7-22	$54.88	$33.76	1.000	$20.97	$8.46	1.000	1.000
HLH 2	None							
LLH 1	Sun 7-22	$43.35	$35.02	1.049	$16.99	$9.45	1.138	1.093
LLH 2	1-6, 23-24	$40.73	$34.49	0.986	$14.35	$7.41	0.961	0.973
LLH 3	None							

Table 32

Quarter 3

		2008			2009			
Peak Period	**Hours Ending**	**Average**	**Standard Deviation**	**Multiplier**	**Average**	**Standard Deviation**	**Multiplier**	**Combined Multiplier**
HLH 1	12 - 19	$65.36	$18.14	1.050	$36.16	$7.65	1.036	1.043
HLH 2	7-11, 20-22	$59.15	$18.74	0.950	$33.64	$7.30	0.964	0.957
LLH 1	Sun 7-22	$58.10	$20.96	1.166	$28.87	$7.65	1.093	1.129
LLH 2	Sun: 1-6, 23-24, M-F: 1-5	$45.43	$18.73	0.911	$24.32	$5.76	0.921	0.916
LLH 3	M-F: 6, 23-24	$51.83	$18.05	1.040	$28.68	$6.40	1.085	1.063

Table 33

Quarter 4

		2008		
Peak Period	**Hours Ending**	**Average**	**Standard Deviation**	**Multiplier**
HLH 1	8-10, 16-20	$52.93	$10.85	1.014
HLH 2	7, 11-15, 21-22	$51.47	$10.38	0.986
LLH 1	Sun 7-22	$47.60	$8.08	1.094
LLH 2	Sun: 1-6, 23-24, M-F: 1-4, 24	$41.32	$10.00	0.950
LLH 3	M-F: 5-6, 23	$46.02	$9.57	1.058

