BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy seeking acceptance of its Triennial Integrated Resource Plan covering the period 2010-2029, including authority to proceed with the permitting and construction of the ON Line transmission project.	Docket No. 09-07003

VOLUME 5 OF 26

LOAD FORECAST AND MARKET FUNDAMENTALS

LOAD FORECAST
&
MARKET FUNDAMENTALS

REDACTED[1]

NEVADA POWER COMPANY d/b/a NV ENERGY
INTEGRATED RESOURCE PLAN
2010 - 2039

LOAD FORECAST AND MARKET FUNDAMENTALS

[1] The confidential material is filed under seal.

LF-1

NEVADA POWER COMPANY
30-YEAR LOAD FORECAST

I. FORECASTING MODELS AND WEATHER NORMALIZATION

On December 15, 2009, Nevada Power filed its Energy Supply Plan for 2010-2012. Included in that filing, and in the December 18, 2009 amendment thereto, was a 30-year load forecast, referred to herein as the "ESP Forecast." The Company refreshed the ESP Forecast as part of this integrated resource plan ("IRP") filing. The refreshed forecast is referred to as the "IRP Forecast." Both forecasts, and the differences between them, are discussed in this technical appendix. All figures in this technical appendix relate to the IRP Forecast, unless designated with an "E" after the figure number. Figures designated with an "E" after the figure number relate to the ESP Forecast.

A. Historical Data

Figure 1 shows the historical sales from 1998-2009. For 2009, the figure shows actual sales for 2009. Weather adjusted values also are shown where applicable. Figure 2 is a summary of the peak demand, both actual and weather adjusted, energy and load factor.

FIGURE 1
HISTORICAL SALES, LOSSES AND COMPANY USE

Year	Annual Billed Sales (MWH)	% Grwth	Annual Sales (MWH) Weather Normalized	% Grwth	Estimated Losses (MWH)	Company Use (MWH)
1998	14,001,310		14,564,982		794,410	16,068
1999	15,165,639	8.3%	15,650,538	7.5%	857,314	14,987
2000	16,526,231	9.0%	16,320,012	4.3%	922,141	36,044
2001	16,962,909	2.6%	16,522,071	1.2%	875,333	39,792
2002	17,665,830	4.1%	17,495,053	5.9%	773,230	41,122
2003	18,215,512	3.1%	17,917,161	2.4%	881,775	38,128
2004	18,860,014	3.5%	18,629,295	4.0%	795,997	35,669
2005	19,865,234	5.3%	20,102,608	7.9%	852,656	33,800
2006	21,018,167	5.8%	20,874,948	3.8%	1,118,734	33,127
2007	21,797,366	3.7%	21,249,767	1.8%	1,003,788	27,639
2008	21,572,455	-1.0%	21,346,219	0.5%	1,199,502	33,745
2009	*21,204,523*	-1.7%	*20,897,519*	-2.1%	*826,428*	*29,748*

FIGURE 2
HISTORICAL PEAK DEMANDS, ENERGY AND LOAD FACTORS

	System Peak (MW)					
Year	Actual	Weather Normalized		Energy (GWh)		Load Factor based on Actual Peak MW
1998	3,855	3,762		14,771		43.7%
1999	3,976	3,957		15,162		43.5%
2000	4,325	4,388		16,058		42.3%
2001	4,412	4,324		17,894		46.3%
2002	4,617	4,591		18,251		45.1%
2003	4,808	4,781		18,364		43.6%
2004	4,969	4,944		19,299		44.2%
2005	5,563	5,234		19,968		41.0%
2006	5,623	5,568		22,352		45.4%
2007	5,866	5,657		22,765		44.3%
2008	5,504	5,724		22,443		46.4%
2009	5,586	5,508		22,061		45.1%

B. Revenue Class Sales Models

System energy requirements are derived from revenue class sales and customer forecasts that are based on econometric models. Residential and commercial sales models are estimated using a Statistically Adjusted Engineering ("SAE") model specification. The SAE modeling approach entails constructing end-use variables that are then used as right-hand variables in monthly average use and sales forecast models. Average use models are estimated for the residential, GS1 and LGS1 classes. A total sales model is estimated and used to forecast the large commercial and industrial ("C&I") and Street Lighting class sales. The Public Authority forecast is based on judgement. Forecast models are estimated for the revenue classes listed below:

- Residential
- GS1 and LGS1 Rate classes (Small Commercial and Industrial)
- Large Commercial and Industrial
- Sales to Public Authorities
- Public Street & Hwy Lights

C. Model Database

Models are estimated from historical monthly billed sales and customer data covering the period January 1998 to November 2009 (July 2009 for the ESP). Historical and projected data sources are described below:

Economic Data. Historical and forecasted demographic and economic data are based on Global Insight's December 2009 (August 2009 for the ESP) forecasts for the Las Vegas-Paradise Metropolitan Statistical Area ("MSA"). Las Vegas-Paradise real household income is used in estimating the residential forecast model. Real Gross Metro Product ("GMP") and employment are used in estimating the commercial sales forecast models. Population is the primary driver in the residential customer forecast model. UNLV's Center for Business and Economic Research ("CBER") population projections are used in constructing the population series. The population forecast series is based on CBER's December 16, 2009 (June 23, 2009 for the ESP) short term population growth rates for 2009 through 2011 (2010 for the ESP), a ramp up to 1.5% in 2012 (3.1% for the ESP) and the CBER long term growth rates from 2013 through 2029 (2011 through 2029 for the ESP) as published in late June 2009. Household size is calculated by dividing the population projection by household projections; household size is incorporated in the residential average use model.

Hotel/Motel Room Additions. As the entertainment industry is a critical component of the Las Vegas economy, hotel/motel room additions are one of the key market parameters that are evaluated as part of the forecast process. Hotel/motel projections are provided by Las Vegas Conventions and Visitors Authority ("LVCVA") construction bulletin dated November 4, 2009 (June 5, 2009 for the ESP), and discussions with the Company's Major Account Executives ("MAEs") in December 2009. Figure 3 is a summary of the major properties to be added and assumed dates of opening compared to the assumptions used in constructing the ESP Forecast while Figure 3E compares the hotel/motel room assumptions for the ESP with the load forecast that was presented in Docket No. 09-03005, Nevada Power's Eleventh Amendment to its 2007-2026 Integrated Resource Plan ("11th Amendment".) For both the IRP and ESP Forecasts, the sales and peak forecasts for MGM City Center were developed separately from the large C&I class forecast. This property is expected to use approximately 60 MW and 404 GWh in 2010, 70 MW and 470 GWh in 2011 and 80 MW and 539 GWH from 2012-2029. The ESP Forecast assumed 70 MW and 470 GWh in 2010. The 10 MW cut for the IRP Forecast reflects the fact that a portion of the retail space is not yet open as well as the staged opening of a couple of condominium towers in 2010. The reason the MGM City Center Complex is forecasted separately is because the large C&I regression model parameter for hotel/motel room additions underestimates the sales of this large property by about 50 percent. This is due to the fact that this is the largest number of rooms added at one property in recent history and the property also includes significant retail load.

FIGURE 3
HOTEL/MOTEL ROOM ADDITIONS: IRP VS. ESP

	Feb 2010 IRP Fcst		Dec 2009 ESP Fcst		
Name	Year	Rooms Added	Year	Rooms Added	Comments
Ceaser's Palace Expansion	N/A		N/A	0	On Hold - Work stopped; 665 rooms
City Center	2009	5,891	2009	5,891	Substantially open
Golden Nugget Expansion	2009	500	2009	500	Open
Binion's	2009	-362			Hotel rooms closed indefinately
Sahara Tower	2009	-612			Tower closed for the holiday season
Hard Rock Café Tower	2010	375	2009	375	Opening now - in Jan 10 for IRP forecast
Planet Hollywood Towers	2010	480	2009	480	Opening now - in Jan 10 for IRP forecast
Cosmopolitan	2010	2,998	2010	3,000	Moved from Sep '10 to Dec. '10
Harmon (MGM City Center)	2010	400	2010	400	December 2010 opening
Sahara Tower	2012	612			
Fontainbleau	2013	3,815	2011	3,889	Bankruptcy - opening date uncertain. Forecast assumes January 2013
Echelon	N/A		N/A	0	On hold. In October, Boyd Gaming announced a 3-5 year delay on use of the property. Removed from the base forecast. 4,910 Rooms

Note also that the IRP Forecast reflects the closure of Binion's hotel rooms and the Sahara Tower.

Weather Data. Monthly heating degree days ("HDD") and cooling degree days ("CDD") (actual and normal) are calculated from historical daily temperature data for McCarran International Airport. Heating and cooling degree-days are defined for a 65 degree base. Cycle-weighted HDD and CDD are constructed to match the monthly sales data billing period. Cycle-weighted degree days are calculated by first computing daily degree-days; the daily degree days are then weighted based on the historical meter read schedule and summed across the revenue month. Calendar HDD and CDD are generated by aggregating the daily degree-days over the calendar month.

Twenty-year normal HDD and CDD are based on daily temperature data from December 1, 1989 through November 30, 2009 (July 1, 1989 to June 30, 2009 for the ESP). Daily normal degree days are first calculated from daily temperature data. Daily HDD and CDD are then averaged by calendar day – all data for January 1st are averaged, all data for January 2nd are averaged, January 3rd, through December 31st; this generates a daily normal HDD and CDD series. Monthly calendar HDD and CDD are calculated by summing across the daily normal HDD and CDD. Cycle-weighted normal HDD and CDD are calculated by first applying the meter-read cycle weight to the daily normal degree-days and aggregating over the revenue-month.

Billing Days. Monthly billed sales can vary significantly across months due to variation in the number of billing days. Billing days are explicitly incorporated into the model through the XOther variable. The number of monthly billing days is calculated from historical meter read schedules.

Retail Price. A price variable is constructed for each revenue class. The price series is defined as a 12-month moving average of the average retail rate. The average retail rate is calculated by dividing billed revenues by billed sales and adjusting the series for inflation. Using a 12-month moving average mitigates the revenue/sales causal relationship (i.e., revenues are up when sales are up), and translates into a more reasonable relationship between price and how customers respond. The Financial Planning Department provided revenue forecasts through 2014. After

2014, we assume constant real prices through the forecast period. The price forecast was used for both the IRP and ESP Forecasts.

Residential Appliance Equipment Indices. Residential heating, cooling, and other use indices are constructed for the residential SAE model. These indices reflect changes in end-use saturation and end-use efficiency projections.[1] An initial set of end-use indices was provided by Itron, Inc. as part of Nevada Power's membership in the Energy Forecasting Group ("EFG"). Itron constructs end-use indices for the nine census regions based on the EIA's energy outlook. The indices were last updated in June 2009 and reflect the Energy Information Agency's ("EIA's") 2009 Energy Outlook, including the effects on electricity usage of the American Recovery and Reinvestment Act ("ARRA").[2] The Nevada Power residential appliance saturation survey completed in December 2008 is used to adjust the regional end-use indices to better reflect the Nevada Power service area.

Commercial Appliance Equipment Indices. Similar end-use indices are calculated for the commercial sector. As the EIA does not break out saturation from efficiency, indices are calculated based on end-use energy intensity projections (energy use per square feet). End-use energy intensity is calculated for eleven different business types for each of nine census regions. Nevada Power starts with the end-use intensities for the Mountain Census Region. The indices are then modified to reflect the Nevada Power business mix based on estimates of sales delivered to specific business categories.

II. MODEL SPECIFICATION

The forecast is based on the SAE modeling framework. The framework entails constructing generalized end-use variables for cooling (XCool), heating (XHeat), and other uses (XOther) and then using these variables as right-hand variables in monthly average use and sales forecast models. The general model specification is:

$$AvgUse_t = b_0 + b_1 * XCool_t + b_2 * XHeat_t + b_3 * XOther_t + e_t$$

The model coefficients are estimated using ordinary least squares. The construction of the end-use variables is presented below. A more detailed description of the SAE modeling approach is included in Technical Appendix Item ESP-3, titled *Using Statistically Adjusted End-use Models*.

A. Residential Cooling and Heating Variables

XCool

The cooling variable (XCool) is constructed by combining a variable that reflects cooling saturation and efficiency (CoolIndex) with a variable that captures stock utilization (CoolUse):

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m}$$

The cooling equipment index is defined as a weighted average across cooling equipment types where the weight represents the average technology energy intensity (kWh per household) in the

[1] The other category includes electric ventilation, water heating, cooking, refrigeration, indoor and outdoor lighting, office and miscellaneous (generally plug loads).
[2] See the Technical Appendix, Items LF-5 and LF-6 for a discussion of the impacts of the ARRA on forecasted electricity use.

base year. The index changes over time with changes in end-use saturation and end-use efficiency ("EFF"). As cooling saturation increases the index increases, as the end-use efficiency increases the index decreases. A structural index variable also is incorporated into the variable calculation. The structural index (StructuralVar) captures change in housing square footage and thermal shell integrity improvement. As the weights are end-use intensities, the resulting CoolIndex is an estimate of annual cooling energy requirements. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralVar * \sum_{Type} Weight^{Type} \times \frac{\left(CoolShare_y^{Type} \big/ Eff_y^{Type} \right)}{\left(CoolShare_{base}^{Type} \big/ Eff_{base}^{Type} \right)}$$

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. Cooling usage is calculated as:[3]

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{NormCDD} \right) \times \left(\frac{HHSize_y}{HHSize_{base}} \right)^{.25} \times \left(\frac{Income_y}{Income_{base}} \right)^{.20} \times \left(\frac{Price_{y,m}}{Price_{base}} \right)^{-.15}$$

where, *CDD* is the number of cooling degree days in year (y) and month (m),
NormCDD is the normal value for annual cooling degree days,
HHSize is average household size in a year (y),
Income is average real income per household in a year (y), and
Price is the average real price of electricity in year (y) and month (m)

By construction, the *CoolUse* variable has an annual sum that is close to one in the base year. The CDD index works to allocate annual cooling index (which is an annual kWh estimate) to months.

The XCool variable is constructed using data specific to Nevada Power where data are available. This includes:

1. Modifying the end-use saturation based on the 2008 residential appliance saturation survey. (See Figure 1 for a summary of Nevada Power saturation survey results).
2. Constructing the CoolUse variable with MSA economic drivers including real personal income, population, and number of households.
3. Basing CDDs (actual and normal) on Nevada Power's historical weather data.
4. Using a price variable that reflects historical revenues and projections of future operating costs.

[3] The elasticities shown in the superscripts are default values taken from the Electric Power Research Institute ("EPRI") developed Residential End-Use Energy Planning System model ("REEPS"), a detailed end-use model. The default values have been modified to reflect estimates of these elasticities for the Nevada Power service territory. The elasticities used in modeling are -0.15 for price, 0.2 for income and 0.2 for households. These elasticities were applied in developing the XCool, XHeat and XOther variables.

XHeat

The heating variable (XHeat) construction is similar to XCool. XHeat is defined as:

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}$$

The heat index (HeatIndex) incorporates residential electric heating saturation and efficiency projections. The utilization variable (HeatUse) is defined like CoolUse but where CDDs are replaced with HDDs. XHeat incorporates Nevada Power's economic and price projections. The heating saturation rates have been modified to reflect the Nevada Power Residential Appliance Saturation Survey. The outcome is an initial estimation of average monthly household heating requirements.

XOther

The same logic is used to construct an initial estimate of non-weather sensitive use (XOther). XOther is defined as:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m}$$

OtherIndex embodies information about appliance saturation levels and efficiency levels. Seasonal usage patterns are captured by applying monthly usage factors (Mult_m) to the annual end-use energy intensity estimates. OtherIndex is defined as:

$$\mathrm{OtherIndex}_{y,m} = \left[\sum_{\mathrm{Use}} \mathrm{Weight}^{\mathrm{Use}} \times \left(\frac{\dfrac{\mathrm{Sat}_y^{\mathrm{Use}}}{\mathrm{Eff}_y^{\mathrm{Use}}}}{\dfrac{\mathrm{Sat}_{\mathrm{base}}^{\mathrm{Use}}}{\mathrm{Eff}_{\mathrm{base}}^{\mathrm{Use}}}}\right) \times \mathrm{Mult}_m^{\mathrm{use}}\right] + \left[\mathrm{UEC}_y^{\mathrm{Light}} \times \mathrm{Mult}_m^{\mathrm{Light}}\right] + \left[\mathrm{UEC}_y^{\mathrm{Misc}} \times \mathrm{Mult}_m^{\mathrm{Misc}}\right]$$

where, $\mathrm{Sat}^{\mathrm{Use}}$ represents the fraction of households, who have an appliance type,
$Mult^{use}$ is a monthly multiplier for the Use in month (m),
Weight is the weight for each use, and
UEC is the unit energy consumption for lighting and miscellaneous uses in year (y).

OtherIndex combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for each end-use. Lighting and miscellaneous use are based on EIA's end-use energy projections. As with heating and cooling, the weights are defined as the base year values of energy use per household for each end use.

The impact of price, household size, and household income is captured in OtherUse:

$$\mathrm{OtherUse}_{y,m} = \left(\frac{\mathrm{BillingDays}_{y,m}}{365}\right) \times \left(\frac{\mathrm{HHSize}_y}{\mathrm{HHSize}_{\mathrm{base}}}\right)^{.46} \times \left(\frac{\mathrm{Income}_y}{\mathrm{Income}_{\mathrm{base}}}\right)^{.10} \times \left(\frac{\mathrm{Price}_{y,m}}{\mathrm{Price}_{\mathrm{base}}}\right)^{-.15}$$

The end-use elasticities on income, household size, and real price are taken from the REEPS default database. The appliance category includes data for cooking, dishwashers, clothes washers, clothes dryers, and televisions. The main source of month-to-month variation is the number of monthly billing-days.

XOther is constructed using information specific to Nevada Power where this information is available. Specific service area data included in XOther are:

1. Modifying the end-use saturation based on the 2008 residential appliance saturation survey. (See Figure 4 for a summary of Nevada Power saturation survey results).
2. Constructing the OtherUse variable with MSA economic drivers including real personal income, population, and number of households.
3. Calculating monthly number of billing days from historical meter read schedules.
4. Estimating a price variable that reflects historical revenues and projections of future costs.

FIGURE 4
RESIDENTIAL APPLIANCE SATURATIONS USED FOR THE BASE YEAR INPUT IN THE SAE MODELING: IRP AND ESP

Appliance	Saturation		Notes
Electric Furnace	16.6%		
Heat Pump Heat	8.4%		
Secondary Electric Heat	5.1%		
Central Air Conditioner	85.5%		
Heat Pump Cooling	9.5%		
Room Air conditioner	4.0%		
Electric Water Heating	28.0%		
Electric Cooking	182.6%		
Refrigerator	100.0%		
Second Refrigerator	27.0%		
Freezer	26.0%		
Dishwasher	87.0%		
Clothes Washer	89.0%		
Electric Dryer	39.6%		
TV	399.8%		Includes set top boxes
Lighting	100.0%		
Miscellaneous	100.0%		Plug Loads

B. Commercial XCool and XHeat

The development of Commercial SAE models is described in Technical Appendix Item LF-4, titled "2008 Commercial Natural Gas Statistically Adjusted End-Use (SAE) Spreadsheets." While this paper is written for gas, the methodology is the same as that used in constructing the commercial electricity sales forecast models.

