

APPENDIX A

Western Regional Air Partnership Regional Haze Rule Reasonable Progress Summary Report, June 28, 2013

Section 6.8 Nevada

STATE AND CLASS I AREA SUMMARIES

As described in Section 2.0, each state is required to submit progress reports at interim points between submittals of Regional Haze Rule (RHR) State Implementation Plans (SIPs), which assess progress towards visibility improvement goals in each state's mandatory Federal Class I areas (CIAs). Data summaries for each CIA in each Western Regional Air Partnership (WRAP) state, which address Regional Haze Rule (RHR) requirements for visibility measurements and emissions inventories are provided in this section. These summaries are intended to provide individual states with the technical information they need to determine if current RHR implementation plan elements and strategies are sufficient to meet all established reasonable progress goals, as defined in their respective initial RHR implementation plans.

6.8 Nevada

The goal of the RHR is to ensure that visibility on the 20% most impaired, or worst, days continues to improve at each Federal Class I area (CIA), and that visibility on the 20% least impaired, or best, days does not get worse, as measured at representative Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites. Nevada has one mandatory Federal Class I area, which is depicted in Figure 6.8-1 and listed in Table 6.8-1, along with the associated IMPROVE monitor locations.

This section addresses differences between the 2000-2004 baseline and 2005-2009 period, for both monitored data and emission inventory estimates. Monitored data are presented for the 20% most impaired, or worst, days and for the 20% least impaired, or best, days, as per Regional Haze Rule (RHR) requirements. Annual average trend statistics for the 2000-2009 10-year period are also presented here to support assessments of changes in each monitored species that contributes to visibility impairment. In general, comparisons of anthropogenic emissions inventory totals for the state showed net decreases, while several of the monitored species increased. Because the JARB1 site is on the northern edge of Nevada, it is likely that regional emissions sources from outside of the state influences the increases in monitored data. Some additional highlights regarding comparisons between the 2000-2004 baseline and 2005-2009 progress period are listed below, and more detailed state specific information is provided in monitoring and emissions sub-sections that follow.

- For the 20% best days, the 5-year average deciview metric decreased at the JARB1 site.
- For the 20% worst days, the 5-year average deciview metric increased at the JARB1, site.
- The increase in the 20% worst day 5-year average deciview value was due to small increases in all aerosol species except particulate organic mass. For these increases:
 - No statistically significant increasing annual trends for any aerosol species occurred for the period 2000-2009.
 - Higher than average monitored ammonium sulfate and ammonium nitrate concentrations in 2005 influenced the 5-year progress period average for these species.
- Emissions inventories indicated net decreases for SO₂ and NO_x between the baseline and 2008 emission inventories. For emissions comparisons:
 - Slight increases in on-road mobile and area source inventory totals were offset by larger decreases in point and off-road mobile totals.
 - Annual total EGU emissions for the state showed dramatic decreases in SO₂ and NO_x.
- The fine soil and coarse mass emissions inventories showed increases in fugitive dust and natural windblown dust, which was likely due to updates in inventory development methodologies rather than actual increases.

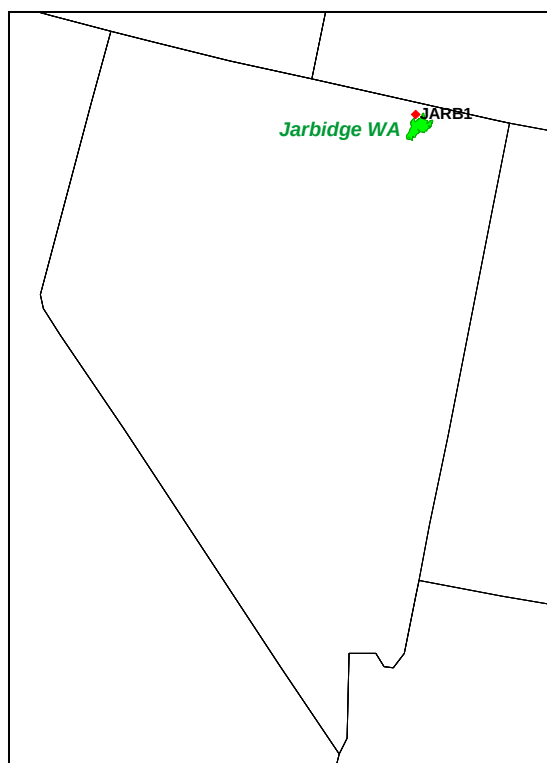


Figure 6.8-1. Map Depicting the Federal CIA and Representative IMPROVE Monitor in Nevada.

Table 6.8-1
Nevada Class I Area and Representative IMPROVE Monitor

Class I Area	Representative IMPROVE Site	Latitude	Longitude	Elevation (m)
Jarbridge WA	JARB1	41.89	-115.43	1869

6.8.1 Monitoring Data

This section addresses RHR regulatory requirements for monitored data as measured by the JARB1 IMPROVE monitor, representing the Jarbridge Wilderness Area, which is the only Federal CIA in Nevada. These summaries are supported by regional data presented in Section 4.0 and by more detailed site specific tables and charts in Appendix H.

As described in Section 3.1, regional haze progress in Federal CIAs is tracked using calculations based on speciated aerosol mass as collected by IMPROVE monitors. The RHR calls for tracking haze in units of deciviews (dv), where the deciview metric was designed to be linearly associated with human perception of visibility. In a pristine atmosphere, the deciview metric is near zero, and a one deciview change is approximately equivalent to a 10% change in cumulative species extinction. To better understand visibility conditions, summaries here include

both the deciview metric, and the apportionment of haze into extinction due to the various measured species in units of inverse megameters (Mm^{-1}).

6.8.1.1 Current Conditions

This section addresses the regulatory question, ***what are the current visibility conditions for the most impaired and least impaired days (40 CFR 51.308 (g)(3)(i))?*** RHR guidance specifies that 5-year averages be calculated over successive 5-year periods, i.e. 2000-2004, 2005-2009, 2010-2014, etc.¹ Current visibility conditions are represented here as the most recent successive 5-year average period available, or the 2005-2009 period average, although the most recent IMPROVE monitoring data currently available includes 2010 data.

Tables 6.8-2 and 6.8-3 present the calculated deciview values for the JARB1 site, along with the percent contribution to extinction from each aerosol species for the 20% most impaired and 20% least impaired days. Figure 6.8-2 presents 5-year average extinction for the current progress period for both the 20% most impaired and 20% least impaired days. Note that the percentages in the tables consider only the aerosol species which contribute to extinction, while the charts also show Rayleigh, or scattering due to background gases in the atmosphere.

Specific observations for the current visibility conditions on the 20% most impaired, or worst, days are as follows:

- The largest contributor to aerosol extinction on the worst days at the JARB1 site was particulate organic mass, followed by coarse mass and ammonium sulfate.

Specific observations for the current visibility conditions on the 20% least impaired, or best, days are as follows:

- Rayleigh, or background visibility impairment in clean air, contributed to approximately 80% of the total extinction (in Mm^{-1}) for the best days. Aerosol species contributions in Table 6.8-3 exclude the Rayleigh portion of extinction.
- Ammonium sulfate is the largest contributor to aerosol extinction for the best days.

¹ EPA's September 2003 *Guidance for Tracking Progress Under the Regional Haze Rule* specifies that progress is tracked against the 2000-2004 baseline period using corresponding averages over successive 5-year periods, i.e. 2005-2009, 2010-2014, etc. (See page 4-2 in the Guidance document.)

Table 6.8-2
Nevada Class I Area IMPROVE Site
Current Visibility Conditions
2005-2009 Progress Period, 20% Most Impaired Days

Site	Deciviews (dv)	Percent Contribution to Aerosol Extinction by Species (Excludes Rayleigh) (% of Mm^{-1}) and Rank*						
		Ammonium Sulfate	Ammonium Nitrate	Particulate Organic Mass	Elemental Carbon	Soil	Coarse Mass	Sea Salt
JARB1	12.4	17% (3)	5% (6)	38% (1)	7% (5)	10% (4)	22% (2)	1% (7)

*Highest aerosol species contribution per site is highlighted in bold.

Table 6.8-3
Nevada Class I Area IMPROVE Site
Current Visibility Conditions
2005-2009 Progress Period, 20% Least Impaired Days

Site	Deciviews (dv)	Percent Contribution to Aerosol Extinction by Species (Excludes Rayleigh) (% of Mm^{-1}) and Rank*						
		Ammonium Sulfate	Ammonium Nitrate	Particulate Organic Mass	Elemental Carbon	Soil	Coarse Mass	Sea Salt
JARB1	2.2	47% (1)	8% (4)	19% (2)	7% (5)	4% (6)	13% (3)	2% (7)

*Highest aerosol species contribution per site is highlighted in bold.

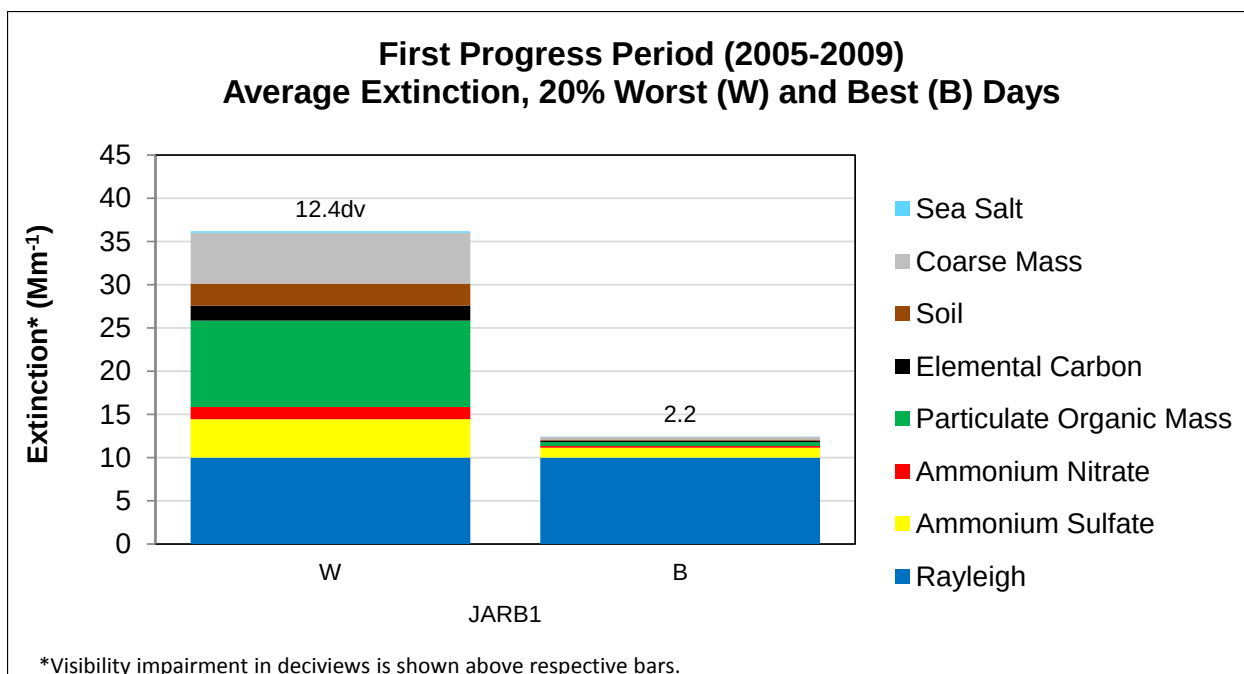


Figure 6.8-2. Average Extinction for Current Progress Period (2005-2009) for the Worst (Most Impaired) and Best (Least Impaired) Days Measured at the Nevada Class I Area IMPROVE Site.

6.8.1.2 Differences between Current and Baseline Conditions

This section addresses the regulatory question, *what is the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions (40 CFR 51.308 (g)(3)(ii))?* Included here are comparisons between the 5-year average baseline conditions (2000-2004) and current progress period extinction (2005-2009).

Table 6.8-4 presents the differences between the 2000-2004 baseline period average extinction and the 2005-2009 progress period average for the JARB1 site in Nevada for the 20% most impaired days, and Table 6.8-5 presents similar data for the least impaired days. Averages that increased are depicted in red text and averages that decreased in blue.

Figure 6.8-3 presents the 5-year average extinction for the baseline and current progress period averages for the worst days and Figure 6.8-4 presents the differences in averages by aerosol species, with increases represented above the zero line and decreases below the zero line. Figures 6.8-5 and 6.8-6 present similar plots for the best days.

For the 20% most impaired days, the 5-year average RHR deciview metric increased at the JARB1 site. Notable differences for individual species averages on the most impaired days were as follows:

- All species except particulate organic mass increased slightly at the JARB1 site. The largest increases were measured for ammonium sulfate, coarse mass and ammonium nitrate.
- Increases in 5-year average ammonium nitrate at the JARB1 monitor were influenced by higher than average ammonium nitrate in 2005, where anomalously high measurements on December 18, 2005, as depicted in Appendix H, Figure H.1-8, influenced the annual average.

For the 20% least impaired or best days, the 5-year average deciview metric decreased at the JARB1 site. Notable differences for individual species averages on the best impaired days were as follows:

- The largest decrease on the best days was measured for particulate organic mass. Soil, coarse mass and sea salt measured very small increases for the best days.

Table 6.8-4
Nevada Class I Area IMPROVE Sites
Difference in Aerosol Extinction by Species
2000-2004 Baseline Period to 2005-2009 Progress Period
20% Most Impaired Days

Site	Deciview (dv)			Change in Extinction by Species (Mm ⁻¹)*						
	2000-2004 Baseline Period	2005-2009 Progress Period	Change in dv*	Amm. Sulfate	Amm. Nitrate	POM	EC	Soil	CM	Sea Salt
JARB1	12.1	12.4	+0.3	+0.4	+0.3	0.0	+0.1	+0.2	+0.4	+0.1

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction and values in blue indicate decreases.

Table 6.8-5
Nevada Class I Area IMPROVE Sites
Difference in Aerosol Extinction by Species
2000-2004 Baseline Period to 2005-2009 Progress Period
20% Least Impaired Days

Site	Deciview (dv)			Change in Extinction by Species (Mm ⁻¹)*						
	2000-2004 Baseline Period	2005-2009 Progress Period	Change in dv*	Amm. Sulfate	Amm. Nitrate	POM	EC	Soil	CM	Sea Salt
JARB1	2.6	2.2	-0.4	-0.1	-0.1	-0.3	-0.1	0.0	0.0	0.0

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction and values in blue indicate decreases.

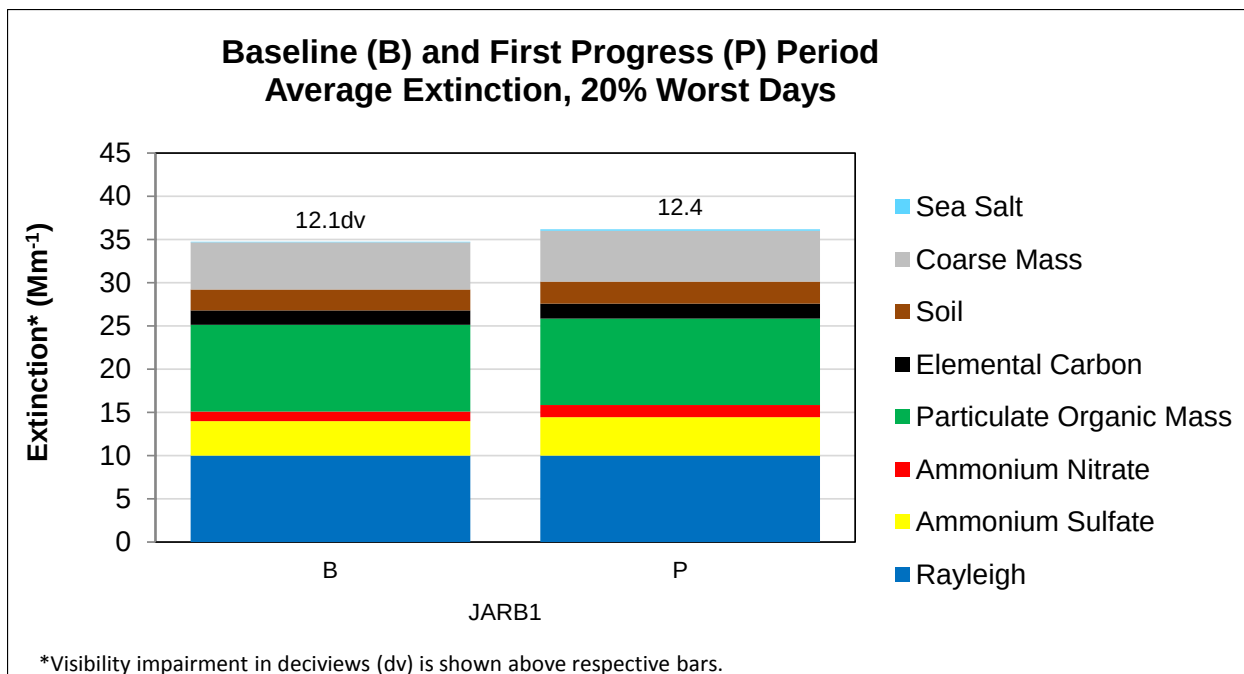


Figure 6.8-3. Average Extinction for Baseline and Progress Period Extinction for Worst (Most Impaired) Days Measured at the Nevada Class I Area IMPROVE Site.

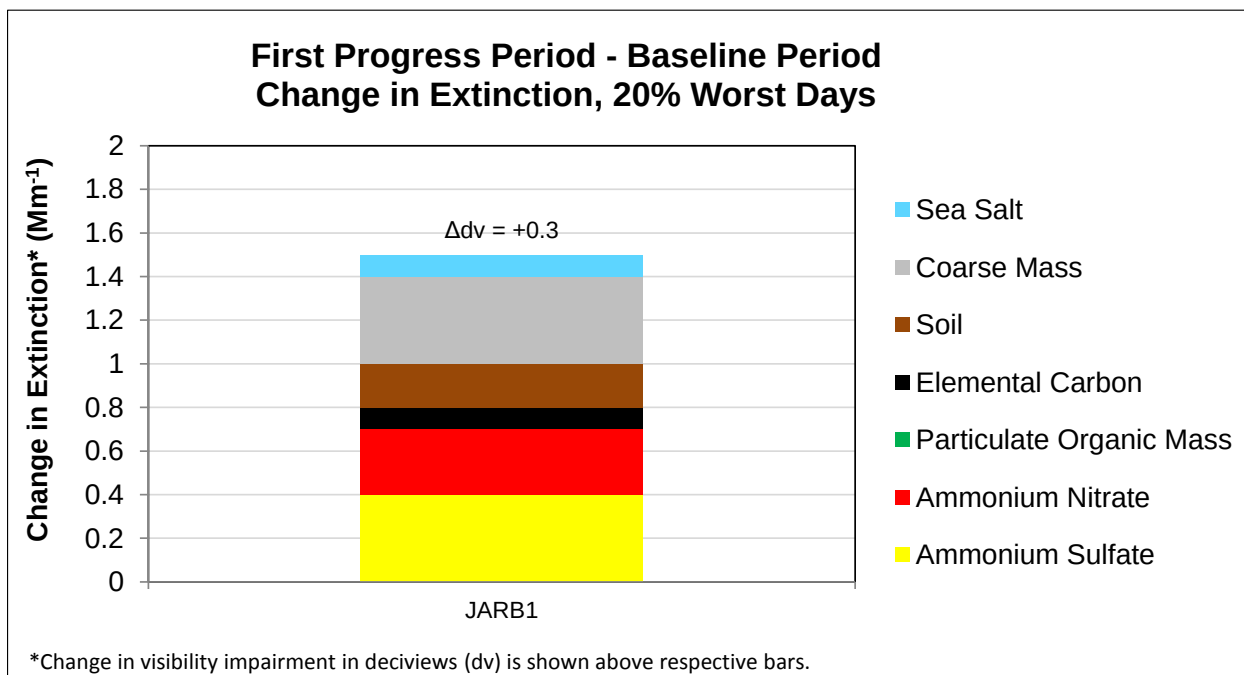


Figure 6.8-4. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Worst (Most Impaired) Days Measured at the Nevada Class I Area IMPROVE Site.

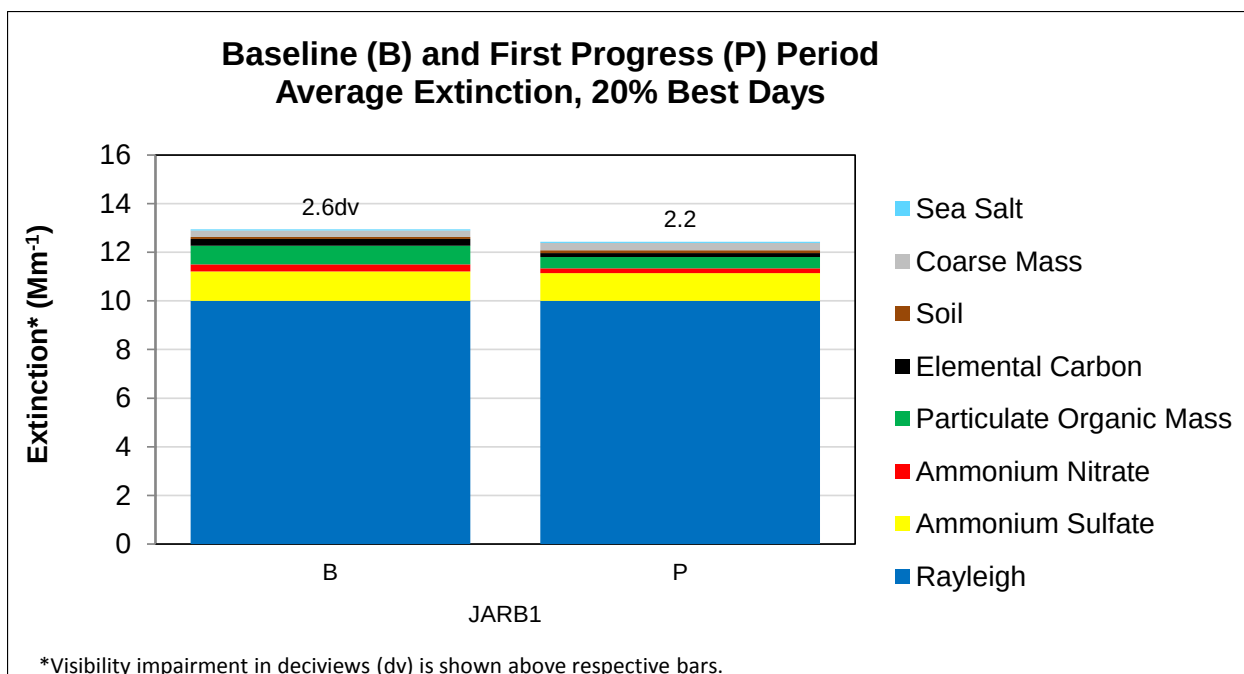


Figure 6.8-5. Average Extinction for Baseline and Progress Period Extinction for Best (Least Impaired) Days Measured at the Nevada Class I Area IMPROVE Site.

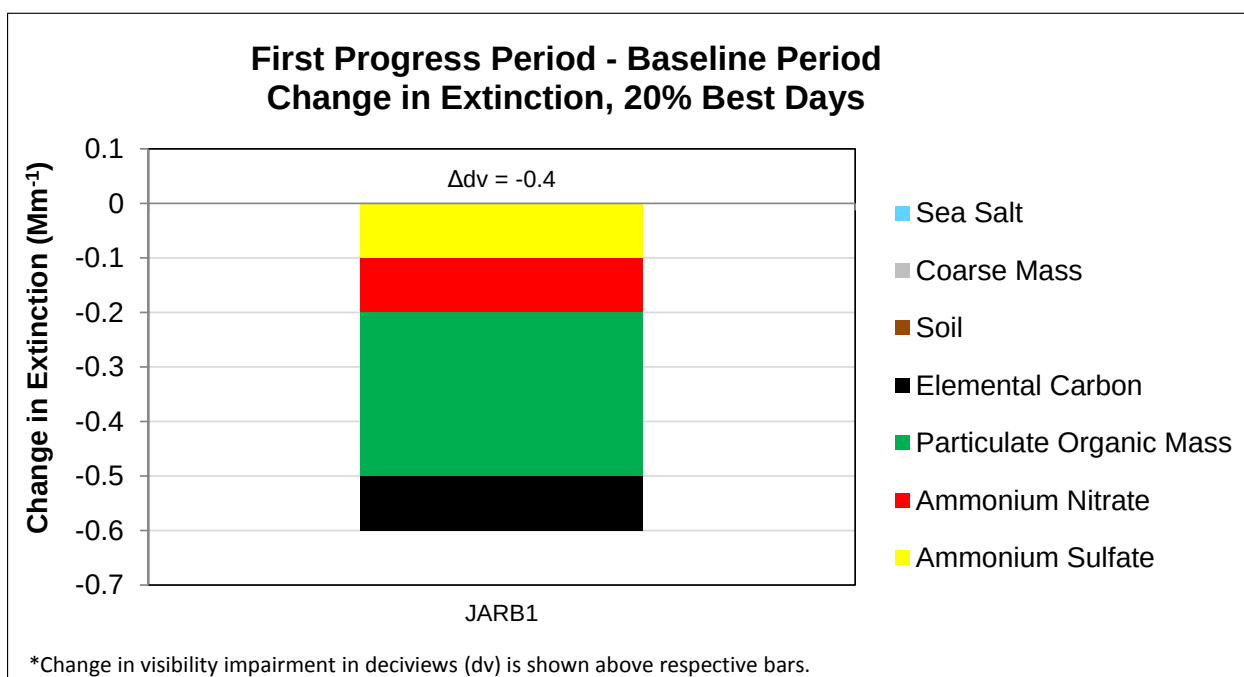


Figure 6.8-6. Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Best (Least Impaired) Days Measured at the Nevada Class I Area IMPROVE Site.

6.8.1.3 Changes in Visibility Impairment

This section addresses the regulatory question, *what is the change in visibility impairment for the most impaired and least impaired days over the past 5 years (40 CFR 51.308 (g)(3)(iii))*? Included here are changes in visibility impairment as characterized by annual average trend statistics, and some general observations regarding local and regional events and outliers on a daily and annual basis that affected the current 5-year progress period. The regulatory requirement asks for a description of changes over the past 5-year period, but trend analysis is better suited to longer periods of time, so trends for the entire 10-year planning period are presented here.

Trend statistics for the years 2000-2009 for species at the Nevada site are summarized in Table 6.8-6, and regional trends were presented earlier in Section 4.1.1.² Only trends for aerosol species trends with p-value statistics less than 0.15 (85% confidence level) are presented in the table here, with increasing slopes in red and decreasing slopes in blue.³ In some cases, trends may show decreasing tendencies while the difference between the 5-year averages do not (or vice versa), as discussed in Section 3.1.2.2. In these cases, the 5-year average for the best and worst days is the important metric for RHR regulatory purposes, but trend statistics may be of value to understand and address visibility impairment issues for planning purposes.

For each site, a more comprehensive list of all trends for all species, including the associated p-values, is provided in Appendix H. Additionally, this appendix includes plots depicting 5-year, annual, monthly, and daily average extinction for each site. These plots are intended to provide a fairly comprehensive compilation of reference information for individual states to investigate local and regional events and outliers that may have influenced changes in visibility impairment as tracked using the 5-year deciview metrics. Note that similar summary products are also available from the WRAP TSS website (<http://vista.cira.colostate.edu/tss/>). Some general observations regarding changes in visibility impairment at sites in Nevada are as follows:

- No increasing aerosol trends were observed at the JARB1 site for the best, worst or all sample days.
- Only particulate organic mass (20% best and all days) and elemental carbon (20% worst days) exhibited statistically significant trends, all decreasing. All other species did not show statistically significant trends for the best, worst or all days from 2000 to 2009.

² Annual trends were calculated for the years 2000-2009, with a trend defined as the slope derived using Theil statistics. Trends derived from Theil statistics are useful in analyzing changes in air quality data because these statistics can show the overall tendency of measurements over long periods of time, while minimizing the effects of year-to-year fluctuations which are common in air quality data. Theil statistics are also used in EPA's National Air Quality Trends Reports (<http://www.epa.gov/airtrends/>) and the IMPROVE program trend reports (http://vista.cira.colostate.edu/improve/Publications/improve_reports.htm)

³ The significance of the trend is represented with p-values calculated using Mann-Kendall trend statistics. Determining a significance level helps to distinguish random variability in data from a real tendency to increase or decrease over time, where lower p-values indicate higher confidence levels in the computed slopes.

Table 6.8-6
Nevada Class I Area IMPROVE Site
Change in Aerosol Extinction by Species
2000-2009 Annual Average Trends

Site	Group	Annual Trend* (Mm ⁻¹ /year)						
		Ammonium Sulfate	Ammonium Nitrate	Particulate Organic Mass	Elemental Carbon	Soil	Coarse Mass	Sea Salt
JARB1	20% Best	0.0	0.0	-0.1	0.0	0.0	--	--
	20% Worst	--	--	--	-0.1	--	--	--
	All Days	--	0.0	-0.1	0.0	--	--	0.0

*(--) Indicates statistically insignificant trend (<85% confidence level). Annual averages and complete trend statistics for all significance levels are included for each site in Appendix H.

6.8.2 Emissions Data

Included here are summaries depicting differences between two emission inventory years that are used to represent the 5-year baseline and current progress periods. The baseline period is represented using a 2002 inventory developed by the WRAP for use in the initial WRAP state SIPs, and the progress period is represented by a 2008 inventory which leverages recent WRAP inventory work for modeling efforts, as referenced in Section 3.2.1. For reference, Table 6.8-7 lists the major emitted pollutants inventoried, the related aerosol species, some of the major sources for each pollutant, and some notes regarding implications of these pollutants. Differences between these baseline and progress period inventories, and a separate summary of annual emissions from electrical generating units (EGUs), are presented in this section.

Table 6.8-7
Nevada
Pollutants, Aerosol Species, and Major Sources

Emitted Pollutant	Related Aerosol	Major Sources	Notes
Sulfur Dioxide (SO ₂)	Ammonium Sulfate	Point Sources; On- and Off-Road Mobile Sources	SO ₂ emissions are generally associated with anthropogenic sources such as coal-burning power plants, other industrial sources such as refineries and cement plants, and both on- and off-road diesel engines.
Oxides of Nitrogen (NO _x)	Ammonium Nitrate	On- and Off-Road Mobile Sources; Point Sources; Area Sources	NO _x emissions are generally associated with anthropogenic sources. Common sources include virtually all combustion activities, especially those involving cars, trucks, power plants, and other industrial processes.
Ammonia (NH ₃)	Ammonium Sulfate and Ammonium Nitrate	Area Sources; On-Road Mobile Sources	Gaseous NH ₃ has implications in particle formation because it can form particulate ammonium. Ammonium is not directly measured by the IMPROVE program, but affects formation potential of ammonium sulfate and ammonium nitrate. All measured nitrate and sulfate is assumed to be associated with ammonium for IMPROVE reporting purposes.
Volatile Organic Compounds (VOCs)	Particulate Organic Mass (POM)	Biogenic Emissions; Vehicle Emissions; Area Sources	VOCs are gaseous emissions of carbon compounds, which are often converted to POM through chemical reactions in the atmosphere. Estimates for biogenic emissions of VOCs have undergone significant updates since 2002, so changes reported here are more reflective of methodology changes than actual changes in emissions (see Section 3.2.1).
Primary Organic Aerosol (POA)	POM	Wildfires; Area Sources	POA represents organic aerosols that are emitted directly as particles, as opposed to gases. Wildfires in the west generally dominate POA emissions, and large wildfire events are generally sporadic and highly variable from year-to-year.
Elemental Carbon (EC)	EC	Wildfires; On- and Off-Road Mobile Sources	Large EC events are often associated with large POM events during wildfires. Other sources include both on- and off-road diesel engines.
Fine soil	Soil	Windblown Dust; Fugitive Dust; Road Dust; Area Sources	Fine soil is reported here as the crustal or soil components of PM _{2.5} .
Coarse Mass (PMC)	Coarse Mass	Windblown Dust; Fugitive Dust	Coarse mass is reported by the IMPROVE Network as the difference between PM ₁₀ and PM _{2.5} mass measurements. Coarse mass is not separated by species in the same way that PM _{2.5} is speciated, but these measurements are generally associated with crustal components. Similar to crustal PM _{2.5} , natural windblown dust is often the largest contributor to PMC.

6.8.2.1 Changes in Emissions

This section addresses the regulatory question, ***what is the change over the past 5 years in emissions of pollutants contributing to visibility impairment from all sources and activities within the State (40 CFR 51.308 (g)(4))?*** For these summaries, emissions during the baseline years are represented using a 2002 inventory, which was developed with support from the WRAP for use in the original RHR SIP strategy development (termed plan02d). Differences between inventories are represented as the difference between the 2002 inventory, and a 2008 inventory which leverages recent inventory development work performed by the WRAP for the WestJumpAQMS and DEASCO₃ modeling projects (termed WestJump2008). Note that the comparisons of differences between inventories does not necessarily reflect a change in emissions, as a number of methodology changes and enhancements have occurred between development of the individual inventories, as referenced in Section 3.2.1. Inventories for all major visibility impairing pollutants are presented for major source categories, and categorized as either anthropogenic or natural emissions. State-wide inventories totals and differences are presented here, and inventory totals on a county level basis are available on the WRAP Technical Support System website (<http://vista.cira.colostate.edu/tss/>).

Table 6.8-8 and Figure 6.8-7 present the differences between the 2002 and 2008 sulfur dioxide (SO₂) inventories by source category. Tables 6.8-9 and Figure 6.8-8 present data for oxides of nitrogen (NO_x), and subsequent tables and figures (Tables 6.8-10 through 6.8-15 and Figures 6.8-9 through 6.8-14) present data for ammonia (NH₃), volatile organic compounds (VOCs), primary organic aerosol (POA), elemental carbon (EC), fine soil and coarse mass. General observations regarding emissions inventory comparisons are listed below.

- State-wide SO₂ inventory totals show a 75% reduction, with some decreases reported for all source categories. The largest decreases are reported from point sources, followed by area sources, natural fire and off-road mobile sources.
- NO_x emissions show a 22% reduction, with area and on-road mobile sources showing significant increases, while all other source categories show decreases. The largest decreases were reported from point sources, followed by off-road mobile, biogenic emissions, and natural fire sources. Note that decreases in biogenic sources were consistent for all contiguous WRAP states, and likely due to inventory enhancements in 2008. Also, current natural fire emissions represent only the year 2008, so all fire events for the 2005-2009 progress period are not represented in these emissions comparison results. Also, for off-road sources, the reclassification of some off-road mobile sources (such as some types of marine vessels and locomotives) into the area source category in 2008, which may have contributed to decreases in the off-road inventory totals, but increases in area source totals.
- Ammonia emission inventory totals decreased by 34%, with decreases due mostly to area and off-road mobile sources.
- VOC emissions showed a 61% decrease, mostly due to biogenic emission inventories. A significant increase is shown for area sources. Significant decreases are shown for biogenic, on-road mobile and natural fire sources. The large difference in biogenic emissions is likely due to enhancements in biogenic inventory methodology, as

described in Section 3.2, rather than decreases of this magnitude in actual emissions. Also, current natural fire emissions represent only the year 2008, so all fire events for the 2005-2009 progress period are not represented in these emissions comparison results.

- POA showed 52% decrease in inventory totals, and elemental carbon showed a 31% decrease, mostly due to natural fire sources. Note that current natural fire emissions represent only the year 2008, so all fire events for the 2005-2009 progress period are not represented in these emissions comparison results.
- Fine soil and coarse mass increased for the windblown dust inventory comparisons and the combined fugitive/road dust inventories. The large increases in windblown dust are likely due in part to enhancements in dust inventory methodology, as described in Section 3.2, rather than increases in actual emissions. Most other sources of fine soil and coarse mass showed increases with the exception of natural fire sources for both pollutants, on-road mobile sources for fine soil, and point sources for coarse mass.

Table 6.8-8
Nevada
Sulfur Dioxide Emissions by Category

Source Category	Sulfur Dioxide Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	50,720	11,155	-39,565
Area	12,953	4,863	-8,090
On-Road Mobile	454	298	-156
Off-Road Mobile	1,403	322	-1,081
Area Oil and Gas	0	0	0
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	12	2	-11
Total Anthropogenic	65,543	16,641	-48,903 (-75%)
Natural Sources			
Natural Fire	2,200	506	-1,695
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	2,200	506	-1,695 (-77%)
All Sources			
Total Emissions	67,743	17,146	-50,597 (-75%)

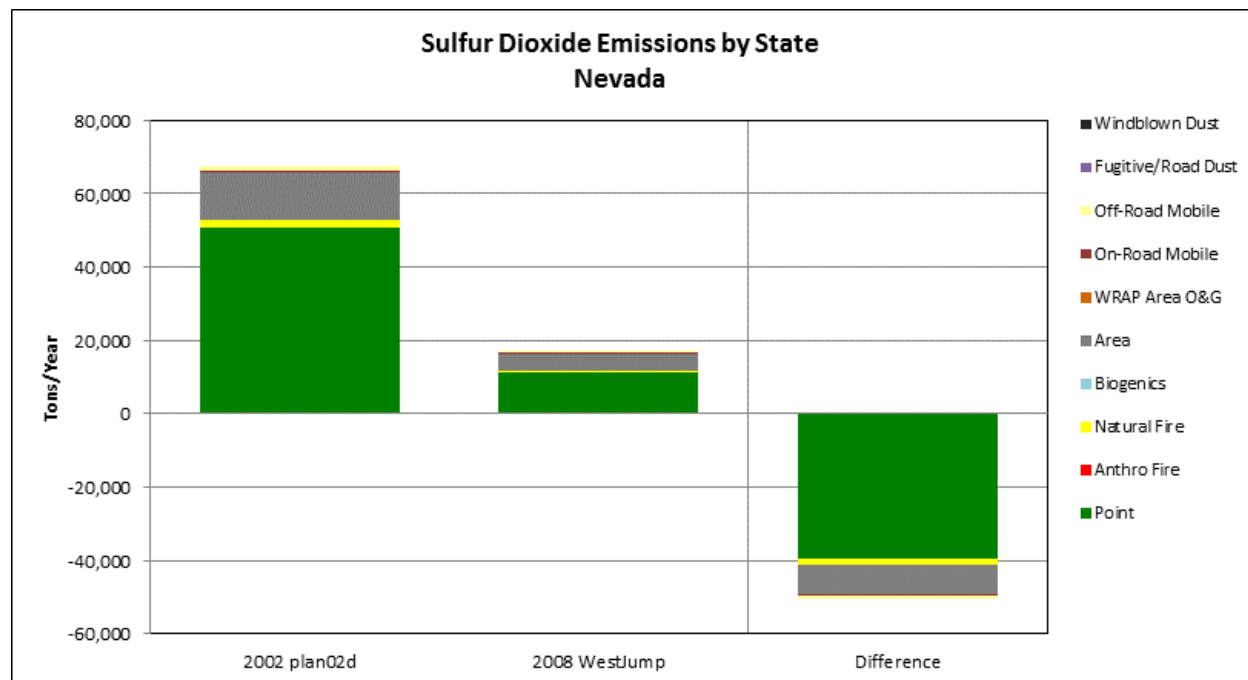


Figure 6.8-7. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Sulfur Dioxide by Source Category for Nevada.