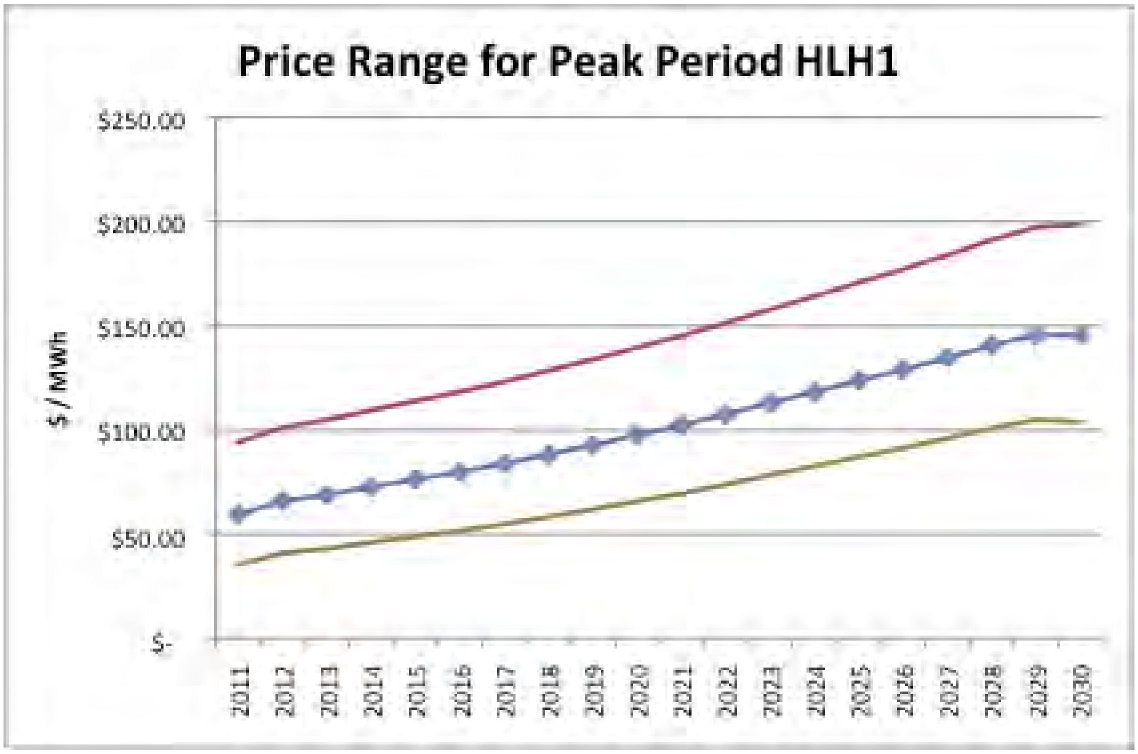
Price Volatility

The price forecasts, even with the different sensitivity levels for low and high cases, do not reflect the actual volatility of the wholesale value of electricity. Electricity markets are volatile due in part to the fact that electrical power must be consumed at the same time it is produced in order to keep the power grid in balance. Single events, such as large unit outages, changes in weather, or disruptions in fuel supplies due to events like hurricanes in Gulf of Mexico (natural gas and petroleum products) or drought (regional hydro) can have significant impacts on market prices and heat rates.

Price volatility forecasts are used as inputs to the stochastic level modeling, which samples from the range of prices provided. In order to determine the volatility inputs, the daily energy markets were reviewed for the period January 2005 – March 2010 and the range of prices for the period observed. As a reference point, this period makes sense as it is recent, it is well after the West Coast Energy Crisis, and includes reasonable water conditions. Of the 6 snow-build and runoff periods (including the current forecasts for 2010 runoff as one of the six), 5 have January-July observed natural runoff at The Dalles on the Columbia River that are below normal, ranging anywhere from a high of 99.2 Million acre-feet (Maf) to a low of 71.2 Maf. 2006 was the lone year with above normal runoff having an observed runoff of 114 Maf. 2010 looks to be the lowest with a current forecast of 71.2 Maf or only 69% of the 50-year average. The median of the 50-year period from 1961-2010 is 101 Maf with a slightly higher mean of 103.0 Maf. Although the sample years are predominantly lower water years, the low water years cover a pretty good range of different drought severities and provide a good sample set to see what prices do when the hydro system is in these conditions. Given NorthWestern Energy’s overall short position, relatively more concern was given to the inclusion of drier years in the volatility computation.

The Intercontinental Exchange daily indices for Mid-Columbia delivered On-Peak and Off-Peak were used over the period to determined a range of observed prices. The On-Peak and Off-Peak values were converted to the relevant super-peak and shoulder hours (these various smaller time periods are referred to as “peak periods”) within each period by applying the multipliers established for each quarter. The raw range for each calendar quarter was computed and then averaged. In other words, the highest observed price in the fourth quarter ("Q4") and the lowest observed price in Q4 established a range for that quarter. The ranges for the four quarters were then averaged together to establish an annual range. This annual observed average range then established the starting range for that peak-period. It was assumed that the range would grow as prices grow, so the first year range was then escalated annually by a 2.55% escalation rate. The same process was used to compute volatility for natural gas by using Stanfield indices (central Oregon gas trading point) as a proxy for northwest delivered natural gas price volatility.