The cooling variable (XCool) is defined as a product of an annual equipment index and a monthly usage multiplier:

$$XCool_{y,m} = CoolIndex_{y} \times CoolUse_{y,m}$$

where, $XCool_{y,m}$ is estimated heating energy use in year (y) and month (m),
$CooltIndex_{y}$ is the annual heating stock, and
$CoolUse_{y,m}$ is the monthly usage multiplier.

CoolIndex is designed to capture the trend in commercial cooling saturation and efficiency. Similar to the residential cooling index, the index changes over time with changes in cooling equipment saturations (Cool*Share*) and operating efficiencies (*Eff*). CoolIndex can be defined as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{\left(CoolShare_{y} / Eff_{y} \right)}{\left(CoolShare_{04} / Eff_{04} \right)}$$

In this expression, 2004 is used as a base year for normalizing the index.[4] The ratio on the right is equal to 1.0 in 2004. Unfortunately, the EIA does not explicitly provide commercial end-use saturation estimates. As a proxy, the index is calculated using end-use energy intensities (use per square foot) by building-type. End-use intensities are derived from EIA's most recent Energy Outlook. As there is effectively a 100 percent cooling saturation, the index generally declines over time as cooling equipment efficiency continues to improve.

The cooling index is calculated as:

$$CoolIndex_{y} = CoolSales_{04} \times \frac{EI_{y}}{EI_{04}}$$

Cooling requirements are driven by economic growth, and price projections. Regional output is used to capture this growth. The utilization variable is defined as:[5]

[4] 2004 is the base year for the commercial indices used in the Nevada Power load forecast models.
[5] The output elasticity for the GS and LGS1 customer class models were 0.2 and for Large C&I, 0.65. The price elasticity was -0.15 for all C&I classes.

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{Output_{y,m}}{Output_{04}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.10}$$

where,

CDD are the number of CDDs in year (y) and month (m) using billing cycle degree days and daily average temperatures.

Output is a real regional output in year (y) and month (m).

Price is the average real price in month (m) and year (y).

A commercial heating variable (XHeat) is constructed in a manner similar to XCool. While there is some electric heat in the small commercial revenue class, there is little to no electric heating in the larger commercial revenue classes.

XCool and XHeat are constructed to reflect the Nevada Power service area. Specific regional inputs include:

1. Adjusting the building mix and resulting energy intensity to reflect the service area business mix. The calculation of HeatUse (and CoolUse) is an aggregation across eleven different business types (see Figure 6). The building-type mix was estimated from the business market survey and estimated MWh sales for each of the eleven business types. Figure 2 shows the distribution of sales across the business types.

2. Constructing HeatUse and CoolUse using the Real GMP for the Las Vegas-Paradise MSA. HDD and CDD are based on Las Vegas weather data. Output elasticities are calibrated to historical output to sales relationship.

C. Commercial XOther

The non-weather sensitive variable (XOther) is derived using a similar approach as that used for the cooling and heating variables. XOther is defined as:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y,m} \times \mathrm{OtherUse}_{y,m}$$

The Other Index is a calculated from energy intensity ("EI") projections for commercial water heating, cooking, and miscellaneous gas use. The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as:

$$OtherIndex_{y,m} = \sum_{Type} Sales_{04}^{Type} \times \left(\frac{EI_{y}^{Type}}{EI_{04}^{Type}}\right)$$

where, *Sales* is the estimated end-use sales in 2004,

EI is the energy intensity for the specific end-use

This index combines information about end-use intensity trends. Monthly variation due to changes in stock utilization is captured by OtherUse:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{Output_{y}}{Output_{04}}\right)^{0.20} \times \left(\frac{\Pr ice_{y.m}}{\Pr ice_{04}}\right)^{-0.10}$$

As with the constructed XCool and Xheat variables, XOther is constructed using service area specific data where these data are available.

FIGURE 5
SMALL COMMERCIAL AND INDUSTRIAL BUSINESS TYPE SALES AND WEIGHTS: IRP AND ESP FORECASTS

BUSINESS TYPE	MWH	% MWh
Education	95,004	1.96%
Food Sales	280,389	5.77%
Food Service	639,989	13.18%
Health Care	245,938	5.06%
Lodging	434,553	8.95%
Office	837,377	17.24%
Other	413,380	8.51%
Public Assembly	176,606	3.64%
Retail	412,418	8.49%
Service	746,864	15.38%
Warehouse	574,407	11.83%
Total	4,856,924	100.00%

Food Sales and Food Services were not calculated separately. Each was assigned half of the weight. Large and small offices also were assigned half of the total weight. Retail and Service were added together.

FIGURE 6
LARGE COMMERCIAL AND INDUSTRIAL BUSINESS TYPE SALES AND WEIGHTS: IRP AND ESP FORECASTS

BUSINESS TYPE	MWH	CUSTS		% MWh	% Custs
Education	457,090,111	280		5.85%	17.73%
Food Sales	297,587,492	121		3.81%	7.66%
Food Service	7,086,054	4		0.09%	0.25%
Health Care	229,834,017	46		2.94%	2.91%
Lodging	3,792,219,517	279		48.50%	17.67%
Office	990,293,214	259		12.67%	16.40%
Other	1,212,140,190	303		15.50%	19.19%
Public Assembly	180,617,383	75		2.31%	4.75%
Retail	471,732,908	160		6.03%	10.13%
Service	46,581,932	13		0.60%	0.82%
Warehouse	133,060,028	39		1.70%	2.47%
Total	7,818,242,848	1,579		100.00%	100.00%

Note: Small and Large Offices were not calculated separately. Each type was assigned half of the total weight.

III. IRP MODEL RESULTS

Estimated model results are summarized below:

Residential Customers. As shown in Figure 7, the model explains nearly 100 percent of the variation in total customers. The forecast is driven by population estimates for the Las Vegas-Paradise MSA.

Residential Average Monthly Use As shown in Figure 8, the dependent variable was the monthly sales per customer. XHeat, XCool and XOther variables and specific monthly binary variables are used where statistically significant. These binary variables adjust for billing data anomalies especially after the institution of the new Banner billing system in early 2002. This model explains approximately 99 percent of the variation in sales per customer.

GS1 (Small Commercial and Industrial) Customers. As shown in Figure 9, this model explains historical customer trend well with population as the primary explanatory variable. The model explains almost 100 percent of the variation in monthly customer counts.

GS1 (Small C&I) Average Monthly use. As shown in Figure 10, this model explains approximately 92 percent of the variation in monthly sales per customer. XHeat, XCool and XOther are statistically significant. Monthly binary variables are used to account for billing data anomalies especially after the institution of the new Banner billing system in early 2002.

LGS1 (Small Commercial and Industrial) Customers. As shown in Figure 11, this model explains historical customer trend well with population, GS1 customers, and monthly binary variables as the explanatory variables. The model explains almost 99 percent of the variation in monthly customer counts.

LGS1 (Small Commercial and Industrial) Average Monthly Use. As shown in Figure 12, this model explains approximately 94 percent of the variation in annual sales. XHeat, XCool and XOther variables, three specific 2002 monthly binary variables and a binary variable for the all months from January 2009 to the end of the forecast were significant. The three monthly binary variables adjust for anomalies after the institution of the new Banner billing system in early 2002, while the 2009 and beyond binary accounts for the downshift in average use due to the recession.

Large Commercial and Industrial Customer Monthly Sales. As shown in Figure 13, this model explains approximately 96 percent of the variation in monthly sales. XCool and XOther variables, a yearly binary variable for 2002 and specific monthly binary variables were used where significant. These binary variables adjust for billing anomalies especially after the institution of the new Banner billing system in early 2002. XHeat was not significant in this model. An additional significant variable is the monthly stock of hotel/motel rooms.

Public Street & Hwy Lights Monthly Sales. As shown in Figure 14, this model explains approximately 96 percent of the variation in monthly sales. The drivers of this model are population and monthly binary variables and a binary variable for February 2009 representing a sales transfer from the GS1 and LGS1 class due to misclassification of lighting customers in those classes.

FIGURE 7
MODEL OF RESIDENTIAL MONTHLY CUSTOMERS

Regression Statistics						
Sample Range		1998:1 thru 2009:11				
Adjusted Observations		142				
Deg. of Freedom for Error		137				
R-Squared		1.000				
Adjusted R-Squared		1.000				
Durbin-Watson Statistic		1.668				
AIC		14.281				
BIC		14.385				
F-Statistic		176708.245				
Prob (F-Statistic)		0.0000				
Std. Error of Regression		1240.35				
Mean Abs. % Err. (MAPE)		0.14%				
Ljung-Box Statistic		73.08				
Prob (Ljung-Box)		0.0000				
Jarque-Bera		4.5				
Prob (Jarque-Bera)		0.0467				

Variable		Coefficient	StdErr	T-Stat	P-Value
Customers		Endogenous			
CONST		689777.420	87605.526	7.874	0.00%
Nov04		-22328.981	882.702	-25.296	0.00%
Jun05		86.987	25.900	3.359	0.10%
Population		2902.624	879.929	3.299	0.12%
AR(1)		0.993	0.002	634.761	0.00%

where:

Customers	=	Monthly Residential Customers
CONST	=	Constant Term
Nov04	=	A binary variable for November 2004
Jun05	=	A binary variable for June 2005
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
AR(1)	=	1st order autoregressive error term

FIGURE 8
MODEL OF RESIDENTIAL MONTHLY SALES (KWH) PER CUSTOMER

Regression Statistics	
Sample Range	1998:1 thru 2009:11
Adjusted Observations	142
Deg. of Freedom for Error	129
R-Squared	0.989
Adjusted R-Squared	0.988
Durbin-Watson Statistic	2.004
AIC	7.746
BIC	8.017
F-Statistic	992.676
Prob (F-Statistic)	0.0000
Std. Error of Regression	46.04
Mean Abs. % Err. (MAPE)	3.44%
Ljung-Box Statistic	87.84
Prob (Ljung-Box)	0.0000
Jarque-Bera	13.7
Prob (Jarque-Bera)	0.0053

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	143.738	65.278	2.202	2.95%
XHeat	2.043	0.086	23.632	0.00%
XCool	2.176	0.030	73.457	0.00%
XOther	0.348	0.080	4.340	0.00%
May02	-141.151	45.311	-3.115	0.23%
Mar02	206.763	42.039	4.918	0.00%
Jun02	163.564	45.571	3.589	0.05%
Sep02	-353.051	46.387	-7.611	0.00%
Oct02	-242.139	45.629	-5.307	0.00%
Apr08	78.134	41.767	1.871	6.37%
Dec07	80.171	42.069	1.906	5.89%
Jun08	-168.567	41.529	-4.059	0.01%
AR(1)	0.491	0.079	6.176	0.00%

where:

Sales per Customer	=	Monthly KWH sales per residential customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
May02	=	A binary variable for May 2002
Mar02	=	A binary variable for March 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Oct02	=	A binary variable for October 2002
Apr08	=	A binary variable for April 2008
Jun08	=	A binary variable for March 1999
Dec07	=	A binary variable for December 2007
AR(1)	=	1st order autoregressive error term

FIGURE 9
MODEL OF MONTHLY GS1 CUSTOMERS

Regression Statistics						
Sample Range		1998:1 thru 2009:11				
Adjusted Observations		142				
Deg. of Freedom for Error		134				
R-Squared		0.997				
Adjusted R-Squared		0.997				
Durbin-Watson Statistic		2.239				
AIC		12.389				
BIC		12.556				
F-Statistic		5480.908				
Prob (F-Statistic)		0.0000				
Std. Error of Regression		476.86				
Mean Abs. % Err. (MAPE)		0.56%				
Ljung-Box Statistic		25.33				
Prob (Ljung-Box)		0.3880				
Jarque-Bera		39.5				
Prob (Jarque-Bera)		0.0006				

Variable		**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Customers			Endogenous		
Population		34.913	0.305	114.649	0.00%
Mar		739.805	130.312	5.677	0.00%
Apr		1013.775	164.551	6.161	0.00%
May		1284.470	174.430	7.364	0.00%
Jun		924.203	164.540	5.617	0.00%
Jul		509.777	130.302	3.912	0.01%
Dec		184.823	105.716	1.748	8.27%
AR(1)		0.924	0.035	26.758	0.00%

Where:

Customers	=	Monthly GS1 Customers
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Mar-Jul, Dec	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
AR(1)	=	1st order autoregressive error term

FIGURE 10
MODEL OF GS1 MONTHLY SALES PER CUSTOMER

Regression Statistics	
Sample Range	1998:1 thru 2009:11
Adjusted Observations	130
Deg. of Freedom for Error	112
R-Squared	0.935
Adjusted R-Squared	0.925
Durbin-Watson Statistic	2.001
AIC	7.080
BIC	7.477
F-Statistic	95.131
Prob (F-Statistic)	0.0000
Std. Error of Regression	32.33
Mean Abs. % Err. (MAPE)	2.97%
Ljung-Box Statistic	15.30
Prob (Ljung-Box)	0.9116
Jarque-Bera	1.2
Prob (Jarque-Bera)	0.3678

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	429.806	63.319	6.788	0.00%
XHeat	0.00242	0.00024	9.908	0.00%
XCool	0.00350	0.00016	21.513	0.00%
XOther	0.00004	0.00001	2.867	0.50%
Yr02	184.115	14.201	12.965	0.00%
Yr03	130.544	13.074	9.985	0.00%
Jan02	-190.811	33.321	-5.726	0.00%
Mar02	-140.997	33.671	-4.188	0.01%
Apr02	-144.111	33.892	-4.252	0.00%
Jun02	175.821	32.014	5.492	0.00%
Sep02	-300.071	33.725	-8.898	0.00%
Feb03	-96.809	32.479	-2.981	0.35%
Apr03	-160.410	33.421	-4.800	0.00%
Dec03	-124.650	34.196	-3.645	0.04%
Feb06	71.764	31.529	2.276	2.48%
Aug08	-61.708	31.674	-1.948	5.39%
AR(1)	0.198	0.101	1.955	5.31%
SAR(1)	0.260	0.093	2.806	0.59%

where:

Sales per Customer	=	Monthly KWH sales per GS1 customer
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
Yr02	=	A binary variable for the year 2002
Yr03	=	A binary variable for the year 2003
XXXYY	=	Binary variables for specified months and years
AR(1)	=	1st order autoregressive error term
SAR(1)	=	Seasonally adjusted 1st order moving average error term

FIGURE 11
MODEL OF LGS1 CUSTOMERS

Regression Statistics	
Sample Range	1998:1 thru 2009:11
Adjusted Observations	142
Deg. of Freedom for Error	129
R-Squared	0.993
Adjusted R-Squared	0.992
Durbin-Watson Statistic	1.877
AIC	11.896
BIC	12.166
F-Statistic	1431.313
Prob (F-Statistic)	0.0000
Std. Error of Regression	366.61
Mean Abs. % Err. (MAPE)	1.08%
Ljung-Box Statistic	29.67
Prob (Ljung-Box)	0.1960
Jarque-Bera	34.5
Prob (Jarque-Bera)	0.0008

Variable	Coefficient	StdErr	T-Stat	P-Value
Customers	Endogenous			
CONST	-1411.130	1885.691	-0.748	45.57%
Jan	-327.662	114.741	-2.856	0.50%
Feb	-700.364	146.464	-4.782	0.00%
Mar	-951.755	164.565	-5.783	0.00%
Apr	-1240.656	173.043	-7.170	0.00%
May	-1298.238	173.391	-7.487	0.00%
Jun	-1087.420	152.733	-7.120	0.00%
Jul	-514.729	116.797	-4.407	0.00%
Sep	146.959	100.781	1.458	14.73%
Oct	180.785	100.826	1.793	7.54%
Population	22.533	2.148	10.491	0.00%
Predicted GS1 Customers	-0.208	0.051	-4.068	0.01%
AR(1)	0.874	0.045	19.290	0.00%

Where:

Customers	=	Monthly LGS1 Customers
CONST	=	Constant Term
Jan-Oct	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Predicted GS1 Customers	=	Monthly history and forecast of GS1 customers
AR(1)	=	1st order autoregressive error term

FIGURE 12
MODEL OF LGS1 AVERAGE USE PER CUSTOMER

Regression Statistics

Sample Range	1998:1 thru 2009:11
Adjusted Observations	142
Deg. of Freedom for Error	133
R-Squared	0.946
Adjusted R-Squared	0.943
Durbin-Watson Statistic	2.095
AIC	12.317
BIC	12.504
F-Statistic	291.447
Prob (F-Statistic)	0.0000
Std. Error of Regression	458.39
Mean Abs. % Err. (MAPE)	2.90%
Ljung-Box Statistic	80.58
Prob (Ljung-Box)	0.0000
Jarque-Bera	9.1
Prob (Jarque-Bera)	0.0118

Variable	Coefficient	StdErr	T-Stat	P-Value
Monthly Sales per customer		Endogenous		
CONST	6908.816	691.077	9.997	0.00%
XOther	0.00898	0.00258	3.476	0.07%
XHeat	0.05393	0.00173	31.127	0.00%
XCool	0.00065	0.00016	3.938	0.01%
Apr02	1164.445	466.768	2.495	1.39%
May02	2068.798	463.537	4.463	0.00%
Sep02	-2268.871	453.065	-5.008	0.00%
Year>=2009	-590.394	185.822	-3.177	0.19%
AR(1)	0.248	0.086	2.897	0.44%

where:

Sales per Customer	=	Monthly KWH sales per GS1 customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
May02	=	A binary variable for May 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Dec02	=	A binary variable for December 2002
Year>=2009	=	A binary variable representing the dowhnshift in avg use due to the recession
AR(1)	=	1st order autoregressive error term

FIGURE 13
MODEL OF LARGE COMMERCIAL AND INDUSTRIAL MONTHLY SALES

Regression Statistics	
Sample Range	1998:1 thru 2009:11
Adjusted Observations	141
Deg. of Freedom for Error	131
R-Squared	0.968
Adjusted R-Squared	0.966
Durbin-Watson Statistic	2.429
AIC	33.484
BIC	33.693
F-Statistic	399.666
Prob (F-Statistic)	0.0000
Std. Error of Regression	18035269
Mean Abs. % Err. (MAPE)	2.58%
Ljung-Box Statistic	46.18
Prob (Ljung-Box)	0.0042
Jarque-Bera	2.6
Prob (Jarque-Bera)	0.1254

Variable	Coefficient	StdErr	T-Stat	P-Value
Monthly Sales		Endogenous		
XCool	1223.811	37.574	32.571	0.00%
XOther	30.807	4.570	6.741	0.00%
Yr02	37,331,719	12,027,197	3.104	0.23%
May02	70,770,715	15,504,490	4.565	0.00%
Sep02	-109,676,288	15,358,496	-7.141	0.00%
Dec07	39,866,933	15,230,100	2.618	0.99%
Jan03	39,008,819	16,483,969	2.366	1.94%
Rooms	2517.291	239.310	10.519	0.00%
AR(1)	0.353	0.077	4.615	0.00%
AR(2)	0.552	0.076	7.251	0.00%

where:

Monthly Sales	=	Monthly billed KWH sales for the LGS2 through LGS4 class
XCool	=	Estimates the monthly use for electric cooling equipment
XOther	=	Estimates the monthly use for all other electrical equipment
Rooms	=	Total Monthly hotel/motel rooms
Yr02	=	A binary variable for the year 2002
May02	=	A binary variable for May 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Dec02	=	A binary variable for December 2002
Jan03	=	A binary variable for January 2003
AR(1)	=	1st order autoregressive error term
AR(2)	=	2nd order autoregressive error term

FIGURE 14
MODEL OF PUBLIC STREET & HWY LIGHTS MONTHLY SALES

Regression Statistics					
Sample Range		1998:1 thru 2009:11			
Adjusted Observations		141			
Deg. of Freedom for Error		125			
R-Squared		0.962			
Adjusted R-Squared		0.958			
Durbin-Watson Statistic		1.974			
AIC		26.158			
BIC		26.492			
F-Statistic		200.018			
Prob (F-Statistic)		0.0000			
Std. Error of Regression		453878.59			
Mean Abs. % Err. (MAPE)		2.62%			
Ljung-Box Statistic		54.45			
Prob (Ljung-Box)		0.0004			
Jarque-Bera		1.4			
Prob (Jarque-Bera)		0.2953			
Variable		**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Monthly Sales			Endogenous		
Population		5,058	257.46	19.646	0.00%
Jan		7,649,197	454,091	16.845	0.00%
Feb		6,022,320	454,627	13.247	0.00%
Mar		5,455,686	448,553	12.163	0.00%
Apr		4,107,719	448,286	9.163	0.00%
May		3,112,265	448,159	6.945	0.00%
Jun		2,693,621	448,789	6.002	0.00%
Jul		2,357,687	449,626	5.244	0.00%
Aug		2,804,984	450,650	6.224	0.00%
Sep		3,900,455	451,758	8.634	0.00%
Oct		4,729,876	452,915	10.443	0.00%
Nov		5,499,387	454,096	12.111	0.00%
Dec		7,424,586	453,320	16.378	0.00%
Feb09		3,314,536	466,888	7.0992	0.00%
AR(1)		0.2081	0.0897	2.3195	2.20%
AR(2)		0.1724	0.0880	1.9602	5.22%

Where:

Monthly Sales	=	Monthly billed KWH sales for the Street Lighting class
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Jan-Dec	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
Feb09	=	A binary variable for February 2009 to account for a customer reclassification from GS1 and LGS1
AR(1), AR(2)	=	1st and 2nd order autoregressive error terms

IV. ESP MODEL RESULTS

Residential Customers. As shown in Figure 7E, the model explains nearly 100 percent of the variation in total customers. The forecast is driven by population estimates for the Las Vegas-Paradise MSA.