Table 6.8-9
Nevada
Oxides of Nitrogen Emissions by Category

Source Category	Oxides of nitrogen Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	59,864	30,090	-29,774
Area	5,725	11,321	5,597
On-Road Mobile	41,089	50,068	8,979
Off-Road Mobile	32,565	17,081	-15,484
Area Oil and Gas	63	0	-63
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	48	13	-35
Total Anthropogenic	139,353	108,574	-30,779 (-22%)
Natural Sources			
Natural Fire	8,026	3,575	-4,451
Biogenic	15,018	7,364	-7,654
Wind Blown Dust	0	0	0
Total Natural	23,044	10,939	-12,105 (-53%)
All Sources			
Total Emissions	162,397	119,513	-42,885 (-26%)

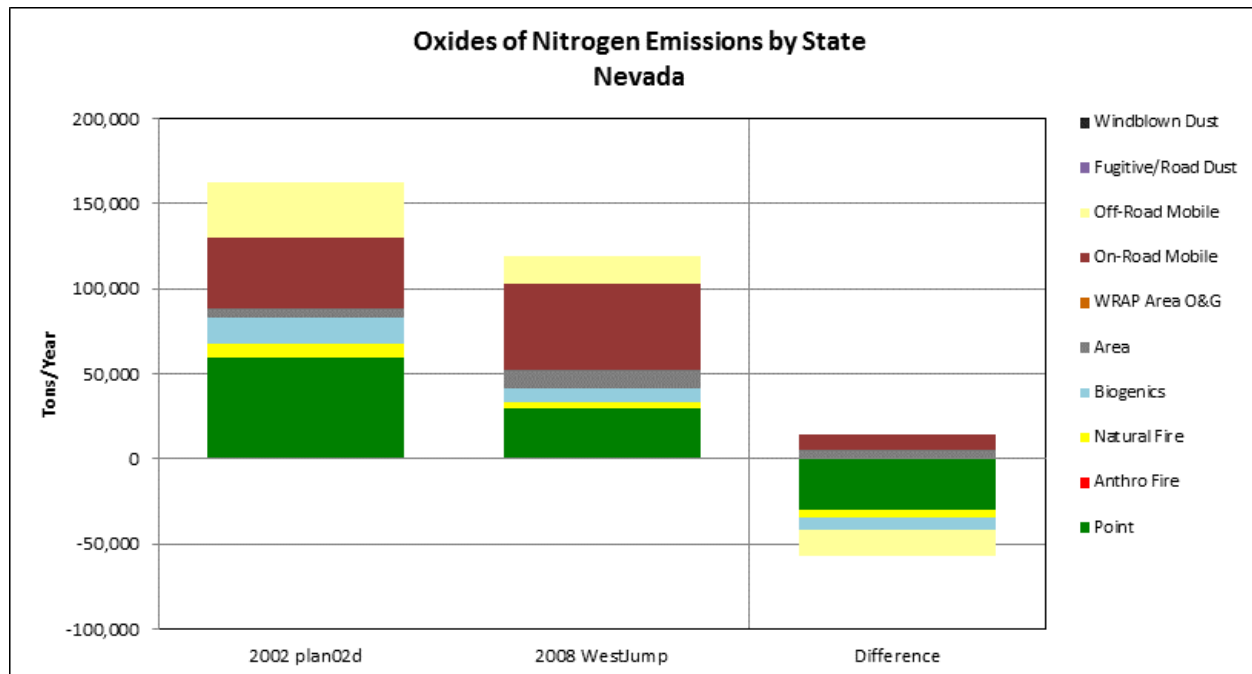


Figure 6.8-8. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Oxides of nitrogen by Source Category for Nevada.

Table 6.8-10
Nevada
Ammonia Emissions by Category

Source Category	Ammonia Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	339	302	-37
Area	8,009	5,717	-2,293
On-Road Mobile	2,030	849	-1,182
Off-Road Mobile	22	20	-2
Area Oil and Gas	0	0	0
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	8	6	-2
Total Anthropogenic	10,408	6,893	-3,515 (-34%)
Natural Sources			
Natural Fire	1,684	2,490	805
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	1,684	2,490	805 (48%)
All Sources			
Total Emissions	12,092	9,382	-2,710 (-22%)

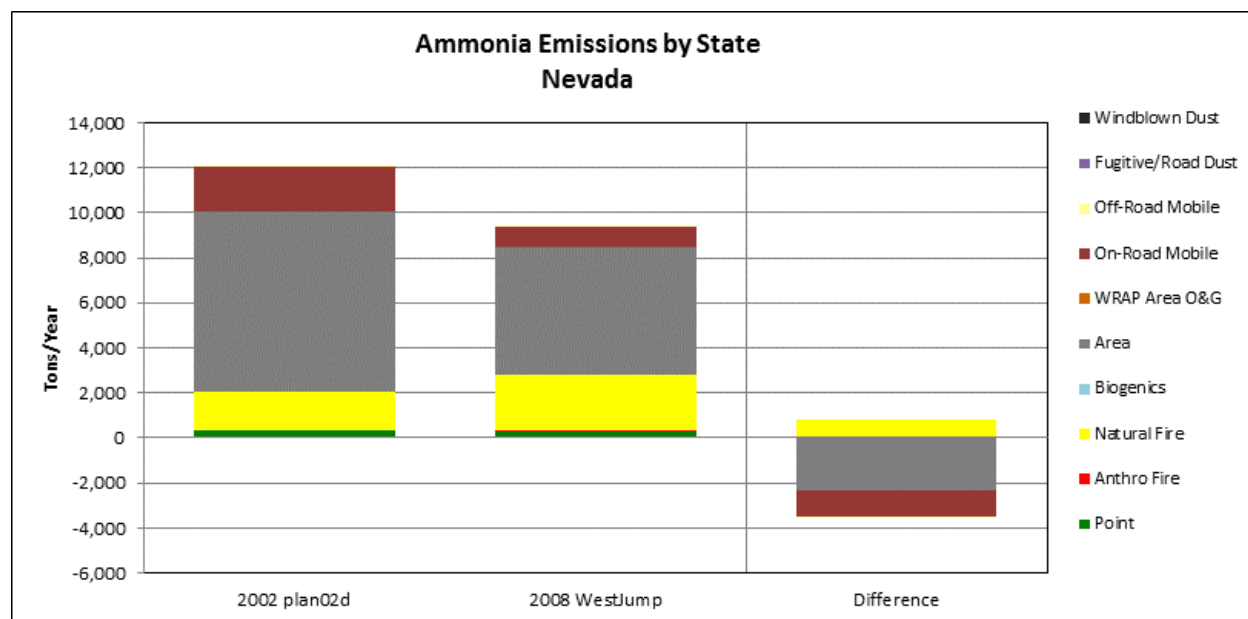


Figure 6.8-9. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Ammonia by Source Category for Nevada.

Table 6.8-11
Nevada
Volatile Organic Compound Emissions by Category

Source Category	Volatile Organic Compound Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point	2,215	2,953	738
Area	28,592	40,973	12,381
On-Road Mobile	36,257	21,302	-14,955
Off-Road Mobile	18,094	18,783	688
Area Oil and Gas	129	0	-129
Fugitive and Road Dust	0	0	0
Anthropogenic Fire	70	16	-54
Total Anthropogenic	85,357	84,026	-1,331 (-2%)
Natural Sources			
Natural Fire	17,606	4,204	-13,403
Biogenic	794,139	262,912	-531,227
Wind Blown Dust	0	0	0
Total Natural	811,745	267,115	-544,630 (-67%)
All Sources			
Total Emissions	897,102	351,142	-545,960 (-61%)

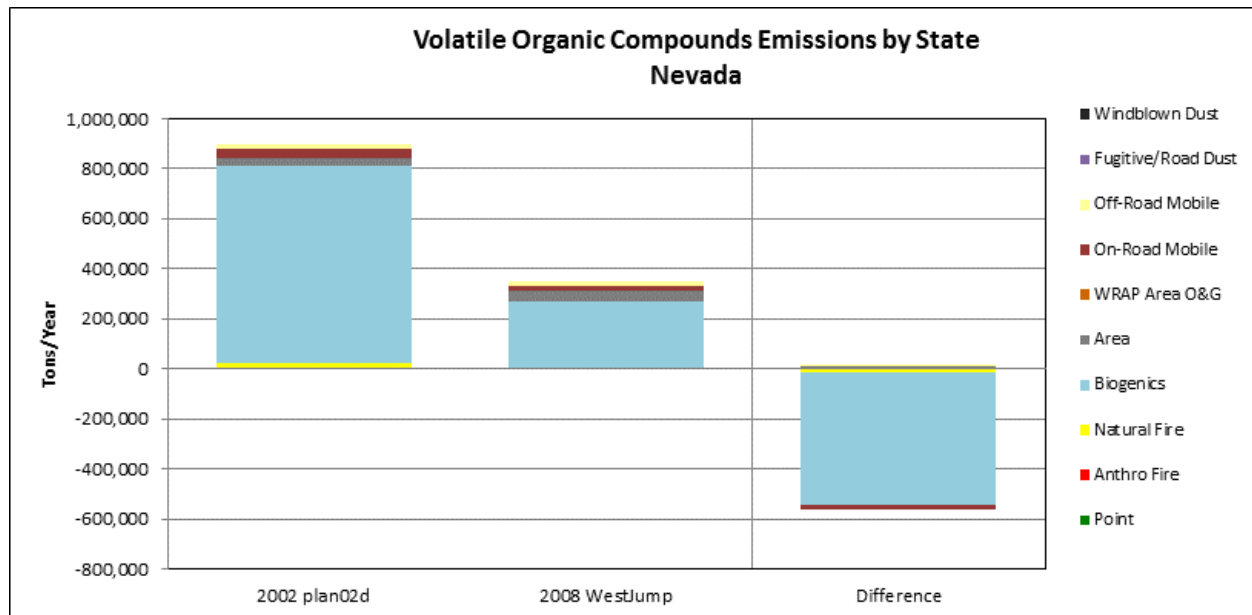


Figure 6.8-10. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Volatile Organic Compounds by Source Category for Nevada.

Table 6.8-12
Nevada
Primary Organic Aerosol Emissions by Category

Source Category	Primary Organic Aerosol Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	256	46	-210
Area	687	2,283	1,596
On-Road Mobile	314	1,053	739
Off-Road Mobile	572	689	117
Area Oil and Gas	0	0	0
Fugitive and Road Dust	332	891	559
Anthropogenic Fire	73	22	-51
Total Anthropogenic	2,233	4,985	2,751 (>100%)
Natural Sources			
Natural Fire	22,501	6,831	-15,670
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	22,501	6,831	-15,670 (-70%)
All Sources			
Total Emissions	24,734	11,816	-12,918 (-52%)

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (<http://vista.cira.colostate.edu/tss/>).

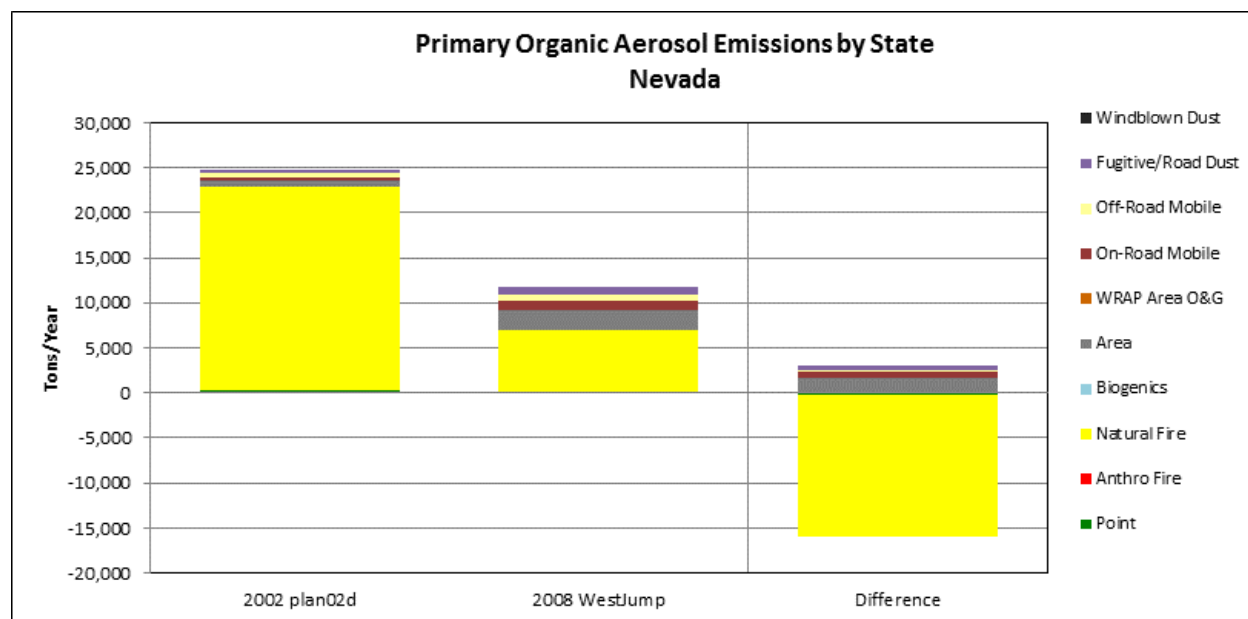


Figure 6.8-11. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Primary Organic Aerosol by Source Category for Nevada.

Table 6.8-13
Nevada
Elemental Carbon Emissions by Category

Source Category	Elemental Carbon Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	13	64	50
Area	96	368	272
On-Road Mobile	235	1,891	1,656
Off-Road Mobile	1,354	954	-400
Area Oil and Gas	0	0	0
Fugitive and Road Dust	24	14	-10
Anthropogenic Fire	13	6	-8
Total Anthropogenic	1,735	3,295	1,561 (90%)
Natural Sources			
Natural Fire	4,674	1,130	-3,544
Biogenic	0	0	0
Wind Blown Dust	0	0	0
Total Natural	4,674	1,130	-3,544 (-76%)
All Sources			
Total Emissions	6,409	4,425	-1,984 (-31%)

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (<http://vista.cira.colostate.edu/tss/>).

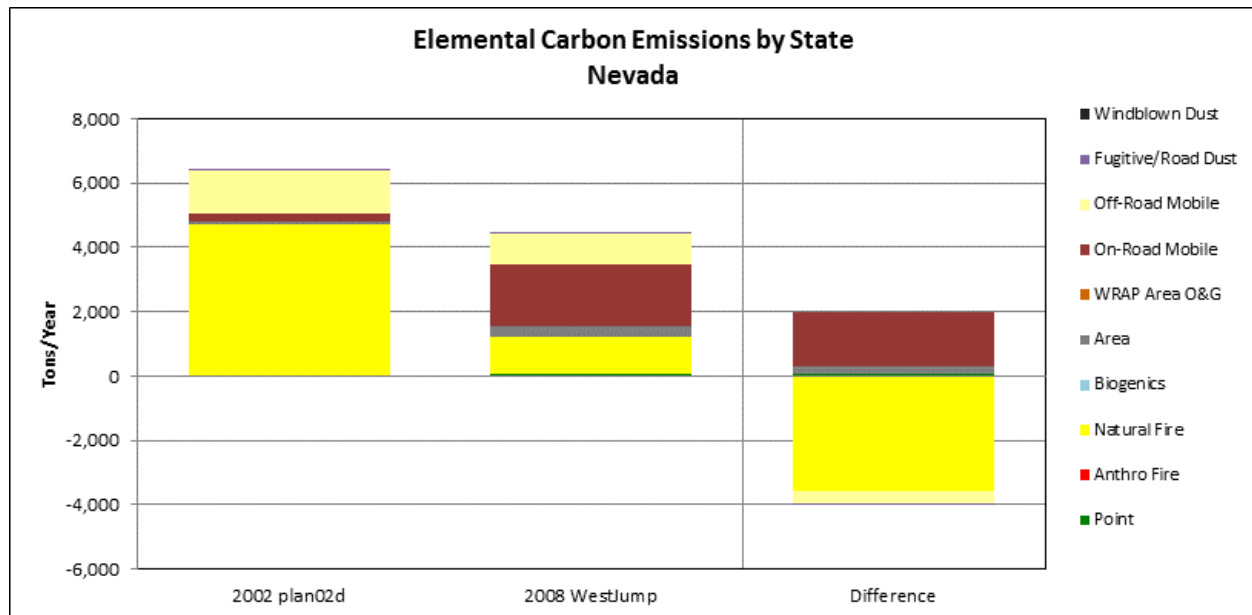


Figure 6.8-12. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Elemental Carbon by Source Category for Nevada.

Table 6.8-14
Nevada
Fine Soil Emissions by Category

Source Category	Fine Soil Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	2,158	209	-1,948
Area	830	1,024	195
On-Road Mobile	239	190	-49
Off-Road Mobile	0	49	49
Area Oil and Gas	0	0	0
Fugitive and Road Dust	6,128	19,216	13,087
Anthropogenic Fire	9	10	1
Total Anthropogenic	9,364	20,698	11,334 (>100%)
Natural Sources			
Natural Fire	1,406	2,552	1,146
Biogenic	0	0	0
Wind Blown Dust	10,438	17,051	6,613
Total Natural	11,845	19,603	7,758 (66%)
All Sources			
Total Emissions	21,208	40,301	19,092 (90%)

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (<http://vista.cira.colostate.edu/tss/>).

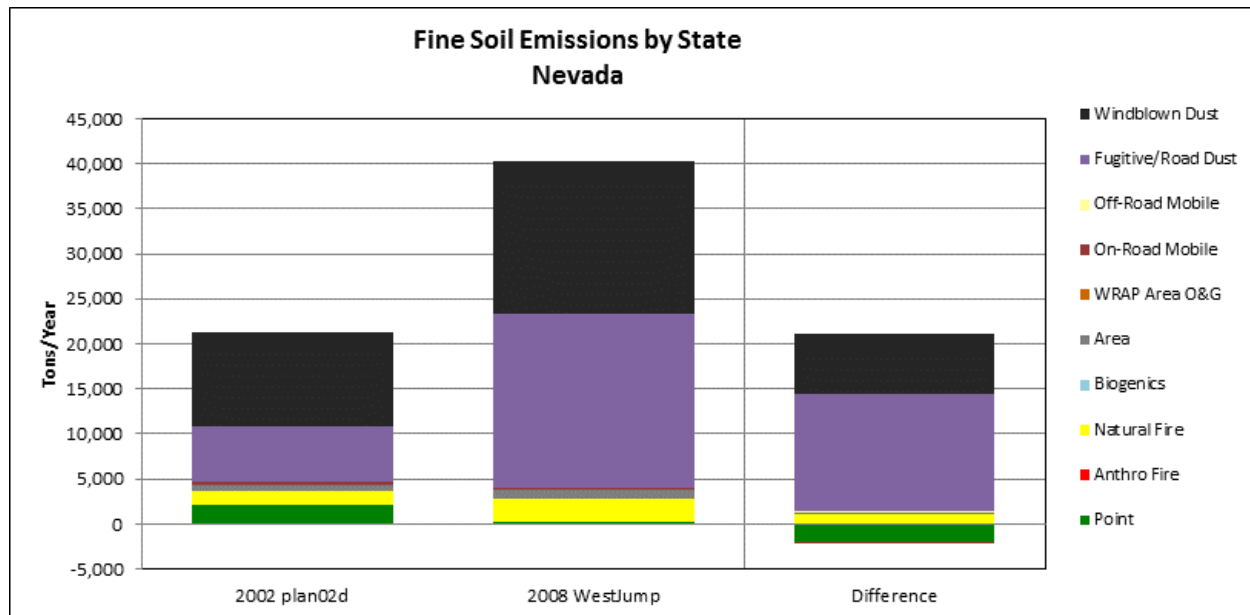


Figure 6.8-13. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Fine Soil by Source Category for Nevada.

Table 6.8-15

Nevada
Coarse Mass Emissions by Category

Source Category	Coarse Mass Emissions (tons/year)		
	2002 (Plan02d)	2008 (WestJump2008)	Difference (Percent Change)
Anthropogenic Sources			
Point*	4,093	1,761	-2,331
Area	897	1,094	198
On-Road Mobile	245	2,014	1,769
Off-Road Mobile	0	82	82
Area Oil and Gas	0	0	0
Fugitive and Road Dust	56,779	161,532	104,753
Anthropogenic Fire	7	4	-3
Total Anthropogenic	62,020	166,488	104,468 (>100%)
Natural Sources			
Natural Fire	5,176	1,310	-3,866
Biogenic	0	0	0
Wind Blown Dust	93,946	153,459	59,513
Total Natural	99,122	154,769	55,647 (56%)
All Sources			
Total Emissions	161,142	321,257	160,115 (99%)

*Point source data includes only oil and gas and regulated CEM sources. More comprehensive point source data were not available at the time this report was prepared but will be made available through the WRAP TSS (<http://vista.cira.colostate.edu/tss/>).

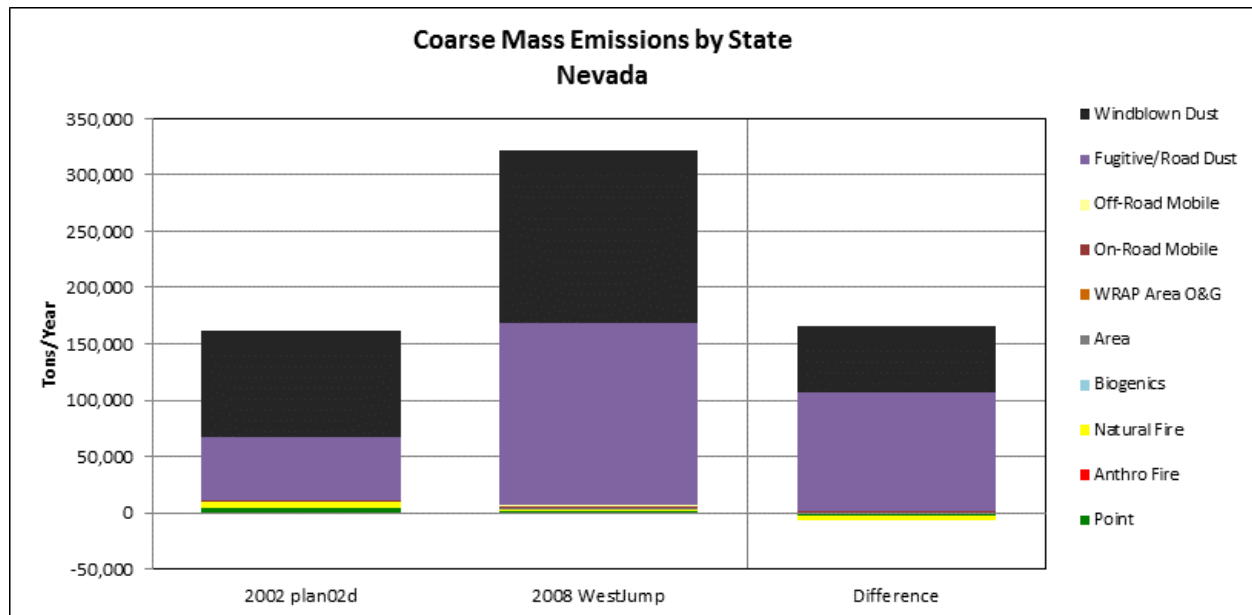


Figure 6.8-14. 2002 and 2008 Emission and Difference between Emissions Inventory Totals, for Coarse Mass by Source Category for Nevada.

6.8.2.2 EGU Summary

As described in previous sections, differences between the baseline and progress period inventories presented here do not necessarily represent changes in actual emissions because numerous updates in inventory methodologies have occurred between the development of the separate inventories. Also, the 2002 baseline and 2008 progress period inventories represent only annual snapshots of emissions estimates, which may not be representative of entire 5-year monitoring periods compared. To better account for year-to-year changes in emissions, annual emission totals for Nevada electrical generating units (EGU) are presented here. EGU emissions are some of the more consistently reported emissions, as tracked in EPA's Air Markets Program Database for permitted Title V facilities in the state (<http://ampd.epa.gov/ampd/>). RHR implementation plans are required to pay specific attention to certain major stationary sources, including EGUs, built between 1962 and 1977.

Figure 6.8-15 presents a sum of annual NO_x and SO₂ emissions as reported for Nevada EGU sources between 1996 and 2010. While these types of facilities are targeted for controls in state regional haze SIPs, it should be noted that many of the controls planned for EGUs in the WRAP states had not taken place yet in 2010, while other controls separate from the RHR may have been implemented. The chart shows a sharp decline for SO₂ and NO_x between 2005 and 2006, mostly resulting from the closure of the Mohave Generating Station in Clark County, which eliminated approximately 20,000 tons per year (tpy) of NO_x and 41,000 tpy of SO₂ emissions. Steady decreases for NO_x emissions are shown for 2006 through 2010.

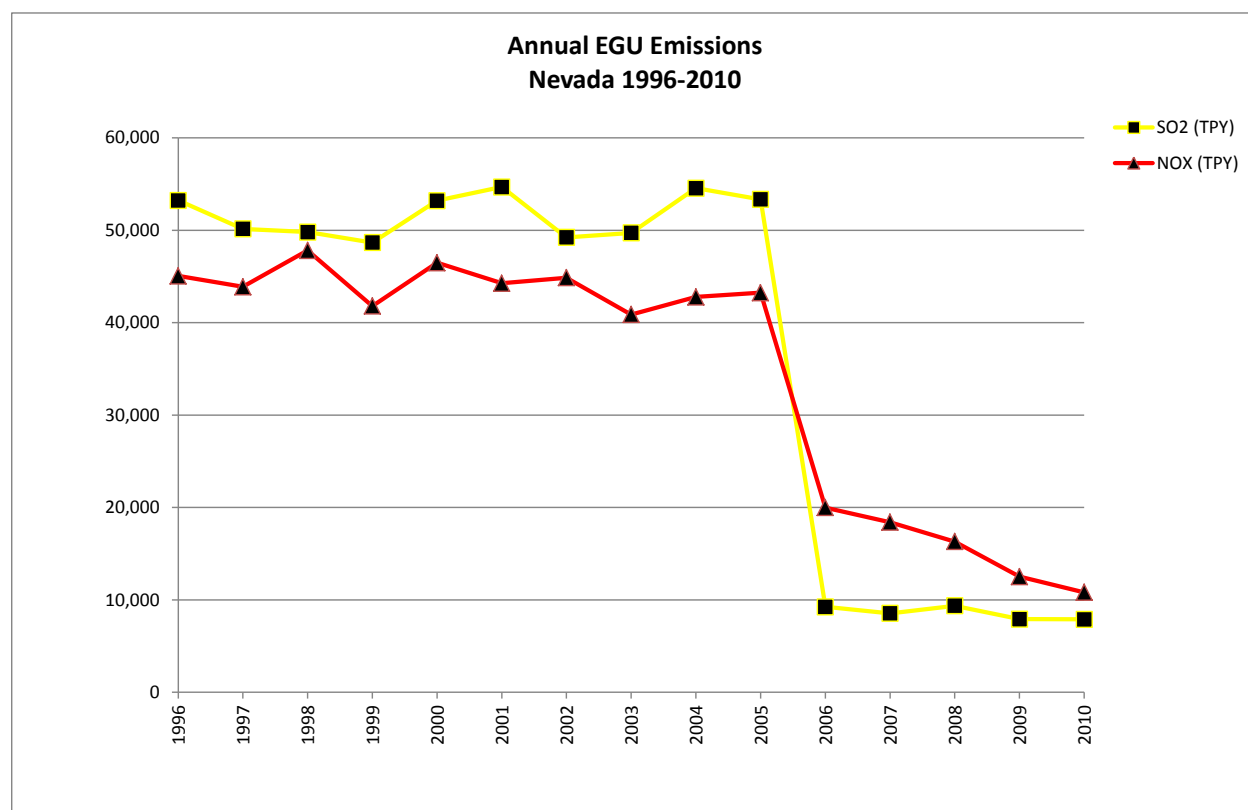


Figure 6.8-15. Sum of EGU Emissions of SO₂ and NO_x reported between 1996 and 2010 for Nevada.

APPENDIX B

Supporting Documentation

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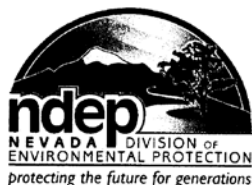
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1 LETTERS AND NEWS RELEASES

1.1 Mohave Operating Permit Cancellation



STATE OF NEVADA
Department of Conservation & Natural Resources
DIVISION OF ENVIRONMENTAL PROTECTION

Jim Gibbons, Governor
Allen Biaggi, Director
Leo M. Drozdoff, P.E., Administrator

April 9, 2010

Rick Greenwood
Director, Corporate EHES
Southern California Edison
2244 Walnut Grove Avenue
Rosemead, CA 91770

**Re: Request to Terminate Class I Air Quality Operating Permit AP4911-0774,
FIN A0013; Mohave Generating Station (MGS)**

Dear Mr. Greenwood:

The Nevada Division of Environmental Protection, Bureau of Air Pollution Control (NDEP-BAPC) received your letter dated April 7, 2010 requesting termination of the Class I Air Quality Operating Permit, No. AP4911-0774, FIN A0013. The Mohave Generating Station has ceased all operations related to generation of electricity from burning coal. Based on the April 7, 2010 letter, all remaining operations have received their air quality operating permits from Clark County Department of Air Quality and Environmental Management. Additionally, Mohave Generating Station has received their Operating Permit to Construct No. AP4911-2627 establishing the emission reduction credits for the permanent shut-down and dismantling of the main steam boilers.

Based on the above, the NDEP-BAPC hereby approves Southern California Edison's request to terminate Air Quality Operating Permit No. AP4911-0774. In accordance with Nevada Revised Statute 445B.340, you may appeal the department's action within 10 days after you receive this notice of termination. Appeals may be filed with the State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada, 89701-5249, telephone 775-687-9308.

If you have any questions, please call me at 775-687-9391.

Sincerely,

Matthew A. DeBurle, P.E.
Supervisor, Bureau of Air Pollution Control

cc: Tina Gingras, CCAQMD
Gerardo Rios, Chief (A-5-1), U.S. EPA, Region IX, 75 Hawthorne Street, San Francisco, CA 94105

Certified Mail No. 7008 1140 0004 4029 8338



901 S. Stewart Street, Suite 4001 • Carson City, Nevada 89701 • p: 775.687.4670 • f: 775.687.5856 • www.ndep.nv.gov

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1.2 Southern California Edison News Releases re Mohave Closure



News Releases

Mohave Generating Station Owners to Dismantle Plant

Added: June 10, 2009

June 10, 2009

Media Contact: Gil Alexander, (626) 302-2255

ROSEMEAD, Calif., June 10, 2009 – The owners of the Mohave Generating Station in Laughlin, Nev., including Southern California Edison, today announced the decision to decommission the station and remove the generating facility from the site. During the coming months, non-generating equipment and facilities will be dismantled. Then, in 2010, the plant's generating equipment will be removed and its operating permits terminated. The site's transmission switchyard and some related facilities will remain in place.

No decision has been made about the final disposition of the plant property. Among the options being considered by Mohave's owners are the sale of the site and construction of a renewable energy project.

Mohave Background Facts

- Owners – Southern California Edison Company (56 percent), Salt River Project Agricultural Improvement and Power District (20 percent), NV Energy (14 percent) and the Los Angeles Department of Water and Power (10 percent).
- Generating capacity when the plant was in operation – 1,580 megawatts or enough power to serve more than one million average homes.
- Service history – The first of two operating units at Mohave went into commercial operation in April 1971, followed by the second unit in October 1971. Mohave ceased power generation in December 2005 due to the lack of new water and coal agreements needed to proceed with emissions control upgrades required for operation after 2005.

About Southern California Edison

An Edison International (NYSE:EIX) company, Southern California Edison is one of the nation's largest electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal and Southern California.



News Releases

SOUTHERN CALIFORNIA EDISON DISMANTLES THE EXHAUST STACK OF THE MOHAVE GENERATING STATION

Added: March 11, 2011

Media Contact: Gil Alexander, (626) 302-2255

BACKGROUND: Southern California Edison (SCE) today imploded a landmark Nevada structure, the 500-foot exhaust stack of the Mohave Generating Station. The stack demolition came midway through the former power plant decommissioning that began in 2009, and will restore most of the plant property to its natural state by mid-2012. Southern California Edison (SCE) offered the following statement about the plant's shutdown.

ROSEMEAD, Calif., March 11, 2011 – Safety and environmental care are Southern California Edison's (SCE) highest priorities during the decommissioning of the Mohave Generating Station, including the dismantling of the plant's exhaust stack. SCE will monitor wind and other factors leading up to the implosion of the stack. If conditions require, this step will be rescheduled. Dust abatement measures will include water trucks soaking the landing area before and after the implosion.

For 35 years, the Mohave Generating Station provided utility customers with reliable, low-cost power, while contributing millions of dollars annually to the Laughlin area economy. The plant's co-owners are considering several options for the property's future use.

Plant Owners

Southern California Edison, 56 percent (885 MW)
Salt River Project Agricultural Improvement and Power District, 20 percent (316 MW)
Nevada Power Co., 14 percent (221 MW)
The Los Angeles Department of Water and Power, 10 percent (158 MW)

About Southern California Edison

An Edison International (NYSE:EIX) company, Southern California Edison is one of the largest U.S. electric utilities, serving a population of nearly 14 million via 4.9 million customer accounts in a 50,000-square-mile service area within Central, Coastal and Southern California.

1.3 White Pine Energy Associates Withdrawal and NDEP Cancellation of Application for White Pine Energy Station

White Pine Energy Associates, LLC

FIN A05B6
AP4911-1502
c/o LS Power Development, LLC
400 Chesterfield Center, Suite 110
St. Louis, Missouri 63017
(636) 532-2200 Tel.
(636) 532-2250 Fax.

February 3, 2011

Mr. Larry Kennedy
Supervisor, Major Source Permits
Nevada Division of Environmental Protection
Bureau of Air Pollution Control
901 South Stewart St., Suite 4001
Carson City, NV 89701

Nevada
Environmental Protection

FEB 04 2011

BAPC/BAQP

ENVIRONMENTAL PROTECTION

FEB 04 2011

RECEIVED

RE: Withdrawal of Application for Class I Air Quality Operating Permit to Construct for the proposed White Pine Energy Station, Draft Permit No. AP4911-1502

Dear Mr. Kennedy:

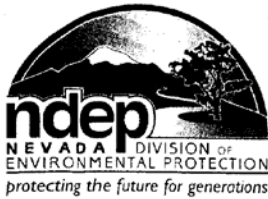
White Pine Energy Associates, LLC ("WPEA") hereby withdraws its application for a Class I Air Quality Operating Permit to Construct associated with the proposed White Pine Energy Station ("WPES"). For reference, Draft Permit No. AP4911-1502 for the WPES and its associated facilities was issued by the Nevada Division of Environmental Protection ("NDEP") in December 2006, and a public hearing regarding the draft permit was held in Ely, Nevada on March 8, 2007.

WPEA would like to extend its thanks and appreciation to NDEP for the time and resources dedicated to the White Pine Energy Station Project. Should you have any questions regarding this request, please contact me at (636) 532-2200. Thank you.

Sincerely,



Mark D. Milburn
Asst. Vice President



STATE OF NEVADA

Department of Conservation & Natural Resources

DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoval, Governor

Leo M. Drozdoff, P.E., Director

Colleen Cripps, Ph.D., Administrator

March 10, 2011

Mr. Mark D. Milburn, Vice-President
White Pine Energy Associates
c/o LS Power Development, LLC
400 Chesterfield Center, Suite 110
St. Louis, MO 63017

**Re: Withdrawal of Application for Class I Air Quality Operating Permit to Construct
White Pine Energy Station, Draft Permit AP4911-1502 (FIN A0586)**

Dear Mr. Milburn:

On February 4, 2011 the Nevada Division of Environmental Protection - Bureau of Air Pollution Control (NDEP-BAPC) received your letter notifying the bureau that White Pine Energy Associates is withdrawing its application for a Class I Air Quality Operating Permit to Construct (OPTC) for the White Pine Energy Station. The NDEP-BAPC issued a draft Class I OPTC for the proposed electrical generating station in December 2006.