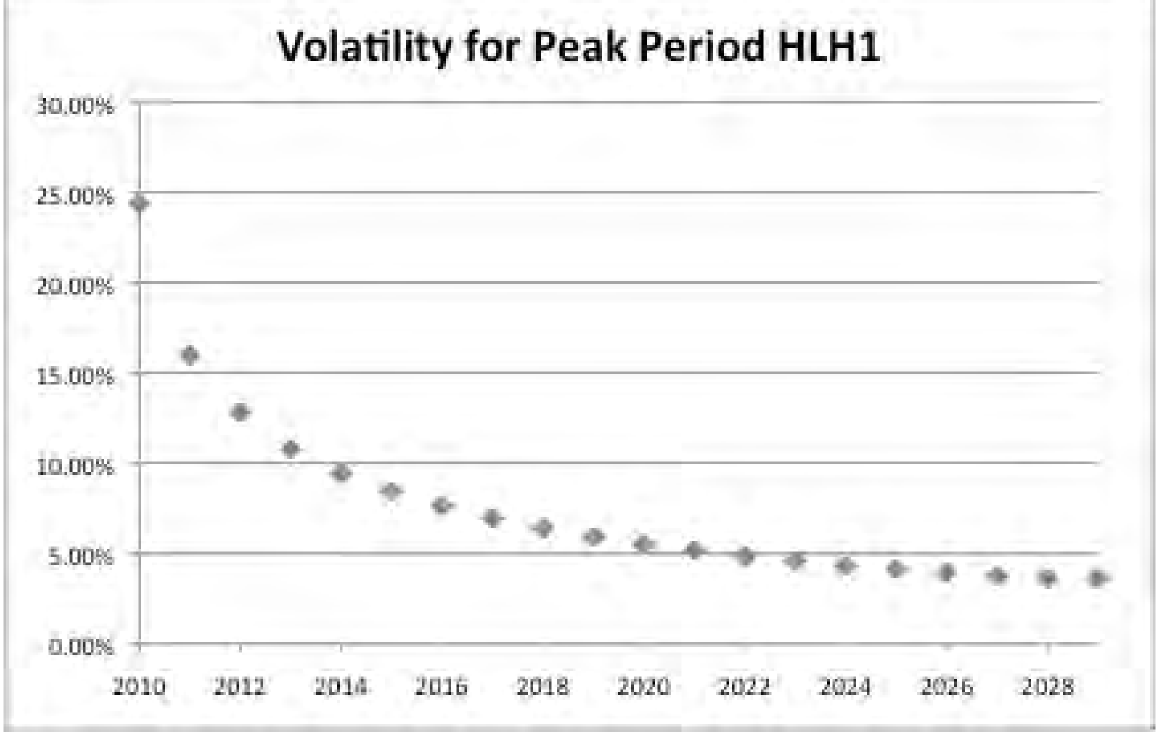
Figure 23



GenTrader® works with market volatility values as inputs to the model. The volatility inputs establish the breadth of the statistical distribution from which prices are drawn during the stochastic runs. To compute the volatility inputs from the ranges, the volatility was set such that the range covered by +/- 2 standard deviations of the distribution equals the forecasted range by year. This was established for each of the peak period definitions. The resulting volatility inputs decline overtime because the statistical function is also time dependant, meaning that the range in later years will be wider due to the time elapsed will have been longer than the nearby years. It is also understood that wholesale prices for deferred years will be less volatile in the forward markets as well as market perturbations are mostly events impacting current spot pricing and are rarely shifts in the underlying market fundamentals requiring long term price corrections.

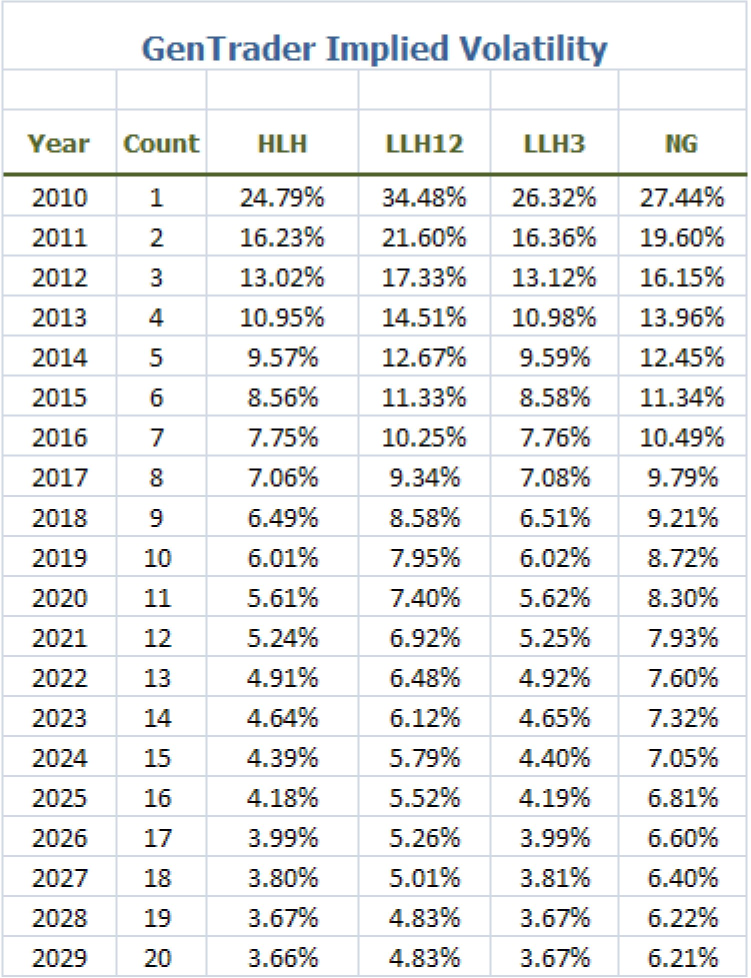
As an example, the volatility for the Peak Period HLH1 are shown in the Figure below:

Figure 24



One issue that had to be addressed was that GenTrader® is limited to only 4 volatility input formulas per period. In order to generate input tables that did not exceed this limit, the volatility inputs for HLH1 and HLH2 were combined as were the volatility inputs for LLH1 and LLH2. These volatility inputs are summarized in the table below:

Table 34



GenTrader Implied Volatility

Year	Count	HLH	LLH12	LLH3	NG
2010	1	24.79%	34.48%	26.32%	27.44%
2011	2	16.23%	21.60%	16.36%	19.60%
2012	3	13.02%	17.33%	13.12%	16.15%
2013	4	10.95%	14.51%	10.98%	13.96%
2014	5	9.57%	12.67%	9.59%	12.45%
2015	6	8.56%	11.33%	8.58%	11.34%
2016	7	7.75%	10.25%	7.76%	10.49%
2017	8	7.06%	9.34%	7.08%	9.79%
2018	9	6.49%	8.58%	6.51%	9.21%
2019	10	6.01%	7.95%	6.02%	8.72%
2020	11	5.61%	7.40%	5.62%	8.30%
2021	12	5.24%	6.92%	5.25%	7.93%
2022	13	4.91%	6.48%	4.92%	7.60%
2023	14	4.64%	6.12%	4.65%	7.32%
2024	15	4.39%	5.79%	4.40%	7.05%
2025	16	4.18%	5.52%	4.19%	6.81%
2026	17	3.99%	5.26%	3.99%	6.60%
2027	18	3.80%	5.01%	3.81%	6.40%
2028	19	3.67%	4.83%	3.67%	6.22%
2029	20	3.66%	4.83%	3.67%	6.21%

Parameters of Resources Modeled

The 2009 Plan contemplates the addition of new resources to meet future customer demand for energy. The range of potential resource types and sizes presents a challenge in terms of selecting a manageable subset of resources from the universe of possibilities. Working with ETAC and using the experience gained from preparing earlier resource plans and the experience of the Supply staff, NorthWestern has selected resources for evaluation in this Plan that have some reasonable likelihood of being chosen for future consideration, more detailed study, and possible inclusion in the Supply portfolio in the future.

The Plan and the work performed in preparing the Plan are important guides to what actions the utility actually intends to pursue. It is, however, important to recognize the limitations of the information that has been developed and presented in the Plan. Much of the resource information, including costs and performance characteristics, comes from the public domain. Professional judgment has been exercised in determining the input parameters of each resource evaluated in the Plan. For thermal resources, none of the input parameters come from supplier or manufacturer bids, and thus, none of the physical or economic performance demonstrated and reported for any of the new resources is guaranteed. Does this mean that the conclusions regarding resource performance are of no value? Certainly not. This type of evaluation is common in the industry and can be readily found in other utility resource planning documents. During the course of future work it will be important to revisit many resource parameters to account for cost changes, technological improvements and other updates. The actual costs, and therefore prices, will ultimately be provided by potential developers and vetted most likely via competitive solicitations.

Delayed Implementation of CCS

Carbon legislation and the associated economic and environmental considerations are driving technological change for electric generation and the utility industry. The scope of carbon capture and sequestration for fossil fuel plants is beyond what we have seen for any other emission. NorthWestern recognizes the significance of carbon legislation and the changes that it may bring to utilities that rely on generation sources fueled by carbon based energy. In the Plan, NorthWestern has examined and attempted to quantify a set of potential impacts from different carbon scenarios. Uncertainty remains regarding the widespread commercial application of carbon capture and sequestration technologies in terms of costs, performance, utility adoption, and the timing of widespread commercial application of these technologies.

Because of the uncertainties surrounding carbon capture and sequestration, NorthWestern has adopted the position of delayed implementation for evolving carbon management technology. In addition, because of risks associated with committing to new coal-fired generation, whether it includes carbon mitigation or not, the same delay strategy applies. Technical literature can be found that suggests that commercial operation of carbon capture and sequestration may occur in the next seven to ten years. NorthWestern, although not directly involved in the development and demonstration of carbon mitigation applications, intends to monitor the progress of the technology for deployment in both existing and new fossil fuel generation. In this plan, all carbon capture and sequestration and new build coal-fueled generation is not introduced into the portfolio models until 2020; the second half of the 20-year planning horizon.