Residential Average Monthly Use. As shown in Figure 8E, the dependent variable was the monthly sales per customer. XHeat, XCool and XOther variables and specific monthly binary variables are used where statistically significant. These binary variables adjust for billing data anomalies especially after the institution of the new Banner billing system in early 2002. This model explains approximately 99 percent of the variation in sales per customer.

GS1 (Small Commercial and Industrial) Customers. As shown in Figure 9E, this model explains historical customer trend well with population as the primary explanatory variable. The model explains almost 100 percent of the variation in monthly customer counts.

GS1 (Small C&I) Average Monthly use. As shown in Figure 10E, this model explains approximately 92 percent of the variation in monthly sales per customer. XHeat, XCool and XOther are statistically significant. Monthly binary variables are used to account for billing data anomalies especially after the institution of the new Banner billing system in early 2002.

LGS1 (Small Commercial and Industrial) Customers. As shown in Figure 11E, this model explains historical customer trend well with population, GS1 customers, and monthly binary variables as the explanatory variables. The model explains almost 99 percent of the variation in monthly customer counts.

LGS1 (Small Commercial and Industrial) Average Monthly Use. As shown in Figure 12E, this model explains approximately 94 percent of the variation in annual sales. XHeat, XCool and XOther variables, three specific 2002 monthly binary variables and a binary variable for the all months from January 2009 to the end of the forecast were significant. The three monthly binary variables adjust for anomalies after the institution of the new Banner billing system in early 2002, while the 2009 and beyond binary accounts for the downshift in average use due to the recession.

Large Commercial and Industrial Customer Monthly Sales. As shown in Figure 13E, this model explains approximately 96 percent of the variation in monthly sales. XCool and XOther variables, a yearly binary variable for 2002 and specific monthly binary variables were used where significant. These binary variables adjust for anomalies especially after the institution of the new Banner billing system in early 2002. XHeat was not significant in this model. An additional significant variable is the monthly stock of hotel/motel rooms.

Public Street & Hwy Lights Monthly Sales. As shown in Figure 14E, this model explains approximately 96 percent of the variation in monthly sales. The drivers of this model are population and monthly binary variables and a binary variable for February 2009 representing a sales transfer from the GS1 and LGS1 class due to misclassification of lighting customers in those classes.

FIGURE 7E
MODEL OF RESIDENTIAL MONTHLY CUSTOMERS

Regression Statistics					
Sample Range	1998:1 thru 2009:11				
Adjusted Observations	142				
Deg. of Freedom for Error	137				
R-Squared	1.000				
Adjusted R-Squared	1.000				
Durbin-Watson Statistic	1.668				
AIC	14.281				
BIC	14.385				
F-Statistic	176708.245				
Prob (F-Statistic)	0.0000				
Std. Error of Regression	1240.35				
Mean Abs. % Err. (MAPE)	0.14%				
Ljung-Box Statistic	73.08				
Prob (Ljung-Box)	0.0000				
Jarque-Bera	4.5				
Prob (Jarque-Bera)	0.0467				

Variable		Coefficient	StdErr	T-Stat	P-Value
Customers		Endogenous			
CONST		689777.420	87605.526	7.874	0.00%
Nov04		-22328.981	882.702	-25.296	0.00%
Jun05		86.987	25.900	3.359	0.10%
Population		2902.624	879.929	3.299	0.12%
AR(1)		0.993	0.002	634.761	0.00%

where:

Customers	=	Monthly Residential Customers
CONST	=	Constant Term
Nov04	=	A binary variable for November 2004
Jun05	=	A binary variable for June 2005
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
AR(1)	=	1st order autoregressive error term

FIGURE 8E
MODEL OF RESIDENTIAL MONTHLY SALES (KWH) PER CUSTOMER

Regression Statistics	
Sample Range	1999:1 thru 2009:7
Adjusted Observations	127
Deg. of Freedom for Error	114
R-Squared	0.989
Adjusted R-Squared	0.987
Durbin-Watson Statistic	1.959
AIC	7.828
BIC	8.119
F-Statistic	820.662
Prob (F-Statistic)	0.0000
Std. Error of Regression	47.74
Mean Abs. % Err. (MAPE)	3.45%
Ljung-Box Statistic	69.27
Prob (Ljung-Box)	0.0000
Jarque-Bera	18.2
Prob (Jarque-Bera)	0.0030

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	196.379	55.495	3.539	0.06%
XHeat	2.018	0.094	21.397	0.00%
XCool	2.160	0.032	68.087	0.00%
XOther	0.283	0.068	4.138	0.01%
May02	-139.223	47.195	-2.950	0.39%
Mar02	202.551	43.965	4.607	0.00%
Jun02	163.839	47.286	3.465	0.08%
Sep02	-346.275	48.214	-7.182	0.00%
Oct02	-245.214	47.506	-5.162	0.00%
Apr08	73.783	43.684	1.689	9.40%
Dec07	73.807	43.807	1.685	9.48%
Jun08	-165.126	43.451	-3.800	0.02%
AR(1)	0.465	0.086	5.389	0.00%

where:

Sales per Customer	=	Monthly KWH sales per residential customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
May02	=	A binary variable for May 2002
Mar02	=	A binary variable for March 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Oct02	=	A binary variable for October 2002
Apr08	=	A binary variable for April 2008
Jun08	=	A binary variable for March 1999
Dec07	=	A binary variable for December 2007
AR(1)	=	1st order autoregressive error term

FIGURE 9E
MODEL OF MONTHLY GS1 CUSTOMERS

Regression Statistics					
Sample Range		1998:1 thru 2009:7			
Adjusted Observations		138			
Deg. of Freedom for Error		130			
R-Squared		0.997			
Adjusted R-Squared		0.996			
Durbin-Watson Statistic		2.162			
AIC		12.467			
BIC		12.637			
F-Statistic		4765.235			
Prob (F-Statistic)		0.0000			
Std. Error of Regression		495.46			
Mean Abs. % Err. (MAPE)		0.57%			
Ljung-Box Statistic		26.22			
Prob (Ljung-Box)		0.3423			
Jarque-Bera		59.8			
Prob (Jarque-Bera)		0.0003			

Variable		**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Customers		Endogenous			
CONST		34.447	0.486	70.899	0.00%
Population		726.821	133.952	5.426	0.00%
Apr		988.041	169.774	5.820	0.00%
May		1246.051	180.777	6.893	0.00%
Jun		873.083	171.791	5.082	0.00%
Jul		445.684	138.883	3.209	0.17%
Dec		185.316	108.286	1.711	8.94%
AR(1)		0.951	0.030	31.911	0.00%

Where:

Customers	=	Monthly GS1 Customers
CONST	=	Constant Term
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Apr-Jul, Dec	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
AR(1)	=	1st order autoregressive error term

FIGURE 10E
MODEL OF GS1 MONTHLY SALES PER CUSTOMER

Regression Statistics	
Sample Range	1998:1 thru 2009:7
Adjusted Observations	126
Deg. of Freedom for Error	108
R-Squared	0.934
Adjusted R-Squared	0.924
Durbin-Watson Statistic	1.987
AIC	7.112
BIC	7.517
F-Statistic	90.096
Prob (F-Statistic)	0.0000
Std. Error of Regression	32.79
Mean Abs. % Err. (MAPE)	3.05%
Ljung-Box Statistic	16.01
Prob (Ljung-Box)	0.8877
Jarque-Bera	1.2
Prob (Jarque-Bera)	0.3505

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	434.312	62.122	6.991	0.00%
XHeat	0.00244	0.000	9.848	0.00%
XCool	0.00352	0.000	20.885	0.00%
XOther	0.00004	0.000	2.832	0.55%
Yr02	184.015	14.486	12.703	0.00%
Yr03	130.695	13.352	9.788	0.00%
Jan02	-190.374	33.857	-5.623	0.00%
Mar02	-140.536	34.218	-4.107	0.01%
Apr02	-143.594	34.383	-4.176	0.01%
Jun02	176.029	32.504	5.416	0.00%
Sep02	-299.036	34.201	-8.743	0.00%
Feb03	-97.441	32.979	-2.955	0.39%
Apr03	-160.496	33.847	-4.742	0.00%
Dec03	-124.008	34.669	-3.577	0.05%
Feb06	71.768	32.010	2.242	2.70%
Aug08	-63.384	33.190	-1.910	5.89%
AR(1)	0.202	0.103	1.960	5.26%
SAR(1)	0.250	0.095	2.638	0.96%

where:

Sales per Customer	=	Monthly KWH sales per GS1 customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
Yr02	=	A binary variable for the year 2002
Yr03	=	A binary variable for the year 2003
XXXYY	=	Binary variables for specified months and years
AR(1)	=	1st order autoregressive error term
SAR(1)	=	Seasonally adjusted 1st order moving average error term

FIGURE 11E
MODEL OF LGS1 CUSTOMERS

Regression Statistics	
Sample Range	1998:1 thru 2009:7
Adjusted Observations	138
Deg. of Freedom for Error	125
R-Squared	0.992
Adjusted R-Squared	0.991
Durbin-Watson Statistic	1.856
AIC	11.996
BIC	12.272
F-Statistic	1231.299
Prob (F-Statistic)	0.0000
Std. Error of Regression	385.01
Mean Abs. % Err. (MAPE)	1.14%
Ljung-Box Statistic	26.05
Prob (Ljung-Box)	0.3505
Jarque-Bera	30.0
Prob (Jarque-Bera)	0.0011

Variable	Coefficient	StdErr	T-Stat	P-Value
Customers		Endogenous		
CONST	-1411.130	1885.691	-0.748	45.57%
Jan	-327.662	114.741	-2.856	0.50%
Feb	-700.364	146.464	-4.782	0.00%
Mar	-951.755	164.565	-5.783	0.00%
Apr	-1240.656	173.043	-7.170	0.00%
May	-1298.238	173.391	-7.487	0.00%
Jun	-1087.420	152.733	-7.120	0.00%
Jul	-514.729	116.797	-4.407	0.00%
Sep	146.959	100.781	1.458	14.73%
Oct	180.785	100.826	1.793	7.54%
Population	22.533	2.148	10.491	0.00%
Predicted GS1 Customers	-0.208	0.051	-4.068	0.01%
AR(1)	0.874	0.045	19.290	0.00%

Where:

Customers	=	Monthly LGS1 Customers
CONST	=	Constant Term
Jan-Oct	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Predicted GS1 Customers	=	Monthly history and forecast of GS1 customers
AR(1)	=	1st order autoregressive error term

FIGURE 12E
MODEL OF LGS1 AVERAGE USE PER CUSTOMER

Regression Statistics	
Sample Range	1998:1 thru 2009:7
Adjusted Observations	138
Deg. of Freedom for Error	129
R-Squared	0.944
Adjusted R-Squared	0.941
Durbin-Watson Statistic	2.098
AIC	12.357
BIC	12.548
F-Statistic	272.444
Prob (F-Statistic)	0.0000
Std. Error of Regression	467.40
Mean Abs. % Err. (MAPE)	2.98%
Ljung-Box Statistic	77.63
Prob (Ljung-Box)	0.0000
Jarque-Bera	8.1
Prob (Jarque-Bera)	0.0149

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	6988.576	690.410	10.122	0.00%
XOther	0.0092	0.0027	3.434	0.08%
XHeat	0.0540	0.0018	29.691	0.00%
XCool	0.0006	0.0002	3.815	0.02%
Apr02	1168.362	475.870	2.455	1.54%
May02	2083.309	472.674	4.407	0.00%
Sep02	-2250.064	460.210	-4.889	0.00%
Year>=2009	-594.242	233.337	-2.547	1.21%
AR(1)	0.264	0.087	3.024	0.30%

where:

Sales per Customer	=	Monthly KWH sales per LGS1 customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
May02	=	A binary variable for May 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Dec02	=	A binary variable for December 2002
Year>=2009	=	A binary variable representing the dowhnshift in avg use due to the recession
AR(1)	=	1st order autoregressive error term

FIGURE 13E
MODEL OF LARGE COMMERCIAL AND INDUSTRIAL MONTHLY SALES

Regression Statistics							
Sample Range		1998:1 thru 2009:7					
Adjusted Observations		137					
Deg. of Freedom for Error		127					
R-Squared		0.967					
Adjusted R-Squared		0.964					
Durbin-Watson Statistic		2.408					
AIC		33.490					
BIC		33.703					
F-Statistic		370.104					
Prob (F-Statistic)		0.0000					
Std. Error of Regression		18070005					
Mean Abs. % Err. (MAPE)		2.60%					
Ljung-Box Statistic		43.82					
Prob (Ljung-Box)		0.0080					
Jarque-Bera		2.2					
Prob (Jarque-Bera)		0.1543					

Variable		Coefficient	StdErr	T-Stat	P-Value
Monthly Sales			Endogenous		
XCool		1219.819	38.544	31.648	0.00%
XOther		30.412	4.395	6.920	0.00%
Yr02		37,125,725	12,088,766	3.071	0.26%
May02		70,562,474	15,612,099	4.520	0.00%
Sep02		-109,131,199	15,431,381	-7.072	0.00%
Dec07		40,647,842	15,321,893	2.653	0.90%
Jan03		39,171,258	16,579,922	2.363	1.97%
Rooms		2511.123	229.351	10.949	0.00%
AR(1)		0.356	0.078	4.559	0.00%
AR(2)		0.541	0.078	6.961	0.00%

where:

Monthly Sales	=	Monthly billed KWH sales for the LGS2 through LGS4 class
Small.XCool	=	Estimates the monthly use for electric cooling equipment
Small.XOther	=	Estimates the monthly use for all other electrical equipment
Rooms	=	Total Monthly hotel/motel rooms
Yr02	=	A binary variable for the year 2002
May02	=	A binary variable for May 2002
Jun02	=	A binary variable for June 2002
Sep02	=	A binary variable for September 2002
Dec02	=	A binary variable for December 2002
Jan03	=	A binary variable for January 2003
AR(1)	=	1st order autoregressive error term
AR(2)	=	2nd order autoregressive error term

FIGURE 14E
MODEL OF PUBLIC STREET & HWY LIGHTS MONTHLY SALES

Regression Statistics					
Sample Range		1998:1 thru 2009:7			
Adjusted Observations		137			
Deg. of Freedom for Error		121			
R-Squared		0.962			
Adjusted R-Squared		0.957			
Durbin-Watson Statistic		1.984			
AIC		26.180			
BIC		26.521			
F-Statistic		192.146			
Prob (F-Statistic)		0.0000			
Std. Error of Regression		458340.87			
Mean Abs. % Err. (MAPE)		2.60%			
Ljung-Box Statistic		52.15			
Prob (Ljung-Box)		0.0007			
Jarque-Bera		2.1			
Prob (Jarque-Bera)		0.1744			
Variable		**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Monthly Sales			Endogenous		
Population		4,784	260.18	18.387	0.00%
Jan		7,984,460	463,029	17.244	0.00%
Feb		6,360,119	464,780	13.684	0.00%
Mar		5,802,417	458,596	12.653	0.00%
Apr		4,458,000	458,433	9.724	0.00%
May		3,465,089	458,273	7.561	0.00%
Jun		3,048,157	458,893	6.642	0.00%
Jul		2,713,641	459,714	5.903	0.00%
Aug		3,142,544	458,394	6.856	0.00%
Sep		4,267,759	458,688	9.304	0.00%
Oct		5,054,167	459,103	11.009	0.00%
Nov		5,797,764	459,996	12.604	0.00%
Dec		7,759,448	461,454	16.815	0.00%
Feb09		3,334,991	470,762	7.0842	0.00%
AR(1)		0.2111	0.0907	2.3275	2.16%
AR(2)		0.1802	0.0889	2.0274	4.49%

Where:

Monthly Sales	=	Monthly billed KWH sales for the Street Lighting class
Population	=	Monthly estimate of population for the Las Vegas-Paradise MSA
Jan-Dec	=	Monthly binary variables with a value of one if it is the specified month and zero otherwise
Feb09	=	A binary variable for February 2009 to account for a customer reclassification from GS1 and LGS1
AR(1), AR(2)	=	1st and 2nd order autoregressive error terms

V. 30 YEAR FORECAST SUMMARY

A. Summary

Figures 15 and 15E are summaries of the peak demand, energy and load factor for the 30 year time horizon of the base case forecasts for the IRP and ESP. As sales and hourly models were developed through 2029, a growth rate based on the years 2025-2029 was applied to the forecast after 2029.