Based on your request, the NDEP-BAPC hereby closes the pending application and any further action regarding draft Class I OPTC AP4911-1502. In accordance with Nevada Revised Statute (NRS) 445B.340 and 445B.360, White Pine Energy Associates may appeal the NDEP-BAPC's action within 10 days after you receive this notice of cancellation. Appeals must be filed with the State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada, 89701-5249; please direct your appeal to John Walker, the Executive Secretary for the SEC.

If you have any questions, please call me at 775-687-9495.

Sincerely,

Lawrence Kennedy, P.E.
Permitting Supervisor
Bureau of Air Pollution Control

✓ LK

cc: Tina Gingras, Clark County DAQM
Gerardo Rios, Chief (A-5-1) Permits Office, U.S. EPA Region IX
White Pine County Board of Commissioners
Kathy French, WPEA
Michael Elges, NDEP
Francisco Vega, NDEP
Pat Anderson, NDEP

Certified Mail No. 7008 1140 0004 4030 4008

1.4 NV Energy Withdrawal and NDEP Cancellation of Application for Ely Energy Center



February 10, 2011

Mr. Mike Elges
Nevada Division of Environmental Protection
Bureau of Air Pollution Control
901 South Stewart Street
Carson City, Nevada 89701-5249

Re: Request for Cancellation of Draft Air Permit No. AP4911-2241
Ely Energy Center, Facility ID No. A0381

Dear Mr. Elges:

On behalf of NV Energy, I would like to request that NDEP cancel the air permitting work in progress, including the draft air permit No. AP4911-2241 associated with the Ely Energy Center, Facility ID No. A0381.

The Company greatly appreciates the significant effort undertaken by your Agency to process the Ely Energy Center application to this point, and we look forward to our continued collaboration on future facility development projects.

Sincerely,

A handwritten signature in black ink, appearing to read "Starla Lacy".

Starla Lacy
Executive
Environmental, Health and Safety

P.O. BOX 98910, LAS VEGAS, NEVADA 89151-0001 6226 WEST SAHARA AVENUE, LAS VEGAS, NEVADA 89146
P.O. BOX 10100, RENO, NEVADA 89520-0024 6100 NEIL ROAD, RENO, NEVADA 89511 NVEnergy.com



STATE OF NEVADA

Department of Conservation & Natural Resources

DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoeval, Governor

Leo M. Erezdell, P.E., Director

Colleen Cripps, Ph.D., Administrator

August 1, 2011

Mr Kevin C. Geraghty
Executive, Generation
NV Energy
6226 West Sahara Avenue, M/S 25
Las Vegas, NV 89146

Re: Withdrawal of Application for Class I Air Quality Operating Permit to Construct Ely Energy Station, Draft Permit AP4911-2241 (FIN A0765)

Dear Ms. Lacy:

On February 10, 2011 the Nevada Division of Environmental Protection - Bureau of Air Pollution Control (NDEP-BAPC) received your letter notifying the Bureau that NV Energy is withdrawing its application for a Class I Air Quality Operating Permit to Construct (OPTC) for the Ely Energy Station. The NDEP-BAPC issued a draft Class I OPTC for the proposed electrical generating station in October 2007.

Based on your request, the NDEP-BAPC hereby closes the pending application and any further action regarding draft Class I OPTC AP4911-2241. In accordance with Nevada Revised Statute (NRS) 445B.340 and 445B.360, NV Energy may appeal the NDEP-BAPC's action within 10 days after you receive this notice of cancellation. Appeals must be filed with the State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada, 89701-5249; please direct your appeal to John Walker, the Executive Secretary for the SEC.

If you have any questions, please call me at 775-687-9495.

Sincerely,

Lawrence Kennedy, P.E.
Bureau Chief
Bureau of Air Pollution Control

LK/jcm

cc: Gerardo Rios, Chief (A-5-1) Permits Office, U.S. EPA Region IX
White Pine County Board of Commissioners
E-Copy: Rob Bamford, NDEP
Francisco Vega, NDEP
Pat Anderson, NDEP
Starla Lacy, NV Energy
Omer Shalev, EPA region IX

Certified Mail No. 7008 1140 0004 4030 1458
901 S. Stewart Street, Suite 4001 • Carson City, Nevada 89701 • p: 775.687.4670 • f: 775.687.5856 • ndep.nv.gov

1.5 Cancellation of Copper Mountain Power Application for Natural Gas Plant at Copper Mountain and USEPA Concurrence



DEPARTMENT OF AIR QUALITY & ENVIRONMENTAL MANAGEMENT

500 S Grand Central Parkway 1st Fl • Box 555210 • Las Vegas, NV 89155-2510
(702) 455-5942 • Fax (702) 383-9994

Lewis Wallenmeyer Director • Alan Pinkerton Assistant Director • Tina Giegias Assistant Director

December 1, 2008

Email Address: rjackson@sempraglobal.com

Federal Express #797147825395

Robert Jackson
Copper Mountain Power, LLC
101 Ash Street
San Diego, CA 92101-3017

Re: Copper Mountain Power Source ID# 15347

Dear Mr. Jackson:

Pursuant to Section 12.9.1, Cancellation of an Authority to Construct Certificate, of the Clark County Air Quality Regulations, DAQEM hereby cancels the Authority to Construct permit originally issued to Copper Mountain Power, LLC on May 14, 2004, and reissued on October 31, 2005 to reflect the 12-month extension approved by the Clark County Board of Commissioners.

On June 18, 2007, as part of its May 2007 Construction Status Report, Copper Mountain Power, LLC notified DAQEM that it had temporarily suspended construction activities (no specific date was provided). The last Construction Status Report, received by DAQEM on December 18, 2007, stated Copper Mountain was continuing its construction hiatus. DAQEM has not received any further notifications regarding construction activities associated with this Authority to Construct.

DAQEM has determined that Copper Mountain Power, LLC did not recommence construction within 18-months after it suspended construction activities in May 2007; therefore, resulting in cancellation of this Authority to Construct permit.

Should Copper Mountain Power, LLC intend to construct and operate emission units at this location in the future, a new air quality permit application must be submitted to DAQEM in accordance with New Source Review requirements.

If you have any questions regarding this action, please contact me at (702) 455-1669, or at the address above.

Sincerely,

Richard D. Beckstead
Permitting Manager

CC: Gerardo Rios, EPA Region IX
Catherine Jorgenson – CC District Attorney's Office

BOARD OF COUNTY COMMISSIONERS

Rory Reid Chairman • Chip Madfield Vice-Chairman
Susan Briggs, Tom Collins, Chris Guadagnoli, Lawrence Weekly, Bruce L. Woodbury
Virginia Valentine, PE, County Manager

15 347-0-0-0 2.25.8-2.F-153-N



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IX

76 Hawthorne Street

San Francisco, CA 94105-3501

February 20, 2008

VIA FACSIMILE AND U.S. MAIL

Joan Heredia
Permitting Manager
Copper Mountain Power, LLC
101 Ash Street, HQ08b
San Diego, California 92101-3017

RECEIVED
COPPER MOUNTAIN
FEB 25 P 2 00

Re: Copper Mountain Power Permit Status

Dear Ms. Heredia:

This letter is in response to your letter dated November 1, 2007. Your November 1 letter concerned the status of a permit issued by the Clark County Department of Air Quality and Environmental Management ("DAQEM") to Copper Mountain Power, LLC ("Copper Mountain"). This permit was issued to allow the construction of a 600 MW gas-fired power plant to be located in the El Dorado Valley in Clark County, Nevada ("EDV Facility").

In your November 1 letter, you requested confirmation that the permit issued by DAQEM to Copper Mountain "remains in effect." For the reasons discussed below, we cannot provide such a confirmation.

As discussed in an attachment to your November 1 letter, the permit for the EDV Facility was issued by DAQEM on May 17, 2004, and extended for a 12-month period on October 31, 2005. Pursuant to DAQEM rules, which have been incorporated into the state implementation plan ("SIP") for Nevada, Copper Mountain had to commence construction of the EDV Facility by October 31, 2006, or the permit which allowed the construction would expire.

To commence construction, the DAQEM rules and the SIP require that the holder of the permit allowing construction of an emitting facility initiate physical on-site construction activities of an emission unit which are of a permanent nature. Most of the physical on-site activities at the EDV Facility described in the attachment to your November 1 letter involve earth moving, grading, and compaction. These activities are generally not considered by EPA to be of a permanent nature. The installation of a short fence to keep out desert tortoises is also generally not considered by EPA to be of a permanent nature.

The one activity listed in the attachment to your November 1 letter that might be considered by EPA to be construction activity of a permanent nature is the installation of a foundation for an emission unit. However, for several reasons, EPA would usually not view the single and very small concrete block installed by Copper Mountain as a construction activity of a permanent nature. Generally, for a construction activity viewed by EPA as being permanent in nature, the activity should be substantial and not a token activity. Judging from the picture included with

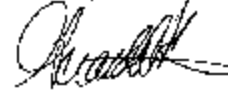
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your November 1 letter, the concrete block created by Copper Mountain is about 4 feet wide, 4 feet tall, and 8 feet long. EPA would usually view this as a token activity.

In addition, rather than supporting an ongoing emission unit, this small concrete block is described as a foundation for an "Emergency Diesel Engine for Fire Water Pump." The emissions from this unit will almost certainly be limited to occasional testing and maintenance, and any actual fire emergency. EPA generally views such emissions as de minimis and not sufficient for commencement of construction of an emission unit at a facility. Had Copper Mountain immediately followed up the installation of this small concrete block with the installation of full foundations for the primary emission units at the EDV Facility, EPA may have deemed the installation of the small concrete block to mark the point at which Copper Mountain commenced construction. However, these are not the facts in this case.

Since EPA would generally not view your activities up to October 31, 2006, as sufficient to commence construction of the EDV Facility, we cannot confirm that the permit issued by DAQEM to Copper Mountain for the construction of the EDV Facility remains in effect. If you have any questions regarding this letter, please call me at 415-972-3974, or have your attorney call Allan Zahel, Office of Regional Counsel, at 415-972-3902.

Sincerely,



Gerardo Rios
Chief, Permits Office

cc: Richard Bockstead, DAQEM

1.6 Toquop Energy, LLC Withdrawal of Application for Toquop Project

ANDREW MACKENZIE
MIKE PAVLAKIS
JOAN C. WRIGHT
PATRICK V. FAGAN
KAREN A. PETERSON
JAMES R. CAVILIA
CHRIS MACKENZIE
DAWN ELLERBROCK
RYAN D. RUSSELL



ALLISON · MACKENZIE
PAVLAKIS · WRIGHT & FAGAN
LTD
ATTORNEYS AND COUNSELORS AT LAW

Larry K.
FYI

JENNIFER M. MAHE
ALICIA G. JOHNSON
JOEL W. LOCKE

MIKE SOUMBENIOTIS
(1932-1997)

GEORGE V. ALLISON
OF COUNSEL

March 9, 2012

RECEIVED

MAR 12 2012

Nevada
Environmental Protection

ENVIRONMENTAL PROTECTION

MAR 13 2012

BAPC/BAQP

Breanne Potter
Assistant Commission Secretary
Public Utilities Commission
1150 East William Street
Carson City, Nevada 89701-3190

RE: Docket No. 07-08020 - Application of Toquop Energy, LLC
For a Construction Permit Pursuant to the Utility Environmental
Protection Act [FIN 40381, 4911-1146]

Dear Ms. Potter:

On behalf of Toquop Energy, LLC ("Toquop"), on August 20, 2007 I filed with the Public Utilities Commission of Nevada ("Commission") an Application for a Permit to Construct Utility Facilities ("UEPA"). The Commission designated the filing as Docket No. 07-08020. The Application was the initial Application of Toquop filed pursuant to NRS 704.870(2)(a). The Application has been pending since the day of its filing to the current date with no action being taken before the Commission.

Toquop has determined that it will no longer pursue the Toquop energy project as described in the UEPA application filed with the Commission. Therefore, Toquop hereby withdraws the application for a permit to construct utility facilities at this time.

If you have comments or questions, please advise.

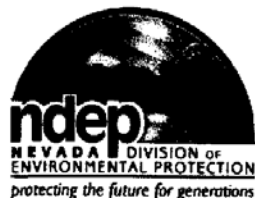
ALLISON, MacKENZIE, PAVLAKIS,
WRIGHT & FAGAN, LTD.

By Patrick V. Fagan
PATRICK V. FAGAN, ESQ.

cc: Nevada State Clearing House
Dept. Of conservation and National Resources
Nevada Division of Environmental Protection
State Environmental Commission
Lincoln County Clerk
Nevada Office of the Attorney General
Diana Genasci, Esq.
Mark Harris, P.E.
Louise Uttinger, Esq.
Alaina Burtenshaw, Esq.
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1.7 NDEP/PUCN Comments to USEPA Re Proposed Rule to Reduce Carbon Pollution from Existing Power Plants, December 9, 2013



STATE OF NEVADA

Department of Conservation & Natural Resources

DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoval, Governor

Leo M. Drozdoff, P.E., Director

Colleen Cripps, Ph.D., Administrator

December 9, 2013

Mr. Jared Blumenfeld
Regional Administrator
OAR-1, USEPA Region IX
75 Hawthorne Street
San Francisco, CA 94105

RE: Nevada Comments on USEPA's "Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants," September 23, 2013

Dear Mr. Blumenfeld:

The Nevada Division of Environmental Protection (NDEP), in consultation with the Public Utilities Commission of Nevada, thanks you for the opportunity to comment on the set of questions circulated by the U.S. Environmental Protection Agency (USEPA) regarding the consideration of potential design of a program under section 111(d) for existing power plants. The comments are organized by the questions posed in USEPA's September 23, 2013 document titled: *Considerations in the Design of a Program to Reduce Carbon Pollution from Existing Power Plants*.

1. What is your experience with programs that reduce CO₂ emissions in the electric power sector?

Questions for further discussion

- *What actions are states, utilities, and power plants taking today that reduce CO₂ emissions from the electric power system? How might these be relevant under section 111(d)?*
- *What systems do states and power plants have in place to measure and verify CO₂ emissions and reductions?*
- *How do state programs and measures affect electricity generation and emissions at a regional level? How are interstate effects accounted for when measuring the progress of a state program? For example, are the multi-state effects of state renewable portfolio standards, end-use energy efficiency resource standards, emissions performance standards, and emissions budget trading programs currently accounted for by the state, and if so, how?*

a. The Nevada Division of Environmental Protection, Bureau of Air Quality Planning (NDEP-BAQP), is aware of several programs in which the State of Nevada and its major electric public utilities, Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy, are taking steps to reduce CO₂ emissions, including the following:

1. Nevada was one of the first states to adopt a renewable portfolio standard. The renewable portfolio standard currently requires the utility to generate, acquire or save 25% of its electricity sold to customers from portfolio energy systems or efficiency measures by 2025.¹

¹ NRS 704.7821 provides, in relevant part:

1. For each provider of electric service, the Commission shall establish a portfolio standard. The portfolio standard must require each provider to generate, acquire or save electricity from portfolio energy systems or efficiency measures in an amount that is:

(a) For calendar years 2005 and 2006, not less than 6 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(b) For calendar years 2007 and 2008, not less than 9 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(c) For calendar years 2009 and 2010, not less than 12 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(d) For calendar years 2011 and 2012, not less than 15 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(e) For calendar years 2013 and 2014, not less than 18 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(f) For calendar years 2015 through 2019, inclusive, not less than 20 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(g) For calendar years 2020 through 2024, inclusive, not less than 22 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

(h) For calendar year 2025 and for each calendar year thereafter, not less than 25 percent of the total amount of electricity sold by the provider to its retail customers in this State during that calendar year.

2. In addition to the requirements set forth in subsection 1, the portfolio standard for each provider must require that:

(a) Of the total amount of electricity that the provider is required to generate, acquire or save from portfolio energy systems or efficiency measures during each calendar year, not less than:

(1) For calendar years 2009 through 2015, inclusive, 5 percent of that amount must be generated or acquired from solar renewable energy systems.

(2) For calendar year 2016 and for each calendar year thereafter, 6 percent of that amount must be generated or acquired from solar renewable energy systems.

(b) Of the total amount of electricity that the provider is required to generate, acquire or save from portfolio energy systems or efficiency measures:

(1) During calendar years 2013 and 2014, not more than 25 percent of that amount may be based on energy efficiency measures;

(2) During each calendar year 2015 to 2019, inclusive, not more than 20 percent of that amount may be based on energy efficiency measures;

(3) During each calendar year 2020 to 2024, inclusive, not more than 10 percent of that amount may be based on energy efficiency measures; and

2. The Nevada Legislature recently enacted SB 123, which requires the retirement of 850 megawatts (MW) of coal fired power plants in Nevada.²

(4) For calendar year 2025 and each calendar year thereafter, no portion of that amount may be based on energy efficiency measures.

➔ If the provider intends to use energy efficiency measures to comply with its portfolio standard during any calendar year, of the total amount of electricity saved from energy efficiency measures for which the provider seeks to obtain portfolio energy credits pursuant to this paragraph, at least 50 percent of that amount must be saved from energy efficiency measures installed at service locations of residential customers of the provider, unless a different percentage is approved by the Commission.

² NRS 704.7316 provides:

1. An electric utility shall file with the Commission, as part of the plan required to be submitted pursuant to NRS 704.741, a comprehensive plan for the reduction of emissions from coal-fired electric generating plants and the replacement of the capacity of such plants with increased capacity from renewable energy facilities and other electric generating plants.

2. The emissions reduction and capacity replacement plan must provide:

(a) For the retirement or elimination of:

(1) Not less than 300 megawatts of coal-fired electric generating capacity on or before December 31, 2014;

(2) In addition to the generating capacity retired or eliminated pursuant to subparagraph (1), not less than 250 megawatts of coal-fired electric generating capacity on or before December 31, 2017; and

(3) In addition to the generating capacity retired or eliminated pursuant to subparagraphs (1) and (2), not less than 250 megawatts of coal-fired electric generating capacity on or before December 31, 2019.

➔ For the purposes of this paragraph, the generating capacity of a coal-fired electric generating plant must be determined by reference to the most recent resource plan filed by the electric utility pursuant to NRS 704.741 and accepted by the Commission pursuant to NRS 704.751.

(b) For the construction or acquisition of, or contracting for, 350 megawatts of electric generating capacity from renewable energy facilities. The electric utility shall:

(1) Issue a request for proposals for 100 megawatts of electric generating capacity from new renewable energy facilities on or before December 31, 2014;

(2) In addition to the request for proposals issued pursuant to subparagraph (1), issue a request for proposals for 100 megawatts of electric generating capacity from new renewable energy facilities on or before December 31, 2015;

(3) In addition to the requests for proposals issued pursuant to subparagraphs (1) and (2), issue a request for proposals for 100 megawatts of electric generating capacity from new renewable energy facilities on or before December 31, 2016;

(4) Review each proposal received pursuant to subparagraphs (1), (2) and (3) and identify those renewable energy facilities that will provide:

(I) The greatest economic benefit to this State;

(II) The greatest opportunity for the creation of new jobs in this State; and

(III) The best value to customers of the electric utility;

(5) Negotiate, in good faith, to construct, acquire or contract with the renewable energy facilities identified pursuant to subparagraph (4), and file with the Commission an amendment to the plan each time the utility wishes to construct, acquire or contract with such facilities; and

(6) Begin, on or before December 31, 2017, the construction or acquisition of a portion of new renewable energy facilities with a generating capacity of 50 megawatts to be owned and operated by the electric utility, and complete construction of such facilities on or before December 31, 2021.

3. The Nevada Legislature enacted the Solar Energy Systems Incentive Program, which requires the Public Utilities Commission of Nevada to set incentive levels and schedules, with a goal of approving solar energy systems totaling at least 250,000 kilowatts of capacity in this State for the period beginning on July 1, 2010, and ending on December 31, 2021. NRS 701B.005 and 701B.010-701B.290. To date, \$160 million has been spent installing a total of 38 MWs of installed capacity in Nevada.
4. Similarly, Nevada has a Solar Thermal Demonstrations Program, which has the goal of promoting the installation of at least 3,000 solar thermal systems in homes, businesses, schools and other governmental buildings throughout this State by 2019. NRS 701B.300-701B.345.
5. The Wind Energy Systems Demonstration Program Act establishes a goal of installing at least 5 MW of wind energy systems by 2012. NRS 701B.400-.650. To date, \$25 million has been spent installing a total of 9 MWs of installed capacity in Nevada.
6. The Waterpower Systems Demonstration Program Act similarly provides for the installation of at least 5 MW of waterpower energy systems in this State by 2016.

➤For the purposes of this paragraph, the generating capacity of a renewable energy facility must be determined by the nameplate capacity of the facility.

(c) For the electric utility to construct or acquire and own electric generating plants with an electric generating capacity of 550 megawatts, which must be constructed or acquired to replace, in an orderly and structured manner, the coal-fired electric generating capacity retired or eliminated pursuant to paragraph (a).

(d) If the plan includes the construction or acquisition of one or more natural gas-fired electric generating plants, a strategy for the commercially reasonable physical procurement of fixed-price natural gas by the electric utility.

(e) A plan for tracking and specifying the accounting treatment for all costs associated with the decommissioning of the coal-fired electric generating plants identified for retirement or elimination.

➤For the purposes of this subsection, an electric utility shall be deemed to own, acquire, retire or eliminate only its pro rata portion of any electric generating facility that is not wholly owned by the electric utility and, except as otherwise provided in paragraph (b), "capacity" means an amount of firm electric generating capacity used by the electric utility for the purpose of preparing a plan filed with the Commission pursuant to NRS 704.736 to 704.754, inclusive.

3. In addition to the requirements for an emissions reduction and capacity replacement plan set forth in subsection 2, the plan may include additional utility facilities, electric generating plants, elements or programs necessary to carry out the plan, including, without limitation:

(a) The construction of natural gas pipelines necessary for the operation of any new natural gas-fired electric generating plants included in the plan;

(b) Entering into contracts for the transportation of natural gas necessary for the operation of any natural gas-fired electric generating plants included in the plan; and

(c) The construction of transmission lines and related infrastructure necessary for the operation or interconnection of any electric generating plants included in the plan.

(Added to NRS by 2013, 3074)

NRS 701B.700-701B.880. To date, \$1.4 million has been spent installing a total of 600 kW of installed capacity in the State.

7. In addition, the Mohave Generating Station, the largest electrical generating station in Nevada, was decommissioned in 2010.

b. Facilities that emit 25,000 metric tons or more per year of GHGs are required to annually report their emissions to EPA's Greenhouse Gas Reporting Program. That includes nearly all of NV Energy's generation facilities in Nevada.

c. The Public Utilities Commission of Nevada has authorized the largest electric and gas utilities serving nearly 95% of the population in the State to expend substantial monies to implement various demand side management (energy efficiency) programs as follows:

1. Nevada Power Company d/b/a NV Energy--\$44,550,000 (2013).
2. Sierra Pacific Power Company d/b/a NV Energy--\$6,100,000 (2013/electric).
3. Sierra Pacific Power Company d/b/a NV Energy--\$445,000 (2014/gas).
4. Southwest Gas Corporation--\$4,400,000 (2014).

2. How should EPA set the performance standard for state 111(d) plans?

Questions for further discussion

- Which approaches to reducing CO₂ emissions from power plants should be included in the evaluation of the "best system of emission reduction" that is used to determine the performance level(s) that state plans must achieve? Should the reduction requirement be source- or system-based?
- How does the amount of flexibility that states are given to include different types of programs in their state plans relate to the "best system of emissions reduction" that is used to set the performance bar for state plans? For example, if state standards to improve end-use energy efficiency were included in state plans, should EPA consider potential improvements in end-use energy efficiency in setting the performance target for states?
- What should be the form and specificity of the performance level(s) in EPA guidelines? (Rate-based or mass-based? Separate levels for each subcategory of sources, or one level for the covered sources in the state? A uniform national level, or different levels by state/region based on an established evaluation process?)
- When can emission reductions from existing power plants be achieved, considering different reduction strategies?
- How should a state, in applying a standard of performance to any particular source, consider a facility's "remaining useful life" and other factors?

a. The NDEP-BAQP believes that "best system of emission reduction" should be defined as broadly as possible to allow states as much flexibility as possible. States are currently

in the slow process of recovering from the economic downturn, and Nevada was one of the hardest hit states. The cost of energy is a key factor in promoting recovery. Therefore, to ensure that Nevada can maintain its energy prices at a reasonable level and to avoid sudden spikes in price, it is imperative that maximum flexibility be provided to the State in effectuating GHG reductions. Source-based reduction requirements will be less flexible, and facilities are already subject to significant source-based requirements to install additional control technologies, such as the Regional Haze Rule. System-based reduction programs will allow for more flexibility and might have the added benefit of encouraging states to work cooperatively to achieve reductions on a regional scale.

b. As set forth above, states should be granted maximum flexibility in employing the tools that will allow them to achieve meaningful GHG reductions over time. Demand-side management programs should be considered as part of the arsenal of tools available to states and improvements in energy efficiencies should be taken into account in setting performance targets. That being said, however, it is important that USEPA establish a reasonable baseline from which reductions and improvements in energy efficiencies should be measured. For example, 2005 would be a reasonable base year from which to establish a baseline because it will take into account the economic downturn, the economic recovery, and early measures that states have taken to independently reduce GHG emissions. States that have actively sought to reduce GHGs through implementation of legislation and regulations should not be penalized for their progressive efforts to reduce GHG emissions to date.

c. The establishment of performance levels should be guided by the same principle of providing as much flexibility as possible to states to achieve those levels. One uniform national standard would likely be too rigid. Each state is faced with its own unique challenges in meeting its energy needs and providing transmission from generation facilities to consumers. In Nevada, for example, creating transmission for natural gas has been and will continue to be a challenge given certain Endangered Species Act obstacles that have arisen. On the other hand, Nevada is uniquely situated to be able to take advantage of geothermal and solar opportunities that are not available to other states. Whatever performance standard is set must take into account such variability and allow states to utilize their unique characteristics in order to meet it.

d. The date by which emission reductions can be achieved will depend largely upon the baseline that USEPA sets from which reductions are measured. As stated previously, the baseline should not be set so as to penalize states for progressive efforts to reduce GHG emissions.

e. The remaining useful life of an EGU should be taken into account in applying a performance standard because it is required by the Clean Air Act. While not necessarily a control technology, the remaining useful life of a facility is a pragmatic concern that will dictate when emissions will ultimately cease from that facility. States should be allowed to take credit for such emission reductions, especially because units taking the place of EGUs being retired will be subject to the NSPS for new generation facilities.

3. What requirements should state plans meet and what flexibility should be provided to states in developing their plans?

Questions for further discussion

- *What level of flexibility should be provided to states in meeting the required level of performance for affected EGUs contained in the emission guidelines?*
- *Can a state plan include requirements that apply to entities other than the affected EGUs? For example, must states place all of the responsibility to meet the emission performance requirements on the owners or operators of affected EGUs, or do states have flexibility to take on some (or all) of the responsibility to achieve the required level of emissions performance themselves or assign it to others (e.g., to require an increase in the use of renewable energy or require end-use energy efficiency improvements, which will result in emissions reductions from affected EGUs)?*
- *What components should a state plan have, and what should be the criteria for approvability?*
- *Can a state plan include programs that rely on a different mix of emission reduction methods than assumed in EPA's analysis of the "best system of emission reduction" that is used to set the performance standard for state plans?*
- *What should be the process for demonstrating that a state plan will achieve a level of emissions performance comparable to the level of performance in the EPA emission guidelines?*
- *What enforceability, measurement, and verification issues might arise, depending on the types of state measures and programs that states include in their plans? For example, what issues are raised by actions that have indirect effects on EGU emissions, such as end-use energy efficiency resource standards, renewable portfolio standards, financial assistance programs to encourage end-use energy efficiency, building energy codes, etc.)?*
- *Do different CO₂ reduction methods under different state plan approaches necessitate different timelines for the achievement of emission reductions?*
- *What issues arise from the fact that operation and planning of the electricity system is often regional, but CAA section 111(d) calls for state plans? How should interstate issues be addressed, where actions in one state may affect EGU emissions in another state? For example, where actions have interstate impacts, which state would receive credit for the emission reductions in its state plan? Could EPA provide for coordinated submittal of state plans that demonstrate performance on a regional basis?*

a. Because no two states are alike, maximum flexibility should be afforded to each state to utilize various tools and methodologies that meet GHG emission reductions requirements while taking into account the unique circumstances of the state's energy infrastructure and economy. The unique circumstances of each state may necessitate different timelines by which the state may meet the performance standards.

b. In Nevada, it would be incorrect to state that all of the responsibility for meeting the performance standards could be placed on the EGUs. For example, the public utility which operates a significant portion of the EGUs in Nevada is subject to oversight by the Public Utilities Commission of Nevada. The public utility can only take the measures that are approved in its triennial resource plan, which may only be approved after taking into account the effect of such measures on ratepayers. The State Legislature, however, has the authority to require increased renewable energy usage. In fact, the Nevada Legislature has been proactive in mandating an aggressive renewable portfolio standard, and Nevada should be able to take credit for such forward-looking action in a 111(d) plan.

c. It is difficult to define what components a state plan should have at this point in time, without the benefit of understanding how USEPA will define “best system of emission reduction” under the Clean Air Act. States should have maximum flexibility to address reductions in their plans, including standards of performance that provide for “less stringent standards or longer compliance schedules” pursuant to the criteria set forth in 40 CFR § 60.24(f). In addition, states have the right to use flexible compliance mechanisms when they “tak[e] into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements” as provided in the definition of “standard of performance” under CAA § 111(a)(1). A list of possible flexible compliance mechanisms could include, but is not limited, to mechanisms such as exemptions for reliability relief due to natural disasters; for commitments to retire the EGU within a specified time frame; for units smaller than a specified number of megawatts; for simple-cycle combustion turbines and limited-use units; for start-up, shutdown and malfunctions.

In addition, unit-specific approaches could include multi-year averaging; credit for natural gas co-firing or fuel switching, co-firing biomass fuels, cogeneration processes, and solar thermal energy to improve operation and efficiency. Carbon sequestration in Nevada is probably not viable at this time given Nevada’s geology.

Averaging measures could also be employed. These might include averaging of coal units, averaging of coal units with lower emitting sources, and/or averaging of intracompany units that may lie both within and outside of a state.

Trading of carbon dioxide credits should be considered. EGUs should be allowed to receive credits for early utility actions that reduced GHG emissions and/or for offsite reductions, such as landfill methane or sulfur hexafluoride from operations.

Demand side management programs and energy efficiency programs should also be allowed as part of the state’s plan. In addition, USEPA should consider utility-sponsored management of forested areas and biomass for avoided emissions and GHG storage.

Finally, states should receive credit for other Clean Air Act programs, such as regional haze, that have a co-benefit of reducing GHGs.

4. What can EPA do to facilitate state plan development and implementation?

Questions for further discussion

- *What types and amount of guidance and implementation support should be provided to states?*
- *Are there benefits for coordination among neighboring states in the development and submittal of state plans? Should EPA facilitate the coordination of multi-state plan submittals?*
- *Would certain types of measures that might be included in state plans increase the need for coordination among states?*
- *Are there model rules that EPA could develop that would assist states, and what would those rules cover?*

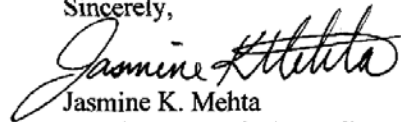
USEPA has made clear that guidance is nonbinding. For clarity and to allow maximum participation by stakeholders, implementation support should be done by rulemaking rather than guidance.

GHG emission reductions may take place on a regional basis, such as cap-and-trade programs. Planning might also require detailed modeling and data analysis on a regional scale, similar to what was done for the Regional Haze program. It might be helpful for USEPA to facilitate coordination of multi-state plan submittals.

Regional electric reliability issues resulting from any such programs should also be coordinated with the Federal Energy Regulatory Commission.

The NDEP appreciates the opportunity to be involved in USEPA's development of a GHG program for existing power plants under section 111(d). If you have any questions about the NDEP's comments or require additional clarification, feel free to contact me at (775) 687-9495.

Sincerely,



Jasmine K. Mehta
Chief, Bureau of Air Quality Planning

cc: Deborah Jordan, Director, EPA R9 Air Division
Amy Zimpfer, Associate Director, EPA R9 Air Division
David Noble, Commissioner, Nevada Public Utilities Commission
ec: Colleen Cripps, Administrator, Nevada Division of Environmental Protection
Rob Bamford, Chief, Bureau of Air Pollution Control

1.8 NV Energy Letter to Jasmine Mehta, NDEP, June 5, 2014



June 5, 2014

Ms. Jasmine Mehta
Bureau Chief, Air Quality Planning
Nevada Division of Environmental Protection
901 S. Stewart St., Ste 4001
Carson City NV 89701

Dear Ms. Mehta:

To assist your staff in finalizing the Agency's Status Update Report associated with Nevada's Regional Haze Plan, I would like to provide you with some additional information regarding NV Energy's BART eligible sources.

Our Fort Churchill facility holds a Title V air permit which allows dual fuel (natural gas and No. 6 fuel oil) firing capability. However, it is important to note from an emissions perspective that Fort Churchill has been operating on natural gas only since 2007. Further, the fuel oil piping associated with both Fort Churchill Units 1 and 2 was dismantled in the spring of 2014 in preparation for scheduled BART retrofits on those units. As you are aware, we made a request to the Public Utility Commission of Nevada in order to remove dual fuel oil capability at both Fort Churchill Units 1 and 2 as well as Tracy Unit 3 associated with our plans for BART compliance. We also asked for, and were granted, retirement of the BART eligible Tracy Units 1 and 2. We further note that our Tracy Generating Station Units 1 and 2 did not operate during the period 2010-2012.

Your staff noted what appeared to be an increase in emissions for both facilities around the 2001 time frame. Looking into our historical records, it appears that both Fort Churchill and Tracy combusted significant amounts of residual fuel oil during that time frame in response to the energy crisis as well as in response to higher natural gas prices. As well, Tracy Units 1, 2 and 3 and both Fort Churchill units ran a significant number of hours during that same time frame.

Lastly, NV Energy filed an Emission Reduction and Capacity Replacement (ERCR) Plan, as required by Senate Bill 123, on May 1, 2014. The ERCR docket is No. 14-05003. In that filing we are asking the Public Utilities Commission for several items, including permission to retire the BART eligible Reid Gardner units 1, 2 & 3 by December 31, 2014 and to retire non-BART eligible Reid Gardner Unit 4 by December 31, 2017. We anticipate the Commission decision on that request to be available at the end of October.

P.O. BOX 98910, LAS VEGAS, NEVADA 89151-0001 6226 WEST SAHARA AVENUE, LAS VEGAS, NEVADA 89146
P.O. BOX 10100, RENO, NEVADA 89520-0024 6100 NEIL ROAD, RENO, NEVADA 89511 nvenergy.com

Please let me know if there is any other information that we can provide to assist your staff in preparation of their report.

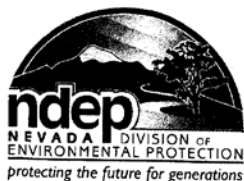
Sincerely,

A handwritten signature in black ink, appearing to read 'Starla Lacy', with a stylized, cursive script.

Starla Lacy
Vice President, Environmental, Health, and Safety

2 NDEP FINDINGS AND ORDERS

2.1 April 25, 2013 NDEP Approval of Proposed Alternative BART Control Technology for Certain EGUs at Fort Churchill and Tracy Power Plants



STATE OF NEVADA
Department of Conservation & Natural Resources
DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoval, Governor
Leo M. Drozdoff, P.E., Director
Colleen Cripps, Ph.D., Administrator

April 25, 2013

Ms. Starla Lacy
Executive, Environmental, Health and Safety
NV Energy
6226 West Sahara Ave.
Box 89710
Las Vegas, NV 89151-0001

Re: Approval of Proposed Alternative BART Control Technology for Specific EGUs at Fort Churchill (FIN #A0028) and Tracy (FIN #A0029).

Dear Ms. Lacy,

By your letters dated December 20, 2012, and February 19, 2013, NV Energy (NVE) requests that the Nevada Division of Environmental Protection – Bureaus of Air Quality (NDEP-BAQ) approve alternatives to certain required Best Available Retrofit Technology (BART) controls under the Regional Haze Rule for Fort Churchill (Churchill) Units #1 and #2 and Tracy Unit #3.

Pursuant to the Regional Haze Rule, BART means “an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant, which is emitted by an existing stationary facility.” (40 CFR §51.301).

The BART control technologies and emission limits under the Regional Haze Rule for the Churchill and Tracy units are defined and mandated under Nevada’s federally approved Applicable State Implementation Plan (ASIP) (40 CFR §51.308) and under Nevada Administrative Code (NAC) (445B.22096.1(a)&(b)).

Furthermore, NAC 445B.22096.2 provides that an approved BART control “may be replaced or supplemented with alternative technologies approved in advance by the [NDEP] Director, provided that the [BART] emissions limits...are [continuously] met.”



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When the BART control technology was initially determined for the applicable Fort Churchill and Tracy BART units in 2009, the units were configured to combust natural gas, No. 2 fuel oil, or both. As No. 2 fuel oil has more pollutant emissions than natural gas, the initial BART controls were more focused toward cleaning the “dirtier” emissions profile of the No. 2 fuel oil. Since the initial BART control determination, Churchill and Tracy have transitioned to exclusively combust natural gas as part of a comprehensive air pollution reduction strategy for various Federal and State air quality standards. As part of this transition, NVE performed engineering re-evaluations of its dual fuel-designed BART controls under a natural gas only configuration. The engineering evaluations concluded that it would be prudent to adjust the BART control technologies in response to the change in the emissions profile. NVE is not requesting a revision to the BART emission limits.