FIGURE 15
30-YEAR IRP FORECAST SUMMARY BASE CASE SCENARIO

Year	Summer Peak MW	Winter Peak MW	Energy GWhs	Load Factor
2009	5,508	2,755	22,077	45.76%
2010	5,591	2,747	21,827	44.57%
2011	5,561	2,789	21,853	44.86%
2012	5,528	2,825	22,107	45.53%
2013	5,588	2,843	22,497	45.96%
2014	5,645	2,911	22,921	46.35%
2015	5,699	2,993	23,268	46.61%
2016	5,775	3,035	23,672	46.67%
2017	5,833	3,101	23,922	46.82%
2018	5,884	3,138	24,233	47.01%
2019	5,965	3,157	24,619	47.11%
2020	6,050	3,299	25,161	47.35%
2021	6,113	3,368	25,509	47.64%
2022	6,187	3,441	25,926	47.84%
2023	6,289	3,539	26,380	47.88%
2024	6,383	3,534	26,868	47.92%
2025	6,466	3,588	27,196	48.01%
2026	6,560	3,671	27,604	48.04%
2027	6,649	3,720	27,990	48.06%
2028	6,732	3,796	28,464	48.13%
2029	6,805	3,809	28,740	48.21%
2030	6,855	3,799	28,918	48.16%
2031	6,937	3,845	29,265	48.16%
2032	7,020	3,891	29,692	48.15%
2033	7,104	3,938	29,972	48.16%
2034	7,189	3,985	30,332	48.16%
2035	7,275	4,033	30,696	48.17%
2036	7,362	4,081	31,148	48.17%
2037	7,450	4,130	31,438	48.17%
2038	7,539	4,180	31,815	48.17%
2039	7,629	4,230	32,197	48.18%
2040	7,721	4,281	32,667	48.30%

FIGURE 15E
30-YEAR FORECAST ESP SUMMARY BASE CASE SCENARIO

Year	Summer Peak		Winter Peak		Energy		Load Factor
	MW		MW		GWhs		
2010	5,655		2,799		22,058		44.53%
2011	5,647		2,884		22,451		45.38%
2012	5,692		2,940		22,881		45.76%
2013	5,773		2,954		23,233		45.94%
2014	5,872		3,020		23,707		46.09%
2015	5,975		3,115		24,123		46.09%
2016	6,068		3,163		24,591		46.14%
2017	6,155		3,245		24,951		46.28%
2018	6,233		3,324		25,453		46.62%
2019	6,310		3,392		25,942		46.93%
2020	6,428		3,499		26,451		46.85%
2021	6,484		3,556		26,788		47.16%
2022	6,567		3,609		27,192		47.27%
2023	6,682		3,688		27,653		47.24%
2024	6,780		3,694		28,178		47.31%
2025	6,870		3,750		28,522		47.39%
2026	6,961		3,833		28,953		47.48%
2027	7,053		3,878		29,360		47.52%
2028	7,156		3,959		29,854		47.49%
2029	7,235		3,993		30,149		47.57%
2030	7,315		3,992		30,513		47.62%
2031	7,417		4,048		30,941		47.62%
2032	7,521		4,105		31,455		47.61%
2033	7,626		4,162		31,814		47.62%
2034	7,733		4,220		32,260		47.62%
2035	7,841		4,279		32,711		47.62%
2036	7,951		4,339		33,259		47.62%
2037	8,062		4,400		33,635		47.63%
2038	8,175		4,462		34,106		47.63%
2039	8,289		4,524		34,583		47.63%

Note: Additional figures reporting the forecasts are contained in the Load Forecast and Market Fundamentals volume, and will not be repeated here.

B. Hourly Load Models

The normal weather used in the modeling was developed using the Rank and Average method. Basically, the daily average temperatures across the 20-year period were ranked from hottest to coldest by season. The average temperatures for the ranked days were then averaged across the 20-years to produce a daily average normal temperature. For example, the 20 hottest temperature days for a season are averaged, then the second 20 hottest days and so on. These daily average temperatures are then assigned to calendar days for the period of the forecast.

C. Forecast Scenario Data and Results

Figures 16 and 16E are summaries of the energy, summer and winter peak demand across all three scenarios. These scenarios were developed by taking the base population, real GMP, households and personal income and ratio'ing those variables based on IHS/Global Insights's August 2009 U.S. GDP base, high and low scenarios. In addition, optimistic and pessimistic assumptions were made regarding the opening dates of the new large hotel/motels and growth rates after 2011. The high case also included an assumption regarding the electricity use of plug-in hybrid vehicles. (See Figure 23 for a summary of the plug-in hybrid energy used in the high scenario).

Figure 17 is a summary of the economic data used in the IRP Forecast. Figure 17E is a summary of the low, ESP base and high economic data.

After comparison with the ESP base case, it was decided that the high scenario did not provide enough deviation from the ESP base forecast in later years given we are near the bottom of an economic cycle. Minor changes also were made to the low scenario. Examination of prior sales and customer growth was used to adjust the sales to obtain the peaks and energy numbers shown in Figure 16E. Figure 18 is a summary of the interim high and low peak load scenarios compared to the ESP base case. Figure 19 summarizes the final high and low peak load scenarios compared to the IRP base case and Figure 19E compares the scenarios with the ESP base case load forecast.

As noted above, Nevada Power examined gross domestic product ("GDP") from national scenarios, prior sales and customer growth and a forecast of plug-in hybrids to develop the high and low scenarios. Customer growth was then adjusted to provide a sales forecast that represented high and low sales growth based on past sales and customer history. Therefore, the high and low growth forecasts are not specifically tied to a base forecast. These high and low scenarios still represent low probability occurances, regardless of the change in the IRP base load forecast versus the ESP base load forecast.

Two additional scenarios were developed as a result of a compliance item from the 8th Amendment Order, Docket Nos. 08-08014 and 08-08015, page 49, which required Nevada Power to file in its 2009 IRP "Alternative Plans that incorporate Base, High and Low DSM plans." These scenarios take the high and low DSM and DR reduction estimates and subtract them from the ESP base forecast. No other changes were made to the ESP base case forecast for these scenarios. Figure 20 is a summary of the DSM, DR avoided capacity and small solar peak effects for the IRP load forecast. Figure 20E is a summary of the DSM, DR avoided capacity and small solar peak effects for the ESP forecast. Figures 21and 21E summarize the annual energy impacts of the DSM, DR, and small solar projects on the IRP forecast and the ESP forecast, as well as the DSM scenarios (Figure 21E).

FIGURE 16
ENERGY, SUMMER AND WINTER PEAK DEMANDS
LOW, BASE AND HIGH LOAD FORECAST SCENARIOS: IRP BASE CASE

	Energy			Summer Peak			Winter Peak		
Year	Low	Base	High	Low	Base	High	Low	Base	High
2010	21,507	21,827	22,767	5,528	5,591	5,850	2,733	2,747	2,888
2011	21,523	21,853	23,252	5,449	5,561	5,872	2,775	2,789	2,986
2012	21,800	22,107	23,701	5,454	5,528	5,901	2,819	2,825	3,039
2013	22,023	22,497	24,371	5,478	5,588	6,057	2,820	2,843	3,107
2014	22,320	22,921	25,054	5,522	5,645	6,226	2,867	2,911	3,197
2015	22,615	23,268	25,711	5,574	5,699	6,397	2,953	2,993	3,308
2016	22,906	23,672	26,455	5,617	5,775	6,564	2,991	3,035	3,396
2017	23,081	23,922	27,088	5,655	5,833	6,723	3,047	3,101	3,527
2018	23,380	24,233	27,879	5,681	5,884	6,880	3,084	3,138	3,641
2019	23,674	24,619	28,660	5,727	5,965	7,038	3,123	3,157	3,742
2020	24,028	25,161	29,451	5,754	6,050	7,238	3,232	3,299	3,868
2021	24,212	25,509	30,049	5,799	6,113	7,368	3,271	3,368	3,953
2022	24,437	25,926	30,737	5,833	6,187	7,537	3,302	3,441	4,041
2023	24,743	26,380	31,504	5,899	6,289	7,741	3,380	3,539	4,167
2024	25,149	26,868	32,344	5,967	6,383	7,927	3,380	3,534	4,205
2025	25,405	27,196	32,986	6,036	6,466	8,102	3,424	3,588	4,301
2026	25,747	27,604	33,730	6,112	6,560	8,281	3,504	3,671	4,429
2027	26,065	27,990	34,453	6,188	6,649	8,462	3,545	3,720	4,518
2028	26,460	28,464	35,284	6,262	6,732	8,654	3,599	3,796	4,650
2029	26,673	28,740	35,893	6,320	6,805	8,823	3,601	3,809	4,707
2030	26,949	28,918	36,553	6,379	6,855	8,992	3,617	3,799	4,756
2031	27,245	29,265	37,320	6,449	6,937	9,181	3,657	3,845	4,856
2032	27,617	29,692	38,203	6,520	7,020	9,374	3,697	3,891	4,958
2033	27,848	29,972	38,906	6,592	7,104	9,571	3,738	3,938	5,062
2034	28,155	30,332	39,723	6,665	7,189	9,772	3,779	3,985	5,168
2035	28,464	30,696	40,557	6,738	7,275	9,977	3,821	4,033	5,277
2036	28,856	31,148	41,520	6,812	7,362	10,187	3,863	4,081	5,388
2037	29,095	31,438	42,281	6,887	7,450	10,401	3,905	4,130	5,501
2038	29,415	31,815	43,169	6,963	7,539	10,619	3,948	4,180	5,617
2039	29,739	32,197	44,076	7,040	7,629	10,842	3,991	4,230	5,735

FIGURE 16E
ENERGY, SUMMER AND WINTER PEAK DEMANDS
LOW, BASE AND HIGH LOAD FORECAST SCENARIOS: ESP Base Case

	Energy				Summer Peak				Winter Peak		
Year	Low	Base	High		Low	Base	High		Low	Base	High
2010	21,507	22,058	22,767		5,528	5,655	5,850		2,733	2,799	2,888
2011	21,523	22,451	23,252		5,449	5,647	5,872		2,775	2,884	2,986
2012	21,800	22,881	23,701		5,454	5,692	5,901		2,819	2,940	3,039
2013	22,023	23,233	24,371		5,478	5,773	6,057		2,820	2,954	3,107
2014	22,320	23,707	25,054		5,522	5,872	6,226		2,867	3,020	3,197
2015	22,615	24,123	25,711		5,574	5,975	6,397		2,953	3,115	3,308
2016	22,906	24,591	26,455		5,617	6,068	6,564		2,991	3,163	3,396
2017	23,081	24,951	27,088		5,655	6,155	6,723		3,047	3,245	3,527
2018	23,380	25,453	27,879		5,681	6,233	6,880		3,084	3,324	3,641
2019	23,674	25,942	28,660		5,727	6,310	7,038		3,123	3,392	3,742
2020	24,028	26,451	29,451		5,754	6,428	7,238		3,232	3,499	3,868
2021	24,212	26,788	30,049		5,799	6,484	7,368		3,271	3,556	3,953
2022	24,437	27,192	30,737		5,833	6,567	7,537		3,302	3,609	4,041
2023	24,743	27,653	31,504		5,899	6,682	7,741		3,380	3,688	4,167
2024	25,149	28,178	32,344		5,967	6,780	7,927		3,380	3,694	4,205
2025	25,405	28,522	32,986		6,036	6,870	8,102		3,424	3,750	4,301
2026	25,747	28,953	33,730		6,112	6,961	8,281		3,504	3,833	4,429
2027	26,065	29,360	34,453		6,188	7,053	8,462		3,545	3,878	4,518
2028	26,460	29,854	35,284		6,262	7,156	8,654		3,599	3,959	4,650
2029	26,673	30,149	35,893		6,320	7,235	8,823		3,601	3,993	4,707
2030	26,949	30,513	36,553		6,379	7,315	8,992		3,617	3,992	4,756
2031	27,245	30,941	37,320		6,449	7,417	9,181		3,657	4,048	4,856
2032	27,617	31,455	38,203		6,520	7,521	9,374		3,697	4,105	4,958
2033	27,848	31,814	38,906		6,592	7,626	9,571		3,738	4,162	5,062
2034	28,155	32,260	39,723		6,665	7,733	9,772		3,779	4,220	5,168
2035	28,464	32,711	40,557		6,738	7,841	9,977		3,821	4,279	5,277
2036	28,856	33,259	41,520		6,812	7,951	10,187		3,863	4,339	5,388
2037	29,095	33,635	42,281		6,887	8,062	10,401		3,905	4,400	5,501
2038	29,415	34,106	43,169		6,963	8,175	10,619		3,948	4,462	5,617
2039	29,739	34,583	44,076		7,040	8,289	10,842		3,991	4,524	5,735

FIGURE 17
LAS VEGAS-PARADISE MSA ECONOMIC DATA FOR THE IRP BASE FORECAST

Year		Real GMP (millions $) (1)		NF Employ. (000's) (1)		RPI (000's $) (1)		Households (000's) (1)		Popn (000's) (2) (3)
2007		79,249		927.94		62,821		670.37		1,954.32
2008		78,859		915.40		62,095		680.29		1,967.72
2009		76,006		860.16		58,688		691.68		1,953.86
2010		77,500		834.90		58,203		704.57		1,957.76
2011		80,311		854.08		59,399		719.70		1,965.56
2012		84,177		891.44		61,944		734.97		1,995.04
2013		87,807		930.51		65,255		750.76		2,052.55
2014		91,091		960.54		68,325		768.00		2,109.17
2015		94,181		984.22		71,253		786.53		2,164.02
2016		97,332		1007.60		74,204		805.53		2,216.22
2017		100,536		1029.47		77,254		825.21		2,265.77
2018		103,941		1050.78		80,379		845.07		2,313.54
2019		107,705		1074.52		83,878		865.43		2,358.66
2020		111,544		1097.80		87,604		887.80		2,402.01
2021		114,765		1119.94		91,343		909.43		2,442.71
2022		118,157		1143.48		95,263		931.57		2,482.52
2023		121,612		1164.93		99,178		953.99		2,521.45
2024		125,123		1184.99		103,043		976.89		2,558.61
2025		128,953		1206.68		107,044		999.88		2,594.88
2026		132,835		1229.42		111,291		1,023.15		2,630.27
2027		136,703		1252.95		115,696		1,045.90		2,664.78
2028		140,710		1277.14		120,168		1,069.94		2,698.39
2029		144,828		1302.41		124,861		1,094.39		2,732.01

FIGURE 17E
LAS VEGAS-PARADISE MSA ECONOMIC DATA FOR THE LOW, ESP BASE AND HIGH SCENARIOS

	Population (thousands)				Households (thousands)				Real Personal Income (Millions)		
Year	Low	Base	High		Low	Base	High		Low	Base	High
2007	1,996.54	1,996.54	1,996.54		670.30	670.30	670.30		60,867	60,867	60,867
2008	1,986.15	1,986.15	1,986.15		679.37	679.37	679.37		60,296	60,296	60,296
2009	1,971.12	1,978.20	1,985.15		686.28	688.74	691.15		58,671	58,879	59,083
2010	1,954.47	1,999.96	2,041.04		685.55	701.50	715.91		57,903	59,251	60,468
2011	1,989.35	2,063.11	2,115.92		690.58	716.18	734.51		58,293	60,454	62,002
2012	2,033.32	2,125.31	2,182.91		700.37	732.06	751.90		60,133	62,854	64,558
2013	2,079.89	2,186.57	2,255.64		712.26	748.80	772.45		62,504	65,710	67,786
2014	2,134.32	2,246.89	2,332.25		727.61	765.99	795.09		65,066	68,497	71,100
2015	2,188.92	2,305.33	2,402.41		744.76	784.37	817.40		67,772	71,376	74,383
2016	2,241.33	2,360.93	2,465.77		762.69	803.39	839.06		70,618	74,386	77,689
2017	2,287.74	2,413.71	2,525.16		779.93	822.87	860.86		73,444	77,489	81,067
2018	2,328.80	2,464.61	2,583.40		796.27	842.71	883.33		76,220	80,665	84,553
2019	2,364.69	2,512.68	2,640.47		812.08	862.90	906.79		79,116	84,068	88,344
2020	2,398.49	2,558.86	2,695.83		829.00	884.41	931.73		82,137	87,621	92,307
2021	2,429.31	2,602.21	2,748.48		845.30	905.41	956.28		85,214	91,262	96,381
2022	2,458.98	2,644.62	2,800.39		862.15	927.17	981.72		88,252	94,889	100,461
2023	2,487.48	2,686.09	2,851.55		879.03	949.11	1,007.50		91,396	98,658	104,711
2024	2,513.97	2,725.68	2,900.95		895.93	971.24	1,033.59		94,580	102,498	109,058
2025	2,539.33	2,764.32	2,949.58		912.91	993.61	1,060.08		98,046	106,673	113,782
2026	2,563.57	2,802.02	2,997.44		929.80	1,016.06	1,086.77		101,573	110,946	118,634
2027	2,586.72	2,838.78	3,044.52		946.03	1,037.96	1,113.00		105,052	115,200	123,490
2028	2,608.78	2,874.59	3,090.80		963.27	1,061.11	1,140.72		108,642	119,608	128,534
2029	2,630.61	2,910.41	3,137.31		980.68	1,084.63	1,168.95		112,380	124,213	133,816

	Real Gross Metro Product (millions)				Real Gross Domestic Product (billions)				Hotel/Motel Rooms		
Year	Low	Base	High		Low	Base	High		Low	Base	High
2007	80,841	80,841	80,841		13,254.05	13,254.05	13,254.05		133,318	133,318	133,318
2008	80,728	80,728	80,728		13,312.18	13,312.18	13,312.18		136,787	136,787	136,787
2009	77,281	77,556	77,826		12,906.59	12,952.88	12,998.30		141,219	141,219	141,219
2010	76,877	78,668	80,285		12,889.73	13,189.75	13,460.68		142,989	144,012	146,987
2011	78,681	81,599	83,688		13,110.79	13,597.02	13,945.10		146,628	150,540	150,540
2012	81,675	85,371	87,685		13,504.17	14,115.22	14,497.81		149,489	150,540	153,810
2013	84,296	88,620	91,420		13,804.95	14,513.03	14,971.45		150,707	152,164	159,393
2014	87,031	91,621	95,102		14,137.66	14,883.32	15,448.71		151,939	153,806	162,677
2015	90,012	94,799	98,791		14,489.05	15,259.62	15,902.25		153,183	155,466	165,996
2016	93,172	98,144	102,502		14,855.76	15,648.51	16,343.36		154,441	157,143	169,351
2017	96,271	101,572	106,262		15,215.52	16,053.36	16,794.57		155,713	158,838	172,742
2018	99,413	105,211	110,283		15,593.03	16,502.41	17,297.83		156,998	160,552	176,169
2019	102,632	109,055	114,602		15,986.34	16,986.81	17,850.78		158,298	162,284	179,634
2020	106,034	113,116	119,166		N/A	N/A	N/A		159,611	164,035	183,136
2021	109,323	117,088	123,658		N/A	N/A	N/A		160,938	165,805	186,676
2022	112,616	121,093	128,208		N/A	N/A	N/A		162,280	167,594	190,253
2023	115,913	125,134	132,818		N/A	N/A	N/A		163,636	169,402	193,870
2024	119,277	129,276	137,559		N/A	N/A	N/A		165,007	171,230	197,526
2025	122,932	133,766	142,692		N/A	N/A	N/A		166,393	173,078	201,220
2026	126,529	138,228	147,821		N/A	N/A	N/A		167,793	174,945	204,955
2027	130,085	142,677	152,962		N/A	N/A	N/A		169,209	176,833	208,730
2028	133,638	147,158	158,161		N/A	N/A	N/A		170,640	178,741	212,546
2029	137,314	151,807	163,567		N/A	N/A	N/A		172,086	180,669	216,403

N/A = Not Available. The August Global Insight GDP forecast went through 2019. The final 10 years of the scenario economic data were developed based on deviations from the base case growth rates.

FIGURE 18
INTERIM LOW AND HIGH PEAK DEMAND SCENARIOS AND DEVIATION FROM THE ESP BASE CASE

	Interim Peak Demand (MW)				Difference with Base			
Year	Low	Base	High		Low	High	% Low	% High
2010	5,533	5,655	5,834		(122)	179	-2.2%	3.2%
2011	5,458	5,647	5,880		(189)	233	-3.4%	4.1%
2012	5,457	5,692	5,915		(235)	223	-4.1%	3.9%
2013	5,477	5,773	6,041		(296)	268	-5.1%	4.6%
2014	5,520	5,872	6,172		(352)	300	-6.0%	5.1%
2015	5,602	5,975	6,337		(373)	362	-6.2%	6.1%
2016	5,621	6,068	6,459		(447)	391	-7.4%	6.4%
2017	5,658	6,155	6,604		(497)	449	-8.1%	7.3%
2018	5,686	6,233	6,746		(547)	513	-8.8%	8.2%
2019	5,736	6,310	6,907		(574)	597	-9.1%	9.5%
2020	5,758	6,428	7,017		(670)	589	-10.4%	9.2%
2021	5,806	6,484	7,156		(678)	672	-10.5%	10.4%
2022	5,844	6,567	7,302		(723)	735	-11.0%	11.2%
2023	5,914	6,682	7,479		(768)	797	-11.5%	11.9%
2024	5,974	6,780	7,636		(806)	856	-11.9%	12.6%
2025	6,043	6,870	7,800		(827)	930	-12.0%	13.5%
2026	6,112	6,961	7,963		(849)	1,002	-12.2%	14.4%
2027	6,194	7,053	8,140		(859)	1,087	-12.2%	15.4%
2028	6,274	7,156	8,319		(882)	1,163	-12.3%	16.2%
2029	6,333	7,235	8,476		(902)	1,241	-12.5%	17.1%

FIGURE 19
FINAL LOW, BASE AND HIGH FORECAST SCENARIO PEAK DEMANDS AND DEVIATION FROM THE IRP BASE LOAD FORECAST

	Peak Demand (MW)				Difference with Base			
Year	Low	Base	High		Low	High	% Low	% High
2010	5,528	5,591	5,850		(63)	259	-1.1%	4.6%
2011	5,449	5,561	5,872		(112)	311	-2.1%	5.6%
2012	5,454	5,528	5,901		(74)	373	-1.4%	6.7%
2013	5,478	5,588	6,057		(110)	469	-2.0%	8.4%
2014	5,522	5,645	6,226		(123)	581	-2.2%	10.3%
2015	5,574	5,699	6,397		(125)	698	-2.2%	12.2%
2016	5,617	5,775	6,564		(158)	789	-2.8%	13.7%
2017	5,655	5,833	6,723		(178)	890	-3.1%	15.3%
2018	5,681	5,884	6,880		(203)	996	-3.6%	16.9%
2019	5,727	5,965	7,038		(238)	1,073	-4.2%	18.0%
2020	5,754	6,050	7,238		(296)	1,188	-5.1%	19.6%
2021	5,799	6,113	7,368		(314)	1,255	-5.4%	20.5%
2022	5,833	6,187	7,537		(354)	1,350	-6.1%	21.8%
2023	5,899	6,289	7,741		(390)	1,452	-6.6%	23.1%
2024	5,967	6,383	7,927		(416)	1,544	-7.0%	24.2%
2025	6,036	6,466	8,102		(430)	1,636	-7.1%	25.3%
2026	6,112	6,560	8,281		(448)	1,721	-7.3%	26.2%
2027	6,188	6,649	8,462		(461)	1,813	-7.4%	27.3%
2028	6,262	6,732	8,654		(470)	1,922	-7.5%	28.6%
2029	6,320	6,805	8,823		(485)	2,018	-7.7%	29.7%

FIGURE 19E
FINAL LOW, BASE AND HIGH FORECAST SCENARIO PEAK DEMANDS AND DEVIATION FROM THE ESP BASE LOAD FORECAST

	Peak Demand (MW)				Difference with Base			
Year	Low	Base	High		Low	High	% Low	% High
2010	5,528	5,655	5,850		(127)	195	-2.3%	3.4%
2011	5,449	5,647	5,872		(198)	225	-3.6%	4.0%
2012	5,454	5,692	5,901		(238)	209	-4.4%	3.7%
2013	5,478	5,773	6,057		(295)	284	-5.4%	4.9%
2014	5,522	5,872	6,226		(350)	354	-6.3%	6.0%
2015	5,574	5,975	6,397		(401)	422	-7.2%	7.1%
2016	5,617	6,068	6,564		(451)	496	-8.0%	8.2%
2017	5,655	6,155	6,723		(500)	568	-8.8%	9.2%
2018	5,681	6,233	6,880		(552)	647	-9.7%	10.4%
2019	5,727	6,310	7,038		(583)	728	-10.2%	11.5%
2020	5,754	6,428	7,238		(674)	810	-11.7%	12.6%
2021	5,799	6,484	7,368		(685)	884	-11.8%	13.6%
2022	5,833	6,567	7,537		(734)	970	-12.6%	14.8%
2023	5,899	6,682	7,741		(783)	1,059	-13.3%	15.8%
2024	5,967	6,780	7,927		(813)	1,147	-13.6%	16.9%
2025	6,036	6,870	8,102		(834)	1,232	-13.8%	17.9%
2026	6,112	6,961	8,281		(849)	1,320	-13.9%	19.0%
2027	6,188	7,053	8,462		(865)	1,409	-14.0%	20.0%
2028	6,262	7,156	8,654		(894)	1,498	-14.3%	20.9%
2029	6,320	7,235	8,823		(915)	1,588	-14.5%	21.9%

FIGURE 20
SUMMARY OF DSM, DR AVOIDED CAPACITY AND SMALL SOLAR SUMMER PEAK EFFECTS (MW) FOR THE IRP FORECAST

Year	DSM	DR Avoided Capacity	Small Solar	Total
	MW	MW	MW	MW
2010	52	123	0	175
2011	100	162	1	263
2012	152	223	1	376
2013	198	243	1	442
2014	243	271	1	515
2015	287	292	2	581
2016	328	292	2	622
2017	370	295	2	667
2018	408	309	2	719
2019	443	298	3	744
2020	469	285	3	757
2021	493	282	4	779
2022	509	286	4	799
2023	499	290	4	793
2024	497	298	4	799
2025	492	307	4	803
2026	489	308	5	802
2027	487	311	5	803
2028	484	323	6	813
2029	481	328	5	814
2030	480	327	6	813

FIGURE 20E
SUMMARY OF DSM, DR AVOIDED CAPACITY AND SMALL SOLAR SUMMER SYSTEM PEAK EFFECTS (MW) FOR THE ESP BASE, LOW DSM/DR AND HIGH DSM/DR SCENARIOS

	Base Case with losses				Low DSM/DR Case with losses				High DSM/DR Case with losses			
Year	DSM	DR Avoided Capacity	Small Solar	Total	DSM	DR Avoided Capacity	Small Solar and Wind	Total	DSM	DR Avoided Capacity	Small Solar	Total
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
2010	43	127	0	170	38	125	0	163	46	155	0	201
2011	72	237	1	310	55	131	1	187	85	233	1	319
2012	103	280	1	384	79	139	1	219	131	281	1	413
2013	135	287	1	423	102	141	1	244	174	294	1	469
2014	164	293	1	458	125	134	1	260	209	308	1	518
2015	192	285	2	479	148	139	2	289	244	309	2	555
2016	222	289	2	513	172	142	2	316	279	310	2	591
2017	249	284	2	535	192	144	2	338	312	301	2	615
2018	269	296	2	567	207	135	2	344	338	317	2	657
2019	289	309	3	601	222	144	3	369	364	304	3	671
2020	306	278	3	587	235	139	3	377	385	289	3	677
2021	325	298	4	627	249	142	4	395	407	293	4	704
2022	337	302	4	643	257	143	4	404	421	296	4	721
2023	319	307	4	630	238	146	4	388	406	311	4	721
2024	319	318	4	641	236	146	4	386	406	311	4	721
2025	323	321	4	648	242	146	4	392	406	321	4	731
2026	325	328	5	658	245	149	5	399	404	324	4	732
2027	326	330	5	661	247	151	5	403	402	324	5	731
2028	327	325	6	658	250	152	6	408	402	337	6	745
2029	328	327	5	660	252	153	5	410	402	344	5	751
2030	329	327	6	662	254	152	6	412	404	343	6	753

The DSM and small solar for all 3 scenarios are measured at 5 pm on the peak day.

FIGURE 21
SUMMARY OF ANNUAL GWH REDUCTIONS FOR DSM, ACLM/DLC, SMALL SOLAR FOR THE IRP LOAD FORECAST

Year		**Total**			
		DSM	DR	Small Solar	Total
2010		223	6	4	232
2011		416	10	6	433
2012		583	17	8	608
2013		708	20	11	739
2014		833	23	14	870
2015		949	27	16	992
2016		1,065	28	19	1,111
2017		1,176	29	21	1,226
2018		1,281	29	24	1,334
2019		1,326	30	27	1,383
2020		1,264	27	29	1,320
2021		1,220	31	32	1,282
2022		1,191	30	34	1,256
2023		1,144	31	37	1,211
2024		1,141	32	39	1,212
2025		1,134	31	42	1,207
2026		1,128	33	45	1,206
2027		1,124	33	47	1,204
2028		1,119	33	50	1,202
2029		1,116	33	52	1,202

The DSM and small solar are at the meter. The DR includes 11% losses.

FIGURE 21E
SUMMARY OF ANNUAL GWH REDUCTIONS FOR DSM, ACLM/DLC, SMALL SOLAR FOR THE ESP BASE, LOW DSM AND HIGH DSM SCENARIOS

	Base Case				Low DSM Case				High DSM Case			
Year	DSM	Demand Response	Small Solar	Total	DSM	ACLM, DLC and TOU	Small Solar and Wind	Total	DSM	ACLM, DLC and TOU	Small Solar	Total
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2010	190	6	4	200	178	5	4	187	206	5	4	215
2011	298	19	6	323	249	6	6	261	360	9	6	375
2012	409	25	8	443	329	6	8	344	515	21	8	545
2013	507	27	11	545	403	7	11	421	644	27	11	682
2014	586	28	14	627	463	7	14	484	748	30	14	791
2015	663	27	16	706	524	7	16	548	847	31	16	895
2016	741	28	19	788	586	7	19	612	947	32	19	997
2017	771	28	21	821	600	7	21	629	999	33	21	1,054
2018	714	29	24	768	527	7	24	558	964	34	24	1,022
2019	677	30	27	733	478	7	27	511	942	35	27	1,003
2020	668	28	29	725	464	7	29	501	936	35	29	1,000
2021	669	31	32	732	464	8	32	503	938	31	32	1,001
2022	679	31	34	744	474	8	34	516	947	37	34	1,018
2023	652	32	37	720	447	8	37	492	920	36	37	993
2024	650	32	39	721	449	8	39	496	916	36	39	992
2025	657	33	42	731	461	8	42	511	911	38	42	991
2026	658	33	45	736	469	8	45	522	901	37	45	983
2027	659	34	47	740	476	8	47	532	892	39	47	979
2028	661	33	50	744	484	8	50	542	887	39	50	976
2029	663	34	52	749	491	8	52	552	882	39	52	974

The DSM and small solar are at the meter. The DR includes 11% losses.

Note: The small solar was not changed from the Base case for the High and Low DSM scenarios.

D. <u>DSM and DR Adjustments to the Peak Hour</u>

The level of DSM and DR during the peak day affects the hour of the peak. Historically, the Nevada Power summer system peak has been at 5 pm more often than other hours. For the peak forecast, the gross peak (non-DSM and DR) was fixed at 5 pm. As the DSM and DR shift the system peak hour, fixing the gross peak at 5 pm allows us to calculate the actual effects of the DSM and DR reductions compared to the gross peak at 5 pm.

Figures 22 and 22E are summaries of the DSM and DR effects on the system peak.

FIGURE 22
IRP PEAK MW BEFORE AND AFTER ACLM

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Year	Gross Peak (1)	Incremental DSM & Small Solar (2)	Uninter-rupted Peak (3)	Less: Demand Response (4)	System Peak	System Peak Hour	DR Installed Capacity (5)
			(B) - (C)	(C) - (E)			
2010	5,766	52	5,714	123	5,591	17	127
2011	5,824	101	5,723	162	5,561	16	246
2012	5,904	153	5,751	223	5,528	18	326
2013	6,030	199	5,831	243	5,588	15	378
2014	6,160	244	5,916	271	5,645	15	390
2015	6,280	289	5,991	292	5,699	20	391
2016	6,397	330	6,067	292	5,775	20	399
2017	6,500	372	6,128	295	5,833	20	411
2018	6,603	410	6,193	309	5,884	18	375
2019	6,709	446	6,263	298	5,965	18	379
2020	6,807	472	6,335	285	6,050	16	339
2021	6,892	497	6,395	282	6,113	18	396
2022	6,986	513	6,473	286	6,187	18	389
2023	7,082	503	6,579	290	6,289	18	394
2024	7,182	501	6,681	298	6,383	18	391
2025	7,269	496	6,773	307	6,466	18	398
2026	7,362	494	6,868	308	6,560	18	403
2027	7,452	492	6,960	311	6,649	18	417
2028	7,545	490	7,055	323	6,732	18	417
2029	7,619	486	7,133	328	6,805	18	420
2030	7,668	486	7,182	327	6,855	18	420

1) Peak at 5 pm without incremental DSM, DR and Solar reductions.
2) Incremental DSM and small solar at 5 pm on the peak day.
3) Peak at 5 pm before demand response effects.
4) This is the avoided capacity of the demand response component. It is calculated by subtracting the system peak at whatever hour it occurs from the uninterrupted peak at 5 pm.
5) The maximum capacity reduction which occurs at 5 pm on the peak day

FIGURE 22E
ESP PEAK MW BEFORE AND AFTER ACLM

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Year	Gross Peak (1)	Incremental DSM & Small Solar (2)	Uninter-rupted Peak (3)	Less: Demand Response (4)	System Peak	System Peak Hour	DR Installed Capacity (5)
			(B) - (C)	(C) - (E)			
2010	5,825	43	5,782	127	5,655	17	127
2011	5,957	73	5,884	237	5,647	15	246
2012	6,076	104	5,972	280	5,692	15	326
2013	6,196	136	6,060	287	5,773	15	378
2014	6,330	165	6,165	293	5,872	16	390
2015	6,454	194	6,260	285	5,975	16	391
2016	6,581	224	6,357	289	6,068	16	399
2017	6,690	251	6,439	284	6,155	16	411
2018	6,800	271	6,529	296	6,233	16	375
2019	6,911	292	6,619	309	6,310	16	379
2020	7,015	309	6,706	278	6,428	16	339
2021	7,111	329	6,782	298	6,484	18	396
2022	7,210	341	6,869	302	6,567	18	389
2023	7,312	323	6,989	307	6,682	18	394
2024	7,421	323	7,098	318	6,780	18	391
2025	7,518	327	7,191	321	6,870	18	398
2026	7,619	330	7,289	328	6,961	18	403
2027	7,714	331	7,383	330	7,053	18	417
2028	7,814	333	7,481	325	7,156	16	417
2029	7,895	333	7,562	327	7,235	16	420
2030	7,977	335	7,642	327	7,315	16	420

1) Peak at 5 pm without incremental DSM, DR and Solar reductions.
2) Incremental DSM and small solar at 5 pm on the peak day.
3) Peak at 5 pm before demand response effects.
4) This is the avoided capacity of the demand response component. It is calculated by subtracting the system peak at whatever hour it occurs from the uninterrupted peak at 5 pm.
5) The maximum capacity reduction which occurs at 5 pm on the peak day

Because the maximum gross peak occurs at 5 pm, DSM and small solar reductions are calculated at that hour to arrive at the uninterrupted peak. From that peak, the system peak load is subtracted from the gross peak to obtain the DR avoided capacity. The DR installed capacity, or maximum DR, occurs at 5 pm. If the peak is shifted from 5 pm to another hour by the DR, then the DR avoided capacity will not equal the DR installed capacity. DR estimates at other hours are lower than the installed capacity due to the operating characteristics of the DR, which requires spreading the two hour period per customer of air conditioner load management ("ACLM") reductions across a longer period to capture all potential peaking hours.

The small solar forecast was developed based on discussions with the responsible Company project manager. SB 358 raised the limits on the connected MW of solar energy from 3.76 in the 2009-2010 program by 9 percent per year through 2016. Undersubscribed amounts may now be carried over to the next program year at the discretion of the new state Energy Commissioner. These new limits were taken into account for the small solar forecast.

The small solar load shape was obtained at:

http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/US/Nevada/Las_Vegas.html

The sales estimate for the plug-in hybrid vehicles used in the high case scenario was developed by National Economic Research Associates, Inc. for the Company. The forecast was based on two documents:

1. "Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation" Oak Ridge National Laboratory, January 2008[6]; and
2. "Environmental Assessment of Plug-in Hybrid Electric Vehicles", Volume 1, Nationwide Greenhouse Gas Reductions, EPRI, Final Report July 2007[7].

Assumptions regarding Nevada vehicle penetrations and load shapes were based on the Oak Ridge National Laboratory ("ORNL") Report. The penetration rate of plug-in hybrids vehicles was assumed to reach 25 percent of all vehicles on the road by 2020 and hold steady at about that level. The ORNL load shapes shown on page ten of the report were modified to include a 24 hour profile with a small amount of charging during the day and peak hours. While off-peak battery charging will be encouraged, the assumption is that some amount of battery charging will take place during peak periods for at least emergency vehicles. Figure 23 is a summary of the energy and summer peak effects of the plug-in hybrid vehicles included in the high case scenario.

6 See http://www.ornl.gov/info/ornlreview/v41_1_08/regional_phev_analysis.pdf

7 See http://mydocs.epri.com/docs/public/000000000001015325.pdf.

FIGURE 23
GWH AND MW IMPACTS OF PLUG-IN HYBRID VEHICLES
HIGH CASE SCENARIO

Year		Annual GWH		Summer Peak MW
2010		1		0
2011		6		0
2012		11		1
2013		16		1
2014		21		1
2015		26		2
2016		62		4
2017		98		7
2018		134		9
2019		170		11
2020		205		14
2021		238		16
2022		270		18
2023		303		20
2024		336		22
2025		369		25
2026		402		27
2027		435		29
2028		469		31
2029		503		33

E. Smart Grid

On October 28, 2009, it was announced that the federal government had awarded Nevada Power and Sierra a grant of $138 million under the Smart Grid Investment Grant program. The grant supports the Advanced Service Delivery (“ASD”) initiative, which in addition to deploying a smart grid for Nevada Power and Sierra integrates with and enhances the Demand Response Program. The projected demand savings estimated to be provided by the Demand Response Program and the ASD initiative are included the Nevada Power ESP and IRP forecasts. The Demand Side Plan provides a further discussion of the ASD initiative, contract negotiation status with the Department of Energy and the Demand Response Program.