For Churchill Units #1 and #2, NVE proposes to replace the BART controls consisting of Flue Gas Recirculation, low NOx burners and the option to combust No. 2 fuel oil (NAC 445B.22096.1(a)) with alternative BART controls of low NOx burners and the combustion of only natural gas. NVE also proposes the option to construct if necessary, and to operate as necessary, an Over Fired Air system as a control supplement to the low NOx burners, to continuously comply with the applicable BART emission limits.

For Tracy Unit #3, NVE proposes to replace the BART controls consisting of Selective Non-Catalytic Reduction, low NOx burners and the option to combust No. 2 fuel oil (NAC 445B.22096.1(b)) with alternative BART controls of a low NOx burner and the combustion of only natural gas. NVE proposes that the existing or new, Over Fired Air Controls shall be operated if necessary, as a supplement to the low NOx burners, to continuously comply with the applicable BART emission limit.

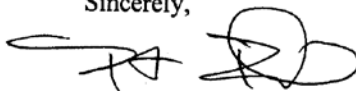
In review of NVE’s request to replace existing BART emission controls with alternative emission controls and as-needed supplemental controls, the NDEP-BAQ concludes:

- “BART” is an emission limitation as defined by Federal and State regulation;
- Nevada’s federally approved SIP provisions for the Regional Haze Rule and NAC 445B.22096.2 provide that BART control measures may be replaced or supplemented provided that BART emission limits are continuously met;
- That as an emission control measure BART-applicable Fort Churchill and Tracy units shall discontinue the combustion of fuel oil and only pipeline quality natural gas shall be combusted;
- That by removing the combustion of fuel oil in BART applicable Fort Churchill and Tracy units, the potential emissions profile of those units will change to emit less PM₁₀, SO₂ and NO_x;

- That because the pollutant profile will be altered by not combusting No 2. fuel oil, NVE subsequently requests alternative BART emissions controls and supplemental controls, as allowed by law under the ASIP and NAC; The proposed BART alternative controls are industry standard controls for the pollutants targeted at the performance level required by the BART emission limits; and
- The proposed BART technology must demonstrate compliance with the BART emission limits by mandatory compliance demonstrations. If the proposed alternative BART control technology cannot achieve the required BART emission limit it shall immediately be revised to a control technology that can continuously comply with the BART emission limit.

Therefore, the NDEP-BAQ hereby grants approval of the proposed replacement and supplemental BART control measures proposed by NVE herein and pursuant to Notice of Findings and Order 2013-06 with issuance date April 25, 2013.

Sincerely,



Rob Bamford
Chief, Bureau of Air Pollution Control
Nevada Division of Environmental Protection

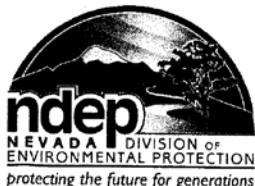
ECC: Starla Lacy, NVE Executive, Environmental Health and Safety

CC: Files (FIN A0028 & A0029)
Francisco Vega, NDEP
Jeffrey Kinder, NDEP

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2.2 April 25, 2013 NDEP Notice of Findings and Order No. 2013-06



STATE OF NEVADA

Department of Conservation & Natural Resources
DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoval, Governor

Leo M. Drozdoff, P.E., Director

Colleen Cripps, Ph.D., Administrator

April 25, 2013

Ms. Starla Lacy
Executive, Environmental, Health and Safety
NV Energy
6226 West Sahara Ave.
Box 89710
Las Vegas, NV 89151-0001

Re: NOTICE OF FINDINGS AND ORDER NO. 2013-06:
Installation of Approved Alternative BART Control Technology for Specific EGUs at Fort Churchill (FIN #A0028) and Tracy (FIN #A0029).

Dear Ms. Lacy,

SIERRA PACIFIC POWER COMPANY dba NV ENERGY operates two electrical generation facilities in Storey and Lyon Counties, Nevada: the Tracy Generating Station (Tracy) and the Fort Churchill Generating Station (Fort Churchill) respectively. Tracy is located at Interstate I-80 East, Exit 32 near the town of Sparks and Fort Churchill is located at 1000 Sierra Way near the town of Yerington. Tracy currently operates under the Class 1 Air Quality Operating Permit # AP4911-0194.01 and Fort Churchill currently operates under the Class 1 Air Quality Operating Permit # AP4911-0091.03.

On April 25, 2013 the Director of the Nevada Division of Environmental Protection (NDEP) approved the proposed alternative equivalent BART emission control technologies for the Tracy and Fort Churchill units, as stated in the enclosed Findings and Order No. 2013-06. Pursuant to Nevada's SIP, SIERRA PACIFIC POWER COMPANY dba NV ENERGY must install the approved alternative BART emissions control technology and operate in compliance with the BART emissions limits on or before January 1, 2015 at Tracy and Fort Churchill. The Nevada Division of Environmental Protection, Bureau of Air Pollution Control (NDEP/BAPC) is issuing Order No. 2013-06, enclosed, to SIERRA PACIFIC POWER COMPANY dba NV ENERGY to install the approved alternative BART emissions control technology.



901 S. Stewart Street, Suite 4001 • Carson City, Nevada 89701 • p: 775.687.4670 • f: 775.687.5856 • ndep.nv.gov

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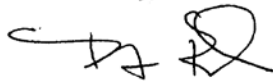
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Ms. Starla Lacey
April 25, 2013
Page 2

Notice of Findings and Order No. 2013-06 has been prepared pursuant to Nevada Revised Statute (NRS) 445B.230 and NRS 445B.450. An appeal of Order No. 2013-06 may be requested pursuant to Nevada Revised Statute 445B.360 and the State Environmental Commission's (SEC) administrative rules. Appeals must be received within 10 days of receipt of this notice, pursuant to NRS 445B.340; SEC Appeal Form #3 is enclosed. Appeals are processed through John Walker, the Executive Secretary for the SEC, at 901 South Stewart Street, Suite 4001, Carson City, Nevada, 89701-5249. Mr. Walker can be reached at (775) 687-9308, or by fax at (775) 687-5856. Please provide me with a copy of any correspondence your company may have with the SEC.

If you have any questions about Order No. 2013-06, please contact me at (775) 687-9330.

Sincerely,



Rob Bamford
Chief
Bureau of Air Pollution Control

Enclosures: 1. Notice of Findings and Order No. 2013-06
2. SEC Appeal Form #3

cc (w/ enc. 1): John Walker, Nevada SEC
Files (FIN A0028 & A0029)
Francisco Vega, NDEP
Jeffrey Kinder, NDEP

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IN THE MATTER OF:

SIERRA PACIFIC POWER COMPANY, DBA
NV ENERGY:

TRACY GENERATING STATION IN
STOREY COUNTY (FIN #A0029) AND

FORT CHURCHILL GENERATING
STATION, LYON COUNTY (FIN #A0028).

NOTICE OF FINDINGS
AND ORDER NO. 2013-06

FINDINGS

1. SIERRA PACIFIC POWER COMPANY dba NV ENERGY operates two electrical generation facilities in Storey and Lyon Counties, Nevada: the Tracy Generating Station (Tracy) and the Fort Churchill Generating Station (Fort Churchill) respectively. Tracy is located at Interstate I-80 East, Exit 32 near the town of Sparks and Fort Churchill is located at 1000 Sierra Way near the town of Yerington.
2. Tracy currently operates under the Class 1 Air Quality Operating Permit # AP4911-0194.01 and Fort Churchill currently operates under the Class 1 Air Quality Operating Permit # AP4911-0091.03.
3. On July 1, 1999, the Regional Haze Rule was promulgated by the US EPA under authority of the Clean Air Act. The intent of the Regional Haze Rule is to improve visibility over a period of 60 years in Class I areas across the country. A key component of the Regional Haze Rule is the requirement to install and operate the best available retrofit technology (BART) for qualifying older, existing sources of visibility impairing pollutants.
4. BART requirements apply to sources at facilities built between 1962 and 1977 that have the potential to emit more than 250 tons a year of visibility-impairing pollution. Those facilities fall into 26 categories, including utility boilers. Boilers at the Tracy and Fort Churchill facilities meet the construction date and pollution thresholds required for BART applicability.
5. Three electrical generation boilers at Tracy are BART eligible sources: units #1-3, and two electrical generation boilers at Fort Churchill are BART eligible sources: units #1-2. As currently permitted, these units may combust pipeline quality natural gas, or fuel oil, or natural gas and fuel oil.
6. Pursuant to the regional haze rule, BART means "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant, which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such

technology" (40 CFR §51.301).

7. Pursuant to the Federal Regional Haze Rule, SIERRA PACIFIC POWER COMPANY dba NV ENERGY submitted detailed BART analyses for the applicable electrical generation boilers proposing BART control technologies and BART emission limits. The NDEP performed an independent review of the SIERRA PACIFIC POWER COMPANY dba NV ENERGY BART analyses and then submitted them to US EPA on November 18, 2009 as part of a State Implementation Plan (SIP) submittal for the Federal Regional Haze program.
8. The Nevada Regional Haze State Implementation Plan (RH SIP) was partially approved in the Federal Register dated March 26, 2012, and again partially approved in the Federal Register dated August 23, 2012. The RH SIP requires SIERRA PACIFIC POWER COMPANY dba NV ENERGY to meet BART emission limits on nitrogen oxides (NO_x), sulfur dioxide (SO₂), and particulate matter less than 10 microns (PM₁₀) for electrical generation boilers at Tracy and Fort Churchill by January 1, 2015 and specifies emission controls to be installed for this purpose.
 - A. The specific BART requirements for electrical generation boilers at Tracy are:
 - The combustion of pipeline quality natural gas and/or No. 2 fuel oil for SO₂ and PM₁₀ control;
 - SO₂ emission limit of 0.05 lb/MMBtu (24-hour average);
 - PM₁₀ emission limit of 0.03 lb/MMBtu (3-hour average);
 - Low NO_x Burners (LNB) and Flue Gas Recirculation (FGR) with a controlled NO_x emission rate of 0.15 lb/MMBtu (12-month rolling average) for Tracy Unit 1;
 - LNB and FGR with a controlled NO_x rate of 0.12 lb/MMBtu (12-month rolling average) for Tracy Unit 2; and
 - LNB and Selective Non-Catalytic Reduction (SNCR) with a controlled NO_x rate of 0.19 lb/MMBtu (12-month rolling average) for Tracy Unit 3.
 - B. The specific BART requirements for electrical generation boilers at Fort Churchill are:
 - The combustion of pipeline quality natural gas and/or No. 2 fuel oil for SO₂ and PM₁₀ control;
 - SO₂ emission limit of 0.05 lb/MMBtu (24-hour average);
 - PM₁₀ emission limit of 0.03 lb/MMBtu (3-hour average);
 - Low NO_x Burners (LNB) and Flue Gas Recirculation (FGR) with a controlled NO_x emission rate of 0.20 lb/MMBtu (12-month rolling average) for Fort Churchill Unit 1; and
 - LNB and FGR with a controlled NO_x rate of 0.16 lb/MMBtu (12-month rolling average) for Fort Churchill Unit 2.

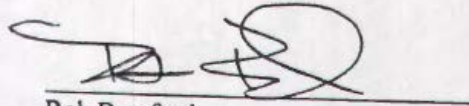
9. In a letter to the NDEP dated December 20, 2012, and revised on February 15, 2013, SIERRA PACIFIC POWER COMPANY dba NV ENERGY stated its intent to retire Tracy Units 1 and 2 by the RH SIP compliance date and requested approval of the following alternate equivalent control technology for BART and supplemental control technology as allowed under the RH SIP and Nevada Administrative Code:

- A. For the electric generation boiler "Unit #3" at Tracy:
 - The combustion of pipeline quality natural gas only for SO₂ and PM₁₀ control;
 - Low NOx burners for NOx control; and
 - The option to supplement NOx control by the operation of the existing, or a new, over fire air system as necessary to continuously meet the BART emission limit.
- B. For the electrical generation boilers "Unit #1" and "Unit #2" at Fort Churchill:
 - The combustion of pipeline quality natural gas only for SO₂ and PM₁₀ control;
 - Low NOx burners for NOx control; and
 - The option to supplement NOx control by the construction and subsequent operation of an over fire air system as necessary to continuously meet the BART emission limit.

Prior to January 1, 2015, the continued operation of Tracy and Fort Churchill under the terms and conditions of their respective Air Quality Operating Permits will not result in a violation of any applicable requirement.

April 25, 2013

Date



Rob Bamford
Chief, Bureau of Air Pollution Control
Nevada Division of Environmental Protection

3 PUBLIC UTILITIES COMMISSION OF NEVADA (PUCN)

[http://pucweb1.state.nv.us/PUC2/\(X\(1\)S\(xwh01uijwrjnov55arhg5taf\)\)/Dktinfo.aspx?Util=All](http://pucweb1.state.nv.us/PUC2/(X(1)S(xwh01uijwrjnov55arhg5taf))/Dktinfo.aspx?Util=All)
(last viewed 6/13/2014)

3.1 Public Utilities Commission of Nevada, Docket No. 12-08009

Stipulation and Order accepting the Stipulation.

- o Tracy Unit 1 will retire as of the BART compliance date. Attachment 1, section 2.C (page 3-4).
- o Tracy Unit 2 will retire as of the BART compliance date. ORDER, section V.B.31 (page 13).
- o Tracy Unit 2 last operated in 2009. ORDER section V.B.20 (page 9).

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Sierra Pacific Power Company d/b/a NV)
Energy for approval of the second amendment to the)
Action Plan of the 2011-2030 Integrated Resource Plan as) Docket No. 12-08009
it relates to a new base load forecast, generating plant)
investments and retirements, and transmission projects.)
_____)

At a general session of the Public Utilities
Commission of Nevada, held at its offices
on December 20, 2012.

PRESENT: Chairman Alaina Burtenshaw
Commissioner Rebecca D. Wagner
Commissioner David Noble
Assistant Commission Secretary Breanne Potter

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following
findings of fact and conclusions of law:

I. INTRODUCTION

Sierra Pacific Power Company d/b/a NV Energy ("SPPC") filed an Application with the Commission for approval of its second amendment to the Action Plan of the 2011-2030 Integrated Resource Plan as it relates to a new base load forecast, generating plant investments and retirements, and transmission projects.

II. SUMMARY

The Commission approves the Partial Issue Stipulation Regarding Load Forecast, Generation Plant Investment and Retirements, and Transmission ("Stipulation"), attached hereto as Attachment 1. The Commission accepts the Application, except for the retirement date for Valmy Unit 1, which is deemed inadequate.

III. PROCEDURAL HISTORY

- On August 13, 2012, SPPC filed the Application. The Commission designated the Application as Docket No. 12-08009.
- The Application was filed pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including but not limited to NRS 704.751, NAC 704.9503, NAC 704.9516, and NAC 704.9518.

- The Regulatory Operations Staff (“Staff”) of the Commission participates as a matter of right pursuant to NRS 703.301.
- On August 17, 2012, the Commission issued a Notice of Application and Notice of Prehearing Conference.
- On August 28, 2012, the Attorney General’s Bureau of Consumer Protection (“BCP”) filed a Notice of Intent to Intervene as a matter of right pursuant to NRS 228.360.
- On September 12, 2012, Northern Nevada Industrial Electric Users (“NNIEU”) filed a Petition for Leave to Intervene (“PLTI”).
- On September 13, 2012, the Commission held a prehearing conference. BCP, NNIEU, SPPC, and Staff made appearances.
- On September 14, 2012, the Presiding Officer issued an Order on Petition for Leave to Intervene of Northern Nevada Industrial Electric Users, granting the PLTI.
- On September 14, 2012, the Presiding Officer issued a Procedural Order, setting forth a procedural schedule.
- On September 14, 2012, the Commission issued a Notice of Hearing.
- On October 1, 2012, the Commission issued an Order on Bifurcation and Consolidation, bifurcating issues related to the One Nevada Transmission Line (“ON-Line”) Project in Docket No. 12-08009 and consolidating them with the identical issues in Docket No. 12-06053.
- On October 30, 2012, BCP and Staff filed direct testimony.
- On November 13, 2012, SPPC filed rebuttal testimony.
- On November 26, 2012, NNIEU filed a letter withdrawing their intervention.
- On November 27, 2012, BCP, SPPC, and Staff (the “Parties”) filed the Stipulation.
- On November 28, 2012, the Commission held a hearing. The Parties made appearances. At the conclusion of the hearing, the Presiding Officer granted an oral motion to accept Exhibits 1 through 25 and Confidential Exhibit C1 into the record pursuant to NAC 703.730.

IV. STIPULATION

Parties’ Position

1. The Parties agree and recommend that the Commission approve the Stipulation.

The Stipulation addresses the following: (1) Load Forecast; (2) Generating Plant and

Retirements; (3) Transmission; and (4) Confidentiality. The Stipulation resolves requests for relief A, B, C, E, F, G, I, J, and O in the Application. The Stipulation also recommends that the Commission direct SPPC to use a constant annual sales share of 1% for plug-in electric vehicles for all new cars in Nevada in 2015 and beyond for load forecasting purposes. (Exhibit 8.)

Commission Discussion and Findings

2. The Commission finds that the Stipulation is a consensus resolution of the issues in this Docket pursuant to the Parties' negotiations, and as such, is a reasonable recommendation and resolution of the issues addressed by the Stipulation.

3. The Commission finds that it is in the public interest to approve the Stipulation.

V. REMAINING ISSUES

A. FT. CHURCHILL UNIT 1¹

SPPC's Position

4. SPPC recommends that the retirement date for Ft. Churchill Unit 1 ("FC1") be extended seven years from the currently approved date in order to align with the best available retrofit technology ("BART") compliance schedule. FC1's retirement date would be 2025 and FC2's retirement date would be 2028. The next BART review is scheduled in 2023, with a five year (2028) deadline for compliance. (Exhibit 11—Hill at 7-8.) Due to the Carson Valley load pocket transmission limitations and the economics presented in the Life Span Analysis Process ("LSAP") analyses², investments should be made to allow the continued operation of both units

¹ Ft. Churchill Unit 2 ("FC2") was addressed in the Stipulation.

² LSAPs are used to reassess a unit's retirement date when certain triggering events occur. The process was first developed in 2008 by Nevada Power Company d/b/a NV Energy ("NPC") in response to the Commission's Modified Final Order in Docket Nos. 06-11022 and 06-11023. (See Docket No. 08-08002, Order issued January 15, 2009.) This process was later acknowledged by the Commission for SPPC. (Docket Nos. 10-06001, 10-06002, 10-06003 and 10-06004, Order issued December 23, 2010 at 49-51.) FC1 and FC2 each experienced two events: the units are in the last decade of their lives and are subject to new environmental regulations. (Exhibit 5 at 44, 82.)

beyond the Regional Haze Rule compliance date.³ (Exhibit 3 at 123.) In 2013, the capital required at FC1 is approximately \$1,800,000 and FC2 is approximately \$2,500,500. (Exhibit 10 at 4.)

5. SPPC identified FC1 and FC2 as BART eligible under the Regional Haze Rule, applicable to sulfur dioxide (“SO₂”), mono-nitrogen oxides (“NO_x”), and particulate matter with a diameter of 10 micrometers or less (“PM₁₀”) pollutants. Using the normal gas supply, FC1 and FC2 are expected to be compliant with BART limits for SO₂ and PM₁₀, but additional controls will be needed for NO_x compliance.⁴ (Exhibit 16 at 4-5.)

6. SPPC states that if either FC1 or FC2 utilizes oil firing they could be subject to the Mercury and Air Toxics Standard (“MATS”) Rule.⁵ The LSAP states that there is limited benchmarking emissions data for diesel No. 2 oil firing units of similar vintage to the FC Units. Without performance and stack testing on the diesel No. 2, it is unclear at this time if either Unit would remain below the emissions level for MATS compliance. (Exhibit 5 at 49, 87; Exhibit 16 at 6.)

7. SPPC’s economic analysis assessed three BART and MATS compliance options for the Units: 1) retire on the BART compliance deadline, 2) invest to meet both BART and MATS requirements, and 3) invest for BART compliance only. Based on the analysis, the FC Units were identified as must-run generation to reliably meet summer peak load obligations in the Carson Valley load pocket. If the FC Units are retired as currently planned, several transmission system additions will be needed to provide reliable (N-1) service, costing between

³ Although the compliance date is not finalized, the LSAP analysis assumed it to be June 30, 2016. (Exhibit 16 at 4, Exhibit Lacey-Direct-2.)

⁴ The technologies required for NO_x BART compliance are low NO_x burners with over-fired air combustion control equipment, combined with a “neural net” for model predictive control. (Exhibit 11 at 8.)

⁵ BART compliance requires the elimination of No. 6 fuel oil as a fuel for both units. If either unit converts to using No. 2 diesel oil, the unit(s) will retain the ability to fire secondary fuel but would also require capital investments for facility upgrades such as fire protection systems, in addition to burner upgrades and the required MATS environmental controls. (Exhibit 5 at 50, 88.)

\$66,900,000 and \$103,400,000, depending on expected mining load growth. Further, these transmission systems cannot permanently replace the generation capacity lost from the FC Units. The transmission will allow access to the Tracy Generating Station, but if that generation is fully subscribed, new generation will be required to serve the load pocket. SPPC adds that it is unclear whether a transmission option could be in place before the BART compliance date. Therefore, the transmission build-out option is not considered a viable alternative to investment for BART compliance. (Exhibit 5 at 51-52, 89-90; Exhibit 9 at 8-11.)

8. SPPC states that the installation of No. 2 diesel oil firing capability is not recommended at this time due to the capital requirements for MATS compliance. Oil firing under BART/MATS is estimated to require an additional \$16,000,000 per Unit. Oil has not been burned in either Unit since 2007. (Exhibit 3 at 123; Exhibit 5 at 41, 53, 79, and 91.)

9. SPPC states that for both FC1 and FC2, the capital investment option to run on gas firing only as a single fuel facility is the most economic option as provided below:

Option	Description	30-Year Present Worth of Revenue Requirement (\$ millions)
FC1 A	Retire on BART compliance deadline	35,012
FC1 B	Invest for BART compliance on natural gas only	34,990
FC1 C	Invest for BART and MATS compliance	35,010
FC2 A	Retire on BART compliance deadline	35,030
FC2 B	Invest for BART compliance on natural gas only	35,003
FC2 C	Invest for BART and MATS compliance	35,021

10. SPPC recommends that the FC1 and FC2 retirement dates remain staggered by three years for three reasons: 1) minimize the system impact by retiring each single 110 megawatt ("MW") Unit at a time (rather than all 220 MWs at once); 2) reduce reliance on the

market for replacement power and capacity; and 3) free up air increment⁶ that might be needed to develop new units at the site ahead of a full FC system retirement of 220 MWs. (Exhibit 11—Hill at 7; Tr. at 51-52.)

Staff's Position

11. Staff recommends the Commission approve the investments needed for FC1 and FC2 to comply with BART regulations as the least cost alternative. Staff states that the FC Units are vital for reliably serving load during the summer peak periods due to their location inside the Carson Valley load pocket. In making its recommendation, Staff states that it analyzed the transmission build-out option, but does not support it. Due to reliability concerns, new transmission would be required to serve the Carson Valley load pocket if the FC Units were retired on or before the BART compliance date. Staff states the transmission alternative is less economical compared to the BART investment option and comes with several risks such as the ability to construct before the compliance deadline and the fact that the transmission option still leaves an open generation position that will have to be filled with additional resources. (Exhibit 21 at 5-6.)

12. Staff also recommends that the Commission extend the retirement date of FC1 to 2028 to match FC2's proposed retirement date in order to spread the compliance costs over an additional three years to minimize rate impacts. Staff does not find merit in any of SPPC's three arguments for staggered retirement dates. There will be minimal system impact or reliance on the markets for replacement power as any new generation and transmission needed to serve the Carson Valley load pocket needs to be constructed prior to retirement of the FC Units. Staff adds that freeing up air increment does not outweigh rate impact minimization. (Exhibit 21 at 7-

⁶ Air increment is the amount of pollution that can be increased in an attainment area without degrading the air quality to a point that it becomes non-attainment. The amount of increment in a new source's air permit is based on the maximum amount of emissions a unit is allowed to emit. (Exhibit 22 at 8-9.)

9.)

13. Staff supports SPPC's decision to conclude the facilities' dual fuel capabilities as there is little value or economic benefit associated with the significant capital expenditures required for their continuance. Staff determined that with the length of time needed to start the Units from a cold shutdown, and the added reliability from the ON-Line, there will be few reliability benefits associated with maintaining the dual fuel capability. (Exhibit 21 at 9-10.)

SPPC's Rebuttal Position

14. SPPC disagrees with Staff regarding the retirement date for FC1. SPPC does not believe rate impact minimization is an appropriate basis for setting new retirement dates. In order to operate FC1 to 2028 additional capital investment may be required, which could offset any rate impact "benefit" of a longer amortization period. SPPC also emphasizes the importance of air increment for permitting in an attainment area. If there is not enough increment to permit a replacement energy supply at the FC site, reductions must be made in existing sources to free up additional air increment. SPPC states that by staggering the retirement dates, the air increment from FC1 can be used to permit the replacement unit(s) for the site, allowing FC2 to bridge the construction years and minimize market exposure. (Exhibit 24 at 3-5.)

15. SPPC adds that it is possible to synchronize the retirement dates of both FC Units to 2028 and adjust the dates closer to retirement if it is later decided FC1 should be retired in 2025, but that this adjustment will impact the undepreciated net book value of the plant at retirement and may result in the collection of the undepreciated plant balance from customers who have not benefited from the unit. (Exhibit 24 at 6-7.)

Commission Discussion and Findings

16. SPPC and Staff agree there will be a reliability issue whenever the FC Units are

retired and as such, there needs to be a new resource and/or new transmission system built prior to retirement. SPPC and Staff agree that building transmission is not the preferred method for serving the Carson Valley load pocket. Instead, upgrades should be made to the existing FC Units to allow for their continued operation. As memorialized in the Stipulation, SPPC and Staff agree FC2's retirement date should be 2028 for reliability and economic reasons.

17. The Commission has to determine if the reliability concerns and economics warrant a staggered retirement between the FC Units with a 2025 date for FC1 or if the retirement dates be set at 2028 for both Units. SPPC supports its staggered retirement date request on the belief that air increment will be needed from a retired FC1 to permit a new plant to be online by the time FC2 retires, thereby negating any reliability concerns.

18. One cannot fail to appreciate the hedge value of FC1's air increment against a future where there is no available air increment. This hedge ensures that SPPC will be able to permit a new resource in the Carson Valley load pocket whenever FC1 is retired- whether it is because there is already available air increment or because SPPC sacrifices FC1 to permit a new facility. Because FC1 retains the ability to retire and free up air increment when needed for new resources, reliability is no longer the main driver behind selecting a retirement date, and it becomes necessary to turn to the economics behind the differing dates.

19. The Commission finds SPPC's assumption to retire FC1 in 2025 to be reasonable. The Commission agrees with SPPC that by setting a longer depreciable life (2028), and then deciding upon further consideration to retire the plant in 2025, the ratepayers existing at the end of the depreciable life of the unit will be shouldering a disproportionate amount of the costs. The Commission believes it is better to set a shorter lifespan today, with a retirement in 2025 for FC1, and preserve the ability to push back the retirement date to 2028 if it is warranted during

the next LSAP analysis. At that time, should there be any change in circumstances surrounding the ability to permit a new facility and/or build new transmission in the Carson Valley load pocket (the main drivers behind the 2025 date), the Commission has the ability to extend the retirement date of FC1 to 2028 with minimal rate impacts.

B. TRACY UNIT 2⁷

SPPC's Position

20. SPPC recommends that it not make the necessary investment of over \$20,000,000 to bring the 47-year-old Tracy Unit 2 ("T2") into BART compliance, which would extend the retirement date of this Unit until 2025. SPPC further recommends that only minimal operations and maintenance expenditures should be performed on T2 until the Unit is retired concurrently with T1, prior to the BART compliance date in April of 2017.⁸ T2 was last operated in 2009, and SPPC currently does not employ staff to operate this Unit. (Exhibit 3 at 124-125; Exhibit 10 at 5-6.)

21. SPPC states that the LSAP for T2 shows a net benefit to keep the Unit operational. SPPC further states that this analysis was performed on a "stand alone" basis for T2 and did not consider the recommendation to continue operation of FC1 through 2025 and FC2 through 2028. SPPC concludes that the delay in retirement of the FC Units shrinks SPPC's open position and negates the benefit as shown in the LSAP to keep T2 operational. (Exhibit 3 at 123.)

22. The \$22,063,000 in investments required to keep T2 operational until 2025 includes \$9,595,000 for low NOx burners, \$4,500,000 for new boiler and burner controls,

⁷ Tracy Unit 1 ("T1") was addressed in the Stipulation, recommending that the Commission approve a retirement date coinciding with the BART compliance date—the date by which units subject to Phase One of the Regional Haze Rule must comply with BART upgrades as mandated by their respective State Implementation Plan.

⁸ The BART compliance date in the LSAP was assumed to be June 30, 2016, but is now April of 2017. (Exhibit 10 at footnote 3; Exhibit 16 at Exhibit Lacy-Direct-2.)

\$1,500,000 for a turbine overhaul, and the remaining \$6,468,000 spent on miscellaneous upgrades and repairs of plant equipment. (Exhibit 4 at 300.)

23. SPPC notes in its LSAP report that SPPC does not have sufficient water rights to operate all of the Tracy Units at one time. During the hearing, SPPC further clarified that it did not have sufficient water rights to operate all of the Tracy Units at full load for 8,760 hours (24 hours a day/7 days a week) in a year. (Exhibit 4 at 289; Tr. at 45.)

24. SPPC further notes that if T2 is required to operate on No. 2 diesel oil to offset extreme winter natural gas (low gas availability) issues, additional investments of approximately \$38,000,000 would be required. The increase in costs is a result of MATS requirements, which require modification to the fuel equipment and additional monitoring equipment. However, SPPC noted that low gas availability is no longer a concern for SPPC at T2 because of the additional natural gas supply from the Tuscarora Pipeline and joint dispatching between NPC and SPPC upon the anticipated completion of ON-Line. SPPC also cannot quantify the amount of Emission Reduction Credits (“ERCs”) that will be available to SPPC with the retirement of T2 and will not have this information until the Unit is retired. (Exhibit 4 at 288-289, 295, 301; Tr. at 53-54, 125-126.)

25. SPPC’s base case loads and resource table indicates that with the retirement of Tracy Unit 1 (“T1”) and T2 in 2016, SPPC will require seven new 70 MW combustion turbines (“CT”) in 2022 . (Exhibit 3 at 152.)

Staff’s Position

26. Staff recommends that SPPC undertake the capital investments required to extend the retirement date for the T2 until 2028, which will in turn defer investments in future generation. Staff’s reason for supporting the additional investment in T2 and not T1 is that the

approximate cost for additional investments of \$241 per kilowatt (“kW”) required for T2 is considerably lower than the \$491 per kW cost for the additional investments required in T1, which the Parties agreed in the Stipulation should be retired in 2016. SPPC’s records show that SPPC has made considerable investments in T2 in the past 10 years as opposed to almost no investment in T1 (\$1,535,077.90 versus \$256,260.51), implying that T2 is in better condition from a reliability standpoint than T1. T2 is also approximately 7% more efficient than T1. SPPC may also be able to reduce the investment in T2 by using some spare parts from T1. Finally, Staff questions the necessity of all of the expenditures for a burner and boiler control system upgrade and notes that only the minimum necessary expenditures should be made to satisfy BART compliance requirements. (Exhibit 21 at 13-14, Attachment GMC-3.)

27. Staff agrees that if SPPC were to invest over \$20,000,000 in T2 to extend the retirement date to 2025, this would defer the investment of one of the seven 70 MW CTs for three years (e.g., 2022 to 2025). The time value of money is about \$125,000,000 for three years. While that analysis is not in the Application, Staff states that it would be beneficial to keep T2 operational, although it probably would be close. (Tr. at 99-100.)

28. Staff notes if T2 is retired, it will receive very few “bankable” ERCs, unlike NPC’s Sunrise Units in Clark County, because of the differences in the air sheds. The Sunrise Units are in a non-attainment area, unlike T2. In attainment areas, there is air increment, which is not bankable. Therefore, the best strategy is to sync up the creation of air increment due to the retirement of an asset with the application for a new source of emissions in order to not lose the use of that air increment. (Exhibit 21 at 14-15.)

SPPC’s Rebuttal Position

29. SPPC opposes Staff’s position for multiple reasons. SPPC does not agree with

Staff's assessment of the expenditures for the burner and boiler controls and notes that these \$4,500,000 in expenditures are necessary to meet National Fire Protection Standards. The investment that is required to meet BART standards will reduce the efficiency of T2 by 3%, and the PROMOD analysis never called upon the Unit as an economic resource through 2025. The present worth of revenue requirement ("PWRR") evaluation assumes that open positions will be filled with capacity calls for the three-month summer period, but in actuality these positions are filled with a less expensive option of calls over a much shorter period. SPPC also states that long term idling of T2, which the PROMOD analysis contemplates, poses a risk for a New Source Review ("NSR")⁹ if the Unit is put back into service. Along with having to shut down the plant, the economic risk associated with an NSR could be substantial. (Tr. at 103-108.) SPPC also questions Staff's proposed extension of the retirement date to 2028 from the LSAP date of 2025. The LSAP analysis only included costs to extend the retirement to 2025 and that analysis did not identify the necessary costs to extend the operation to 2028. (Exhibit 22 at 12; and Exhibit 24 at 7-9.)

Commission Discussion and Findings

30. The Commission finds that SPPC should not make the necessary investment in T2 to extend the life of the Unit to 2025. SPPC's analysis indicates additions in 2022 consisting of seven 70 MW CTs. Keeping T2 operational for an additional three years would only defer one of these CTs, and the savings would be offset by the cost of the required improvements necessary to keep T2 operating. Given that there is little difference in the investment costs of the

⁹ Congress established the NSR permitting program as part of the 1977 Clean Air Act Amendments. The NSR process requires utilities to undergo an Environmental Protection Agency ("EPA") pre-construction review for environmental controls if a utility proposes either building new facilities or any modification to existing facilities that would create a "significant increase" of a regulated pollutant. The legislation allowed "routine scheduled maintenance" to not be covered in the NSR process. Since the terms "significant increase" and "routine scheduled maintenance" were never precisely defined in legislation, they have become a source of contention in many lawsuits filed by the EPA, public interest groups, and utilities.

projects and the risk associated with the cost estimate for the work required for T2, the Commission believes that it is in the ratepayers' best interests to not make the additional investments in T2 for BART compliance. (Tr. at 118-121.)

31. Furthermore, SPPC's PROMOD analysis indicates that T2, if upgraded, would be uneconomical to operate compared to purchased power. The investment in T2 would simply be a capital hedge against a capacity market. (Exhibit 24 at 9; Tr. at 118-119.) However, by not operating T2 for an extended period of time, SPPC could also be subject to an NSR and corresponding fines. This risk is not quantified in SPPC's analysis and creates the potential for an earlier retirement or higher operating costs from "out of merit" operations. Operating T2 out of merit—simply running T2 to keep the permit valid—costs money. SPPC has fuel costs of almost \$900,000,000 per year. While the net cost to operate T2 for a few hundred hours is comparatively small, it is still a cost. Given the marginal value of T2 after upgrades, the Commission sees no reason to keep T2 in service past the BART compliance date.

C. FALLON/CARSON LAKE TRANSMISSION PROJECT

SPPC's Position

32. SPPC recommends that the Commission approve a revised project scope, budget, and schedule for the Fallon/Carson Lake Transmission Project ("Project"). The Project was originally approved in Docket No. 07-06049.¹⁰ SPPC later provided an update, which redefined the scope of the Project, in Docket No. 10-07003.¹¹ The Project budget was originally approved by the Commission at \$22,000,000 in Docket No. 07-06049 and was subsequently revised to \$35,000,000 in Docket No. 10-07003. In Docket No. 10-07003, the Commission found it unnecessary to update the resource plan approval of the Project and indicated that project costs

¹⁰ Application of Sierra Pacific Power Company for approval of its 2008-2027 Integrated Resource Plan.

¹¹ Application of Sierra Pacific Power Company d/b/a NV Energy for approval of its 2011-2030 Triennial Integrated Resource Plan.

would be reviewed in subsequent ratemaking proceedings.¹² (Exhibit 2 at 14; Exhibit 3 at 173-174; Exhibit 9 at 5.)

33. SPPC states that it has significantly reduced the scope of the Project as a result of the reduction in load in the Fallon area and the cancellation of one of the renewable projects in the area. The revised scope now includes the facilities required to serve one existing geothermal generation plant (Enel Salt Wells, LLC) and one Large Generation Interconnection Agreement (“LGIA”) for ORNI 16 (Carson Lake), calling for the construction of the Pony Express Switching Station, and completing the acquisition of the 230kV transmission line from a tap on the Austin – Frontier 230kV line to the new Pony Express Switching Station. The new budget is approximately \$10,150,000, which includes \$2,806,000 for Transmission Provider’s Interconnect Facilities, \$5,044,000 for Network Upgrades, and \$2,300,000 for finalizing the acquisition of the 230KV transmission line. (Exhibit 9 at 3-5.)

BCP’s Position

34. BCP recommends that the Commission take no action on the Project as the resource has not been affected and thus an amendment to SPPC’s Action Plan is not required in accordance with NAC 704.9503(1)(f). During the hearing, BCP indicated that the Commission could make a finding similar to its ruling in Docket 10-07003 for the Project. (Exhibit 17 at 2; Tr. at 75-76.)