F. DSM Lighting Add Back

To avoid double counting of the residential lighting reductions for the DSM programs and the new lighting standards taking effect in 2012, residential DSM lighting impacts for 2010 through 2011 have been reversed in 2012 to the end of the forecast.[8] The SAE forecast assumes current lighting stocks as of 2008 and does not account for Nevada Power’s more aggressive DSM. Therefore, the reductions due to the Company’s aggressive lighting programs are reversed in the SAE forecast beginning in 2012, when the new lighting standard takes effect, to avoid double

[8] Because the forecast started in 2010, Nevada Power did not include the 2009 lighting reductions in the lighting add back beginning in 2012.

counting the impacts. Figure 24 is a summary of the energy effects of this lighting adjustment for the IRP Forecast. Figure 24E summarizes this adjustment for the ESP base, and the low DSM/DR and high DSM/DR cases.

FIGURE 24
RESIDENTIAL LIGHTING ADJUSTMENT TO THE
IRP LOAD FORECAST

Year		IRP
2010		0
2011		0
2012		56
2013		115
2014		171
2015		171
2016		171
2017		171
2018		171
2019		171
2020		171
2021		171
2022		171
2023		171
2024		171
2025		171
2026		171
2027		171
2028		171
2029		171

FIGURE 24E
RESIDENTIAL LIGHTING ADJUSTMENTS
TO THE ESP BASE CASE, LOW AND HIGH DSM SCENARIOS

		Lighting Add Back (GWh)				
Year		Base Case		Low DSM		High DSM
2010		0		0		0
2011		0		0		0
2012		43		58		50
2013		87		116		101
2014		130		116		151
2015		130		116		151
2016		130		116		151
2017		130		116		151
2018		130		116		151
2019		130		116		151
2020		130		116		151
2021		130		116		151
2022		130		116		151
2023		130		116		151
2024		130		116		151
2025		130		116		151
2026		130		116		151
2027		130		116		151
2028		130		116		151
2029		130		116		151

G. Co-Generation and Distributed Generation at Peak

There are a couple of cogeneration sites in the Nevada Power territory that affect the peak. The Rio Hotel has a number of small turbines that can generate 3 to 4 MW at system peak. The MGM City Center has installed two turbines that can provide up to 8 MW.

With respect to distributed generation, the largest site is the photovoltaic plant at Nellis Air Force Base. This plant can generate up to 14 MW at the system peak. There are also a number of small solar and wind sites. As of September 2009, the small solar installed capacity is about 468 kW and small wind is about 5 kW, so combined they would reduce the peak by less than 500 kW.

H. Effects of Stand-by Customers on the Peak Demand

To determine the impacts on peak demand of the Nevada Power Stand-by customers, load research data from 10/01/06 through 9/30/08 for the LGS-3T-LSR, LGS-3P-LSR and LGS-2S-LSR were analyzed.[9] Figure 25 summarizes that analysis.

[9] The Water Pumping ("WP") stand-by rates, LSR2-LGS-WP-3S and LGS3-WP-LSR2 were not included in the analysis as no customers were on those rates from August 2007 forward.

FIGURE 25
ANALYSIS OF STAND-BY CUSTOMERS PEAK DEMANDS

Year Ending	Custs.	MWh	Max MW	Peak MW	Coincidence Factor	Peak Date	Hour
9/30/2007	11	62,943	17.9	8.5	47.6%	7/5/2007	17
9/30/2008	13	128,453	32.3	21.8	67.5%	7/10/2008	16
Note: Nellis AFB became a stand-by customer on 2/1/2008. The stand-by account includes							
the generation of the photovoltaic plant as a subtraction to load.							

The peak MW rose from 8.5 in 2007 to 21.8 MW in 2008, mainly due to the addition of the Nellis AFB account. On the 2008 peak day, for hours ending 15 through 18, the coincidence factor averages 65 percent. For the same hours on weekdays where the maximum temperature is above 108, the coincidence factor is 64.4 percent. Given the large change in peak demand due to the addition of Nellis AFB, the 2008 coincidence factors are more relevant to future peaks. Therefore, the demand at the time of peak for these standby customers will probably be 20-22 MW.

I. <u>Interruptible Demand by Type</u>

There are three different types of interruptible demand included in the Demand Response Program and the Advanced Service Delivery Initiative.

1. Residential and Small Commercial. The air conditioning load management program has been expanded to include a technology package consisting of in home displays, programmable and controllable thermostats, and web tools.

2. Large Commercial interruptible. The large customer interruptible program is set to begin in 2011. Customers with 1 MW of load that can be shed voluntarily will be recruited to participate in this program.

3. Price Response. This includes expanded Time of Use Rates ("TOU") and peak time rebates and critical peak pricing.

Figures 26 and 26E are summaries of the estimated peak demand effects of each program on the IRP and ESP Forecasts respectively.

FIGURE 26
ESTIMATE OF THE PEAK DEMAND EFFECT OF EACH DR PROGRAM: IRP FORECAST

Year		TOU & Peak Time Rebate(MW)	Large C&I Interruptible (MW)	ACLM (MW)	Total
2010		0.5	0.0	122.5	123
2011		12.0	2.9	147.1	162
2012		23.0	7.6	192.4	223
2013		27.6	19.3	196.1	243
2014		40.2	34.4	196.4	271
2015		52.2	49.4	190.4	292
2016		52.6	49.5	189.9	292
2017		52.3	50.4	192.3	295
2018		51.0	57.5	200.6	309
2019		49.6	55.5	192.8	298
2020		55.4	62.5	167.1	285
2021		46.7	53.1	182.2	282
2022		38.8	56.0	191.2	286
2023		38.8	57.0	194.2	290
2024		44.7	58.7	194.6	298
2025		36.5	63.2	207.3	307
2026		46.5	60.6	201.0	308
2027		47.1	60.2	203.7	311
2028		41.6	64.7	216.7	323
2029		40.0	64.0	224.1	328

FIGURE 26E
ESTIMATE OF THE PEAK DEMAND EFFECT OF EACH DR PROGRAM: ESP FORECAST

Year		TOU & Peak Time Rebate(MW)	Large C&I Interruptible (MW)	ACLM (MW)	Total
2010		0.5	0.0	126.5	127
2011		47.9	27.6	161.5	237
2012		42.3	47.3	190.4	280
2013		38.2	51.6	197.2	287
2014		39.0	52.8	201.2	293
2015		30.6	51.7	202.7	285
2016		31.2	52.6	205.3	289
2017		30.5	51.4	202.1	284
2018		28.5	59.3	208.2	296
2019		29.9	62.2	216.9	309
2020		29.5	61.9	186.6	278
2021		28.8	60.0	209.2	298
2022		27.6	61.8	212.6	302
2023		27.7	63.0	216.3	307
2024		29.4	66.6	221.9	318
2025		30.0	67.0	224.0	321
2026		30.6	68.6	228.8	328
2027		31.3	67.9	230.8	330
2028		26.5	67.4	231.1	325
2029		26.4	68.0	232.5	327

For further information regarding these programs, please see the Demand Side Plan.

J. Difference in DSM/DR used in the ESP Load Forecast and the October 15, 2009 DSM/DR

The DSM and DR were iterated between Energy Efficiency/Conservation and the Resource Planning & Analysis sections several times prior to mid-September. An interim DSM and DR forecast from mid-September was used to complete the ESP Forecast. A final DSM forecast was used to complete the IRP Forecast, but an interim DR from December 22, 2009 was used instead of the final produced on December 30, 2009. See below for a discussion of the immaterial differences between the two DR forecasts.

The differences in peak demand and system energy from the ESP base forecast if the final DSM and DR reductions were used are shown in Figures 27 and 28.

FIGURE 27
COMPARISON OF THE ESP BASE CASE PEAK FORECAST AND A PEAK FORECAST USING A MORE CURRENT (OCTOBER 15, 2009) DSM AND DR

	DSM & solar				DR Avoided Capacity				System Peak			
Year	IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff		IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff		IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff	% Diff: IRP to Final DSM
2010	43	50	-7		127	122	5		5,655	5,653	2	0.0%
2011	73	99	-26		237	175	62		5,647	5,683	**-36**	-0.6%
2012	104	152	-48		280	225	55		5,692	5,699	-7	-0.1%
2013	136	193	-57		287	252	35		5,773	5,751	22	0.4%
2014	165	225	-60		293	276	17		5,872	5,830	42	0.7%
2015	194	253	-59		285	300	-15		5,975	5,903	72	1.2%
2016	224	281	-57		289	308	-19		6,068	5,992	**76**	1.3%
2017	251	306	-55		284	300	-16		6,155	6,085	70	1.1%
2018	271	324	-53		296	310	-14		6,233	6,167	66	1.1%
2019	292	344	-52		309	299	10		6,310	6,269	41	0.6%
2020	309	359	-50		278	279	-1		6,428	6,378	50	0.8%
2021	329	375	-46		298	287	11		6,484	6,450	34	0.5%
2022	341	379	-38		302	292	10		6,567	6,540	27	0.4%
2023	323	356	-33		307	298	9		6,682	6,660	22	0.3%
2024	323	343	-20		318	308	10		6,780	6,771	9	0.1%
2025	327	330	-3		321	315	6		6,870	6,874	-4	-0.1%
2026	330	318	12		328	320	8		6,961	6,982	-21	-0.3%
2027	331	308	23		330	321	9		7,053	7,086	-33	-0.5%
2028	333	305	28		325	333	-8		7,156	7,177	-21	-0.3%
2029	333	299	34		327	340	-13		7,235	7,257	-22	-0.3%
2030	335	298	37		327	338	-11		7,315	7,342	-27	-0.4%

(1) The base case load forecast used in the ProMod runs for the Dec. 1, 2009 IRP Filing

(2) What the load forecast would be if the final DSM/DR was used, assuming no other changes.

FIGURE 28
COMPARISON OF THE ESP BASE CASE ENERGY AND SALES TO A FORECAST USING MORE CURRENT (OCTOBER 15,2009) DSM AND DR

	Energy (GWhs)					Sales (GWh)					DSM/DR (GWhs)			
Year	IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff	% Diff		IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff	% Diff		IRP Load Fcst (1)	Fcst with Final DSM (2)	Diff	% Diff
2010	22,058	22,026	32	0.1%		21,171	21,140	31	0.1%		197	228	31	15.6%
2011	22,451	22,337	113	0.5%		21,549	21,440	109	0.5%		319	428	109	34.0%
2012	22,881	22,727	154	0.7%		21,912	21,765	148	0.7%		437	596	159	36.4%
2013	23,233	23,074	159	0.7%		22,301	22,148	153	0.7%		537	714	177	33.0%
2014	23,707	23,544	163	0.7%		22,756	22,599	157	0.7%		617	810	194	31.4%
2015	24,123	23,953	170	0.7%		23,155	22,992	163	0.7%		693	893	200	28.9%
2016	24,591	24,419	172	0.7%		23,555	23,391	164	0.7%		772	974	202	26.1%
2017	24,951	24,778	173	0.7%		23,951	23,785	166	0.7%		803	1,006	203	25.3%
2018	25,453	25,279	175	0.7%		24,433	24,266	167	0.7%		747	952	205	27.4%
2019	25,942	25,777	165	0.6%		24,902	24,744	158	0.6%		710	905	195	27.5%
2020	26,451	26,314	137	0.5%		25,340	25,209	131	0.5%		699	867	168	24.0%
2021	26,788	26,666	122	0.5%		25,715	25,598	117	0.5%		703	858	154	21.9%
2022	27,192	27,087	104	0.4%		26,102	26,003	99	0.4%		713	850	137	19.2%
2023	27,653	27,575	79	0.3%		26,546	26,471	75	0.3%		687	800	113	16.4%
2024	28,178	28,130	48	0.2%		26,987	26,941	45	0.2%		685	768	83	12.1%
2025	28,522	28,512	11	0.0%		27,379	27,369	10	0.0%		693	740	47	6.8%
2026	28,953	28,970	(17)	-0.1%		27,793	27,810	(16)	-0.1%		695	716	21	3.0%
2027	29,360	29,399	(40)	-0.1%		28,184	28,222	(38)	-0.1%		697	696	(0)	0.0%
2028	29,854	29,907	(54)	-0.2%		28,592	28,643	(51)	-0.2%		698	685	(13)	-1.9%
2029	30,149	30,214	(65)	-0.2%		28,942	29,003	(61)	-0.2%		700	676	(24)	-3.4%

(1) The Base case load forecast used in the ProMod runs for the Dec. 1, 2009 IRP Filing

(2) What the load forecast would be if the final DSM/DR was used, assuming no other changes.

Note: The sales change is not as large as the DSM change due to the lighting addback beginning in 2012.

The change in ESP base case peak demand ranges from a maximum reduction of 36 MW to an increase of 76 MW from what it would have been with final DSM.

The low and high DSM MWh reductions were based on the final DSM, not the base case DSM used in the ESP load forecast. Therefore, to preserve the MWh differentials between the low and final DSM and the high and the final DSM, the MWh deviations from the low/high to the final DSM were subtracted/added to the base case DSM MWh reductions to create the low DSM and high DSM MWh reductions for the two DSM scenarios reported in Figures 15 and 16 above. The absolute MWh band width of the low and high DSM to the final DSM and Base DSM are therefore the same.

Figure 29 is a summary of these adjustments.

FIGURE 29
ADJUSTED LOW AND HIGH DSM MWH REDUCTIONS

	MWH				Deviation from Final DSM					
Year	Final DSM	Low	High		Low	High		Base Case DSM	Low case DSM	High case DSM
2010	221,540	208,893	237,177		-12,647	28,284		190,477	177,830	218,760
2011	412,135	363,583	474,011		-48,552	110,428		297,836	249,284	408,264
2012	577,448	497,059	683,427		-80,389	186,368		409,334	328,944	595,702
2013	692,235	588,794	829,834		-103,441	241,040		506,569	403,128	747,609
2014	784,353	662,110	946,895		-122,243	284,786		585,676	463,433	870,462
2015	863,003	724,504	1,047,272		-138,499	322,767		662,835	524,336	985,602
2016	942,804	788,050	1,148,799		-154,754	360,749		741,144	586,390	1,101,893
2017	974,485	803,476	1,202,206		-171,009	398,730		771,333	600,324	1,170,063
2018	919,069	731,804	1,168,516		-187,264	436,712		714,425	527,161	1,151,137
2019	872,015	672,806	1,137,107		-199,208	464,301		676,777	477,569	1,141,078
2020	837,223	634,009	1,105,430		-203,214	471,421		667,650	464,435	1,139,071
2021	823,162	617,644	1,091,808		-205,517	474,164		669,113	463,596	1,143,277
2022	816,353	611,744	1,084,792		-204,609	473,048		678,503	473,894	1,151,551
2023	765,273	560,857	1,034,002		-204,417	473,145		651,674	447,258	1,124,819
2024	732,840	531,944	999,238		-200,897	467,294		649,684	448,788	1,116,979
2025	705,709	510,517	960,468		-195,192	449,951		656,553	461,361	1,106,504
2026	679,402	490,225	922,619		-189,177	432,394		657,876	468,699	1,090,270
2027	659,351	476,290	892,504		-183,061	416,214		659,085	476,024	1,075,299
2028	648,540	471,756	874,658		-176,783	402,901		660,874	484,091	1,063,776
2029	639,029	467,223	858,761		-171,806	391,539		662,664	490,858	1,054,202
2030	634,518	462,689	854,365		-171,828	391,676		664,453	492,625	1,056,129

K. <u>Differences in DSM and DR Used for IRP Forecast vs. More Current Estimates</u>

The DR forecast was updated on December 22, 2009, based on project delays due to contract negotiations with DOE for Nevada Power's smart-grid grant. These DR estimates were used in the IRP Forecast. The DR was updated again on December 30, 2009, to reflect more refined project information. The differences are immaterial, as shown in Figure 30. The largest differences occur in the 2020-2027 time frame. The largest difference is <0.5% of the peak, an immaterial amount.

FIGURE 30
COMPARE IRP AND DEC. 30, 2009 DR PEAK MW

Year	IRP	Dec. 30, 2009	Diff: IRP less Dec. 30	% of Peak
2010	123	125	-2	0.0%
2011	162	160	2	0.0%
2012	223	215	8	0.1%
2013	243	241	2	0.0%
2014	271	263	8	0.1%
2015	292	290	2	0.0%
2016	292	293	-1	0.0%
2017	295	298	-3	0.0%
2018	309	302	7	0.1%
2019	298	306	-8	-0.1%
2020	285	307	-22	-0.4%
2021	282	305	-23	-0.4%
2022	286	303	-17	-0.3%
2023	290	308	-18	-0.3%
2024	298	318	-20	-0.3%
2025	307	305	2	0.0%
2026	308	327	-19	-0.3%
2027	311	332	-21	-0.3%
2028	323	318	5	0.1%
2029	328	323	5	0.1%

The proposed 2010-2012 DSM Plan includes a budget of $52,828,000 for 2010. In Docket No. 09-08020, the parties filed a stipulation that would establish a lower, interim 2010 DSM budget of $17,165,000 for DSM programs for the first seven months of 2010. If the stipulation is approved and DSM expenditures are limited to the stipulated amount for the first seven months of 2010, then DSM savings will be lower (and load will be higher) than the IRP Forecast assumptions. Figure 30A is a summary of the estimated effects of the reduction in DSM estimates on the IRP Forecast.