Staff’s Position

35. Staff recommends that the Commission accept SPPC’s request to reduce the scope and change the in-service date of the Project. However, by accepting the Project, SPPC should be required to closely monitor the geothermal projects that are driving the need for the

¹² Docket Nos. 09-12002 and 10-07003, Compliance Order: Phase I and Phase II issued December 10, 2010 at 24-25.

Project, and if the geothermal projects do not move forward, SPPC should not spend the funds for permitting and constructing the Project. The revised scope is due to the cancellation of a renewable energy project in the area and to the reduction in the Fallon area load forecast. The revised scope will also accommodate another LGIA for a geothermal project with a proposed 70 MW nameplate rating, designated as “Company DT”. Staff states that “Company DT” is the Gradient Patua Geothermal Project, which has a Purchased Power Agreement with the Sacramento Municipal Utility District. The revised budget is approximately \$25,000,000 less than what was proposed by SPPC in Docket No. 10-07003. (Exhibit 20 at 2-3.)

36. Staff states that the entire need for this Project is predicated on a belief that two new geothermal projects, ORNI 16 and “Company DT”, will move forward and execute Transmission Service Agreements. Although both projects have Transmission Service Requests that are in the System Impact Study phase, these geothermal projects are still somewhat speculative. Staff is concerned that if the Project is approved and SPPC begins construction, native load ratepayers could be responsible for the cost of any unnecessary construction if neither geothermal project moves forward. Without the 80 MWs in new transmission billing determinants from these new geothermal projects, SPPC would not receive any new transmission revenue to offset the \$10,150,000 in new investment. (Exhibit 20 at 3-5.)

37. Alternatively, Staff indicates that the Commission could make a finding similar to the one the Commission made in Docket No. 10-07003 where the Commission determined it was not necessary to update resource planning approval for the Project. The Commission stated it was SPPC’s responsibility to execute the Project and to ensure all costs incurred were just and reasonable, and that those costs would be reviewed at an appropriate rate case. Similar to the circumstances in Docket No. 10-07003, the general scope of the Project has not changed—it is

being driven by the need to connect geothermal projects. (Exhibit 20 at 4-5.)

Commission Discussion and Findings

38. The Commission accepts the revised scope, budget, and schedule for the Project. There are potentially two geothermal projects that are driving the need for this Project. The Commission further agrees with Staff that this Project should be closely monitored. If the geothermal projects do not go forward, SPPC should not expend funds for permitting and constructing the Project, which includes purchasing the existing Austin-Frontier 230kV line from Enel Salt Wells, LLC. SPPC is responsible for executing the Project to ensure whatever costs that are incurred are just and reasonable. These Project costs will be reviewed at a later date in the appropriate general rate case.

D. VALMY UNITS 1 AND 2

SPPC's Position

39. SPPC proposes to keep the retirement date for Valmy Unit 1 ("V1") at 2021 due to the high levels of uncertainty around the capital requirements for environmental controls to operate V1 beyond 2021. SPPC also proposes to keep the retirement date for Valmy Unit 2 ("V2") at 2025. The PWRR analysis indicates that it is in the ratepayers' best interest to operate V1 to 2021 while investing for MATS compliance. If V1 is shutdown in 2015, the fuel mix for SPPC's energy supply would be further shifted towards natural gas. While the forecast for available natural gas continues to be positive, basing the majority of generation on a single fuel is risky because costs may rise if the supply is suddenly constrained. The PWRR analysis did not consider operating V1 beyond 2021 because of the environmental uncertainties associated with the Unit. Further, retiring both Units on the same date would create a several hundred MW impact to the open position for SPPC's system. By staggering the retirement of the Units, air

increment, if needed, can be made available from the retirement of the first Unit. This will support the immediate permitting of a newer, modern, lower emission level generating resource at the site. (Exhibit 3 at 127; Exhibit 5 at 17-18; Exhibit 10 at 7-8; Tr. at 21, 25-27.)

BCP's Position

40. BCP recommends that the depreciated life of V1 and V2 each be set at 50 years instead of the current 40 years. BCP notes that Idaho Power Company, the co-owner of V1 and V2, has set the life of these Units at 50 years. Moreover, the predominance of life spans for coal-fired generation units is between 50 and 65 years as recently admitted by SPPC's depreciation consulting firm. SPPC has not provided any documentation to support a 40-year life for these Units. Finally, the claim that future environmental regulations might not support operation beyond 2021 for V1 and V2 is unsupported. (Exhibit 18 at 2-10.)

Staff's Position

41. Staff recommends extending the retirement date for V1 to 2025 for four reasons. First, SPPC is making the necessary investments in V1 to meet MATS compliance. Second, SPPC's LSAP indicates that there are no identified conditions that would prevent operation beyond 2021. Third, if V1 is retired 4 years earlier than V2, the fixed operating costs for the Valmy Generating Station would be spread over one Unit instead of the two Units for the four-year period, which would make V2 disproportionately expensive to operate. Because of the disproportionate expenses, Staff notes that individual units are not generally retired at generating stations. Fourth, Staff notes that with the completion of the LSAP for V1, retrofits have been identified and the cost estimates are known. The timeframe for making these environmental investments are also much more clearly defined. As such, the environmental uncertainty argument for not syncing V1 and V2 no longer has credence for the purposes of setting a

forecasted retirement date. (Exhibit 21 at 17-20.)

SPPC's Rebuttal Position

42. SPPC disagrees with Staff and BCP that the retirement date for V1 should be extended beyond 2021. SPPC cites to economic uncertainties as the main driver to maintain the current retirement date at 2021. SPPC notes that the environmental regulation investments in V1 are different than V2 and may be difficult to justify. In response to BCP's position that coal units should have 50-year lives, SPPC notes that the Mohave Generating Station was retired after only 35 years of operation and Portland General Electric's Boardman coal plant will be retired after only 40 years of operation. (Exhibit 25 at 4-7; Tr. at 133-135.)

43. SPPC states that while it has not identified any technological (physical) reason why the Units cannot be operated indefinitely, economics are always the driving force behind any retirement decision. SPPC further notes that V2 is not due for an LSAP study until 2016. The 2025 retirement date for V2 is a legacy retirement date approved in SPPC's last depreciation study. There is absolutely no analytical support in the record in this docket supporting a change in the retirement date for V2. (Exhibit 25 at 7-8.)

Commission Discussion and Findings

44. The Commission finds that SPPC's LSAP for V1 is inadequate. The LSAP for V1 did not adequately analyze the economics and risks for the Unit to operate beyond 2021. The LSAP also did not discuss the necessary capital and maintenance expenditures or cost-benefit analysis that would be necessary to operate the Unit beyond 2021. SPPC's claim that the environmental uncertainties surrounding V1 did not warrant studying operation of the Unit beyond that time frame is unsupported.

45. The Commission directs SPPC to include the risk and cost for operating V1

beyond 2021 in the LSAP for V1 when SPPC files its next depreciation study with the Commission. The Commission can then make a more informed decision as to the life of the Unit for rate making purposes. The Commission also directs SPPC to provide an update to the LSAP for V1 when it completes the LSAP for V2 in 2016. At that time, SPPC will have a better indication of the environmental policies and their potential costs for the Units.

46. BCP's recommendation to increase the life for V2 is unsupported by the record in this Docket. The latest analysis for V2 indicates the retirement date for this Unit is 2025, which is the only analytically supported recommendation on record in this proceeding.¹³

47. Notwithstanding, the Commission is concerned that the two owners of V1 and V2, Idaho Power Company and SPPC, have different retirement dates for the Units. In the aforementioned LSAPs for V1 and V2 (see paragraph 45 above), SPPC shall include an analysis of the decision(s) in support of Idaho Power Company's use of 50-years life spans for V1 and V2.

E. DIRECTIVE IN DOCKET NO. 10-06003

SPPC's Position

48. SPPC recommends that the Commission find that SPPC has complied with paragraph 123 of the Order in Docket No. 10-06003 related to the LSAP analyses. (Exhibit 2 at 13.)

Staff's Position

49. Staff recommends the Commission find that SPPC has complied with the portion

¹³ BCP references Idaho Power Company's most recent Application before the Idaho Public Utilities Commission in which the Idaho Public Utilities Commission purportedly approved the 50-year life spans for the Valmy Units. (Exhibit 18 at 4, footnote 11, citing Case No. IPC-E-12-08, Order No. 32559, issued May 31, 2012.) However, that decision approved a Stipulation that included an Attachment showing the remaining life for the Valmy Units, equating to 50-year life spans. The decision is devoid of any discussion on why the 50-year life spans are appropriate. Without any additional supporting documentation from this case or any previous case before the Idaho Public Utilities Commission regarding the life spans for the Valmy Units, the Commission has no basis upon which to compare the analysis performed in Idaho to the LSAP performed in Nevada.

of paragraph 123 in Docket No. 10-06003 related to the LSAP only. There is more of that paragraph that SPPC has yet to comply with, that being the filing of a deprecation study no later than 2013. (Exhibit 21 at 20.)

Commission Discussion and Findings

50. In Docket No. 10-06003, the Commission directed SPPC to complete the LSAP analyses for FC1, FC2, and V1. (Docket Nos. 10-06001, 10-06002, 10-06003, and 10-06004, Order issued December 23, 2010 at 50-51, 221.) While the Commission has directed SPPC to conduct additional analysis regarding the LSAP for V1 (see paragraphs 45 and 47 above), the Commission finds that SPPC has satisfied paragraph 123 and ordering paragraph 11 of the Order in Docket No. 10-06003 related to the LSAP analyses only. SPPC has yet to comply with the filing of a deprecation study that includes the LSAP analyses for FC1, FC2, and V1 no later than the time SPPC files its next general rate case in 2013.

THEREFORE, it is hereby ORDERED that:

1. The Partial Issue Stipulation Regarding Load Forecast, Generation Plant Investment and Retirements, and Transmission, attached hereto and incorporated herein as Attachment 1, is APPROVED.
2. The Application of Sierra Pacific Power Company d/b/a NV Energy in Docket No. 12-08009 is ACCEPTED, except for the retirement date for Valmy Unit 1, which is DEEMED INADEQUATE.
3. The Commission's approval of the Partial Issue Stipulation Regarding Load Forecast, Generation Plant Investment and Retirements, and Transmission does not constitute precedent regarding any legal or factual issue in this proceeding.

Directives:

4. Sierra Pacific Power Company d/b/a NV Energy shall use a constant annual sales share of 1% for plug-in electric vehicles for all new cars in Nevada in 2015 and beyond for load forecasting purposes.

5. Sierra Pacific Power Company d/b/a NV Energy shall include the risk and cost for operating Valmy Unit 1 beyond 2021 in the Life Span Analysis Process for Valmy Unit 1 when Sierra Pacific Power Company d/b/a NV Energy files its next depreciation study with the Commission. Sierra Pacific Power Company d/b/a NV Energy shall also include an analysis of the decision(s) in support of Idaho Power Company's use of a 50-year life for Valmy Unit 1.

6. Sierra Pacific Power Company d/b/a NV Energy shall provide an update to the Life Span Analysis Process for Valmy Unit 1 when it completes the Life Span Analysis Process for Valmy Unit 2 in 2016. Sierra Pacific Power Company d/b/a NV Energy shall also include an analysis of the decision(s) in support of Idaho Power Company's use of a 50-year life for Valmy Unit 2.

7. Failure to comply with the directives in this Order may subject Sierra Pacific Power Company d/b/a NV Energy to administrative fines pursuant to NRS 703.380 and/or revocation of the underlying relief granted as appropriate.

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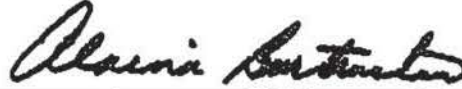
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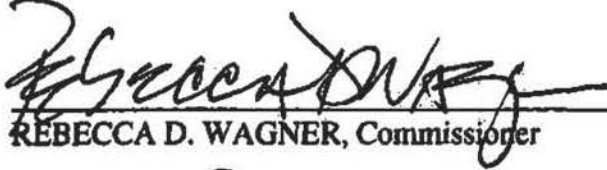
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8. The Commission may correct any errors that may have occurred in the drafting or issuance of this Order without further proceedings.

By the Commission,



ALAINA BURTENSHAW, Chairman



REBECCA D. WAGNER, Commissioner



DAVID NOBLE, Commissioner and
Presiding Officer

Attest: 
BREANNE POTTER,
Assistant Commission Secretary

Dated: Carson City, Nevada

12-24-12

(SEAL)



ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Sierra Pacific Power Company d/b/a NV
Energy for approval of the Second Amendment to its
2011-2030 Integrated Resource Plan

Docket No. 12-08009

**PARTIAL ISSUE STIPULATION REGARDING LOAD FORECAST, GENERATION
PLANT INVESTMENT AND RETIREMENTS, AND TRANSMISSION**

Pursuant to Nevada Administrative Code ("NAC") 703.750 and NAC 703.845, Sierra Pacific Power Company, d/b/a NV Energy ("Sierra"), the Regulatory Operations Staff of the Public Utilities Commission of Nevada ("Staff"), and the Office of the Attorney General's Bureau of Consumer Protection ("BCP"), together with the Companies and Staff, the "Parties", enter this Stipulation to resolve various issues in Docket No. 12-08009. Specifically this Stipulation resolves Requests for Relief items A, B, C, E, F, G, I, J, and O.

SUMMARY OF STIPULATION

The Parties agree that this Stipulation provides a fair, just and reasonable resolution of specific issues raised in Docket No. 12-08009, and that the Stipulation is in the public interest. The Stipulation only settles issues related to this docket and does not seek relief that the Commission is not empowered to grant. Accordingly, the Parties recommend that the Commission accept the Stipulation, implement all of the terms of the Stipulation, and grant the relief requested by the Companies in the applications as modified by the Stipulation. The Stipulation is a partial issue resolution, therefore the Parties will present and defend the remaining portion of their direct case as modified by this Stipulation at Hearing.

RECITALS

1. On August 13, 2012, Sierra filed with the Commission an application, designated as

1 Docket No. 12-08009, with the Commission for approval of the Second Amendment to its 2011-
2 2030 Integrated Resource Plan ("Second Amendment").

3 2. The Sierra Second Amendment Application was made pursuant to the NRS and the NAC,
4 Chapters 703 and 704, including but not limited to NRS § 704.751 (2) and NAC § 704.9503
5 (monitoring and amendment of action plan), NAC §704.9516 (contents of amendments to action
6 plan), and NAC §704.9518 (approval of amendment to action plan or energy supply plan).

7 3. Pursuant to NRS 703.301 and 228.360, Staff and the BCP participate in the proceeding as
8 a matter of right.

9 4. Northern Nevada Industrial Electric Users ("NNIEU") was granted leave to intervene in
10 Docket No. 12-08009 on September 14, 2012. NNIEU filed a letter withdrawing its petition for
11 leave to intervene on November 26, 2012.

12 5. On September 26, 2012, the Commission voted to bifurcate the On Line project issues in
13 Sierra's application for the remaining issues in Docket No. 12-08009 and consolidate them with
14 Nevada Power's requests related to the On Line project in Docket No. 12-06053. An Order for
15 the same was issued on October 1, 2012.

16 6. Staff and BCP investigated Sierra's Second Amendment, conducted analysis of the
17 Companies' requests therein, and filed testimony (the "Testimony") with the Commission in
18 Docket No. 12-08009. NNIEU did not file prepared testimony.

19 7. This Stipulation resolves Request for Relief items A, B, C, E, F, G, I, J, and O, as
20 contained in the Application of Docket No. 12-08009. The issues resolved by this Stipulation
21 are collectively hereinafter referred to as the "Stipulated Issues."

22 8. This is a partial issue Stipulation. The Parties will not present their witnesses on the
23 Stipulated Issues and waive cross-examination of the other Parties' witnesses on the Stipulated
24 Issues. However, the Parties will present their direct case at hearing for Docket No. 12-08009
25 for all issues not addressed in the Stipulation. The Parties recommend the Commission approve
26 this Stipulation.

27 **AGREEMENT OF THE PARTIES**

1 In light of the foregoing considerations, the Parties agree and recommend:

2 1. Load Forecast.

3 A. The Commission should find that the updated base, low and high load forecast
4 meets the requirements of:

- 5 i. NAC § 704.9321 because it is based on substantially accurate data and is
6 adequately documented, justified demonstrated and defended,
7 ii. NAC § 704.9482 because the ESP Update uses a base load forecast, and
8 iii. NAC §§ 704.9482(7) and 704.922 because the technical appendices
9 provide sufficient detail on how the Second Amendment Forecast was
10 prepared and to evaluate the validity of the assumptions and the accuracy
11 of the data used;

12 B. The Commission should find that the Second Amendment Forecast is suitable for
13 making long-term planning decisions;

14 C. The Commission should find that the extreme weather peak demand load forecast
15 is suitable for use in performing transmission planning.

16 D. The Commission should order Sierra to use a constant annual sales share of 1%
17 for plug-in electric vehicles for all new cars in Nevada in 2015 and beyond for forecasting
18 purposes.

19
20 2. Generating Plant and Retirements.

21 A. The Commission should approve investment in Ft. Churchill Unit 2 to support a
22 December 31, 2028 retirement date, including a budget during the Action Plan period (2013) of
23 approximately \$2,600,000 (Request for Relief item E).

24 B. The Commission should approve investment in Tracy Unit 3 to support a
25 December 31, 2028 retirement date, including a budget during the Action Plan period (2013) of
26 approximately \$1,700,000 (Request for Relief item F).

27 C. The Commission should approve a retirement date for Tracy Unit 1 of the BART
28

1 compliance date.¹ (Request for Relief item G).

2 D. The Commission should approve the retirement of the remote diesel site at Gabbs,
3 and regulatory asset treatment of associated decommissioning costs associated with the site
4 (Request for Relief item I).

5 E. The Commission should approve the designation of the remote diesel site at
6 Brunswick to "black start only," removing the unit from use as a capacity and energy resource
7 (Request for Relief item J).

8
9 3. Transmission.

10 The Commission should approve the budget of \$73,000 for Sierra's participation in
11 WestConnect (Request for Relief item O).

12
13 4. Confidentiality.

14 The Commission should grant the Companies' requests for confidential treatment of
15 certain portions of the Applications pursuant to NAC 704.7272.

16
17 5. General Points of Agreement.

18 A. This Stipulation represents a compromise of the positions of the signatory Parties.
19 Except as set forth herein, neither this Stipulation, nor its terms, nor the Commission's
20 acceptance of the recommendations contained in this Stipulation shall have any precedential
21 effect in future proceedings.

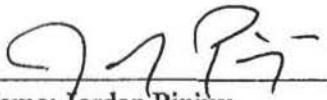
22 B. This Stipulation shall not become effective and shall be given no force or effect
23 until the issuance of a Commission order that accepts this Stipulation. If the Commission does
24 not accept the Stipulation, then the Stipulation is withdrawn and no part of the Stipulation shall
25 be admissible in any proceeding before the Commission or any other tribunal.

26 C. This Stipulation may be executed in one or more counterparts, all of which

27
28 ¹ The date by which units subject to Phase One of the Regional Haze Rule must comply with "best available retrofit technology" upgrades as mandated by their respective State Implementation Plan ("SIP").

1 together shall constitute the original executed document. This Stipulation may be executed by
2 signatures provided by electronic facsimile transmission, which facsimile signatures shall be as
3 binding and effective as original signatures.

4
5
6 REGULATORY OPERATIONS STAFF

7 By: 
8 Name: Jordan Pinjov
9 Title: Assistant Staff Counsel

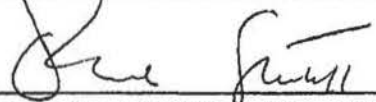
Dated: 11 / 27 / 12

10 NEVADA POWER COMPANY D/B/A NV ENERGY
11 SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

12 By: 
13 Name: Elizabeth Elliot
14 Title: Associate General Counsel

Dated: 11/27/12

15
16 OFFICE OF ATTORNEY GENERAL,
17 BUREAU OF CONSUMER PROTECTION

18 By: 
19 Name: Paul Stuhff 12-08009
20 Title: Senior Deputy Attorney General

Dated: November 27, 2012

PROOF OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding by electronic mail to the recipient's current electronic mail address and mailing a copy thereof, properly addressed to:

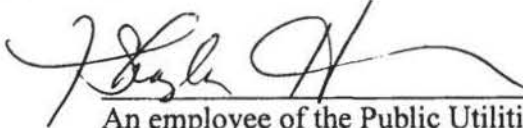
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DATED at Las Vegas, Nevada on the 27th day of November, 2012.


An employee of the Public Utilities
Commission of Nevada

3.2 Public Utilities Commission of Nevada, Dockets No. 13-07002 and 13-07005

Stipulation and Order accepting the Stipulation.

- o ORDER: Only pages 1 and 62 are included here to provide evidence that the PUCN accepted the Stipulation attached to the ORDER as Attachment 1. The rest of the ORDER may be viewed at: [http://pucweb1.state.nv.us/PUC2/\(X\(1\)S\(xwh01uijwrjnov55arhg5taf\)\)/Dktinfo.aspx?Util=All](http://pucweb1.state.nv.us/PUC2/(X(1)S(xwh01uijwrjnov55arhg5taf))/Dktinfo.aspx?Util=All) (last viewed 6/13/2014).
- o Attachment 1, Stipulation: BART upgrades at Tracy Unit 3 and Fort Churchill Units 1 and 2 do not allow for continued use of oil-firing capacity beyond December 31, 2014. Attachment 1, Agreement of the Parties, paragraph 3.B (page 3).

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV)
Energy for approval of its 2013 Annual Demand Side)
Management Update Report as it relates to the Action) Docket No. 13-07002
Plan of its 2013-2032 Integrated Resource Plan.)
_____)

Application of Sierra Pacific Power Company d/b/a NV)
Energy for approval of its 2014-2033 Triennial)
Integrated Resource Plan and 2014-2016 Energy Supply) Docket No. 13-07005
Plan.)
_____)

At a general session of the Public Utilities
Commission of Nevada, held at its offices
on December 16, 2013.

PRESENT: Chairman Alaina Burtenshaw
Commissioner Rebecca D. Wagner
Commissioner David Noble
Assistant Commission Secretary Breanne Potter

ORDER: PHASE II

The Public Utilities Commission of Nevada ("Commission") makes the following
findings of fact and conclusions of law:

I. INTRODUCTION

Nevada Power Company d/b/a NV Energy ("Nevada Power") filed with the Commission an Application, designated as Docket No. 13-07002, for approval of its 2013 Annual Demand Side Management ("DSM") Update Report as it relates to the Action Plan for its 2013-2032 Integrated Resource Plan ("IRP"). Sierra Pacific Power Company d/b/a NV Energy ("Sierra," collectively with Nevada Power, "NV Energy") filed with the Commission an Application, designated as Docket No. 13-07005, for approval of its 2014-2033 Triennial IRP and 2014-2016 Energy Supply Plan ("ESP").

II. SUMMARY

The Commission grants Nevada Power's and Sierra's Applications as set forth below.

III. PROCEDURAL HISTORY

- On July 1, 2013, Nevada Power filed with the Commission an Application, designated as Docket No. 13-07002, for approval of its 2013 Annual Electric DSM Update Report as it relates

THEREFORE, it is ORDERED that:

1. The Stipulations, attached hereto as Attachment 1 and Attachment 2, are ACCEPTED.
2. The Commission's acceptance of the attached Stipulations does not constitute precedent regarding any legal or factual issue.
3. Sierra Pacific Power Company d/b/a NV Energy's 2014-2033 Triennial Integrated Resource Plan is ACCEPTED and APPROVED. The non-Demand Side Management portions of Sierra Pacific Power Company d/b/a NV Energy's 2014-2033 Triennial Integrated Resource Plan are ACCEPTED and APPROVED as set forth in the Stipulations. The Demand Side Management portion of Sierra Pacific Power Company d/b/a NV Energy's Triennial Integrated Resource Plan is ACCEPTED and APPROVED as modified by this Order. Accordingly, Sierra Pacific Power Company d/b/a NV Energy's Application for approval of its 2013-2032 Triennial Integrated Resource Plan and 2013-2015 Energy Supply Plan, designated as Docket No. 13-07005, is GRANTED as modified by this Order.
4. Nevada Power Company d/b/a NV Energy's 2013 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Integrated Resource Plan is ACCEPTED as modified by this Order. Accordingly, Nevada Power Company d/b/a NV Energy's Application for approval of its 2013 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Integrated Resource Plan, designated as Docket No. 13-07002, is GRANTED as modified by this Order.

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ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy for Approval of its 2013 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2013-2032 Triennial Integrated Resource Plan

Docket No. 13-07002

Application of Sierra Pacific Power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2014-2033 and Approval of its Energy Supply Plan for the period 2014-2016.

Docket No. 13-07005

STIPULATION

Pursuant to Nevada Administrative Code ("NAC") 703.750 and NAC 703.845, the Parties (as defined below) enter this stipulation (the "Stipulation"). The Stipulation resolves certain Phase 2 issues in Docket Nos. 13-07002 and 13-07005 (the "Consolidated Dockets").

SUMMARY OF STIPULATION

The Parties agree that this Stipulation provides a fair, just and reasonable resolution of certain Phase 2 issues raised in these dockets and that the Stipulation is in the public interest. The Stipulation provides for the approval of the low load forecast for 2015 through the end of the planning period prepared by Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company"), as well as specific elements of the Company's supply side plan. The Stipulation does not address the Fort Churchill Solar Array or the Company's demand side plan. A separate stipulation addresses the Fort Churchill Array.

The Stipulation only settles issues related to the Consolidated Dockets. The Stipulation seeks relief that the Commission is empowered to grant. Accordingly, the Parties recommend that the Commission accept the Stipulation, implement all of the terms of the Stipulation, and grant certain requests for relief made by the Sierra, as modified by the Stipulation.

RECITALS

1. On July 1, 2013, Sierra filed with the Commission an application requesting approval and acceptance of its integrated resource plan ("IRP") covering the period 2014 through 2033 (the "Application").

2. Sierra made the Application pursuant to the applicable provisions of the Nevada Revised Statutes ("NRS") and the NAC, Chapters 703 and 704, including but not limited to NAC 704.9208.

3. Pursuant to NRS 703.301 and NRS 228.360, the Regulatory Operations Staff ("Staff") and the Nevada Attorney General's Bureau of Consumer Protection ("BCP") participate in these Consolidated Dockets.

4. The Commission granted petitions for leave to intervene filed by Apple Inc. ("Apple"), the Building & Construction Trades Council of Northern Nevada ("Building & Construction Trades"), EnerNoc, Inc. ("EnerNoc"), Nevadans for Clean Affordable Reliable Energy ("NCARE"), Newmont USA, LTD d/b/a Newmont Mining Corporation ("Newmont"), and the Northern Nevada Industrial Electric Users ("NNIEU").

5. EnerNoc's petition was limited to the demand side management portion of the proceeding.

6. Staff, BCP, Apple, the Building & Construction Trades, and NCARE (the "Parties") have investigated the Application, the IRP and have analyzed the Company's requests.

7. Apple, the Building & Construction Trades, NCARE, Newmont and the NNIEU do not support nor do they oppose this Stipulation.

AGREEMENT OF THE PARTIES

In light of the foregoing considerations, the Parties agree and recommend the following:

1. Load Forecast.

1 A. Regarding prayer for relief numbers 1 and 2 in Sierra's Application, the Commission
2 should find that the Application contains information necessary to satisfy the requirements of NAC
3 704.922, 704.9225, 704.9245, and 704.925.

4 B. The Commission should approve the load forecasts for 2014 through 2033 submitted
5 by the Company as meeting the requirements of NAC 704.9321.

6 C. The Commission should find the base load forecast for 2014 and the low load
7 forecast for 2015 through 2033 is suitable for making long-term planning decisions for the period
8 between 2014 and 2033.¹

9 2. Fuel and Purchased Power Forecast.

10 Regarding prayer for relief number 3, the Commission should find that the fuel and
11 purchased power forecast as presented is the best and most accurate information upon which to base
12 long-term planning decisions.

13 3. Supply Side Plan and Requests for Relief.

14 A. Regarding prayer for relief number 4, the Commission should accept Sierra's request
15 to perform a comprehensive study and conceptual design, with an estimated cost of \$1.25 million,
16 for a company-owned generating facility suitable for commercial operation as early as 2022. In
17 performing the study, Sierra shall consider relevant factors such as any Commission decision on
18 whether to extend the forecasted life of Valmy Unit 1 from 2021 to 2025, and the availability of
19 other generating resources, including the Newmont Mining TS Power Plant after 2022.

20 B. Regarding prayer for relief number 5, the Company acknowledges that Commission
21 action on the prayer for relief is not necessary. The Parties acknowledge, and recommend that the
22 Commission find, that the Nevada Department of Environmental Protection ("NDEP") and the
23 Commission have already approved the Best Available Retrofit Technology ("BART") upgrades for
24

25 ¹ Sierra, Staff and BCP entered into a stipulation in the Consolidated Dockets, which was filed with the
26 Commission on September 16, 2013, whereby they agreed and recommended that the Commission find Sierra's
27 short-term load forecast for 2014 contained in the Energy Supply Plan meets the requirements of NAC 704.922,
704.9321, 704.9482 and 704.9484(7) and is suitable for making planning decisions for 2014.

1 Tracy Unit 3 and Fort Churchill Units 1 and 2. The BART upgrades at Tracy Unit 3 and Fort
2 Churchill Units 1 and 2 do not allow for the continued use of oil-firing capacity beyond December
3 31, 2014. Sierra has begun to design and procure the equipment necessary to have the BART
4 upgrades installed to permit the continued operation of such generating units after December 31,
5 2014, although such operation necessarily entails the retirement of oil-firing capability on or before
6 December 31, 2014.

7 C. Regarding prayer for relief number 6, the Commission should accept the request to
8 complete a capital project involving the installation of dry sorbent injection equipment at North
9 Valmy Unit 1 with an estimated cost of \$14.2 million, of which Sierra would be responsible for
10 approximately \$7.1 million.

11 D. Regarding prayer for relief number 7, the Commission should accept Sierra's
12 proposal to establish a regulatory asset for the cost associated with the retirement of Tracy Units 1
13 and 2.

14 E. Regarding prayer for relief number 11, the Company withdraws its request for
15 approval of modifications to the scope of the Fallon 230 kV project and its request for approval of
16 changes to the schedule of the 345 kV Voltage Support project. With respect to the Bordertown to
17 Cal Sub project, the Parties acknowledge that the increase in budget does not affect the Company's
18 choice of resources and recommend that the Commission approve the changes in schedule for the
19 project.

20 F. The Commission should accept the Company's requests for:

21 1. With regard to prayer for relief 12, construction of the new 345/120 kV
22 substation at Oreana provided that the customer for whom the project is being undertaken provides
23 funding for the project;

24 2. With regard to prayer for relief 13, the Carlin Trend Area under voltage load
25 shedding project;

3 4. With regard to prayer for relief 15, the Coyote Creek 120 kV Breaker
4 Addition Project.

5 5. With regard to prayer for relief 16, the Company withdraws its request; the
6 withdrawal of this request does not preclude the Company from undertaking studies necessary to
7 facilitate integrated resource planning.

8 G. The Commission should authorize Sierra to continue to participate as a member in
9 West Connect.²

10 H. With regard to prayer for relief 17, the Commission should accept Sierra's
11 Renewable Conceptual Transmission Plan as meeting the requirements of NAC 707.9385(6).

1. With regard to prayer for relief 38 and in accordance with NRS 704.746(3), the Commission should find that (1) Sierra's forecasted requirements are based on substantially accurate data and an adequate method of forecasting; (2) the IRP identifies and takes into account present and projected reductions in demand for energy that may result from measures to improve energy efficiency; and (3) the IRP adequately demonstrates the economic, environmental and other benefits to the State of Nevada and Sierra's customers associated with improvement in energy efficiency, pooling of power, purchases of power from neighboring states, renewable energy generation, co-generation, hydro-generation, and other generating resources. However, as a directive, the Commission should direct Sierra to include an analysis in future Supply Side Plans detailing the expected cooling technology in each new generation facility, conventional and renewable, modeled in the expansion plans and to quantify each plan's expected water consumption in the next IRP where major capital expenditures are requested.

24 J. Regarding prayer for relief 39, the Commission should accept Sierra's IRP as
25 satisfying the requirements of Nevada's statutory and regulatory provisions governing the integrated

27 | ² Prayer for relief 18 in Sierra's Application.

1 resource planning process, as modified by this Stipulation. The Stipulation shall not be construed as
2 accepting or approving any action except actions enumerated in the "Action Plan," again as
3 modified by this Stipulation.

4 K. The Commission should find that for the purposes of determining the estimated rates
5 for long-term avoided cost to be filed pursuant to NAC 704.9496(2) that such rates be limited to a
6 maximum of 25 MW of QF contracts and be based upon the base load forecast for 2014; the low
7 load forecast for 2015 through 2033; the base fuel and power purchase forecasts; the Case 4 Low
8 Load expansion plan as depicted in the Loads and Resources Table of ECON-9, Volume 13 of the
9 Application; and the amounts of DSM and DR programs as determined by the Commission.

10 4. Confidentiality.

11 Regarding all confidential matters addressed by prayer for relief 37 except the Company's
12 request for confidentiality of information relating to the Fort Churchill Solar Array, the Commission
13 should grant the Company's request for confidential treatment of certain portions of the filing and
14 the Technical Appendices pursuant to NAC 704.7272.

15 5. General Points of Agreement.

16 A. This Stipulation represents a compromise of the positions of the Parties. Except as
17 set forth herein, neither this Stipulation, nor its terms, nor the Commission's acceptance of the
18 recommendations contained in this Stipulation shall have any precedential effect in future
19 proceedings.

20 B. This Stipulation shall not become effective and shall be given no force or effect until
21 the issuance of a Commission order that accepts this Stipulation. If the Commission does not accept
22 the Stipulation, then the Stipulation is withdrawn and no part of the Stipulation shall be admissible
23 in any proceeding before the Commission or any other tribunal.

24 C. This Stipulation may be executed in one or more counterparts, all of which together
25 shall constitute the original executed document. This Stipulation may be executed by signatures
26
27

provided by electronic facsimile transmission, which facsimile signatures shall be as binding and effective as original signatures.

Regulatory Operations Staff

By: Jermaine Grubbs
Name: Jermaine Grubbs
Title: Assistant Staff Counsel

Dated: 10/8/2013

Sierra Pacific Power Company d/b/a NV Energy

By: Shawn M. Elicequi
Name: Shawn Elicequi
Title: Associate General Counsel

Dated: 10/09/2013

Office of the Attorney General,
Bureau of Consumer Protection

By: David Norris
Name: David Norris
Title: Senior Deputy Attorney General

Dated: 10/8/13

Apple Inc. (Does Not Oppose)

By: _____ Dated: _____
Name:
Title:

Building & Construction Trades Council of Northern Nevada (Does Not Oppose)

By: _____ Dated: _____
Name:
Title:

Nevadans for Clean Affordable Reliable Energy (Does Not Oppose)

By: _____ Dated: _____
Name:
Title:

1 provided by electronic facsimile transmission, which facsimile signatures shall be as binding and
2 effective as original signatures.

3 Regulatory Operations Staff

4
5 By: _____ Dated: _____
6 Name: Jermaine Grubbs
7 Title: Assistant Staff Counsel

8
9 Sierra Pacific Power Company d/b/a NV Energy

10 By: _____ Dated: _____
11 Name: Shawn Elicegui
12 Title: Associate General Counsel

13 Office of the Attorney General,
14 Bureau of Consumer Protection

15 By: _____ Dated: _____
16 Name: David Norris
17 Title: Senior Deputy Attorney General

18 Apple Inc. (Does Not Oppose)

19 By: Stephen Hall Dated: 10/9/13
20 Name: _____
21 Title: _____

22 Building & Construction Trades Council of Northern Nevada (Does Not Oppose)

23 By: _____ Dated: _____
24 Name: _____
25 Title: _____

26 Nevadans for Clean Affordable Reliable Energy (Does Not Oppose)

27 By: _____ Dated: _____
28 Name: _____
Title: _____

1 provided by electronic facsimile transmission, which facsimile signatures shall be as binding and
2 effective as original signatures.

3 Regulatory Operations Staff

4
5 By: _____ Dated: _____
6 Name: Jermaine Grubbs
7 Title: Assistant Staff Counsel

8
9 Sierra Pacific Power Company d/b/a NV Energy

10 By: _____ Dated: _____
11 Name: Shawn Elicegui
12 Title: Associate General Counsel

13 Office of the Attorney General,
14 Bureau of Consumer Protection

15 By: _____ Dated: _____
16 Name: David Norris
17 Title: Senior Deputy Attorney General

18 Apple Inc. (Does Not Oppose)

19 By: _____ Dated: _____
20 Name:
21 Title:

22 Building & Construction Trades Council of Northern Nevada (Does Not Oppose)

23 By: _____ Dated: _____
24 Name:
25 Title:

26 Nevadans for Clean Affordable Reliable Energy confirms that it does not oppose the Stipulation.

27 By: Robert G. Johnston Dated: 10/8/13
28 Robert G. Johnston

provided by electronic facsimile transmission, which facsimile signatures shall be as binding and effective as original signatures.

Regulatory Operations Staff

By: _____ Dated: _____
Name: Jermaine Grubbs
Title: Assistant Staff Counsel

Sierra Pacific Power Company d/b/a NV Energy

By: _____ Dated: _____
Name: Shawn Elicequi
Title: Associate General Counsel

Office of the Attorney General,
Bureau of Consumer Protection

By: _____ Dated: _____
Name: David Norris
Title: Senior Deputy Attorney General

Apple Inc. (Does Not Oppose)

By: _____ Dated: _____
Name:
Title:

Building & Construction Trades Council of Northern Nevada (Does Not Oppose)

By: Michael E. Langton Dated: 10/8/13
Name: MICHAEL E. LANGTON
Title: ATTORNEY

Nevadans for Clean Affordable Reliable Energy (Does Not Oppose)

By: _____ Dated: _____
Name:
Title:

1 Newmont USA, LTD d/b/a Newmont Mining Corporation (Does Not Oppose)

2
3 By: Patrick V. Fogarty Dated: 10/9/13
4 Name:
5 Title:

6 Northern Nevada Industrial Electric Users (Does Not Oppose)

7 By: Patrick V. Fogarty Dated: 10/9/13
8 Name:
9 Title:

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing **NEVADA POWER COMPANY D/B/A NV ENERGY AND SIERRA PACIFIC POWER COMPANY D/B/A AS NV ENERGY'S STIPULATION** in Docket No. 13-07002/5 upon the persons listed below via electronic media to the following:

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Robert Johnston
Kilpatrick Johnston & Adler
412 N. Division St.
Carson City, NV 89703
rjohnston.kja@pyramid.net

DATED this 9TH day of October, 2013.

/s/ Connie Silveira
Connie Silveira
Legal Secretary
Nevada Power Company

3.3 Public Utilities Commission of Nevada, Docket No. 14-05003

May 1, 2014 Filing with the PUCN.

NV Power Company dba NV Energy: Emission Reduction and Capacity Replacement Plan (ERCR Plan). Application to amend its 2013-2031 Integrated Resource Plan and retire Reid Gardner Generating Station Units 1, 2 and 3 on 12/31/2014, and Unit 4 on 12/31/2017 (page 3).

Contact Filer Regarding Image Clarity

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy
Seeking Acceptance of the First Amendment to its 2013-
2032 integrated resource plan and its Energy Supply Plan
Update for 2015, which include an emissions reduction and
capacity replacement plan filed pursuant to NRS § 704.7311
et seq.

Docket No. 14-05 ____

VOLUME 3 OF 15

EMISSIONS REDUCTION AND CAPACITY REPLACEMENT PLAN

SUMMARY

DESCRIPTION	PAGE NUMBER
SUMMARY	2

SUMMARY

SECTION I - INTRODUCTION: NAC § 704.9215(2)(a)

This Emissions Reduction and Capacity Replacement plan (“ERCR Plan”) is filed by Nevada Power Company d/b/a NV Energy (“Nevada Power” or the “Company”). Nevada Power is a wholly-owned subsidiary of NV Energy, Inc. (“NVE”). NVE has two utility subsidiaries: Nevada Power and Sierra Pacific Power Company d/b/a NV Energy (“Sierra”).

In preparing the ERCR filing, Nevada Power sought to develop a balanced plan, weighing a number of factors such as the effects on customers, resource diversity and economic benefits to the State of Nevada. The Company developed a strategy based on opportunistic acquisitions, looking first to the acquisition of existing resources in Nevada rather than the construction of new fossil-fuel fired units. The Company then sought opportunities that immediately advance the development of new renewable resources in Nevada and add construction jobs to the local economy upon approval by the Public Utilities Commission of Nevada (the “Commission”). The result is a cost-effective, orderly and structured plan. Under the plan, Nevada Power will retire or eliminate 812 MW of coal-fired generation over the next six years, acquire 496 MW of existing gas-fired generation needed to provide reliable service, construct 215 MW of new, company-owned solar facilities that add fuel diversity, issue three separate 100 MW requests for proposals (“RFPs”) for transaction with new renewable energy, and begin permitting of land in Clark County for new renewable energy facilities (the “Preferred Plan”).

The purpose of this Summary Volume is to provide an overview of Nevada Power’s ERCR Plan. This volume also describes how the plan fits into the broader Company strategic and planning requirements. Finally, this volume presents the Company’s plan which outlines the specific approval requests (“Action Plan”) for the Commission’s consideration.

A. EMISSIONS REDUCTION AND CAPACITY REPLACEMENT.

Background. On June 11, 2013, Governor Brian Sandoval signed SB 123, marking the completion of a bi-partisan effort to change Nevada’s energy landscape.¹ Sponsored by Senator Atkinson, Assemblywoman Kirkpatrick, and Assemblyman Bobzien, the legislation requires Nevada Power to prepare and file with the Commission an ERCR Plan. Section 704.7316 of the Nevada Revised Statutes (“NRS”) prescribes the minimum elements of the ERCR Plan.

NRS § 704.7316(2)(a) provides for the retirement or elimination in three phases of not less than 800 MW of coal-fired electric generating capacity. The first 300 MW of coal-fired generating capacity must be retired or eliminated on or before December 31, 2014, then 250 MW of coal-fired generation on or before December 31, 2017, followed by 250 MW of coal-fired generation on or before December 31, 2019.

¹ Senate Bill 123 received unanimous support from Nevada’s 11 Democratic and 10 Republican Senators.

NRS § 704.7316(2)(c) provides that retired or eliminated coal-fired generation is to be replaced by 550 MW of constructed or acquired generating capacity that is owned by Nevada Power. The fuel source for this 550 MW of owned generating capacity is not specified by the legislation. However, the legislation does require that this 550 MW of replacement generating capacity be constructed or acquired in an orderly and structured manner.

NRS § 704.7316(2)(b) provides that retired or eliminated coal-fired generation is to be replaced by 350 MW of constructed, acquired or contracted for renewable energy resources. Nevada Power is required to issue three 100 MW RFPs from new renewable energy, on or before December 31, 2014, December 31, 2015 and December 31, 2016, respectively. Nevada Power must begin to construct or acquire 50 MW of new renewable energy resources on or before December 31, 2017.

In 2013, the Legislature made the “choice to move our state forward by moving away from this form [coal] of production of energy.”² According to Senator Atkinson, the legislation took “a distinct and bold new approach to the development of renewable energy for our State.”³ The legislation secured for Nevada a “bright future with clean energy production,” helping the State contribute to “solutions for climate change.”⁴ At the same time, the statute was designed and intended to provide “jobs at a critical point in the emerging recovery of Nevada’s economy.”⁵ In short, the legislation was intended to do what is “right for our environment, for the health of all Nevadans, and for our economy.”⁶

Key Elements of Nevada Power’s ERCR Plan. Nevada Power has developed a thoughtful and comprehensive approach to meeting the challenges of long-term resource planning while considering the requirements of the ERCR Plan. The Company’s Preferred Plan was selected from four alternative plans (or “cases”), all of which met the ERCR Plan requirements. Nevada Power tested each of the four alternative plans against different assumptions for fuel prices, load growth, and carbon prices. The Preferred Plan provides a balanced, orderly and structured solution for customers with a present worth of revenue requirement (“PWRR”) 0.008 percent of the case with the lowest PWRR (the construction of a single large natural gas-fired combined cycle power plant). The Preferred Plan maintains critical system diversity, and has immediate positive economic impacts on Nevada by advancing renewable energy and jobs in the state. The Preferred Plan meets the three main requirements of the ERCR Plan.

² See Assembly Journal at 241 (“This session we are making the choice to move our state forward by moving away from this form of production of energy.”) (Statement of Assemblyman Bobzien).

³ See Senate Journal at 8 (“The bill also makes a distinct and bold new approach to the development of renewable energy for our State.”) (Statement of Senator Atkinson).

⁴ See Assembly Journal 241 (“Nevada has a bright future with clean energy production and the finding of solutions for climate change.”) (Statement of Assemblyman Bobzien).

⁵ See Senate Journal at 8 (“The bill requires NV Energy to take appropriate and necessary steps to develop 350 megawatts of new renewable facilities, and provides construction jobs at a critical point in the emerging recovery of Nevada’s economy.”) (Statement of Senator Atkinson).

⁶ See Assembly Journal at 244 (“This is planning. This is getting ready for the future. This is what’s right for our environment, for the health of all Nevadans, and for our economy.”).

1. Retire or Eliminate at Least 800 MW of Coal Fired Generation

Nevada Power must file with the Commission a plan for the retirement or elimination of at least 800 MW of coal-fired generating facilities according to a defined schedule. All required retirements and eliminations must be completed before December 31, 2019. This ERCR Plan meets this requirement by proposing the following action as shown in Table S-1.

**TABLE S-1
PROPOSED RETIREMENT OR ELIMINATION OF
COAL-FIRED GENERATION CAPACITY⁷**

Unit	Planning Capacity	Retire or Eliminate	Date
Reid Gardner Generating Station, Units 1, 2 & 3	300 MW	Retire	12/31/2014
Reid Gardner Generating Station, Unit 4	257 MW	Retire	12/31/2017
Navajo Generating Station, 11.3 percent Ownership Interest	255 MW	Eliminate	12/22/2019
Total Retired/Eliminated Planning Capacity	812 MW		

Note: Retire is to remove a unit permanently from service.

Eliminate is to divest a utility's ownership interest in the facility.

The details of the retirements, including schedules and costs for decommissioning, are described in the Generation Section beginning with the Supply Side Plan, Section 2.A.3.

2. 550 MW of Replacement “Planning” Capacity

Nevada Power developed a package of replacement generating units that adds company-owned capacity in an orderly and structured manner, and also provides fuel diversity. Equally important, instead of proposing construction of new gas-fired generating units, the package provides for the acquisition of existing units. As shown in Table S-2, the first addition of replacement capacity occurs on January 1, 2015, when Nevada Power plans to acquire the existing 224 MW Las Vegas Cogeneration (“LV Cogen”) Unit 2. The next addition of replacement capacity occurs on June 1, 2016, when an existing power purchase agreement (“PPA”) terminates, and the existing 222 MW Sun-Peak Generating Unit becomes replacement capacity. Nevada Power adds the third element of the replacement capacity package in October 2016, when the 200 MW Moapa Solar Project (which provides 76 MW of planning capacity) is placed into service. The final element of the replacement capacity package involves the addition of 50 MW of incremental capacity in

⁷ See Regulation Section 12, Para. 2.

October 2017, when Nevada Power’s existing PPA with LV Cogen Unit 1 becomes replacement capacity.

The Preferred Plan is cost effective, with lower capital costs than a single new combined-cycle generating unit. Moreover, the economics of the Preferred Plan are improved with the opportunity to obtain an Investment Tax Credit (“ITC”) on two of the proposed investments that will reduce the overall cost of providing service. The Preferred Plan results in a 20-year present worth of revenue requirement (“PWRR”) that under base assumptions is within 0.008 percent of the case with the lowest PWRR (the construction of a single large natural gas-fired combined cycle power plant). The package balances cost-effective acquisitions of existing natural gas resources with the environmental and economic objectives of SB 123 by also providing for the construction of a new 200 MW (nameplate rating, 76 MW planning capacity) solar photovoltaic (“PV”) facility. Table S-2 describes the replacement capacity package developed by Nevada Power.

TABLE S-2
COMPANY-OWNED REPLACEMENT CAPACITY
(NON-TECHNOLOGY SPECIFIC)⁸

Unit	Timing of Replacement	Planning Capacity	Type of Capacity	Fuel	Estimated Cost
LV Cogen Unit 2	1/1/2015	224 MW	Intermediate	Natural Gas	\$130.8m
Sun-Peak Generating Unit	6/1/2016	222 MW	Peaking	Natural Gas	\$15.8m
Moapa Solar Generating Station	10/1/2016	76 MW	Intermittent	Solar	\$438.1m ⁹
LV Cogen Unit 1	10/1/2017	50 MW	Peaking	Natural Gas	\$0.0 ¹⁰
Total Replacement Capacity		572 MW			\$584.7m

Note: Planning capacity refers to the amount of firm electric generating capacity required to meet Nevada Power’s peak load and provide a planning reserve margin that is authorized by the Commission. With regard to the Moapa Solar Generating Station, the “nameplate” capacity is approximately 200 MW but a planning capacity of 76 MW.

The details of the replacement capacity, including schedules and costs are described in Section IV of this Summary and Section 2.A.4. of the Supply Side Volume for LV Cogen Units 1 and 2,

⁸ Nev. Rev. Stat. § 704.7361(2)(c). Million is abbreviated to “m” and thousand is abbreviated to “k.”

⁹ This estimate does not include an allowance for funds used during construction (“AFUDC”).

¹⁰ LV Cogen Unit 1 will be acquired as a package with LV Cogen Unit 2.

and Sun-Peak, and in Section V of this Summary and Section 2.D.6. of the Supply Side Plan the for the Moapa Solar Project.

The transmission requirements associated with the Moapa Solar Project are described in the Supply Side Volume, Section 2.E. Because the Preferred Plan contains natural gas fired replacement capacity, the Company is proposing a fixed physical gas hedging strategy. The hedging strategy is explained in detail in the Energy Supply Plan filed with this ERCR Plan.

3. 350 MW Renewable Replacement “Nameplate” Capacity

Under the provisions of SB 123, Nevada Power is required to acquire or construct 50 MW of renewable resources and issue three 100 MW RFPs for renewable energy. The Company is seeking Commission approval to invest up to \$54.5 million to build a 15 MW (alternating current) PV generating facility at Nellis Air Force Base. The Company will take appropriate steps to identify opportunities for another 35 MW or more. Proposals will be brought to the Commission for approval in an amendment.

Nevada Power is also requesting Commission approval to issue three 100 MW RFPs (300 MW in total) for transactions with new renewable energy. The Company will follow the structure of its previous solicitation and contracting process used in securing renewable power purchase agreements (“PPAs”). The Company expects to receive additional guidance from the Commission as a result of continued rulemaking known as Phase 2 of Docket No. 13-06023. The Company anticipates that it will request interim approval of PPAs in an effort to allow projects eligible for an investment tax credit (“ITC”) to meet a 2016 commercial operation date and to allow the Company to maintain schedule compliance with SB 123 requirements.

**TABLE S-3
RENEWABLE RFP ESTIMATED SCHEDULE**

RFP Schedule 300 MW			
EVENT	2014	2015	2016
Release Public Notice	10/01/14	12/14/15 ¹¹	11/15/16
Initial Short List	01/13/15	02/11/16	01/24/17
Final Short List	02/13/15	03/11/16	02/24/17
Negotiations	03/30/15	04/22/16	04/07/17
Management Approvals	04/30/15	05/23/16	05/08/17
IRP (Amendment) Approval Filing	07/01/15	06/15/16	06/01/17
PUCN Approval Timeline	12/28/15	10/28/16	10/13/17

The details of the renewable PPAs, Nellis Solar Array II and Clark County site permitting for future renewables is described in the Supply Side Plan, Section 2.D.

Analysis of Alternatives. Nevada Power considered four alternative plans to replacing coal-fired generating capacity that will be retired or eliminated pursuant to NRS § 704.7316. Specifically, Nevada Power considered replacing retired coal-fired generating capacity with: (1) a 597 MW combined-cycle generating unit in 2018 (Case A); (2) 568 MW of simple-cycle, peaking units in 2018 (Case B); (3) a replacement package of diverse peaking (272 MW), intermediate (224 MW) and intermittent units (approximately 200 MW, or approximately 76 MW planning), which is the Company's Preferred Plan (Case C); and, (4) a modified replacement package of peaking (50 MW), intermediate (224 MW) and intermittent units (700 MW nameplate, and 266 MW planning) (Case D).

Table S-4 compares the Cases A, B, C, and D for the base load forecast, base fuel and purchase power forecast, and mid-carbon price forecast.

¹¹ NAC [Section 3] requires that the Company shall not accept proposals until the previous RFP is complete. Proposals would be accepted (due) in February 2016.

TABLE S-4
SUMMARY-BASE LOAD FORECAST WITH
BASE FUEL AND PURCHASED POWER - MID CARBON

BASE LOAD BASE FUEL Mid Carbon No Sales										
Case	Description	10 Year PWRR 2015-2024 (million \$)	20 Year PWRR 2015-2034 (million \$)	30 Year PWRR 2015-2044 (million \$)	10 Year PWRR Increase vs Least Cost (million \$)	20 Year PWRR Increase vs Least Cost (million \$)	30 Year PWRR Increase vs Least Cost (million \$)	10 Year PWRR Rank	20 Year PWRR Rank	30 Year PWRR Rank
Case A	2x1 CC 2018 ERCR	\$ 13,871	\$ 24,199	\$ 31,903	\$ -	\$ -	\$ -	1	1	1
Case B	CTs 2018 ERCR	\$ 13,935	\$ 24,285	\$ 31,999	\$ 63	\$ 85	\$ 96	3	3	3
Case C	200 PV LVC SP ERCR	\$ 13,875	\$ 24,201	\$ 31,967	\$ 3	\$ 2	\$ 64	2	2	2
Case D	200 PV LVC 500 PV ERCR	\$ 14,337	\$ 24,724	\$ 32,406	\$ 466	\$ 525	\$ 503	4	4	4

In an analysis of alternative plans, the Preferred Plan resulted in a 20-year PWRR that under base assumptions is within 0.008 percent of the case with the lowest PWRR (the construction of a single large natural gas-fired combined cycle power plant), and was the least cost plan in 6 of 12 sensitivity scenarios.

Diversity Concerns. Diversification plays an important role in reducing risk related to price volatility and, consequently, cost. With respect to electric generation, both capacity and fuel diversity are important.

Capacity diversity refers to the nature of a generating unit (e.g., baseload, intermediate, peaking and intermittent resources). Capacity diversity is important because it allows a utility to use the appropriate and most efficient “tool” for the “job.” When properly deployed, each type of capacity can operate synergistically to allow a utility to meet increases and decreases in demand in the most cost effective manner.

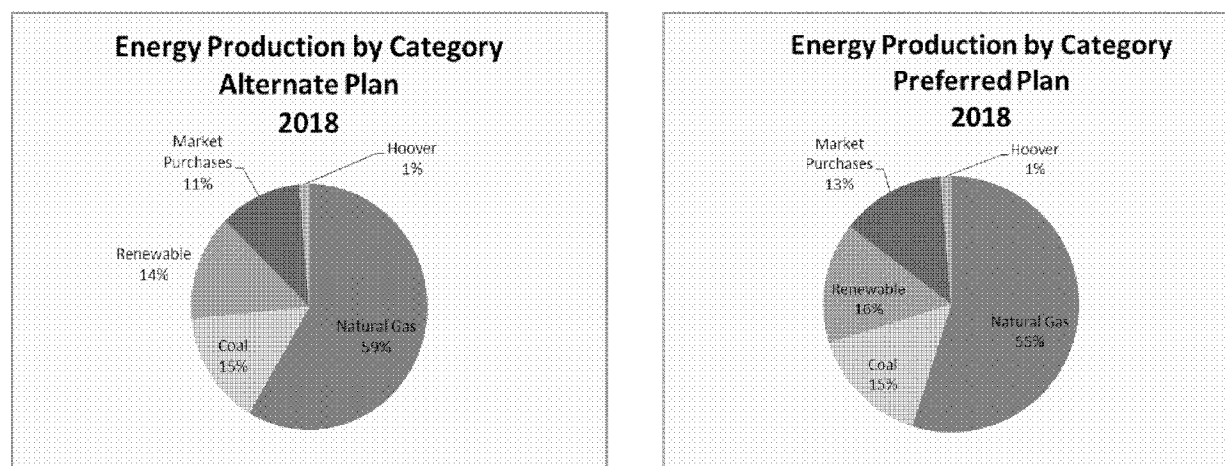
Fuel (or production) diversity refers to the type of fuel or process that a given unit uses to produce electricity. More specifically, fuel diversity – that is, the development of a portfolio of generation resources that rely on different means of generating electricity – has the potential to reduce the impact that uncontrollable changes in fuel markets have on customers. Fuel diversity assures economic and energy security; too great a reliance on any one source of energy increases risk by exposing customers to potential price increases and supply disruptions. Equally important, fuel diversity can reduce the effect that major changes in public policy might have on the Company’s customers. In summary, capacity and fuel diversity play important roles in enhancing Nevada Power’s ability to provide safe and reliable electric service to its customers while maintaining just, reasonable and predictable rates.

A variety of different resources can be used to generate electricity, including coal, natural gas, uranium, wind, water, solar, geothermal and biomass. Each of these options has a unique cost profile, based on the supply and demand of the fuel and technology used to turn chemical, solar or kinetic energy into electricity. Each option presents different diversity, and thus risk, characteristics and unique operating considerations related to availability, performance and reliability. Each option has different implications for capacity and fuel diversity.

The Company's Preferred Plan maintains both capacity and fuel diversity. When comparing Case C to Case A, Case C provides more fuel diversity and more capacity diversity than does Case A. The combined-cycle unit in Case A is gas-fired base load capacity. The replacement capacity developed by the Company in Case C provides 224 MW of gas-fired intermediate capacity, 272 MW of gas-fired peaking capacity, and 76 MW (planning capacity) of renewable intermittent capacity.

The inclusion of new renewable energy facilities in the Preferred Plan provides an element of fuel diversity, which is particularly important in light of the retirement of coal-fired generation. See Figure S-1, below.

**FIGURE S-1
ENERGY PRODUCTION BY CATEGORY
PREFERRED PLAN AND ALTERNATE PLAN**



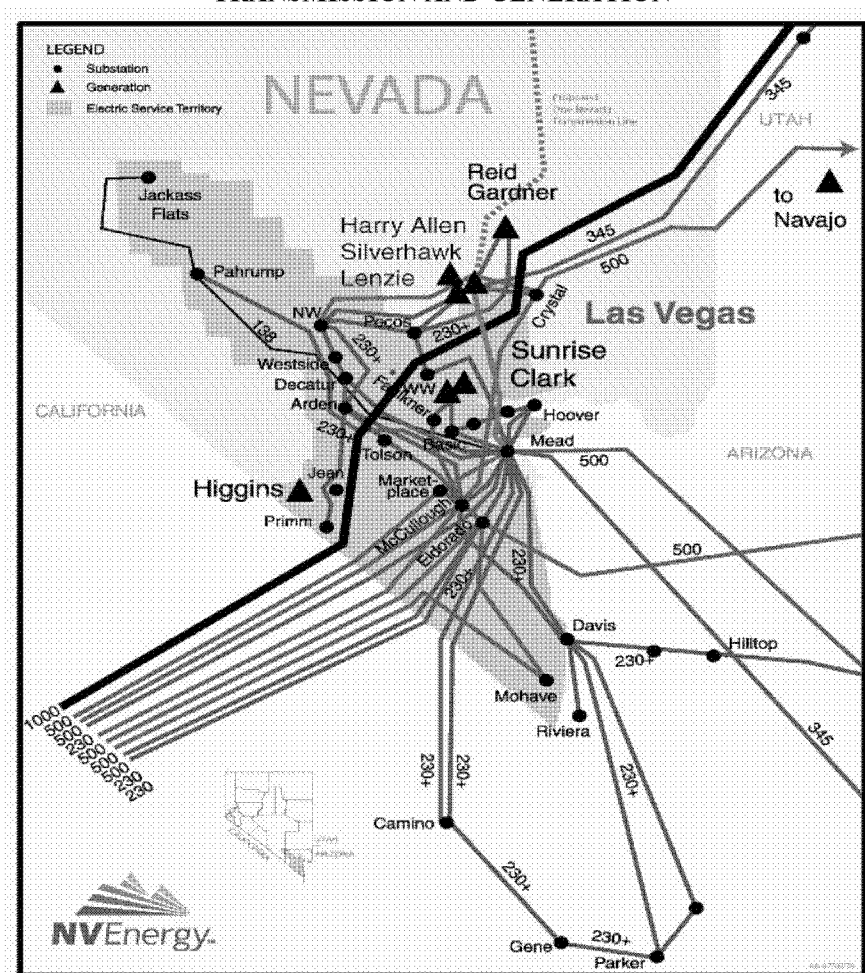
B. SUMMARY VOLUME REQUIREMENTS¹²

Nevada Power Described. Nevada Power generates, transmits and distributes electric energy to approximately 850,000 customers in Las Vegas, North Las Vegas, Henderson, Searchlight, Laughlin, and adjoining areas, including Nellis Air Force Base.

¹² This Section of the Summary contains an integrated evaluation of the components of the resource plan, which relates the preferred plan to the objectives of the strategic plan. See NAC §704.9215(2)(h).

Nevada Power is regulated by the Commission and the Federal Energy Regulatory Commission (“FERC”). Nevada Power’s primary place of business is at 6226 West Sahara Avenue, in Las Vegas, Nevada. Figure S-2 shows Nevada Power’s service territory along with existing transmission and generation stations.

**FIGURE S-2
NEVADA POWER SERVICE TERRITORY, EXISTING
TRANSMISSION AND GENERATION**



With the Commission’s leadership and support, Nevada Power has reduced its reliance on volatile wholesale markets in recent years. In 2008, Nevada Power generated just 67.5 percent of its total energy requirements from Company-owned facilities, while purchasing the remaining 32.5 percent from neighboring utilities and renewable energy developers. Nevada Power now has sufficient Company owned and/or controlled generation to meet nearly all of its customers’ 2014 needs. Considering pending generation retirements and expiring contracts, and utilizing the results of a new long-term load forecast, the Company’s approved demand-side management plan (“DSM Plan”) and a refreshed renewable energy plan, Nevada Power identified the Company’s resource requirements over a full 30-year planning period. This analysis indicates

that Nevada Power needs to execute a comprehensive replacement strategy to replace retiring capacity.

Resource Planning Described. Beginning in 1983, the Legislature gave the Commission oversight authority over Nevada Power’s long-term planning process. Every three years, Nevada Power formulates and presents its Preferred Plan for meeting the long-term needs of its customers. Based on projections of customers’ load requirements, Nevada Power prepares a long-term integrated resource plan (“IRP”), in which it lays out programs to fill projected requirements with programs that reduce energy consumption (demand-side management or “DSM”), by building or purchasing generation (from conventional and renewable energy sources), by building or purchasing transmission, and by purchasing fuel (natural gas and coal).

ERCR Planning Period and Action Period. This 2014 ERCR Plan filing addresses the 20-year planning period 2015 to 2034, and the 30-year planning period 2015-2044. The Company’s Preferred and Alternate Plans are formulated and compared to different options using economic models. The ERCR Plan includes an “Action Plan” which details the steps that Nevada Power will take over the next year (2015) to implement the Preferred Plan. The Action Plan includes a description of the costs, timeline, and planning activities for each recommended project. A more detailed description of each project is provided in detailed narratives that are included in the ERCR Supply Side Volume.

Economic Analysis and Selection of Nevada Power’s ERCR Preferred Plan. In selecting its Preferred and Alternate Plans, Nevada Power has evaluated various factors that are set forth in the Commission’s regulations, including:

- The PWRR for each alternative (see NAC § 704.9357(3))
- The present worth of societal cost (“PWSC”) for each alternative (see NAC § 704.9357(4))
- Whether the plan mitigates risk (see NAC § 704.9357(5))
- Whether the plan provides adequate reliability (see NAC § 704.9357(6)(a))
- Regulatory and financial constraints (see NAC § 704.9357(6)(b))
- Whether the plan meets the Renewable Portfolio Standard (“RPS”) (see NAC § 704.9357(6)(c))
- Whether the plan meets the requirements for environmental protection (see NAC § 704.9357(6)(d))

In accordance with NAC § 704.948(2), the Company considered the relationship among these factors in selecting the Preferred and Alternate Plans, including the relationship between mitigating risk, minimizing cost and volatility, maximizing reliability, and resource diversification. The Company selected Preferred and Alternate Plans that provide the best combination of attributes, without assigning specific weights to any particular factor.

As discussed above, Nevada Power considered four alternative plans to replacing coal-fired generating capacity that will be retired or eliminated. In addition, scenario analyses were conducted by modeling all alternative plans under high and low fuel and purchased power prices; high and low load forecasts; and mid, high, and low carbon price impacts, including a scenario with no future carbon or greenhouse gas (“GHG”) cap-and-trade program. Each of the alternative plans is run under 12 sensitivities as identified in Table S-5.

**TABLE S-5
SUMMARY OF ANALYSIS SENSITIVITIES**

	<u>Load</u>	<u>Fuel</u>	<u>GHG</u>
1	BASE	BASE	MID C
2		LOW	MID C
3		HIGH	MID C
4	HIGH	BASE	MID C
5	LOW	BASE	MID C
6	BASE	BASE	NO C
7		LOW	NO C
8		HIGH	NO C
9	HIGH	BASE	NO C
10	LOW	BASE	NO C
11	BASE	BASE	HIGH
12	BASE	BASE	LOW

The Company has chosen Case C as the Preferred Plan and Case A as the Alternate Plan. With respect to PWRR, Cases C and A consistently provide the lowest PWRR among all scenarios among all planning periods. It is important to recognize that the difference between Case C and Case A (the case with the lowest PWRR under base assumptions) is negligible, especially in 10-year and 20-year periods. Indeed, in those years, the PWRR differences between Case C and Case A are \$3.0 million and \$2.0 million, respectively. This amounts to 0.02 percent and 0.008 percent of the total PWRR.

In light of the objective – the orderly and structured replacement of retired or eliminated coal-fired generating capacity – the replacement package developed by Nevada Power provides a favorably to Case B (the construction of a simple-cycle peaking project) and Case D (the acquisition of 274 MW of gas-fired generation and the addition of another 500 MW of PV). The

Preferred Plan also provides a more balanced outcome than the Alternate Plan, Case A (the construction of a 2x1 combined-cycle generating unit).

First, the overall capital cost of the replacement package is lower than the estimated cost of constructing a combined-cycle generating unit. Nevada Power estimates the cost of constructing a single natural gas-fired 576 MW combined-cycle generating unit by June 1, 2018, at least \$711 million (2015 dollars without an allowance for funds used during construction). In contrast, the estimated capital cost of the Preferred Plan is \$584.7 million.¹³ Importantly, the construction of a single combined-cycle unit would not receive the benefit of the federal ITC. The ITC equals 30 percent of eligible expenditures, with no maximum credit limitation on renewable systems placed in service on or before December 31, 2016. While Nevada Power, as a regulated utility, must normalize the tax credit over time, the credit reduces the overall cost of providing service to customers.

Second, the construction of a combined-cycle unit or simple cycle units would not provide the same type of capacity diversity delivered by the replacement package. While natural gas-fired combined-cycle units provide flexibility, including the ability to follow intermittent resources, those units today provide either base load or intermediate capacity. Simple-cycle units, on the other hand, provide peaking capacity. The replacement capacity package developed by the Company provides a mixture of replacement capacity. The package provides 224 MW of intermediate capacity, 272 MW of peaking capacity, 76 MW of intermittent capacity and another 6 MW of intermittent capacity. The package thus expands the capacity diversity of Nevada Power's portfolio.

Third, the construction or acquisition of a single-combined cycle unit or the construction of simple-cycle units would not enhance fuel diversity within Nevada Power's generating fleet. The first option (Case A) adds 597 MW of natural-gas fired combined-cycle generating capacity; the second option (Case B) adds 568 MW of natural-gas fired simple-cycle generating capacity. In either case, the Company would be relying entirely on natural gas as the fuel for fulfilling the 550 MW of non-technology specific replacement capacity required by NRS § 704.7316(2)(c). Case C, on the other hand, improves the Company's fuel diversity. By adding 200 MW (nameplate) of solar generating facilities, the Preferred Plan incorporates into its portfolio a resource that produces electricity without the need to procure additional natural gas. Case C not only increases the capacity diversity within Nevada Power's portfolio, but also increases the fuel diversity within the portfolio.

Fourth, and possibly most importantly, the Preferred Plan provides a distinct and bold option for Nevada. The package provides "construction jobs" in the renewable energy industry "at a critical

¹³ The estimated capital costs of the 200 MW, nameplate, of solar generating capacity shown in Table S-2 do not take into consideration the investment tax credit. While the Company must normalize the investment tax credit pursuant to federal law, Nevada Power's customers realize the benefit of the credit over time.

point in the emerging recovery of Nevada’s economy.” The Preferred Plan ensures that Nevada has a “bright future with clean energy production.” And, the Preferred Plan ensures local benefits, providing the best value for Nevadans as the Moapa Solar Project should generate up to \$181 million in benefits to Nevada.¹⁴

ERCR Plan Long-Term Resource Planning. Nevada Power needs to take action now, in 2014 and 2015, to replace the coal-fired generating capacity that it plans to retire in 2014 and 2017 pursuant to SB 123. Nevada Power will seek permission in its triennial IRP filing (due 2015), to ensure that it maintains the ability to continue to provide industry-leading reliable electric service at just and reasonable rates throughout the planning period. Between 2014 and 2022, Nevada Power must replace not only coal-fired generating capacity but capacity from expiring long-term purchased power agreements. In total, Nevada Power must replace approximately 2,320 MW of generating capacity by 2022, as is shown in Table S-6.

**TABLE S-6
CAPACITY ELIMINATIONS 2013-2022**

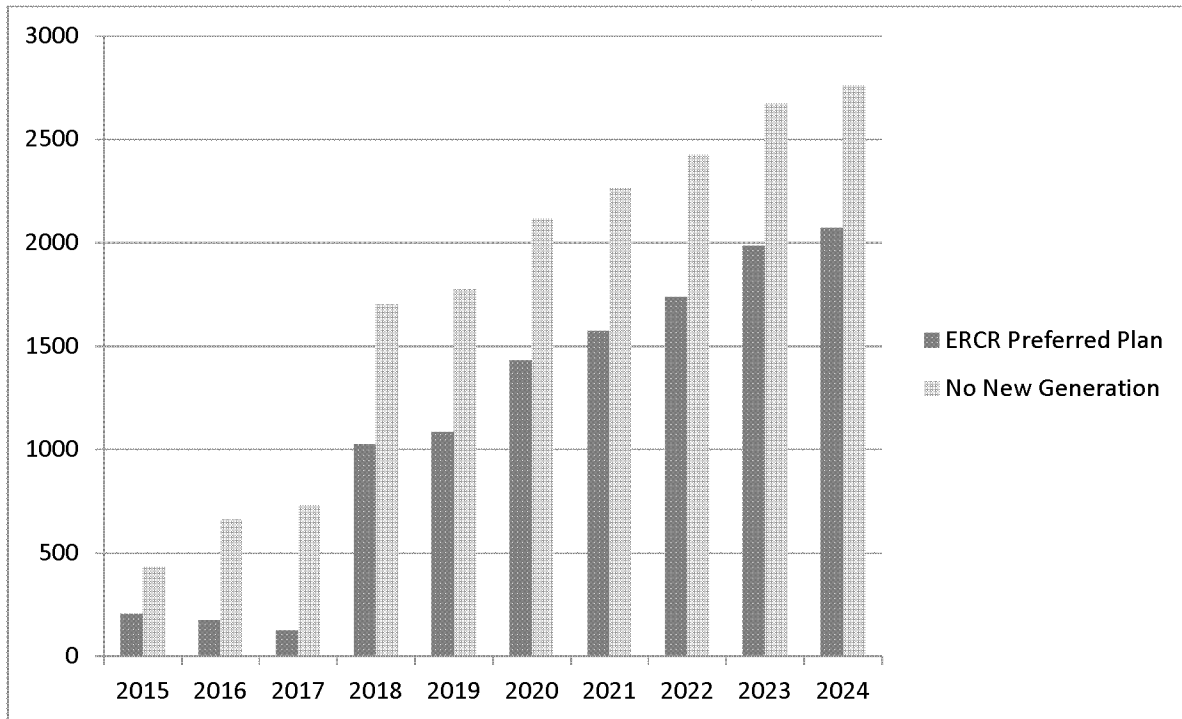
Unit/ PPA	Megawatts (MW) Summer Capacity	Retirement (R), Elimination (E) or Contract Expiration (C) Year
Las Vegas Cogeneration II	224	2013-C
Reid Gardner 1,2,3	300	2014-R
Sunpeak	222	2016-C
Griffith	570	2017-C
Las Vegas Cogeneration I	50	2017-C
Reid Gardner 4	257	2017-R
Southern Nevada Water Authority Transaction	130	2018-C
Navajo	255	2019-E
Clark 4	54	2020-C
Saguaro	90	2021-C
Nevada Cogeneration Associates 1	85	2022-C
Nevada Cogeneration Associates 2	85	2022-C

Absent action as a result of this filing, Figure S-3 shows that Nevada Power’s open capacity position (“Open Position”) grows to over 1,500 MW by 2018. Even if the Company takes action and adds the diverse portfolio of replacement capacity included in this ERCR Plan, Nevada Power projects that its Open Position will grow to approximately 1,000 MW by 2018.¹⁵

¹⁴ See Technical Appendix Item ECON-19, Solar Photovoltaic Plant Economic Impact Analysis prepared by Applied Analysis.

¹⁵ The Company has options to mitigate its open position and, in fact, is in the process of pursuing those options.

FIGURE S-3
OPEN POSITION WITH NO ACTION AND WITH CASE C
(PREFERRED PLAN)



ERCR and the Strategic Plan.¹⁶ Nevada Power is guided by six core principles. The Company's ERCR Plan is consistent with these core principles: customer service, employee commitment, environmental respect, regulatory integrity, operational excellence, and financial strength. As such, the Company's ERCR Plan consistent with Nevada Power's strategic plan and is supported and endorsed at the highest levels of NV Energy.

The Company's ERCR Plan is viewed as an efficient and effective strategic plan to meet the requirements of SB 123 while maintaining the reliability and cost effectiveness of its energy supply resources. The Company has incorporated the DSM Plan consistent with that included in Nevada Power's application for approval of its 2012 Integrated Resource Plan, as modified by the Commission's order and approved on December 24, 2012, in Docket 12-06053. After accounting for the contributions of DSM resources, the Company has identified the need to execute new generation supply acquisitions and initiate new generation construction activities to replace retiring generation and ensure it can reliably meet the needs of its customers.

Taking orderly and structured steps now—by executing on the acquisition of existing generating resources and beginning construction of new generating resources—will ensure that the

¹⁶ See LCB File No. R131-13, Sec. 13(2)(a).

Company and its customers are well-positioned to maintain a strong generation portfolio and avoid the risks of high levels of energy market exposure in the future.