FIGURE 30A
ESTIMATED LOAD FORECAST CHANGES DUE TO THE DSM STIPULATION

	Summer Peak Demand (MW)						
Year	IRP	ESP	IRP + 12TH STIP	Change: IRP+Stip to IRP	Change: IRP+Stip to ESP	% Change: IRP+Stip to IRP	% Change: IRP+Stip to ESP
2010	5,591	5,655	5,610	19	(45)	0.3%	-0.8%
2011	5,561	5,647	5,579	18	(68)	0.3%	-1.2%
2012	5,528	5,692	5,545	17	(147)	0.3%	-2.6%
2013	5,588	5,773	5,604	16	(169)	0.3%	-2.9%
2014	5,645	5,872	5,660	15	(212)	0.3%	-3.6%
2015	5,699	5,975	5,713	14	(262)	0.2%	-4.4%
2016	5,775	6,068	5,789	14	(279)	0.2%	-4.6%
2017	5,833	6,155	5,846	13	(309)	0.2%	-5.0%
2018	5,884	6,233	5,896	12	(337)	0.2%	-5.4%
2019	5,965	6,310	5,977	12	(333)	0.2%	-5.3%
2020	6,050	6,428	6,061	11	(367)	0.2%	-5.7%
2021	6,113	6,484	6,124	11	(360)	0.2%	-5.6%
2022	6,187	6,567	6,197	10	(370)	0.2%	-5.6%
2023	6,289	6,682	6,299	10	(383)	0.2%	-5.7%
2024	6,383	6,780	6,392	9	(388)	0.1%	-5.7%
2025	6,466	6,870	6,475	9	(395)	0.1%	-5.7%
2026	6,560	6,961	6,568	8	(393)	0.1%	-5.6%
2027	6,649	7,053	6,657	8	(396)	0.1%	-5.6%
2028	6,732	7,156	6,739	7	(417)	0.1%	-5.8%
2029	6,805	7,235	6,812	7	(423)	0.1%	-5.8%
2030	6,855	7,315	6,862	7	(453)	0.1%	-6.2%
2031	6,937	7,417	6,943	6	(474)	0.1%	-6.4%
2032	7,020	7,521	7,026	6	(495)	0.1%	-6.6%
2033	7,104	7,626	7,110	6	(516)	0.1%	-6.8%
2034	7,189	7,733	7,194	5	(539)	0.1%	-7.0%
2035	7,275	7,841	7,280	5	(561)	0.1%	-7.2%
2036	7,362	7,951	7,367	5	(584)	0.1%	-7.3%
2037	7,450	8,062	7,455	5	(607)	0.1%	-7.5%
2038	7,539	8,175	7,543	4	(632)	0.1%	-7.7%
2039	7,629	8,289	7,633	4	(656)	0.1%	-7.9%

	Energy (GWh)						
Year	IRP	ESP	IRP + 12TH STIP	Change: IRP+Stip to IRP	Change: IRP+Stip to ESP	% Change: IRP+Stip to IRP	% Change: IRP+Stip to ESP
2010	21,827	22,058	21,898	71	(160)	0.3%	-0.7%
2011	21,853	22,451	21,920	67	(530)	0.3%	-2.4%
2012	22,107	22,881	22,171	64	(709)	0.3%	-3.1%
2013	22,497	23,233	22,558	61	(675)	0.3%	-2.9%
2014	22,921	23,707	22,979	58	(728)	0.3%	-3.1%
2015	23,268	24,123	23,323	55	(799)	0.2%	-3.3%
2016	23,672	24,591	23,724	52	(866)	0.2%	-3.5%
2017	23,922	24,951	23,971	49	(980)	0.2%	-3.9%
2018	24,233	25,453	24,280	47	(1,173)	0.2%	-4.6%
2019	24,619	25,942	24,664	45	(1,278)	0.2%	-4.9%
2020	25,161	26,451	25,203	42	(1,248)	0.2%	-4.7%
2021	25,509	26,788	25,549	40	(1,239)	0.2%	-4.6%
2022	25,926	27,192	25,964	38	(1,228)	0.1%	-4.5%
2023	26,380	27,653	26,416	36	(1,238)	0.1%	-4.5%
2024	26,868	28,178	26,903	35	(1,275)	0.1%	-4.5%
2025	27,196	28,522	27,229	33	(1,293)	0.1%	-4.5%
2026	27,604	28,953	27,635	31	(1,318)	0.1%	-4.6%
2027	27,990	29,360	28,020	30	(1,339)	0.1%	-4.6%
2028	28,464	29,854	28,492	28	(1,362)	0.1%	-4.6%
2029	28,740	30,149	28,767	27	(1,382)	0.1%	-4.6%
2030	28,918	30,513	28,943	25	(1,571)	0.1%	-5.1%
2031	29,265	30,941	29,289	24	(1,652)	0.1%	-5.3%
2032	29,692	31,455	29,715	23	(1,740)	0.1%	-5.5%
2033	29,972	31,814	29,994	22	(1,820)	0.1%	-5.7%
2034	30,332	32,260	30,353	21	(1,907)	0.1%	-5.9%
2035	30,696	32,711	30,716	20	(1,995)	0.1%	-6.1%
2036	31,148	33,259	31,167	19	(2,092)	0.1%	-6.3%
2037	31,438	33,635	31,456	18	(2,179)	0.1%	-6.5%
2038	31,815	34,106	31,832	17	(2,274)	0.1%	-6.7%
2039	32,197	34,583	32,213	16	(2,370)	0.0%	-6.9%

L. Differences in IRP DSM/DR vs. ESP DSM/DR

Figure 31 compares the DSM energy used in the ESP forecast and the IRP forecast.[10]

FIGURE 31
COMPARISON OF DSM REDUCTIONS: IRP AND ESP FORECASTS

	DSM Energy (GWh)				Demand Response (MW) - Avoided Capacity				DSM and Small Solar Peak (MW)			
Year	IRP	ESP	Diff: IRP less ESP	% change:	IRP	ESP	Diff: IRP less ESP	% change:	IRP	ESP	Diff: IRP less ESP	% change:
2010	232	190	42	17.9%	123	127	-4	-3.3%	52	43	9	17.3%
2011	433	298	135	31.2%	162	237	-75	-46.3%	101	73	28	27.7%
2012	608	409	199	32.7%	223	280	-57	-25.6%	153	104	49	32.0%
2013	739	507	233	31.5%	243	287	-44	-18.1%	199	136	63	31.7%
2014	870	586	284	32.7%	271	293	-22	-8.1%	244	165	79	32.4%
2015	992	663	329	33.2%	292	285	7	2.4%	289	194	95	32.9%
2016	1,111	741	370	33.3%	292	289	3	1.0%	330	224	106	32.1%
2017	1,226	771	455	37.1%	295	284	11	3.7%	372	251	121	32.5%
2018	1,334	714	619	46.4%	309	296	13	4.2%	410	271	139	33.9%
2019	1,383	677	706	51.1%	298	309	-11	-3.7%	446	292	154	34.5%
2020	1,320	668	653	49.4%	285	278	7	2.5%	472	309	163	34.5%
2021	1,282	669	613	47.8%	282	298	-16	-5.7%	497	329	168	33.8%
2022	1,256	679	577	46.0%	286	302	-16	-5.6%	513	341	172	33.5%
2023	1,211	652	560	46.2%	290	307	-17	-5.9%	503	323	180	35.8%
2024	1,212	650	563	46.4%	298	318	-20	-6.7%	501	323	178	35.5%
2025	1,207	657	551	45.6%	307	321	-14	-4.6%	496	327	169	34.1%
2026	1,206	658	548	45.4%	308	328	-20	-6.5%	494	330	164	33.2%
2027	1,204	659	545	45.3%	311	330	-19	-6.1%	492	331	161	32.7%
2028	1,202	661	541	45.0%	323	325	-2	-0.6%	490	333	157	32.0%
2029	1,202	663	539	44.8%	328	327	1	0.3%	486	333	153	31.5%

M. Weather Normalization of Sales

Sales of the Company's residential and small C&I classes are particularly sensitive to weather. The SAE models are not well designed for weather normalization as the constructed interactive variables tend to reduce the size of the weather impacts. Less complex model coefficients from non-SAE models were used to weather normalize sales. The following process was followed:

- Derive the difference between the actual and normal degree days for each month;
- Multiply the difference obtained above by the estimated weather coefficient(s) for that month (the slope estimate); and
- Add the value from the step above to the dependent variable in the econometric equation.

As an example of the calculation of weather normalized sales, the following pertains to residential sales per customer for July 2009**:**

Actual Sales per Customer:	1,498.20	kWh
Total Sales:	1,085,280	mWh
Actual CDDs:	692.90	
Normal CDDs:	757.33	
CDD Coefficient:	1.644264	
Customers:	724,390	

[10] The stipulation in Docket No. 09-09003, Nevada Power's 12th Amendment, will produce lower estimated DSM sales reductions of about 68 GWh and lower the peak effects by 17 MW (both at the meter) through 2012.

The weather normalized equation is:

> Adjusted Sales = Customers * (Actual Sales per customer + ((Normal Billing Month CDDs - Actual Billing Month CDDs) * CDD Coefficient)
>
> where:
>
> Normal Billing Month CDDs = the billing month cooling degree days based on a 20 year average
>
> Billing Month Actual CDDs = the actual billing monthly degree days for July 2009
>
> CDD Coefficient = coefficient from regression equation

Inserting actual values and coefficients:

Adjusted Sales Per Customer	=	1,498.20 +
		(757.33 – 692.90)*1.644264
	=	1,604.14

The total weather adjusted MWh sales are 1,162,022 (1,604.14 * 724,390) and the weather adjustment is +105.94 KWh per customer.

N. System Peak Demand Normalization

Econometric models were developed for weather normalizing winter and summer system peaks. Winter seasons were defined as the period between December through February; for example, December 1, 2008 through February 28, 2009 makes up the 2009 Winter Season. Summer was defined as the period between June and September. The dependent variable for both the summer and winter regressions for 2009 was the daily peak per residential customer. Because residential customer counts are only reported monthly, an estimate of the total residential customers for each day was linearly interpolated. For both the summer and winter, individual regression models were developed for each year. In addition to temperature as an independent variable, a weekend dummy variable was included as peaks that occur on a weekend are lower than those for a weekday given identical temperatures.

Figures 32 and 33 compare the actual and weather normalized peaks[11] for the summer and winter system peaks for the period 1998 through 2009. For the 2009 summer peak, the normalization is almost completely due to the low temperature being 4 degrees above the 20-year normal. The high temperature was normal at 112 degrees. A 10-year normal temperature adjustment, with the low normal at 87.6 degrees and the high normal at 112.2 degrees, would provide a weather adjusted peak of 5,581 MW. The difference between the actual peak of 5,586 MW and the weather normalized peak of 5,508 MW in Figure 31 (78 MW) using a 20-year normal seems large given that the high was normal for the day.

[11] Normal temperature derived based on 20-years of historical data.

FIGURE 32
SUMMER SYSTEM PEAKS

Year		Coincident Summer Peak Demand (MW) Weather Normalized			
		Min Daily Temperature	Max Daily Temperature	System Peak (MW)	
		(Normal = 86.1)	(Normal = 111.9)	Actual	Weather Normalized
1998		84	114	3,855	3,762
1999		85	112	3,976	3,957
2000		86	110	4,325	4,388
2001		86	113	4,412	4,324
2002		85	112	4,617	4,591
2003		87	112	4,808	4,781
2004		85	112	4,969	4,944
2005		92	116	5,563	5,234
2006		94	110	5,623	5,568
2007		86	116	5,866	5,657
2008	(1)	85	109	5,504	5,724
2009		90	112	5,586	5,508
	(1) The peak includes a reduction of 47 MW of air conditioner load management (ACLM) for 2008.				

FIGURE 33
WINTER SYSTEM PEAKS

Period		Coincident Winter Peak Demand (MW) Weather Normalized		
		Maximum Temperature	System Peak (MW)	
		(Normal = 44.6)	Actual	Weather Normalized
1998-99		42	2,137	2,098
1999-00		54	2,117	2,208
2000-01		48	2,209	2,227
2001-02		44	2,277	2,261
2002-03		44	2,300	2,290
2003-04		47	2,392	2,408
2004-05		45	2,574	2,571
2005-06		51	2,624	2,673
2006-07		48	2,711	2,742
2007-08		44	2,810	2,800
2008-09		39	2,819	2,755

O. Retail Prices

As shown in Figure 34, real residential retail energy rates are expected to trend upward until 2014 and then stabilize. Real prices are deflated to the level of January 1990 prices.

FIGURE 34
CLASS FORECASTS OF NEVADA REAL RETAIL AVERAGE PRICE PER KWH[12]

Year		Res Real Dollars per Kwh	GS1 & LGS1 Real Dollars per Kwh	Lg C&I Real Dollars per Kwh
1998		$0.0506	$0.0511	N/A
1999		$0.0515	$0.0527	N/A
2000		$0.0512	$0.0532	N/A
2001		$0.0566	$0.0576	N/A
2002		$0.0640	$0.0638	N/A
2003		$0.0608	$0.0616	N/A
2004		$0.0531	$0.0550	$0.0437
2005		$0.0564	$0.0595	$0.0440
2006		$0.0600	$0.0623	$0.0476
2007		$0.0628	$0.0647	$0.0495
2008		$0.0662	$0.0654	$0.0489
2009		$0.0684	$0.0670	$0.0500
2010		$0.0716	$0.0703	$0.0525
2011		$0.0716	$0.0711	$0.0531
2012		$0.0736	$0.0736	$0.0555
2013		$0.0725	$0.0728	$0.0552
2014		$0.0717	$0.0722	$0.0556
2015		$0.0717	$0.0721	$0.0557
2016		$0.0717	$0.0721	$0.0556
2017		$0.0717	$0.0721	$0.0556
2018		$0.0717	$0.0722	$0.0556
2019		$0.0717	$0.0722	$0.0556
2020		$0.0717	$0.0721	$0.0557
2021		$0.0717	$0.0721	$0.0557
2022		$0.0717	$0.0721	$0.0557
2023		$0.0717	$0.0722	$0.0557
2024		$0.0717	$0.0722	$0.0556
2025		$0.0717	$0.0722	$0.0556
2026		$0.0717	$0.0721	$0.0557
2027		$0.0717	$0.0721	$0.0556
2028		$0.0717	$0.0721	$0.0556
2029		$0.0717	$0.0722	$0.0556
	N/A= Not available			

[12] Based on forecasted revenue information through 2014 from the Nevada Power Financial Planning Department.

VI. COMPLIANCE ITEMS FROM DOCKET NO. 09-03005 (NEVADA POWER'S 11TH AMENDMENT TO THE 2007-2026 INTEGRATED RESOURCE PLAN)

A. Analysis of Residential Annual Model

Staff witness Mr. Howard Hirsch in the 11th Amendment recommend Nevada Power use annual historical data in the load forecast models, rather than monthly data. As noted in Mr. Baxter's Direct Testimony in this case, Nevada Power does not support the use of annual data for the following reasons:

- Estimated heating and cooling coefficients are generally stronger in a monthly model as there is more weather variation in the monthly CDD and HDD than in models estimated with annual HDD and CDD. With the high saturation of air conditioning, it is especially important at Nevada Power to accurately capture the weather impacts on sales and system energy. As an example of how weather impacts are affected by using an annual mode, Figure 39 shows a comparison of the weather impacts from the monthly and annual models prepared for the ESP Forecast[13]. For 2005, the annual model sales are 2.4 percent less than the monthly model sales and 2.0 percent less in 2007. These are fairly large percentages, especially when growth in the near term is less than the weather impacts.
- In an annual model it is also more difficult to capture the impact of changing end-use energy demand across the seasons and months. For example, the new lighting standards will have a much larger impact on winter month sales than on summer month sales. Improvements in cooling efficiency trends will have the biggest impact on those months with the greatest cooling usage.
- A model using monthly data also does a better job of capturing the near-term impact of changing economic conditions as the economy changes across the year. In the current economic outlook, the economy is projected to improve beginning in the second half of 2010. An annual model would miss this turn around.
- In addition to the long-term forecast, the same monthly model can be used to provide sales and revenue to support the budgeting and financial planning requirements. This results in a short-term forecast that is consistent with the modeling assumptions, economic projections, and end-use efficiency trends used in the long-term resource planning forecast.

A monthly model is also more robust from a statistical perspective. A ten-year monthly model, even after using binary variables for bad data, will have more than 100 degrees of freedom; this allows for estimating strong model coefficients and meaningful variable T statistics and model fit statistics. For an annual model you would need to use at least 20 years of historical data; a model with four variables would have only 15 degrees of freedom; this is relatively few degrees of freedom for an econometric-based forecasting model. While there is more noise in a model constructed with monthly billing data, there is also more information that can be extracted.

Also, with a monthly model it is not necessary to estimate data for an incomplete year or use a past year of historical data that could be up to 11 months old. The model can start with the latest month of historical data, capturing the most up-to-date economic trends. In addition, it is not clear how much explanatory power there is from data back as far as the 1980's given the extensive changes in building codes, appliance efficiencies, home sizes, etc.

[13] All comparisons are made to the ESP forecast. The alternative models were not re-run using updated historical or economic forecast data.

Consistent with the Commission's Order, Nevada Power ran residential customer and average use per customer models using annual data, including constructed SAE annual variables. Figures 35 and 36 report the statistical output from these models. The use per customer model, as measured by R^2 and mean absolute percent error ("MAPE"), were worse than the monthly model (see Figure 37).[14] The R^2, which measures the amount of variation captured in the model, was quite a bit lower for the annual residential use per customer model (0.818 vs 0.987 for the monthly model). More importantly, the forecasted sales using the annual model shows a decline of 4.9 percent from weather normalized sales for 2009 over 2008 and a decline of 3.9 percent for 2010 over 2009. Year-to-date ("YTD") through September 2009, the decline in actual billed sales is 1.9 percent for 2009 vs. YTD 2008 and 2.2 percent on a weather normalized basis. Based on our estimate of billed sales for 2009, there is a huge 8.6% drop in annual model forecasted sales versus estimated billed sales for 2010 over 2009. (See Figure 38.) In the annual model, use per customer continues to decline significantly while the monthly model use per customer is fairly stable. Annual model customer growth is much faster beginning in 2011 than for the monthly model. (See Figure 38.).

Figure 38 shows the weather impacts for the monthly model compared to the annual model. The annual model sales are lower than the monthly model from 2003 through 2008, with differences of 2.4 percent in 2005 and 2.7 percent in 2007. As can be seen when comparing the weather coefficients, which measure the weather impact on use per customer, for the two models, the main reasons for the differences are the very low impact of HDD for the annual model, which is 83 percent lower than the monthly model. The annual model fails to account for the heating impact on electricity sales while the monthly model does account for it. The CDD coefficient is also higher for the monthly model, indicating it is picking up more of the cooling impact as well.

[14] The actual and predicted total sales were calculated by multiplying the monthly/annual actual customers by the monthly/annual use per customer. The monthly model numbers were than aggregated to an annual basis for comparison purpose. The monthly customer model actual and predicted were also averaged annually.

FIGURE 35
MODEL OF ANNUAL RESIDENTIAL CUSTOMERS

Regression Statistics						
Sample Range		1981 - 2008				
Adjusted Observations		27				
Deg. of Freedom for Error		25				
R-Squared		0.999				
Adjusted R-Squared		0.999				
Durbin-Watson Statistic		2.240				
AIC		17.290				
BIC		17.386				
F-Statistic		14,224				
Prob (F-Statistic)		0.0000				
Mean Squared Error		30,065,546				
Std. Error of Regression		5,483				
Mean Abs. % Err. (MAPE)		1.13%				
Ljung-Box Statistic		2.53				
Prob (Ljung-Box)		0.7720				
Jarque-Bera		0.4				
Prob (Jarque-Bera)		0.7159				

Variable		Coefficient	StdErr	T-Stat	P-Value
Customers					
Population		366.166	3.510	104.329	0.00%
AR(1)		0.787	0.126	6.249	0.00%

where:

Customers	=	Annual Residential Customers
Population	=	Annual estimate of population for the Las Vegas-Paradise MSA
AR(1)	=	1st order autoregressive error term

FIGURE 36
MODEL OF ANNUAL RESIDENTIAL USE PER CUSTOMER

Regression Statistics	
Sample Range	1982 - 2008
Adjusted Observations	26
Deg. of Freedom for Error	22
R-Squared	0.839
Adjusted R-Squared	0.818
Durbin-Watson Statistic	2.221
AIC	-2.950
BIC	-2.757
F-Statistic	28.753
Prob (F-Statistic)	0.0000
Mean Squared Error	5.2277
Std. Error of Regression	1.0000
Mean Abs. % Err. (MAPE)	1.22%
Ljung-Box Statistic	8.88
Prob (Ljung-Box)	0.1139
Jarque-Bera	0.1
Prob (Jarque-Bera)	0.9529

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer				
XHeat	0.001431	0.000	4.221	0.04%
XCool	0.001930	0.000	9.064	0.00%
XOther	0.000163	0.000	6.618	0.00%
AR(1)	0.897842	0.082	10.890	0.00%

where:

Sales per Customer	=	Annual MWH sales per residential customer
XHeat	=	Estimates the annual average use for electric heating equipment
XCool	=	Estimates the annual average use for electric cooling equipment
XOther		Estimates the annual average use for all other electrical equipment
AR(1)	=	1st order autoregressive error term

FIGURE 37
SUMMARY OF MODEL STATISTICS: ANNUAL VS. MONTHLY

	Residential Total Sales			**Residential Customers**		
Model	R^2	MAPE	MAPE 99-08	R^2	MAPE	MAPE 99-08
Annual	0.818	1.22%	1.48%	0.9991	1.13%	1.88%
Monthly (1)	0.987	1.10%	1.10%	0.9998	1.07%	1.07%

(1) MAPE based on the summation of the monthly predicted and actual sales to annual data.