Managing the Renewable Portfolio. The renewable energy plan set forth in this ERCR Plan continues Nevada Power's RPS compliance planning and advances important facets of SB 123, namely the development of renewable energy in Nevada and providing Nevada jobs to fuel the recovery of our economy. The Preferred Plan allows the Company to continue to manage its diverse portfolio of renewable PPAs while carefully monitoring the completion of approved projects that are not yet in service and pursue new PPAs and Company-owned renewable projects. Additionally, the Company intends to investigate new distributed generation options. NV Energy will complete an analysis of distributed generation and subscription options. Section VII describes the renewable energy action items that the Company is requesting approval.

Managing Generation and Purchased Power Portfolio. The Preferred Plan provides both capacity and fuel diversity. The Preferred Plan is based on the acquisition of existing gas-fired generating units and construction of new renewable generation that complements the Company's existing fleet of owned generation and long-term PPAs. The Company will continue to manage its generation fleet and PPAs to optimize the overall value to its customers and maintain a safe and reliable electric system. Additionally, the Company will continue to seek opportunities for its customers by investigating generation acquisition opportunities and long-term PPA extensions where it is economically beneficial. Section VII of this Summary describes the generation action items that the Company is requesting approval.

Managing Strategic Transmission Resources. The updated transmission plan submitted in this ERCR Plan filing is built upon the plan's load forecasts, system characteristics, existing and future transmission facilities, and obligations. Based on these key system characteristics, the transmission plan examines the capabilities of the existing transmission system and determines the need and timing of any additional transmission facilities. The Preferred Plan requires investment in transmission infrastructure. The transmission plan includes a previous study to address the development of Nevada's renewable resources for both internal consumption and for potential export to other markets. Finally the transmission plan discusses new or updated WestConnect and FERC policies. All facets of the transmission plan are intended to preserve and enhance the safety, reliability and effectiveness of the Company's transmission system. Section VII describes the transmission action items that the Company is requesting approval.

SECTION II - FORECAST OF GROWTH: NAC § 704.9215(2)(b)

Nevada Power has prepared a new load forecast for the 2014 ERCR Plan ("2014 ERCR Forecast"). The 2014 ERCR Forecast updates the 2014-15 Energy Supply Plan Update ("2014-2015 ESP Update Forecast" or "2014-2015 ESP"), which was completed in January 2013 and

filed with the Commission on September 1, 2013 in Docket No. 13-08009. The 2014 ERCR Forecast was completed in November 2013 and incorporates actual sales and load data through August 2013. Nevada Power seeks approval of the 2014 ERCR Forecast.

Forecast Summary. In 2008, the downturn in the national and local economy began to significantly impact economic performance and electric sales in Nevada Power's service territory. The economic downturn worsened in 2009 and continued to adversely impact Nevada Power's sales through 2011. Fueled by an uptick in the tourism industry, sales turned positive in 2012 across all sectors with weather normalized sales up 1.7 percent compared to the previous year. However, in 2013 year-over-year sales fell again as the tourism industry remained sluggish and the Department of Energy's Nevada Test Site ("Nevada Test Site") exited Nevada Power's system to take service from Valley Electric Association.¹⁷ In 2013, total sales fell 1.0 percent, with small and large commercial and industrial ("C&I") weather normalized sales dropping 1.5 percent and 2.4 percent respectively from 2012.

Unlike sales, customer counts continued to modestly increase even during the economic downturn that started in 2008. Residential customer counts increased 1.5 percent in 2012 and 1.2 percent in 2013. Despite continued increases in customer counts, however, end-use efficiency, new appliance and commercial end-use standards, solar photovoltaic ("PV") market penetration, and demand side management ("DSM") program activity will continue to put downward pressure on long-term projections of customer usage (measured in terms of kWh/per customer). Residential average use is projected to decline 0.2 percent annually from 2013 through 2023 and commercial average use (small- and medium-size commercial customers) is projected to decline 0.1 percent annually over this period. In the near-term (2013 through 2016) residential use per customer is forecast to decline 0.5 percent on average as a result of the new lighting standards and continued DSM program activity. New residential lighting standards have had the largest impact on customer usage, as 100 watt and 75 watt incandescent light bulbs were scheduled for phase out in 2013, and 60 watt and 40 watt incandescent light bulbs are scheduled to be phased out in 2014. A full discussion of customer usage is contained in Technical Appendix LF-1.

Overall, Nevada Power expects to see positive sales growth over the next 10 years as the economy continues to improve, and Nevada Power adds new customers. Sales are expected to grow at an average annual rate of 1.0 percent over the next 10 years. Table S-7 summarizes historical (weather normalized) and forecasted class sales. Table S-8 presents residential historical and forecasted customer counts and weather normalized average usage. The forecast begins in 2014. Full results are summarized in Technical Appendix LF-1.

¹⁷ The Nevada Test Site represented a sales loss of approximately 65 GWh from 2012 to 2013.

**TABLE S-7
HISTORICAL (WEATHER NORMALIZED) AND FORECASTED SALES (GWH)**

Year	Res	chg	Small C&I	chg	Large C&I	chg	StLight	chg	Public Authority	chg	Total	chg
2003	7,456		3,743		6,292		153		258		17,901	
2004	7,742	3.8%	3,923	4.8%	6,548	4.1%	158	3.2%	249	-3.2%	18,620	4.0%
2005	8,512	9.9%	4,243	8.2%	6,986	6.7%	167	5.6%	184	-26.3%	20,091	7.9%
2006	8,907	4.6%	4,410	3.9%	7,270	4.1%	170	2.2%	110	-40.0%	20,867	3.9%
2007	8,979	0.8%	4,573	3.7%	7,472	2.8%	171	0.5%	64	-42.1%	21,259	1.9%
2008	8,884	-1.1%	4,604	0.7%	7,645	2.3%	173	1.0%	58	-9.5%	21,364	0.5%
2009	8,718	-1.9%	4,447	-3.4%	7,596	-0.6%	185	6.7%	55	-4.3%	21,001	-1.7%
2010	8,639	-0.9%	4,358	-2.0%	7,653	0.7%	177	-4.2%	56	0.4%	20,883	-0.6%
2011	8,604	-0.4%	4,352	-0.1%	7,627	-0.3%	170	-4.2%	55	-0.9%	20,807	-0.4%
2012	8,833	2.7%	4,456	2.4%	7,645	0.2%	166	-1.9%	53	-4.4%	21,153	1.7%
2013	8,871	0.4%	4,391	-1.5%	7,458	-2.4%	155	-6.8%	56	6.2%	20,931	-1.0%
2014	8,969	1.1%	4,462	1.6%	7,563	1.4%	154	-0.7%	54	-3.3%	21,202	1.3%
2015	8,985	0.2%	4,477	0.3%	7,588	0.3%	152	-1.0%	54	0.0%	21,256	0.3%
2016	9,010	0.3%	4,525	1.1%	7,633	0.6%	151	-1.0%	54	0.0%	21,372	0.5%
2017	9,083	0.8%	4,595	1.6%	7,703	0.9%	149	-1.0%	54	0.0%	21,585	1.0%
2018	9,207	1.4%	4,678	1.8%	7,789	1.1%	149	0.0%	54	0.0%	21,878	1.4%
2019	9,335	1.4%	4,767	1.9%	7,875	1.1%	149	0.0%	54	0.0%	22,180	1.4%
2020	9,450	1.2%	4,861	2.0%	7,957	1.0%	149	0.0%	54	0.0%	22,471	1.3%
2021	9,565	1.2%	4,956	2.0%	8,015	0.7%	149	0.0%	54	0.0%	22,740	1.2%
2022	9,654	0.9%	5,049	1.9%	8,062	0.6%	149	0.0%	54	0.0%	22,968	1.0%
2023	9,756	1.1%	5,145	1.9%	8,122	0.8%	149	0.0%	54	0.0%	23,227	1.1%
2003 - 13		1.8%		1.6%		1.7%		0.1%		-14.2%		1.6%
2013 - 23		1.0%		1.6%		0.9%		-0.4%		-0.3%		1.0%

Notes:

“Res” – Residential
 “Chg” – Change
 “Small C&I” – Small Commercial and Industrial
 “Large C&I” – Large Commercial and Industrial
 “StLight” – Street Lighting

TABLE S-8
HISTORICAL AND FORECASTED CUSTOMER COUNTS AND
AVERAGE USE PER CUSTOMER

Year	Res Custs	chg	Res Avg Use (kWh)	chg	Small C&I Custs	chg	Small C&I Avg Use (kWh)	chg
2003	606,187		12,299		78,794		47,498	
2004	633,907	4.6%	12,213	-0.7%	83,149	5.5%	47,179	-0.7%
2005	667,742	5.3%	12,747	4.4%	87,819	5.6%	48,318	2.4%
2006	700,309	4.9%	12,718	-0.2%	92,367	5.2%	47,741	-1.2%
2007	720,116	2.8%	12,469	-2.0%	96,579	4.6%	47,345	-0.8%
2008	724,663	0.6%	12,259	-1.7%	99,089	2.6%	46,466	-1.9%
2009	725,557	0.1%	12,015	-2.0%	99,446	0.4%	44,716	-3.8%
2010	729,565	0.6%	11,842	-1.4%	100,270	0.8%	43,466	-2.8%
2011	737,500	1.1%	11,666	-1.5%	100,712	0.4%	43,213	-0.6%
2012	748,226	1.5%	11,805	1.2%	101,410	0.7%	43,937	1.7%
2013	757,052	1.2%	11,718	-0.7%	102,981	1.5%	42,635	-3.0%
2014	768,297	1.5%	11,674	-0.4%	104,166	1.2%	42,839	0.5%
2015	777,535	1.2%	11,556	-1.0%	105,522	1.3%	42,428	-1.0%
2016	786,458	1.1%	11,456	-0.9%	107,187	1.6%	42,213	-0.5%
2017	795,438	1.1%	11,419	-0.3%	109,138	1.8%	42,106	-0.3%
2018	804,507	1.1%	11,444	0.2%	111,269	2.0%	42,046	-0.1%
2019	813,309	1.1%	11,478	0.3%	113,514	2.0%	41,996	-0.1%
2020	821,678	1.0%	11,500	0.2%	115,772	2.0%	41,990	0.0%
2021	829,994	1.0%	11,525	0.2%	117,962	1.9%	42,015	0.1%
2022	837,917	1.0%	11,521	0.0%	120,076	1.8%	42,047	0.1%
2023	845,641	0.9%	11,537	0.1%	122,075	1.7%	42,142	0.2%
2003 - 13		2.2%	-0.5%		2.7%		-1.1%	
2013 - 23		1.1%	-0.2%		1.7%		-0.1%	

Required Figures. Table S-9 shows the forecast of energy sales for each of the twenty years of the planning period under the low, base and high scenarios, both with and without DSM. Table S-10 shows the forecast of peak demand for each of the 20 years of the planning period, also under the low, base and high scenarios with and without DSM. Table S-11 is a summary of the DSM MW on peak, by program. The values are the cumulative incremental additions from 2013.

TABLE S-9
LOW, BASE AND HIGH SALES SCENARIOS
WITH AND WITHOUT DSM

Year	SALES (GWH) WITH DSM			SALES (GWH) WITHOUT DSM/DR		
	LOW	BASE	HIGH	LOW	BASE	HIGH
2014	20,878	21,202	21,083	21,017	21,341	21,222
2015	20,507	21,256	21,288	20,790	21,539	21,571
2016	20,470	21,372	21,603	20,896	21,798	22,029
2017	20,622	21,585	22,006	21,181	22,144	22,566
2018	20,883	21,878	22,487	21,574	22,569	23,178
2019	21,105	22,180	22,888	21,928	23,003	23,711
2020	21,329	22,471	23,284	22,284	23,426	24,238
2021	21,547	22,740	23,681	22,630	23,823	24,764
2022	21,798	22,968	24,127	23,007	24,177	25,337
2023	22,058	23,227	24,560	23,390	24,558	25,892
2024	22,328	23,503	25,022	23,777	24,952	26,470
2025	22,613	23,744	25,511	24,179	25,310	27,076
2026	22,943	24,026	26,052	24,620	25,702	27,729
2027	23,231	24,318	26,538	25,012	26,099	28,319
2028	23,559	24,638	27,085	25,415	26,494	28,941
2029	23,882	24,912	27,653	25,775	26,805	29,546
2030	24,234	25,200	28,257	26,147	27,113	30,170
2031	24,526	25,501	28,799	26,445	27,420	30,717
2032	24,842	25,836	29,382	26,766	27,760	31,306
2033	25,171	26,105	29,993	27,101	28,034	31,922
2034	25,544	26,413	30,622	27,477	28,346	32,554

Includes the effects of solar PV and wind net metering.

TABLE S-10
LOW, BASE, AND HIGH PEAK DEMAND SCENARIOS
WITH AND WITHOUT DSM

Year	PEAK DEMAND (MW) WITH DSM			PEAK DEMAND (MW) WITHOUT DSM/DR		
	LOW	BASE	HIGH	LOW	BASE	HIGH
2014	5,563	5,656	5,703	5,785	5,878	5,925
2015	5,480	5,629	5,727	5,769	5,918	6,016
2016	5,460	5,654	5,795	5,781	5,975	6,116
2017	5,470	5,713	5,899	5,818	6,061	6,247
2018	5,505	5,795	6,021	5,879	6,169	6,395
2019	5,548	5,883	6,142	5,949	6,284	6,543
2020	5,592	5,963	6,255	6,020	6,391	6,683
2021	5,636	6,043	6,363	6,090	6,497	6,817
2022	5,670	6,108	6,460	6,150	6,588	6,940
2023	5,710	6,180	6,564	6,215	6,685	7,069
2024	5,755	6,256	6,671	6,285	6,786	7,201
2025	5,793	6,322	6,770	6,347	6,876	7,324
2026	5,840	6,400	6,879	6,417	6,977	7,456
2027	5,889	6,480	6,994	6,489	7,080	7,594
2028	5,949	6,570	7,120	6,568	7,189	7,739
2029	5,993	6,642	7,227	6,626	7,275	7,860
2030	6,042	6,720	7,344	6,683	7,361	7,985
2031	6,094	6,803	7,466	6,735	7,444	8,107
2032	6,156	6,893	7,599	6,798	7,535	8,241
2033	6,204	6,969	7,721	6,846	7,611	8,363
2034	6,258	7,052	7,849	6,900	7,694	8,491

Includes the effects of solar PV and wind net metering.

TABLE S-11
DSM CONTRIBUTIONS TO THE LOAD FORECAST (MW)

Program	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Non-Profit Grants	4.3	9.0	13.9	18.9	23.7	28.6	33.6	38.4	43.4	48.2	53.2	58.1	62.7	67.1	69.8	70.3	70.5	70.5	70.4	70.4	
Commercial Incentives	2.8	5.8	9.0	12.1	15.2	18.4	21.6	24.7	27.9	31.0	34.2	37.4	40.3	43.1	44.9	45.2	45.4	45.3	45.3	45.3	
Energy Smart Schools	3.2	6.8	10.5	14.2	17.8	21.5	25.3	28.9	32.6	36.3	40.1	43.7	47.2	50.5	52.5	52.9	53.1	53.0	53.1	53.0	
Low Income Weatherization	5.0	10.1	15.3	20.5	25.5	30.7	35.9	40.9	45.8	50.4	54.8	59.1	63.2	67.5	71.8	76.2	78.8	78.8	79.1	79.2	
Residential Lighting	0.9	1.7	2.6	3.5	4.3	5.2	6.1	7.0	7.8	8.6	9.3	10.1	10.8	11.5	12.2	13.0	13.4	13.4	13.5	13.5	
Refrigerator Recycling	1.1	2.3	3.5	4.7	5.8	7.0	8.2	9.3	10.4	11.4	12.5	13.4	14.4	15.3	16.3	17.3	17.9	17.9	18.0	18.0	
Residential High Efficiency AC	5.0	10.1	15.3	20.5	25.5	30.7	35.9	40.9	45.8	50.4	54.8	59.1	63.2	67.5	71.8	76.2	78.8	78.8	79.1	79.2	
Energy Efficient Pools and Spas	1.6	3.3	5.0	6.7	8.3	10.0	11.6	13.2	14.8	16.3	17.8	19.1	20.5	21.9	23.2	24.7	25.5	25.5	25.6	25.7	
Solar Thermal Water Heating	0.9	1.9	2.9	3.8	4.8	5.7	6.7	7.6	8.5	9.4	10.2	11.0	11.8	12.6	13.4	14.2	14.7	14.7	14.8	14.8	
Demand Response (1)	82	123	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	
Total MW	107	174	206	233	259	286	313	339	365	390	415	439	462	485	504	518	526	526	527	527	

Footnote 1: The estimates are based on the expected MW realized at 5 pm of the peak day for the specified year. These are not the first year savings.

SECTION III - DEMAND SIDE PLAN SUMMARY: NAC § 704.9215(2)(c)

The DSM portfolio of programs is consistent with that included in Nevada Power's application for approval of its 2013 Annual Demand Side Management Update Report, as modified by the Commission's order and approved on December 19, 2013 in Docket 13-07002. The estimated energy efficiency savings attributed to this portfolio is consistent in all of the alternative plans evaluated for this ERCR Plan.

SECTION IV - SUMMARY OF THE SUPPLY SIDE PREFERRED PLAN: NAC § 704.9215(2)(d)

The Company's Preferred Plan (Case C) includes a package of company-owned generation of different capacity and fuel types that maximizes the use of existing generating facilities coupled with the construction of new renewable facilities to replace retiring coal generation capacity. Case C includes the purchase of LV Cogen on January 1, 2015, the Sun-Peak Generation Station on January 1, 2015, and construction of the 200 MW Moapa Solar Project, with an in-service date of October 2016. LV Cogen—an existing gas-fired generator—includes 50 MW of peaking capacity from LV Cogen Unit 1 and 224 MW of intermediate capacity from LV Cogen Unit 2. The cost of acquisition of LV Cogen is \$130.8 million.¹⁸ Sun-Peak Generation Unit—an existing gas-fired generator—includes 222 MW of peaking capacity. The cost of acquisition of the Sun-Peak Generation Station is \$15.8 million.¹⁹ The cost of constructing the Moapa Solar Project is \$438.1 million (excluding allowance of funds used during construction). The Moapa Solar Project provides 76 MW of planning capacity for a total planned replacement capacity package of 572 MW to meet the non-technology specific replacement capacity SB 123 requirement.²⁰ The Preferred Plan also includes the 15 MW Nellis Solar Array II, with a construction cost of \$54.5 million, a request to permit acreage in Clark County for additional solar facilities, and authorization to issue the first of three separate 100 MW RFPs for transaction with new renewable energy.

a.) LV Cogen Units 1 and 2

The Company requests Commission approval to spend \$130.8 million or \$477/kW, to acquire the LV Cogen facility. LV Cogen consists of two combined cycle units with a total capacity of 274 MW. LV Cogen Unit 1 is a 50 MW 1x1 natural gas-fired combined cycle unit that has been

¹⁸ The total transaction costs consist of \$129.9 million purchase price plus \$0.900 million of transaction costs.

¹⁹ The total transaction costs consists of a purchase price of \$11.0 million, integration costs of approximately \$4.5 million, and transaction costs of \$300 thousand

²⁰ The thirty-eight percent capacity value across the PV portfolio is based on an analysis performed by Pacific Northwest National Laboratories using data from Nevada Power's PV Integration Study. See Docket No. 11-03014, Technical Appendix Item SUP-ECON-6.

in-service since 1994. LV Cogen Unit 2 is a 224 MW dual 2x1 natural gas-fired combined cycle unit that has been in-service since 2003.

b.) Sun-Peak Generating Facility

The Company requests to spend \$15.8 million or \$71/kW to acquire the Sun-Peak facility. Sun-Peak consists of three simple cycle combustion turbine units with a total capacity of 222 MW. Sun-Peak has been in-service since 1991.

c.) Moapa Solar Project

The Company is seeking the Commission's approval to invest approximately \$438.1 million (excluding AFUDC) to acquire the development assets and to construct and ultimately operate the Moapa Solar Project, a solar photovoltaic ("PV") electric generating facility with an expected capacity of 200 MWac, measured at the delivery point. The Moapa Solar Project is being developed by RES Americas Development, Inc. ("RES") and will be located on reservation lands of the Moapa Band of Paiutes, approximately 45 miles north east of Las Vegas, Nevada. Based on the proposed capital cost and expected output, the renewable nature of the project requiring only Nevada's abundant solar resource for fuel, and taking advantage of the ITC set to expire at the end of 2016, the Moapa Solar Project represents an opportunistic acquisition for Nevada Power Company and will provide many years of fuel and emissions free energy for Nevada Power customers.

d.) Nellis Solar Array II

The Company is seeking Commission approval to invest up to \$54.5 million (without AFUDC) to build a 15 MW (alternating current) solar PV generating facility at Nellis Air Force Base. The solar facility would be built on the premises of Nellis Air Force Base and would interconnect directly to the Nellis Air Force Base electric distribution system. The Company must begin construction of at least 50 MW of new renewable energy facilities before December 31, 2017. This project satisfies that requirement, by beginning construction in 2015 for several good reasons. First, the Company takes advantage of the existing 30 percent investment tax credit. Second, the project cements the Company's relationship with a long-standing customer by developing an option that meets the customer's mission-critical goals. Third, the Company's customers will benefit from the 2.4 portfolio credit ("PC") multiplier associated with this project. In order to receive the multiplier at least 50 percent of the energy produced must be consumed on site and the project must be in place by December 31, 2015. The electrical interconnection requirements related to this project are described in the project narrative contained in the Supply Side Plan, Section 2.D.5.

e.) Clark County Solar Siting Work

Nevada Power is requesting Commission approval to spend up to \$4.4 million on initial siting activities related to one or more proposed new solar PV generating facilities northeast of Las Vegas in Clark County, Nevada. NV Energy has identified several locations capable of supporting approximately 500 MW of solar PV capacity near the Harry Allen power generation facility. The proposed sites occupy approximately 4,000 acres and are located on U.S. Bureau of Land Management land, within or near the current Nevada Power right-of-way grant.

f.) Renewable RFPs for 300 MWs

Nevada Power is requesting Commission approval to issue three 100 MW RFPs for transactions with new renewable energy. The Company will generally follow the structure of its previous solicitation and contracting process used in securing renewable power purchase agreements. The Company expects to receive additional guidance from the Commission as a result of continued rulemaking in Docket 13-06023, known as Phase 2.

Tables S-12 through S-16 show Nevada Power's projected loads and resources under the Preferred Plan, assuming base load conditions. The Company also developed a number of sensitivities around the base case; the sensitivities are presented in the Supply Side Plan, Section 3 (Economic Analysis) Figure EA-3 – Sensitivities Conducted for Economic Analysis.

TABLE S-12
L&R TABLE – 2015 – 2029

NEVADA POWER COMPANY - 2014 ERCR - Base Load																
200PV, LVC, SP ERCR																
	Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
6	GROSS SYSTEM PEAK LOAD FORECAST (January 2014)	5,933	5,998	6,088	6,204	6,325	6,440	6,549	6,640	6,738	6,839	6,930	7,033	7,137	7,246	7,333
7	DSM	51	78	105	131	158	185	211	237	262	287	311	334	357	376	390
8	Net Metering	15	23	27	35	41	49	52	52	53	53	54	56	57	57	58
9	Demand Response	238	243	243	243	243	243	243	243	243	243	243	243	243	243	243
10	SYSTEM PEAK LOAD FORECAST (1) (January 2014 Load Forecast)	5,629	5,654	5,713	5,795	5,883	5,963	6,043	6,108	6,180	6,256	6,322	6,400	6,480	6,570	6,642
11	SNWA Obligation	125	125	125	125	-	-	-	-	-	-	-	-	-	-	-
12	NET SYSTEM PEAK LOAD	5,754	5,779	5,838	5,920	5,883	5,963	6,043	6,108	6,180	6,256	6,322	6,400	6,480	6,570	6,642
13	Planning Reserve Requirement (12%)	690	693	701	710	706	716	725	733	742	751	759	768	778	788	797
14	REQUIRED RESOURCES	6,444	6,472	6,539	6,630	6,589	6,679	6,768	6,841	6,922	7,007	7,081	7,168	7,258	7,358	7,439
15	RESOURCES (Itemized)															
16	Existing Internal Generation Facilities (Retire Date, 12/31/xx)															
17	Clark 4 (2020)	54	54	54	54	54	54	-	-	-	-	-	-	-	-	-
18	Clark 9,10 (9 - 2033, 10 - 2034)	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430
19	Clark Peakers 11-22 (2038)	619	619	619	619	619	619	619	619	619	619	619	619	619	619	619
20	Goodsprings (2043)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
21	Harry Allen 3 (2025)	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-
22	Harry Allen 4 (2036)	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
23	Harry Allen 5,6,7 (2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
24	Higgins (2039)	530	530	530	530	530	530	530	530	530	530	530	530	530	530	530
25	Lenzie 1 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551
26	Lenzie 2 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	551	551	551
27	Reid Gardner 1,2,3 (2014)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Reid Gardner 4 - Base (2017)	257	257	257	-	-	-	-	-	-	-	-	-	-	-	-
29	Silverhawk (75% Share) (2039)	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
30	Sunpeak 3,4,5 (2026)	222	222	222	222	222	222	222	222	222	222	222	222	-	-	-
31		4,237	4,237	4,237	3,980	3,980	3,980	3,926	3,926	3,926	3,926	3,926	3,854	3,632	3,632	3,632
32	Existing Generation Requiring or Affecting Imports															
33	Hoover	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
34	Navajo 1,2,3 (2019)	255	255	255	255	255	-	-	-	-	-	-	-	-	-	-
35		455	455	455	455	455	200	200	200	200	200	200	200	200	200	200
36	Total Existing Generation	4,692	4,692	4,692	4,435	4,435	4,180	4,126	4,126	4,126	4,126	4,126	4,054	3,832	3,832	3,832
37	Planned Internal Generation Facilities															
38	15 MW PV 2016 (COD 1/1/2016)	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6
39	200 MW PV 2016 (COD 10/1/2016)	-	-	76	76	76	76	76	76	76	76	76	76	76	76	76
40	35 MW PV 2021 (COD 1/1/2021)	-	-	-	-	-	-	13	13	13	13	13	13	13	13	13
41	3x 7EA 27	-	-	-	-	-	-	-	-	-	-	-	-	213	213	213
42	2x1_CC_20	-	-	-	-	-	597	597	597	597	597	597	597	597	597	597
43		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Total Planned Internal Generation	-	6	82	82	82	679	692	692	692	692	692	692	905	905	905
45	Planned Generation Facilities Requiring Import Rights															
46	1x1_CC_22	-	-	-	-	-	-	-	-	273	273	273	273	273	273	273
47	3x 7EA 23	-	-	-	-	-	-	-	-	-	213	213	213	213	213	213
48	2x1_CC_24	-	-	-	-	-	-	-	-	-	-	597	597	597	597	597
49	3x LMS 100_30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	3x LMS 100_32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	2x1_CC_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	3x LMS 100_36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	1x1_CC_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	1x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	2x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	2x1_CC_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	3x LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	1x1_CC_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Total Planned Generation Requiring Imports	-	-	-	-	-	-	-	-	273	486	1,083	1,083	1,083	1,083	1,083
62	Total Planned Generation	-	-	6	82	82	82	679	692	965	1,178	1,775	1,775	1,775	1,988	1,988
63	Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	TOTAL GENERATION	4,992	4,692	4,698	4,774	4,517	4,517	4,859	4,818	5,091	5,304	5,901	5,901	5,829	5,820	5,820

TABLE S-13
L&R TABLE –2015 – 2029

NEVADA POWER COMPANY - 2014 ERCR - Base Load 200PV, LVC, SP ERCR																
	Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
IMP	Specific Purchases															
	Qualifying Facilities															
	NCA 1 (2022)	85	85	85	85	85	85	85	85	-	-	-	-	-	-	-
	NCA 2 (2022)	85	85	85	85	85	85	85	85	-	-	-	-	-	-	-
	Saguro (2021)	90	90	90	90	90	90	90	-	-	-	-	-	-	-	-
	Total Qualifying Facilities	260	260	260	260	260	260	260	170	-	-	-	-	-	-	-
	Contracts (Internal)															
	LV CoGen I (Buy, Retire 2036)	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
	LV CoGen II (Buy, Retire 2036)	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224
	Total Contracts (Internal)	274	274	274	274	274	274	274	274	274	274	274	274	274	274	274
	Contracts (External)															
	Griffith	570	570	570	-	-	-	-	-	-	-	-	-	-	-	-
	Silverhawk (SNWA Transaction)	130	130	130	130	-	-	-	-	-	-	-	-	-	-	-
	Solar1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
	ACE Searchlight	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Fotowatio Apex	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Republic Apex Landfill	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Next Light Silver State	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
	JayValNP	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	DartPkNP	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	(Blue Mountain) FlakerNP	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	GalZNP	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	ShWdNP	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
SdWtrNP (PV & GEO)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	
Tuscarora	15	15	15	15	21	21	21	21	21	21	21	21	21	21	21	
Tuscarora Expansion (Option)	-	-	-	-	7	7	7	7	7	7	7	7	7	7	7	
McGinness	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	
McGinness Hills Expansion	-	16	16	16	16	16	16	16	16	16	16	16	16	16	16	
NextEra Mountain View	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	
FRV Spectrum	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	
Crescent Dunes	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92	
SpValley	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	
WMRE Lockwood	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	
TRN	Future Purchases (ERCR)															
	100 MW PV_2016	-	38	38	38	38	38	38	38	38	38	38	38	38	38	38
	100 MW PV_2017	-	-	38	38	38	38	38	38	38	38	38	38	38	38	38
	50 MW PV_2018	-	-	-	19	19	19	19	19	19	19	19	19	19	19	19
	51 MW GEO_2019	-	-	-	-	17	17	17	17	17	17	17	17	17	17	17
	102 MW GEO_2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	76.5 MW GEO_2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	100 MW PV_2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	50 MW PV_2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	50 MW PV_2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	50 MW PV_2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	25 MW PV_2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Renewables - Subtotal	311	365	403	422	453	453	453	453	453	453	453	453	453	453	453
	Total Contracts (External)	1,011	1,065	1,103	552	453	453	453	453	453	453	453	453	453	453	453
	TOTAL GROSS PURCHASES	1,545	1,599	1,637	1,086	987	987	987	897	727	727	727	727	727	727	727
	Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL NET PURCHASES	1,545	1,599	1,637	1,086	987	987	987	897	727	727	727	727	727	727	727	
IMP	AVAILABLE RESOURCES	6,237	6,297	6,411	5,603	5,504	5,846	5,805	5,988	6,031	6,628	6,628	6,556	6,547	6,547	6,547
	OPEN POSITION	207	176	128	1,028	1,085	833	963	853	891	379	453	612	711	811	892
	LONG POSITION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION															
	Balancing Area Import Transmission Capacity	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
	Balancing Area Customer Load (2)	262	265	267	269	271	273	274	278	279	280	299	299	299	299	299
	System Import Transmission Capacity	2,238	2,235	2,233	2,231	2,229	2,227	2,226	2,222	2,221	2,220	2,201	2,201	2,201	2,201	2,201
	Import Capacity for Reserve Sharing (3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transfer of Renewable Resources	216	232	232	232	263	263	263	263	263	263	263	263	263	263	263
	Subtotal	2,022	2,003	2,001	1,999	1,966	1,964	1,963	1,959	1,948	1,947	1,938	1,938	1,938	1,938	1,938
	Import Capacity for other Native Load Requirements	1,232	1,201	1,153	1,483	1,540	1,033	1,163	1,053	1,090	579	652	812	910	1,011	1,092
	Import Capacity Requirement for Planned Generation	-	-	-	-	-	-	-	273	486	1,083	1,083	1,083	1,083	1,083	1,083
	Estimated Available Transmission Capacity (4)	790	802	848	516	426	931	800	633	381	295	203	43	(55)	(156)	(237)

TABLE S-14
L&R TABLE – 2030 - 2044

NEVADA POWER COMPANY - 2014 ERCR - Base Load 200PV, LVC, SP ERCR															
Description	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
GROSS SYSTEM PEAK LOAD FORECAST (January 2014)	7,420	7,504	7,596	7,672	7,756	7,841	7,927	8,014	8,102	8,191	8,281	8,372	8,464	8,557	8,651
DSM	398	398	399	399	399	399	399	399	399	399	399	399	399	399	399
Net Metering	59	60	61	61	62	62	62	62	62	62	62	62	62	62	62
Demand Response	243	243	243	243	243	243	243	243	243	243	243	243	243	243	243
SYSTEM PEAK LOAD FORECAST (1) (January 2014 Load Forecast)	6,720	6,803	6,893	6,969	7,052	7,137	7,223	7,310	7,398	7,487	7,577	7,668	7,760	7,853	7,947
SNWA Obligation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NET SYSTEM PEAK LOAD	6,720	6,803	6,893	6,969	7,052	7,137	7,223	7,310	7,398	7,487	7,577	7,668	7,760	7,853	7,947
Planning Reserve Requirement (12%)	806	816	827	836	846	856	867	877	888	898	909	920	931	942	954
REQUIRED RESOURCES	7,526	7,619	7,720	7,805	7,898	7,993	8,090	8,187	8,286	8,385	8,486	8,588	8,691	8,795	8,901
RESOURCES (Itemized)															
<u>Existing Internal Generation Facilities (Retire Date, 12/31/xx)</u>															
Clark 4 (2020)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Clark 9,10 (9 - 2033, 10 - 2034)	430	430	430	430	215	-	-	-	-	-	-	-	-	-	-
Clark Peakers 11-22 (2038)	619	619	619	619	619	619	619	619	619	-	-	-	-	-	-
Goodsprings (2043)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Harry Allen 3 (2025)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Harry Allen 4 (2036)	72	72	72	72	72	72	72	-	-	-	-	-	-	-	-
Harry Allen 5,6,7 (2046)	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
Higgins (2039)	530	530	530	530	530	530	530	530	530	530	-	-	-	-	-
Lenzie 1 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-
Lenzie 2 (2041)	551	551	551	551	551	551	551	551	551	551	551	551	-	-	-
Reid Gardner 1,2,3 (2014)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Reid Gardner 4 - Base (2017)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Silverhawk (75% Share) (2039)	390	390	390	390	390	390	390	390	390	390	-	-	-	-	-
Sunpeak 3,4,5 (2026)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,632	3,632	3,632	3,632	3,417	3,202	3,202	3,130	3,130	2,511	1,591	1,591	489	489	489
<u>Existing Generation Requiring or Affecting Imports</u>															
Hoover	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Navajo 1,2,3 (2019)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Existing Generation	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	3,832	3,832	3,832	3,832	3,617	3,402	3,402	3,330	3,330	2,711	1,791	1,791	689	689	689
<u>Planned Internal Generation Facilities</u>															
15 MW PV 2016 (COD 1/1/2016)	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
200 MW PV 2016 (COD 10/1/2016)	76	76	76	76	76	76	76	76	76	76	76	76	76	76	76
35 MW PV 2021 (COD 1/1/2021)	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
3x 7EA 27	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213
2x1_CC_20	597	597	597	597	597	597	597	597	597	597	597	597	597	597	597
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Planned Internal Generation	905	905	905	905	905	905	905	905	905	905	905	905	905	905	905
<u>Planned Generation Facilities Requiring Import Rights</u>															
1x1_CC_22	273	273	273	273	273	273	273	273	273	273	273	273	273	273	273
3x 7EA 23	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213
2x1_CC_24	597	597	597	597	597	597	597	597	597	597	597	597	597	597	597
3x LMS 100_30	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234
3x LMS 100_32	-	-	234	234	234	234	234	234	234	234	234	234	234	234	234
2x1_CC_35	-	-	-	-	-	597	597	597	597	597	597	597	597	597	597
3x LMS 100_36	-	-	-	-	-	-	234	234	234	234	234	234	234	234	234
1x1_CC_38	-	-	-	-	-	-	-	-	273	273	273	273	273	273	273
1x1_CC_39	-	-	-	-	-	-	-	-	-	273	273	273	273	273	273
2x1_CC_39	-	-	-	-	-	-	-	-	-	597	597	597	597	597	597
2x1_CC_40	-	-	-	-	-	-	-	-	-	-	597	597	597	597	597
3x LMS 100_40	-	-	-	-	-	-	-	-	-	-	234	234	234	234	234
1x1_CC_41	-	-	-	-	-	-	-	-	-	-	273	273	273	273	273
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	597	597	597	597
2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	597	597	597	597
Total Planned Generation Requiring Imports	1,317	1,317	1,551	1,551	1,551	2,148	2,382	2,382	2,655	3,525	4,356	4,629	5,823	5,823	5,823
Total Planned Generation	2,222	2,222	2,456	2,456	2,456	3,053	3,287	3,287	3,560	4,430	5,261	5,534	6,728	6,728	6,728
Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL GENERATION	6,054	6,054	6,288	6,288	6,073	6,455	6,689	6,617	6,890	7,141	7,052	7,325	7,417	7,417	7,417

TABLE S-15
L&R TABLE – 2030 – 2044

	NEVADA POWER COMPANY - 2014 ERCR - Base Load															
	200PV, LVC, SP ERCR															
	Description	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
	Specific Purchases															
	Qualifying Facilities															
	NCA 1 (2022)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	NCA 2 (2022)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Saguro (2021)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Qualifying Facilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Contracts (Internal)															
	LV CoGen I (Buy, Retire 2036)	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-
	LV CoGen II (Buy, Retire 2036)	224	224	224	224	224	224	224	-	-	-	-	-	-	-	-
	Total Contracts (Internal)	274	274	274	274	274	274	274	-	-	-	-	-	-	-	-
	Contracts (External)															
	Griffith	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IMP	Silverhawk (SNWA Transaction)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar1	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
TRN	ACE Searchlight	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Fotowatio Apex	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
	Republic Apex Landfill	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	Next Light Silver State	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
TRN	JayValNP	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
TRN	DartPkNP	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
TRN	(Blue Mountain) FlakerNP	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
TRN	GalNP	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
TRN	ShWNP	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
TRN	SdWtrNP (PV & GEO)	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
TRN	Tuscarora	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
TRN	Tuscarora Expansion (Option)	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
TRN	McGinness	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TRN	McGinness Hills Expansion	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
TRN	NextEra Mountain View	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
TRN	FRV Spectrum	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
TRN	Crescent Dunes	92	92	92	92	92	92	92	92	92	92	92	92	92	92	92
TRN	SpValley	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TRN	WMRE Lockwood	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
	Future Purchases (ERCR)															
	100 MW PV_2016	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
	100 MW PV_2017	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
	50 MW PV_2018	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
	51 MW GEO_2019	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
TRN	76.5 MW GEO_2032	-	-	-	34	34	34	34	34	34	34	34	34	34	34	34
	100 MW PV_2032	-	-	-	26	26	26	26	26	26	26	26	26	26	26	26
	100 MW PV_2032	-	-	-	38	38	38	38	38	38	38	38	38	38	38	38
	50 MW PV_2032	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10
TRN	51 MW GEO_2033	-	-	-	-	-	10	10	10	10	10	10	10	10	10	10
	25 MW PV_2034	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10
	25 MW PV_2035	-	-	-	-	-	-	10	10	10	10	10	10	10	10	10
TRN	25.5 MW GEO_2037	-	-	-	-	-	-	-	19	19	19	19	19	19	19	19
	25 MW PV_2038	-	-	-	-	-	-	-	-	10	10	10	10	10	10	10
	25 MW PV_2039	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10
	50 MW PV_2040	-	-	-	-	-	-	-	-	-	-	19	19	19	19	19
	25 MW PV_2041	-	-	-	-	-	-	-	-	-	-	-	19	19	19	19
	25 MW PV_2041	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10
	50 MW PV_2042	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Renewables - Subtotal	453	453	453	551	551	561	570	589	608	618	627	646	665	675	684
	Total Contracts (External)	453	453	453	551	551	561	570	589	608	618	627	646	665	675	684
	TOTAL GROSS PURCHASES	727	727	727	825	825	835	844	589	608	618	627	646	665	675	684
	Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL NET PURCHASES	727	727	727	825	825	835	844	589	608	618	627	646	665	675	684
	AVAILABLE RESOURCES	6,781	6,781	7,015	7,113	6,898	7,290	7,533	7,206	7,498	7,789	7,679	7,971	8,082	8,092	8,101
IMP	OPEN POSITION	745	838	705	692	1,000	704	556	981	787	627	807	617	609	704	799
	LONG POSITION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TRANSMISSION															
	Balancing Area Import Transmission Capacity	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
	Balancing Area Customer Load (2)	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299
	System Import Transmission Capacity	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201	2,201
	Import Capacity for Reserve Sharing (3)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transfer of Renewable Resources	263	263	263	323	323	323	323	323	323	323	323	323	323	323	323
	Subtotal	1,938	1,938	1,938	1,878	1,878	1,878	1,878	1,878	1,878	1,878	1,878	1,878	1,878	1,878	1,878
	Import Capacity for other Native Load Requirements	945	1,038	905	892	1,200	904	756	1,181	987	827	1,007	817	809	903	999
	Import Capacity Requirement for Planned Generation	1,317	1,317	1,551	1,551	1,551	2,148	2,382	2,382	2,655	3,525	4,356	4,629	5,823	5,823	5,823
	Estimated Available Transmission Capacity (4)	(324)	(417)	(518)	(565)	(873)	(1,174)	(1,260)	(1,685)	(1,764)	(2,474)	(3,485)	(4,629)	(4,754)	(4,848)	(4,944)

TABLE S-16
FOOTNOTES TO NEVADA POWER'S L&R TABLES

- (1) SNWA 125 MW contract through 2018.
- (2) Coincident combined loads for Boulder City, CRC-BMI, City of LV SB211, LVVWD, Lincoln, Overton, East Side / Newport, SB 211, , City of Henderson.
- (3) Reserve sharing assistance assumed to change from the Southwest Reserve Sharing Group (SRSRG) to the Northwest Power Pool.
- (4) Estimates are based on summer peak conditions only.