FIGURE 38
COMPARE FORECASTS OF MONTHLY AND ANNUAL MODELS

	Customers				Total WN Sales				Using Billed Sales for 2008 & 2009			
	Number		% Growth		GWH		% Growth		GWH		% Growth	
Year	Annual	Monthly	Annual	Monthly	Annual	Monthly	Annual	Monthly	Annual	Monthly	Annual	Monthly
2008	724,663	724,663			8,867	8,867			9,050	9,050		
2009	722,308	726,647	-0.3%	0.3%	8,436	8,671	-4.9%	-2.2%	8,874	8,874	-1.9%	-1.9%
2010	730,712	737,364	1.2%	1.5%	8,111	8,635	-3.9%	-0.4%	8,111	8,635	**-8.6%**	-2.7%
2011	754,177	753,153	3.2%	2.1%	8,163	8,726	0.7%	1.1%				
2012	777,223	768,242	3.1%	2.0%	8,250	8,843	1.1%	1.3%				
2013	799,868	782,588	2.9%	1.9%	8,383	8,978	1.6%	1.5%				
2014	822,121	796,232	2.8%	1.7%	8,552	9,155	2.0%	2.0%				
2015	843,649	809,148	2.6%	1.6%	8,660	9,278	1.3%	1.3%				
2016	864,114	821,302	2.4%	1.5%	8,754	9,393	1.1%	1.2%				
2017	883,521	832,731	2.2%	1.4%	8,873	9,536	1.4%	1.5%				
2018	902,221	843,534	2.1%	1.3%	9,072	9,767	2.2%	2.4%				
2019	919,872	853,680	2.0%	1.2%	9,246	9,963	1.9%	2.0%				
2020	936,821	863,260	1.8%	1.1%	9,364	10,090	1.3%	1.3%				

	Sales per customers (KWh)			
Year	Annual	Monthly	Diff	% Diff
2010	11,100	11,710	-611	-5.2%
2011	10,824	11,586	-762	-6.6%
2012	10,614	11,511	-896	-7.8%
2013	10,481	11,472	-991	-8.6%
2014	10,402	11,498	-1,096	-9.5%
2015	10,265	11,467	-1,202	-10.5%
2016	10,131	11,437	-1,306	-11.4%
2017	10,043	11,452	-1,409	-12.3%
2018	10,056	11,578	-1,523	-13.2%
2019	10,051	11,671	-1,620	-13.9%
2020	9,995	11,688	-1,693	-14.5%

Note: These numbers are after DSM, DR and small solar reductions.

FIGURE 39
COMPARISON OF WEATHER IMPACTS OF MONTHLY AND ANNUAL MODELS

	Average Use					Total Sales			
	KWh per Customer		Diff. w/ Monthly			GWH		Diff. w/ Monthly	
Year	Annual	Monthly	Avg. KWh	% Diff		Annual	Monthly	GWh	% Diff
1998	12,969	12,936	33	0.3%		6,106	6,091	16	0.3%
1999	12,740	12,972	-232	-1.8%		6,358	6,474	-116	-1.8%
2000	12,948	12,983	-35	-0.3%		6,822	6,841	-18	-0.3%
2001	12,450	12,426	24	0.2%		6,876	6,863	13	0.2%
2002	12,310	12,328	-19	-0.2%		7,108	7,076	32	0.5%
2003	12,160	12,388	-228	-1.8%		7,371	7,442	-70	-0.9%
2004	12,157	12,189	-32	-0.3%		7,706	7,723	-17	-0.2%
2005	12,412	12,753	-340	-2.7%		8,288	8,493	-205	-2.4%
2006	12,541	12,685	-144	-1.1%		8,783	8,885	-102	-1.1%
2007	12,186	12,447	-261	-2.1%		8,775	8,954	-179	-2.0%
2008	12,102	12,231	-129	-1.1%		8,770	8,867	-97	-1.1%
		MWH/Customer							
Coefficients:		CDD	HDD						
Annual		1.5137	0.1543						
Monthly		1.6443	0.8807						
% Diff:		-7.9%	-82.5%						

B. Price Model

In his 11th Amendment Direct Testimony, Docket No. 09-03005, page 2 of 11, lines 16 and 17, Staff Economist Mr. Howard Hirsch recommended that Nevada Power "Account for the effects of changes in prices of electricity and substitute fuels directly in the forecast models, as required by NAC 704.9225(2)." As noted in the Direct Testimony of Mr. Terry Baxter, in the answer to Question 12, the NAC in question does not specify how prices are to be accounted for in the forecast.

The Commission order in the 11th Amendment required Nevada Power to "explore other forms of price in the equation" (paragraph 42, page 15 of the final order in Docket No. 09-03005). Nevada Power removed price from the XCool, XHeat and XOther variables from the residential average use per customer model and placed it directly in the equation. The price variable is highly significant and has the correct sign. See Figure 40 for a summary of the model statistics.

FIGURE 40
MODEL OF RESIDENTIAL AVERAGE USE WITH SEPARATE PRICE VARIABLE

Regression Statistics	
Sample Range	1999:1 thru 2009:7
Adjusted Observations	126
Deg. of Freedom for Error	112
R-Squared	0.989
Adjusted R-Squared	0.988
Durbin-Watson Statistic	1.976
AIC	7.821
BIC	8.136
F-Statistic	768.933
Prob (F-Statistic)	0.0000
Std. Error of Regression	47.38
Mean Abs. % Err. (MAPE)	3.41%
Ljung-Box Statistic	73.83
Prob (Ljung-Box)	0.0000
Jarque-Bera	13.7
Prob (Jarque-Bera)	0.0053

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
CONST	299.098	104.127	2.872	0.49%
XHeat	2.002	0.093	21.638	0.00%
XCool	2.153	0.032	66.927	0.00%
XOther	0.384	0.084	4.582	0.00%
May02	-131.720	46.950	-2.806	0.59%
Mar02	212.840	43.674	4.873	0.00%
Jun02	174.332	47.198	3.694	0.03%
Sep02	-355.898	48.033	-7.409	0.00%
Oct02	-236.870	47.270	-5.011	0.00%
Apr08	85.732	43.479	1.972	5.11%
Dec07	87.391	43.738	1.998	4.82%
Jun08	-167.753	43.226	-3.881	0.02%
Price	-3234.648	1462.745	-2.211	2.91%
AR(1)	0.470	0.086	5.486	0.00%

where:

Sales per Customer	=	Monthly KWH sales per residential customer
CONST	=	Constant Term
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
XXXYY	=	Binary variables for the indicated month and year
Price	=	Rolling 12 month average real revenue per KWh
AR(1)	=	1st order autoregressive error term

Figure 41 is a comparison of the residential forecasts with and without a separate price variable.

FIGURE 41
COMPARISON OF RESIDENTIAL SALES FORECASTS WITH AND WITHOUT PRICE AS A SEPARATE VARIABLE IN THE MODEL

	Total WN Residential Sales					Difference: Separate vs. Base			Total using billed Sales			
Year	Base Case	% grwth	Separate Price	% grwth		GWH	% Diff		Base Case	% grwth	Separate Price	% grwth
2008	8,867		8,867						9,050			
2009	8,671	-2.2%	8,577	-3.3%		-94	-1.1%		8,874	-1.9%	8,874	
2010	8,635	-0.4%	8,159	-4.9%		-475	-5.5%		8,635	-2.7%	8,159	-8.1%
2011	8,726	1.1%	8,242	1.0%		-484	-5.5%					
2012	8,843	1.3%	8,288	0.6%		-554	-6.3%					
2013	8,978	1.5%	8,433	1.7%		-545	-6.1%					
2014	9,155	2.0%	8,626	2.3%		-530	-5.8%					
2015	9,278	1.3%	8,740	1.3%		-539	-5.8%					

Note: These numbers are after DSM, DR and small solar reductions.

As with the annual model, the 2009 and especially 2010 forecasts do not look reasonable. With the price as a separate variable, the growth decline from estimated billed (not weather normalized) sales for 2010 over 2009 is 8.1 percent.

However, even with the odd results above, Nevada Power will continue to study alternative price configurations in the modeling, in conjunction with staff, as part of our load forecast process improvement.

C. Integrating DSM into the Forecast Modeling

In his Direct Testimony in the 11th Amendment, Docket No. 09-03005 Staff Economist Mr. Howard Hirsch made the following recommendation:

> "Base forecasts on historical energy use and peak demand adjusted for the impacts of DSM measures already taken in order to avoid the double-counting of the incremental savings from such measures going forward."

Nevada Power attempted to model DSM in the Residential forecast model without success. A model adding DSM back into the history and then subtracting cumulative DSM from the forecast provided similar growth declines of 5.5 percent and 4.4 percent for weather normalized sales for 2009 over 2008 and for 2010 over 2009 and a 7.8 percent decline for 2010 forecasted sales vs. 2009 billed sales. See Figure 42 for a summary of the DSM added back forecast vs. the base.

Another model included a variable of the monthly estimates of DSM savings. The purpose of the variable was to attempt to estimate the use per customer reduction from DSM included in the model. This estimate could then be added back to the forecasted sales. While the variable coefficient was significant, the resulting estimate of 0.1 percent of sales due to DSM embedded in the model and that 1.9 percent of total accumulated DSM savings was embedded in the model was insignificant. This low amount of embedded DSM, given the five year ramp up of DSM projects, intuitively does not seem reasonable. See Figure 43 for a summary of the results of this model.

Figures 44 and 45 are the model statistics.

FIGURE 42
COMPARE DSM ADDED BACK MODEL FORECAST TO THE BASE CASE FORECAST

Year	Billed GWH Sales w/o DSM	Cum GWH DSM reductions	GWH Sales without DSM (1)	Fcst with DSM , DR and Small Solar subtracted	% Grwth	IRP Base Cased Fcst (WN 08 & 09)	% Grwth	Fcst with DSM , DR and Small Solar subtracted vs. Billed 09	
1999	6,138	0	6,138						
2000	7,015	0	7,015						
2001	7,216	0	7,216						
2002	7,241	0	7,241						
2003	7,678	4	7,682						
2004	7,928	18	7,946						
2005	8,310	40	8,350						
2006	9,005	84	9,088						
2007	9,366	177	9,543						
2008	9,050	322	9,371	9,050		8,867			
2009		514	9,065	8,551	-5.5%	8,671	-2.2%	8,874	
2010		647	8,825	8,178	-4.4%	8,635	-0.4%	8,178	-7.8%
2011		718	8,997	8,279	1.2%	8,726	1.1%		
2012		790	9,140	8,350	0.9%	8,843	1.3%		
2013		847	9,273	8,426	0.9%	8,978	1.5%		
2014		887	9,449	8,563	1.6%	9,155	2.0%		
2015		925	9,614	8,689	1.5%	9,278	1.3%		

(1) 2009 on are estimated from the model.

FIGURE 43
ESTIMATE OF EMBEDDED DSM USING MODEL WITH A DSM VARIABLE

Year	Custs	MWH	% Grwth	Avg Use	DSM Variable Coefficient	% Embedded	MWH Sales Embedded in DSM	% of Sales	Cum DSM	% of DSM
1999	499,074	6,138,436		12,300	0	0				
2000	526,899	7,015,103	14.3%	13,314	0	0				
2001	552,276	7,215,737	2.9%	13,065	0	0				
2002	577,422	7,241,487	0.4%	12,541	0	0				
2003	606,187	7,678,491	6.0%	12,667	-8.304674	-0.066%				
2004	633,907	7,927,629	3.2%	12,506	-8.304674	-0.066%				
2005	667,742	8,310,161	4.8%	12,445	-8.304674	-0.067%				
2006	700,309	9,004,704	8.4%	12,858	-8.304674	-0.065%				
2007	720,116	9,365,721	4.0%	13,006	-8.304674	-0.064%				
2008	724,663	9,049,596	-3.4%	12,488	-8.304674	-0.067%	-6,018	-0.07%	321,507	-1.9%

FIGURE 44
RESIDENTIAL AVERAGE USE MODEL WITH DSM ADDED BACK TO SALES

Regression Statistics					
Sample Range		1999:1 thru 2009:7			
Adjusted Observations		126			
Deg. of Freedom for Error		113			
R-Squared		0.989			
Adjusted R-Squared		0.988			
Durbin-Watson Statistic		1.983			
AIC		7.781			
BIC		8.073			
F-Statistic		800.210			
Prob (F-Statistic)		0.0000			
Std. Error of Regression		46.60			
Mean Abs. % Err. (MAPE)		3.39%			
Ljung-Box Statistic		68.98			
Prob (Ljung-Box)		0.0000			
Jarque-Bera		11.7			
Prob (Jarque-Bera)		0.0073			

Variable		Coefficient	StdErr	T-Stat	P-Value
Sales per Customer		Endogenous			
XHeat		2.213	0.029	75.323	0.00%
XCool		0.522	0.017	30.387	0.00%
XOther		2.077	0.091	22.727	0.00%
May02		180.550	45.787	3.943	0.01%
Mar02		216.876	42.527	5.100	0.00%
Jun02		-369.293	46.582	-7.928	0.00%
Sep02		-233.918	46.196	-5.064	0.00%
Oct02		-171.519	42.300	-4.055	0.01%
Apr08		-132.622	45.978	-2.884	0.47%
Dec07		83.770	42.370	1.977	5.05%
Jun08		94.620	42.242	2.240	2.71%
AR(1)		66.339	42.247	1.570	11.92%
		0.470	0.085	5.508	0.00%

where:

Sales per Customer	=	Monthly KWH sales per residential customer with historical DSM added back
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
XXX02	=	Binary variables for the indicated month in 2002
Apr08	=	A binary variable for April 2008
Jun08	=	A binary variable for March 1999
Dec07	=	A binary variable for December 2007
AR(1)	=	1st order autoregressive error term

FIGURE 45
RESIDENTIAL AVERAGE USE MODEL WITH A DSM VARIABLE

Regression Statistics	
Sample Range	1999:1 thru 2009:7
Adjusted Observations	126
Deg. of Freedom for Error	112
R-Squared	0.989
Adjusted R-Squared	0.988
Durbin-Watson Statistic	1.986
AIC	7.792
BIC	8.107
F-Statistic	735.424
Prob (F-Statistic)	0.0000
Std. Error of Regression	46.69
Mean Abs. % Err. (MAPE)	3.39%
Ljung-Box Statistic	70.10
Prob (Ljung-Box)	0.0000
Jarque-Bera	13.7
Prob (Jarque-Bera)	0.0053

Variable	Coefficient	StdErr	T-Stat	P-Value
Sales per Customer	Endogenous			
XHeat	2.209	0.030	73.724	0.00%
XCool	2.068	0.093	22.358	0.00%
XOther	0.520	0.017	29.757	0.00%
Jun02	182.297	45.928	3.969	0.01%
Mar02	217.287	42.674	5.092	0.00%
Sep02	-367.356	46.800	-7.850	0.00%
Oct02	-232.964	46.353	-5.026	0.00%
Apr08	85.484	42.580	2.008	4.71%
Jun08	-172.277	42.458	-4.058	0.01%
Mar99	66.814	42.402	1.576	11.80%
Dec07	95.070	42.402	2.242	2.70%
May02	-131.352	46.113	-2.848	0.52%
DSM_AvgUse	-0.692	0.418	-1.654	10.09%
AR(1)	0.466	0.085	5.447	0.00%

where:

Sales per Customer	=	Monthly KWH sales per residential customer
XHeat	=	Estimates the monthly average use for electric heating equipment
XCool	=	Estimates the monthly average use for electric cooling equipment
XOther	=	Estimates the monthly average use for all other electrical equipment
XXX02	=	Binary variables for the indicated month in 2002
Apr08	=	A binary variable for April 2008
Jun08	=	A binary variable for June 2008
Mar99	=	A binary variable for March 1999
Dec07	=	A binary variable for December 2007
DSM_AvgUse	=	Estimated monthly DSM reduction per customer
AR(1)	=	1st order autoregressive error term

Nevada Power recognizes that the separate price variable, DSM and perhaps the annual model could merit further study. To this end, as a part of Nevada Power's commitment to load forecast process improvement, we have been in discussions with Staff regarding meeting for a workshop with interested parties on February 2nd, 2010 to discuss these issues further. The goal of the workshop will be to reach agreement where possible, to institute those agreements as soon as practical, and report back to the Commission on areas of disagreement.

D. Saturation Survey Issues

In his Direct Testimony in the 11th Amendment, Staff witness Mr. Howard Hirsch recommended that the Company implement the following enhancements to the saturation survey:

- Develop NPC-specific historical appliance and equipment rates based on surveys already taken and conduct surveys at regular intervals.
- Ensure that appliance saturation survey samples are of sufficient size as to yield a 95% confidence level with a 5% margin of error.
- Ensure sufficient appliance saturation survey sample stratification consistent with known characteristics of the service territory population.

These issues were discussed in the direct testimony of Company witness Mr. Terry Baxter. The purpose of this section is to discuss a draft schedule and sample sizes for future Nevada Power (and Sierra Pacific) saturation surveys.

After internal discussion and discussions with Mr. Hirsch, Nevada Power tentatively intends to survey residential customers every three years in the year prior to filing the IRP. For Nevada Power, surveys would be conducted in 2012, 2015, 2018, etc. If Sierra Pacific follows the same schedule, the surveys would be in 2011, 2014, 2017, etc. However, it may be more cost effective to do both Company surveys at one time.

Surveys for each Company will be designed to yield a 95 percent confidence level with a 5 percent margin of error. The sample size will be about 400-500 for each Company. Surveys will include at a minimum questions regarding appliance types, fuel, and age as well as age and square footage of the home and customer demographics.

Commercial surveys are also being considered on the same timeline. The major use of the surveys for SAE modeling has been to estimate the MWh usage for each of the eleven business types included in the SAE indices development. Square footage information would be valuable, but sample sizes may become too large to be cost effective to obtain statistically accurate information on those business types with low numbers in the population. Prior to the commercial survey, Nevada Power will examine the issue of inaccurate North American Industry Classification System business coding in the customer data to facilitate sample selection of the 11 business types.