SECTION V – SUMMARY OF THE RENEWABLE ENERGY PLAN: NAC § 704.9215(2)(e)

The renewable energy plan set forth in this ERCR Plan continues Nevada Power's RPS compliance planning and advances important facets of SB 123, namely developing renewable energy for our state and providing jobs for the recovery of our economy. The Preferred Plan efficiently and effectively meets the requirements of the Commission's regulations implementing that legislation by meeting the requirements for new renewable energy RFPs and new utility-sponsored construction or acquisition of renewable energy facilities. SB 123 and the associated regulations related to renewable energy require Nevada Power, in its ERCR Plan filing, to provide, at a minimum, for a) the construction or acquisition of 50 MW of electric generating capacity from renewable energy facilities, and b) the issuance of RFPs for 300 MW of electric generating capacity from renewable energy facilities. The renewable energy plan complies with the requirements set forth in SB 123 and supports Nevada Powers continued compliance with the RPS.

The Preferred Plan will solidly position Nevada Power to meet the requirements of Nevada's RPS. These requirements grow to 25 percent by 2025, with five percent of the RPS that must be generated or acquired from solar resources (growing to six percent starting in 2016). These RPS requirements continue to grow in accordance with statutory requirements, even during periods of low or flat load growth. Nevada Power's ability to comply with the RPS is dependent on variables that will evolve over time, such as load, changes in law, continued successful operation of the existing portfolio and stable resource for projects. Compliance with the RPS requires the Company to measure against a continuously evolving target. Nonetheless, Nevada Power expects to be fully compliant with the RPS requirements during the Action Plan Period of the ERCR Plan, 2015, and beyond. Execution of the Preferred Plan that includes new renewable construction of 15 MW of solar PV at Nellis, 200 MW of solar PV at Moapa, and RFPs for 300 MW of additional renewable energy will position the Nevada Power and its customers to meet future RPS requirements through at least 2033. Please see Section IV for a more detailed discussion of these facilities.

While Nevada Power's renewable energy portfolio is adequate to satisfy the RPS through the Action Plan Period, the Company must diligently plan to meet its ongoing RPS compliance requirements after the Action Plan Period. Although no new power purchase agreements with renewable energy projects are presented for approval in this ERCR Plan, the Company is asking the Commission to approve an RFP program, the completion of 15 MW of solar PV and 200 MW of solar PV, and solar siting work described below.

EXISTING RENEWABLE ENERGY CONTRACTS

Nevada Power has been able to contract for many of Nevada's prime renewable resources through long-term PPAs, and is now seeing the results of these efforts as numerous projects complete construction and begin operating. The following list sets forth all of the facilities that are operating and contributing to RPS requirements as of the end of 2013:

1. Goodsprings Recovered Energy Generation Station, waste heat-7.5 MW
2. Desert Peak 2 Geothermal Power, geothermal PPA-25 MW
3. Faulkner 1 Geothermal Power Plant, geothermal PPA-49.5 MW
4. Galena 2 Geothermal Power Plant, geothermal PPA-13 MW
5. Jersey Valley Geothermal Project, geothermal PPA-22.5 MW
6. McGinness Hills Geothermal Project, geothermal PPA-48 MW
7. Salt Wells Geothermal Plant, geothermal PPA-23.6 MW
8. Stillwater 2 Geothermal Plant, geothermal PPA-47.2 MW
9. Tuscarora Geothermal Plant, geothermal PPA-32 MW
10. Apex Nevada Solar, solar PPA-20 MW
11. Las Vegas Valley Water District ("LVVWD"; six projects), solar PPA-3 MW
12. Mountain View Solar, solar PPA-20 MW
13. Nellis Air Force Base, Solar Star, solar PPA-13.2 MW
14. Nevada Solar One, solar PPA-46.9 MW (balance of plant contracted to Sierra)
15. Silver State Solar, solar PPA-52 MW
16. Spectrum Nevada Solar, solar PPA-30 MW
17. Stillwater 2 Solar, solar PPA-22 MW
18. Spring Valley Wind, wind PPA-151.8 MW
19. CC Landfill Facility, gas recovery PPA-12 MW
20. Lockwood Renewable Energy Facility, gas recovery PPA-3.2 MW

SECTION VI - SUMMARY OF ENERGY SUPPLY PLAN: NAC § 704.9215(f)

Pursuant to NAC § 704.9061, an “Energy Supply Plan” means a plan that:

1. Establishes the parameters of an energy supply portfolio for a utility for the three-year period covered by its Action Plan and which balances the objectives of:
 - a) Minimizing the cost of supply;
 - b) Minimizing retail price volatility; and
 - c) Maximizing the reliability of energy supply over the term of the energy supply plan.
2. Is composed of a purchased power procurement plan, fuel procurement plan and risk management strategy.

Nevada Power’s 2015 Energy Supply Plan Update (“ESP Update”) will be filed concurrent with this 2014 ERCR. The ESP Update provides the Company’s recommended power procurement plan, fuel procurement plan, and risk management strategy based on current conditions. This ESP may need to be adjusted over the Action Plan period to adequately respond to changes in the market, changes in the Company’s expected loads and resources, and other significant changes in circumstances. Pursuant to NAC § 704.9504, Nevada Power may deviate from the approved ESP “to the extent necessary to respond adequately to any significant change in circumstances not contemplated by the Energy Supply Plan.” If Nevada Power deviates from its approved ESP, it will inform the Commission’s Staff of the deviation as soon as practical. In addition, Nevada Power will include in its next annual deferred energy application a description of and justification for the deviation. If a deviation from the ESP is of a continuing nature, Nevada Power will seek authority from the Commission to deviate prospectively from the ESP in an update of the ESP filed pursuant to NAC § 704.9506, or by filing an amendment to the ESP pursuant to NAC § 704.9504(3).

Pursuant to NAC §§ 704.9508(2) and 704.9494, the Commission may determine that the elements of an ESP are prudent if the following requirements are met:

- The ESP balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.
- The ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.

- The ESP does not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

The 2015 ESP Update balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.

Price volatility risk remains, particularly with respect to fuel supplies. Assuming approval of the proposed ESP Update, the estimated costs of fuel and purchased power costs during the Action Plan period under the low, base, and high fuel & purchased power price scenarios are summarized in Figure S-4.

**FIGURE S-4
ESTIMATED COST TO SERVE FOR 2015**

TOTAL PRODUCTION COSTS, EXCLUDING FIXED & VARIABLE OPERATIONS AND MAINTENANCE (UNHEDGED)				TOTAL PRODUCTION COSTS, EXCLUDING FIXED & VARIABLE OPERATIONS AND MAINTENANCE (25,000 MMBTU/DAY OF FIXED PHYSICAL NATURAL GAS)		
Year	Cost to Serve Assuming Low F&PP Prices (\$000) (A)	Cost to Serve Assuming Base F&PP Prices (\$000) (B)	Cost to Serve Assuming High F&PP Prices (\$000) (C)	Cost to Serve Assuming Low F&PP Prices (\$000) (D)	Cost to Serve Assuming Base F&PP Prices (\$000) (E)	Cost to Serve Assuming High F&PP Prices (\$000) (F)
2015	\$886,906	\$1,053,192	\$1,276,874	\$896,353	\$1,053,192	\$1,282,554

The Company calculated the projected Base Tariff Energy Rates (“BTERs”) and Deferred Energy Accounting Adjustment (“DEAA”) rates for 2015 under the low, base, and high fuel and purchased power price forecasts. The projected BTER and DEAA rates, along with estimated carrying charges, are presented in Technical Appendices.

The expected cost to serve and forecasted rates are expected to remain within a reasonable band under the Company’s proposed procurement strategies.

This ESP optimizes the value of the overall supply portfolio of the utility for the benefit of its bundled retail customers.

The Company will continue to monitor and adjust the power portfolio. By monitoring the portfolio, Nevada Power can identify and account for changes in load, cost, volatility, reliability, and other commercial or technical factors. Day-ahead or day-of power purchases are expected to be made if there is an open position, or if system costs of decremental energy exceed the additional cost of market purchases. Similarly, day-ahead or day-of power sales are expected to be made as opportunities appear, including spot, fixed price, or indexed agreements as specified in the Energy Risk Management and Control Policy. The Company intends to continue to issue

reverse RFPs for the prospective forward sale of heat rate call options, as specified in the Portfolio Optimization Procedures Manual.

This ESP does not contain any feature or mechanism that would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

Historically, the Commission has implemented an energy supply planning process and the Company's credit has improved. Currently, the Company is able to provide financing for this ESP without impairing its creditworthiness, assuming timely recovery under current rate recovery mechanisms.

A. POWER PROCUREMENT PLAN

The Company's power position for 2015 is projected to be 250 MW open. The Company does not propose to take any short-term action to close the position at this time. If Nevada Power later determines a need for additional capacity or energy, the Company will procure needed products through a competitive bidding process. Any proposed purchases of greater than three years in duration will be submitted to the Commission for approval in accordance with NAC §§ 704.9113 and 704.9512. In addition, Nevada Power will continue to make forward and short-term sales of resources not expected to be needed to serve native load.

The Company currently anticipates satisfying the RPS through the Action Plan Period based on current load forecasts and current renewable supply projections. The Company's goal for short-term purchases of renewable energy is to augment, not supplant, supplies from long-term renewable energy PPAs by helping to close gaps resulting from under-producing, late and cancelled projects. To the extent short-term purchases can be made on an opportunistic basis, they help Nevada Power meet its RPS requirements and bridge to between project completion dates. In addition, the Company expects to continue with the past practice of purchasing PCs from customers in Nevada who host renewable energy systems with uncommitted PCs.

B. GAS PROCUREMENT PLAN

The gas procurement plan has three components: physical gas procurement plan; gas transportation plan; and gas hedging plan.

Physical Gas Procurement Plan. Nevada Power employs a four-season laddering strategy for physical gas purchases through which 25 percent of projected monthly gas requirements per season are procured, subject to the availability of conforming bids and the willingness of

suppliers to accept reasonable commercial terms. All of Nevada Power's physical gas is expected to come from the Rocky Mountain gas supply basin.

Gas Transportation Plan. Nevada Power is requesting acceptance and approval of its gas transportation plan. Presently, no contracts will be discontinued. Two existing gas transport contracts with Kern River Gas Transmission Company are set to expire on September 30, 2016, and require a decision to extend by September 30, 2015. Nevada Power is requesting approval to renew these two contracts at lower Period Two²¹ rates for rolled-in rate service for up to fifteen years, resulting in lower annual costs by approximately \$0.7 million. Nevada Power is also requesting approval to acquire additional firm gas transportation capacity, up to 40,075 MMBtu/day, through a competitive bid process as part of the proposed gas transportation strategy. The additional capacity will assist in minimizing any future open position with respect to firm interstate gas transportation. Nevada Power will continue to purchase firm delivered gas to reliably meet small open positions. As part of the acquisition of LV Cogen, Nevada Power will assume and maintain two gas transportation agreements with Southwest Gas Company.

Gas Hedging Plan. For delivery periods April 2015 to March 2016, the Company proposes to procure fixed physical natural gas in the amount of 25,000 MMBtu/day to cover two gas seasons. The Company will continue to monitor the natural gas market fundamentals and recommend changes to the hedging strategy in an ESP Update or ESP Amendment as necessary. Should the Company determine that additional hedging would be in the best interest of its customers for periods beyond March 2014, it will make a specific proposal to the Commission in its next ESP filing, a future ESP update or in an ESP amendment filed pursuant to NAC § 704.9504(3).

C. COAL PROCUREMENT PLAN

Nevada Power is proposing to continue the current coal procurement strategy containing the following elements:

- Fill Reid Gardner Unit 4's coal requirements for 2015 via spot market solicitations as necessary.

D. RISK MANAGEMENT STRATEGY

The Company's risk management strategy includes:

- Detailed corporate governance and risk control policies and procedures;

²¹ Kern River Gas Transmission Company's Tariff in Section 30.1(c), Sheet No. 299 defines Period Two as "The contract term that commences when the primary term of an Eligible Shipper's Period One transportation service agreement ends and during which an Eligible shipper will be charged Period Two rates."

- Compliance with approved supply plans;
- Reduced reliance on volatile wholesale markets;
- Increased fuel diversity;
- Use of competitive procurement processes;
- Gas hedging strategies; and
- Market monitoring.

Risk Control measures the Company's energy portfolio against specific criteria, including transaction approval limits, test period mark-to-base, value at risk, and credit risk limits. Specific measurements are compared to the approved exposure notification thresholds. Reports are prepared to identify, track and report compliance with the Company's risk policies.

Credit Risk Management mitigates risk of the organization by reviewing potential transactions with counterparties to make sure they comply with credit limits. All potential transactions are reviewed to determine the credit ratings, policy limits based on credit ratings, the current mark-to-market exposure of all current transactions, and whether the potential credit exposure calculations are within the Company's policy limits.

SECTION VII – A SUMMARY OF THE ACTIVITIES, ACQUISITIONS, AND COSTS INCLUDED IN THE ACTION PLAN OF THE UTILITY: NAC § 704.9215(2)(g)²²

The Company seeks Commission approval of the following Action Plan items, which must be acted upon within the Action Plan period, 2015. Items denoted with an asterisk (*) meet the requirements of NAC § 704.9512(2)(g) and Section 13(2)(b) of LCB R131-13.

A. LOAD FORECAST – ERCR & ESP

- Approval of the load forecast that is provided in the Load Forecast, Market Fundamentals and Fuel and Purchase Power volume. Approval of the loads and resources tables for 2015 that are presented in the ESP Update, Economic Analysis and Financial Plan volume. A finding that the load forecast is based upon substantially accurate data that has been adequately demonstrated and defended, and has been adequately documented and justified. A finding that the load forecast is appropriate for resource planning decision making through the Action Plan period.*

B. FUEL AND PURCHASED POWER FORECAST – IRP & ESP

- Approval of the fuel and purchased power price forecasts presented in the Load Forecast and Market Fundamentals volume. A finding that the fuel and purchased power price

²² See LCB File No. R131-13, Sec. 13(2)(b).

forecasts are based upon substantially accurate data that has been adequately demonstrated and defended, and has been adequately documented and justified. A finding that the fuel and purchased power forecasts are appropriate for resource planning decision making through the Action Plan period.*

C. ERCR PLAN

(1) Retirement Plan

- Approval to retire coal-fired generating units as shown in Table S-17.

**TABLE S-17
RETIREMENT PLAN**

Unit	Planning Capacity	Retire or Eliminate	Date
Reid Gardner Generating Station, Units 1, 2 & 3	300 MW	Retire	12/31/2014
Reid Gardner Generating Station, Unit 4	257 MW	Retire	12/31/2017
Navajo Generating Station, 11.3 percent Ownership Interest	255 MW	Eliminate	12/22/2019
Total Retired/Eliminated Planning Capacity	812 MW		

Note: Retire is to remove a unit permanently from service.

Eliminate is to divest a utility's ownership interest in the facility.

(2) 550 MW of Company-Owned Replacement Capacity, see Table S-18

- A finding, pursuant to NAC § 704.0097, that good cause exists for deviating from LCB R131-13 § 12(8).
- Approval to acquire 224 MW of intermediate gas-fired combined cycle capacity from LV Cogen Unit 2.
- Approval to acquire 222 MW of natural gas-fired peaking capacity from Sun-Peak Generating Company.
- Approval to invest approximately \$471.6 million to acquire the development assets and complete the construction of the Moapa Solar Project, a 200 MW (nameplate) solar PV facility.

- Approval to acquire LV Cogen Unit 1 as a package with LV Cogen Unit 2.

TABLE S-18
550 MW COMPANY-OWNED REPLACEMENT CAPACITY
(NON-TECHNOLOGY SPECIFIC)

Unit	Timing of Replacement	Planning Capacity	Type of Capacity	Fuel	Estimated Cost
LV Cogen Unit 2	1/1/2015	224 MW	Intermediate	Natural Gas	\$130.8m
Sun-Peak Generating Unit	6/1/2016	222 MW	Peaking	Natural Gas	\$15.8m
Moapa Solar Generating Station	10/1/2016	76 MW	Intermittent	Solar	\$438.1m ²³
LV Cogen Unit 1	10/1/2017	50 MW	Peaking	Natural Gas	\$0.0 ²⁴
Total Replacement Capacity		572 MW			\$584.7m

Note: Planning capacity is the reliable capacity at the time of summer peak. With regard to the Moapa Solar Generating Station, the “nameplate” capacity is approximately 200 MW.

(3) 350 MW of Replacement Renewable Capacity

- Approval to issue three 100 MW RFPs for renewable resources pursuant to the schedule set forth in Table S-19.

²³ This estimate does not include an allowance for funds used during construction (“AFUDC”).

²⁴ LV Cogen Unit 1 will be acquired as a package with LV Cogen Unit 2.

TABLE S-19
THREE 100 MW RFPS

RFP Schedule 300 MW			
EVENT	2014	2015	2016
Release Public Notice	10/01/14	12/14/15 ²⁵	11/15/16
Short List/Start Negotiations	02/13/15	03/11/16	02/24/17
Conclude Negotiations	03/30/15	04/22/16	04/07/17
IRP (Amendment) Approval Filing	07/01/15	06/15/16	06/01/17
PUCN Approval Timeline	12/28/15	10/28/16	10/14/17

- Approval of the Nellis Solar Array II, a 15 MW solar PV facility located on the Nellis Air Force Base at a cost of approximately \$54.5 million (excluding AFUDC). Included in the budget are the new distribution interconnection facilities to interconnect the facility with the Company's Nellis 69/12 kV substation at a cost of \$4.6 million and the distribution interconnection facilities to interconnect the PV facility and Nellis Air Force Base to the Company's Lincoln 138/12 kV substation and a new Clinton 69/12 kV substation at a cost of \$3.2 million, excluding AFUDC.
- Approval to spend up to \$4.4 million as shown in Table S-20 on initial siting activities related to one or more proposed new solar PV generating facilities northeast of Las Vegas in Clark County, Nevada.

²⁵ LCB R131-13 § 12.3(a) requires that the Company shall not accept proposals until the previous RFP is complete. Proposals would be accepted (due) in February 2016.

TABLE S-20
CLARK COUNTY SOLAR DEVELOPMENT BUDGET

	TOTAL PRE- 2015	2015	TOTAL²⁶
Permitting costs	\$95	\$1,101	\$1,196
Project management and internal labor	40	150	190
Outside services: design, consulting, legal, etc.	40	600	640
BLM auction	2,347	-	2,347
TOTAL	\$2,522	\$1,851	\$4,373

D. RENEWABLES

- Approval of the Renewable Expansion Plan set forth in Section 2.D. of the Supply Side Plan.

E. TRANSMISSION

- Harry Allen Transformer. Because Nevada Power does not seek to include the Harry Allen 1,500 MVA, 500/230 kV autotransformer in the regulatory asset to be established for SB 123 eligible projects, Nevada Power will file a brief amendment seeking separate approval of the new Harry Allen 1,500 MVA, 500/230 kV autotransformer 45 days after it files the ERCR. The Company will rely on the information provided in this ERCR in making its amendment filing and seek to consolidate the amendment requesting approval for the Harry Allen 500/230 kV transformer with the ERCR filing for hearing purposes.
- To interconnect the Moapa Solar Project to the Company's transmission system at Harry Allen, the Company requests approval to spend approximately \$1.7 million on network upgrades at the Harry Allen substation. This work will include site metering and communication, substation entrance work, permit assistance, environmental work and protection review.

²⁶ If permitting efforts continue beyond 2015, estimated costs total approximately \$7.3 million.

F. DEMAND SIDE PROGRAMS

Nevada Power is not seeking approval of any change to its approved DSM Plan. The DSM portfolio of programs is consistent with that included in Nevada Power's application for approval of its 2012 Integrated Resource Plan, as modified by the Commission's order and approved on December 24, 2012 in Docket 12-06053. The estimated energy efficiency savings attributed to this portfolio is consistent in all of the alternative expansion plans evaluated for this Emissions Reduction and Capacity Replacement plan. As required by the Commission's regulations, the Company will file an update to its 2015 DSM Plan by July 1, 2014.

G. ENERGY SUPPLY PLAN

Nevada Power's Energy Supply Plan is described in Section VI above.

H. ACTION PLAN BUDGET

Table S-21 lists the individual projects and the associated budgets for the Action Plan period.

TABLE S-21
ACTION PLAN BUDGET²⁷

NEVADA POWER COMPANY

ESTIMATED CASH FLOWS

(millions excluding AFUDC)

Action Plan Projects	Total	Total Pre-2015	Action Plan 2015	Non-Action Plan Period	Expected Completion/In-service
Generation					
LV Cogen 1 and 2	\$ 130.82		\$ 130.82		12/31/2014
Sun-Peak	\$ 15.83		\$ 15.83		12/31/2014
<i>Subtotal Generation</i>	\$ 146.65	\$ -	\$ 146.65	\$ -	
Renewables					
Nellis Solar II	\$ 54.50		\$ 54.50		12/31/2015
Moapa Solar	\$ 438.09	\$ 6.00	\$ 192.21	\$ 239.88	10/1/2016
Clark County Solar Development	\$ 4.37	\$ 2.52	\$ 1.85		12/31/2016
<i>Subtotal Renewables</i>	\$ 496.96	\$ 8.52	\$ 248.56	\$ 239.88	
Transmission					
Harry Allen ("HA") Transformer	\$ 46.70		\$ 0.94	\$ 45.77	6/1/2017
Breaker Bay at HA for Moapa	\$ 1.70		\$ 1.70		12/31/2015
<i>previously approved</i>					
ON Line (Nevada Power's portion 95%)			\$ 0.12		
WestConnect membership			\$ 0.15		
<i>Subtotal transmission</i>	\$ 48.40	\$ -	\$ 2.91	\$ 45.77	
Demand Side					
Per Approved DSM Plan			\$ 53.05		12/31/2015
<i>Subtotal DSM</i>	\$ -	\$ -	\$ 53.05	\$ -	
Total	\$ 692.01	\$ 8.52	\$ 451.17	\$ 285.65	

²⁷ Harry Allen Transformer. Because Nevada Power does not seek to include the Harry Allen 1,500 MVA, 500/230 kV autotransformer in the regulatory asset to be established for SB 123 eligible projects, Nevada Power will file a brief amendment seeking separate approval of new Harry Allen 1,500 MVA, 500/230 kV autotransformer 45 days after it files the ERCR. The Company will rely on the information provided in this ERCR in making its amendment filing, and seek to consolidate the amendment requesting approval for the Harry Allen 500/230 kV transformer with the ERCR filing for hearing purposes.

APPENDIX C

Federal Land Management Agency Comments and Nevada's Responses

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Appendix C

Federal Land Management Agency Comments and Nevada's Responses September 15, 2014

On June 16, 2014, pursuant to 40 C.F.R. 51.308(i)(2), the Nevada Division of Environmental Protection (NDEP) provided the Federal Land Managers with a draft Regional Haze 5-Year Progress Report (Report) for a 60-day review. The NDEP received comment letters from:

- The United States Department of the Interior National Parks Service (NPS) on August 15, 2014.
- The United States Department of Agriculture Forest Service (USFS) on August 29, 2014

Nevada replied to the NPS on September 12, 2014 with the responses presented below. The responses are organized by Report chapter; if a chapter is not listed below, there were no comments. The USFS letter had no comments that required a response. Copies of the NPS and USFS comment letters follow the set of comments and responses below.

NPS Comments

CHAPTER FOUR

COMMENT 1: *Table 4-2 and 4-3 do not show the same deciview values for 2007-2011 and 2008-2012. Please check.*

RESPONSE: The value for the 2008-2012 worst days has been corrected from the 2012 annual average to the 2008-2012 5-year average in Table 4-3. The 2007-2011 values are correct in Table 4-3. The values in Table 4-2 were confirmed as correct.

CHAPTER FIVE

COMMENT 2: *Section 5.4, p. 5-8. Please add in the introductory section that the tables compare fire inventories for one year, 2008, to the five-year average for 2000-2004. This point is made on p. 5-16 under discussion of volatile organic carbon, but it is relevant to every pollutant and every inventory sector.*

RESPONSE: Text was added to Section 5.4, p 5-8, noting that fire emissions from only a single year (2008) were used for the 2008 DEASCO₃ study, which was used as the data source for fire emissions in developing the WestJump2008 inventory. It is noted that this results in a somewhat misleading comparison with the baseline period, which used a 5-year average from 2000-2004.

COMMENT 3: Section 5.5.8 Coarse Mass. Please make the connection that coarse mass has the second greatest contribution to visibility impairment on the 20% worst visibility days at Jarbidge WA. Anthropogenic coarse mass is projected to increase in the 2008 inventory; possibly due to increased activity and/or changes in inventory methods. These data together suggest that NDEP should consider control options for anthropogenic sources of coarse mass the 2018 revisions to Nevada's regional haze plan.

RESPONSE: The point that coarse mass is the second greatest contributor to visibility impairment on the 20% worst visibility days at Jarbidge WA is made in Chapter Four, Assessment of Visibility Conditions, Sections 4.1 and 4.4, as well as Section 1.3 of the introductory chapter. Chapter Five is rather a straightforward analysis tracking the changes in emissions of visibility impairing pollutants over the last five years and does not discuss the relative impacts of the pollutants at Jarbidge. While it is true that anthropogenic coarse mass emissions are projected to increase in the 2008 inventory, these increases may in large part be due to changes in inventory development methodologies rather than actual increases, as noted in Chapter Five. Interestingly, examination of county level data in the WestJump2008 inventory for coarse mass indicates that over 60 % of these emissions are in Clark County.

In the 2018 SIP revision, the NDEP will consider all appropriate control scenarios for anthropogenic sources of coarse mass emissions. A sentence has been added to the Executive Summary indicating that the NDEP will re-evaluate sources of visibility impairment in the 2018 SIP revision and revise its strategy, as appropriate.

CHAPTER SIX

COMMENT 4: Chapter 6: The WRAP 2002 and 2018 modeling included particulate source apportionment analyses that demonstrated Nevada's contribution to visibility impairment at Class I areas in neighboring states and other states' contributions at Jarbidge WA. Summarizing these data would assist in demonstrating that Nevada is reducing its contribution to neighboring states and would provide context for the discussions of controls in Idaho and Oregon.

RESPONSE: The NDEP added a new summary of other states' contributions to visibility impairment measured at JARB1 in Section 6.3 to provide additional context for the discussion of BART implementation in Idaho and Oregon. The text describes the sulfate and nitrate contributions to visibility impairment at JARB1 based on the particulate source apportionment modeling conducted by the WRAP for the original RH SIPs. The NDEP also added a new section to Chapter 6 providing a discussion of Nevada's contributions to other Class I areas based on the source apportionment modeling results to assist with the demonstration that Nevada is reducing its contributions to neighboring states, including a summary of emissions reductions from Nevada sources between 2002 and 2008.

National Park Service Comment Letter



United States Department of the Interior

NATIONAL PARK SERVICE

Air Resources Division

P.O. Box 25287

Denver, CO 80225-0287

TRANSMITTED VIA ELECTRONIC MAIL - NO HARDCOPY TO FOLLOW

N3615 (2350)

August 15, 2014

Adele K. Malone
Bureau of Air Quality Planning
Division of Environmental Protection
901 S. Steward Street, Suite 4001
Carson City, NV 89701

Dear Ms. Malone:

Thank you for the opportunity to review and comment on Nevada's draft Regional Haze 5-Year Progress Report. We believe that Nevada Division of Environmental Protection (NDEP) has met the requirements for the periodic progress report as outlined in 40 CFR 41.508 (g) and (h). NDEP has demonstrated significant reductions of anthropogenic emissions, primarily through retirements or controls of electric generating units (EGU) and implementation of federal air regulations. Anthropogenic emissions are already below the 2018 emissions projections that were used by the Western Regional Air Partnership in the 2018 regional air quality modeling. Additional retirements of coal fired power plants, installation of BART controls, and Nevada state laws will further reduce Nevada anthropogenic emissions by 2018. Because Nevada and the western states used the 2018 WRAP model results to set 2018 visibility reasonable progress goals, we agree that Nevada is not interfering with the ability of its neighboring states to meet their 2018 goals.

NDEP has demonstrated that particulate organic carbon, coarse mass, and sulfate are the most important pollutants contributing to impairment on the 20% worst visibility days at Jarbidge Wilderness Area (WA). Despite anthropogenic emission reductions to date, visibility on the 20% worst days in the 2008-2012 period has shown little improvement compared to the 2000-2004 base period. Due to the contributions of uncontrollable emissions, it is not clear that the 2018 visibility goals for Jarbidge will be met. Visibility on the 20% best days has improved and is close to natural conditions. Given the additional anthropogenic emissions reductions required by 2018, we agree that no additional control measures are needed at this time.

Below are suggestions to improve NDEP's demonstration.

- 1) Table 4-2 and 4-3 do not show the same deciview values for 2007-2011 and 2008-2012. Please check.
- 2) Section 5.4, p. 5-8. Please add in the introductory section that the tables compare fire inventories for one year, 2008, to the five-year average for 2000-2004. This point is made on p. 5-16 under discussion of volatile organic carbon, but it is relevant to every pollutant and every inventory sector.
- 3) Section 5.5.8 Coarse Mass. Please make the connection that coarse mass has the second greatest contribution to visibility impairment on the 20% worst visibility days at Jarbidge WA. Anthropogenic coarse mass is projected to increase in the 2008 inventory; possibly due to increased activity and/or changes in inventory methods. These data together suggest that NDEP should consider control options for anthropogenic sources of coarse mass the 2018 revisions to Nevada's regional haze plan.
- 4) Chapter 6: The WRAP 2002 and 2018 modeling included particulate source apportionment analyses that demonstrated Nevada's contribution to visibility impairment at Class I areas in neighboring states and other states' contributions at Jarbidge WA. Summarizing these data would assist in demonstrating that Nevada is reducing its contribution to neighboring states and would provide context for the discussions of controls in Idaho and Oregon.

We appreciate the opportunity to work closely with NDEP to improve visibility in our Class I national park and wilderness areas. If you have questions, please contact me at patricia_f_brewer@nps.gov or 303-969-2153.

Sincerely,



Pat Brewer

cc:

Tom Webb, EPA Region 9

U.S. Forest Service Comment Letter



United States
Department of
Agriculture

Forest
Service

Intermountain Region

324 25th Street
Ogden, UT 84401
801-625-5605

Adele K. Malone
Supervisor
Bureau of Air Quality Planning
901 S. Stewart Street
Suite 4001
Carson City, NV 89701

File Code: 2580
Date: AUG 28 2014
Nevada
Environmental Protection
RECEIVED
ENVIRONMENTAL PROTECTION
AUG 29 2014
BAPC/BAQP

Dear Ms. Malone:

On June 16, 2014, The State of Nevada submitted a draft regional haze 5-year progress report. The report demonstrated the progress made toward achieving visibility improvement goals for mandatory Class I areas, including the Jarbidge Wilderness, as outlined in the Nevada regional haze implementation plan. This letter acknowledges that the U.S. Department of Agriculture, Forest Service, has received and conducted a review of this 5-year Progress Report. We have no additional comments at this time. We look forward to reviewing future updates and reports.

We appreciate the opportunity to continue working closely with the state on achieving the Clean Air Act's goal of natural visibility conditions in mandatory Class I wilderness areas and parks. For further information or if you have any questions, please contact Intermountain Region Air Resource Program Manager, Jeff Sorkin at (303) 275-5759.

Sincerely,


for NORA B. RASURE
Regional Forester



Caring for the Land and Serving People

Printed on Recycled Paper



APPENDIX D

Evidence of Public Participation; Public Comments and Nevada's Responses

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SECTION D.1

EVIDENCE OF PUBLIC PARTICIPATION

D.1. 1 Notice of Public Hearing



NOTICE OF PUBLIC COMMENT PERIOD BEGINNING SEPTEMBER 15, 2014 AND A PUBLIC HEARING ON OCTOBER 15, 2014, IF REQUESTED

Conducted by the Nevada Division of Environmental Protection
Bureau of Air Quality Planning

Pursuant to the public hearing requirements in Title 40 of the Code of Federal Regulations Part 51 section 102, the Nevada Division of Environmental Protection (NDEP) is issuing the following notice.

In 1977, Congress amended the Clean Air Act (CAA) establishing a national goal to protect visibility in Class I federal areas - primarily national parks and wilderness areas. The amendments called for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." Nevada has one mandatory Class I area, the Jarbidge Wilderness Area, in the northeast corner of the state managed by the U.S. Forest Service.

In 1999, the U.S. Environmental Protection Agency (USEPA) adopted the Regional Haze Rule (RHR) requiring each affected state to develop and adopt a plan to improve the haziest days and protect the clearest days at each mandatory Class I area in the state with a goal of returning to natural visibility conditions by the year 2064. The NDEP prepared a Regional Haze state implementation plan (SIP) to meet the requirements of the federal rule and submitted it to USEPA on November 18, 2009. The RHR further requires periodic progress reports every five years after the initial SIP is submitted. The NDEP has prepared a draft "Nevada Regional Haze 5-Year Progress Report" (Report) to meet the requirements of the federal rule. The Report will be submitted to the USEPA by November 18, 2014.

The draft Report and related materials are available on the NDEP website at: http://ndep.nv.gov/admin/public.htm#air_gp or <http://ndep.nv.gov/bagp/index.htm>. Access to the draft report may also be obtained by contacting Adele Malone at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9356; or e-mail to amalone@ndep.nv.gov.

Persons wishing to comment on the draft 5-year progress report during the comment period or to request a public hearing should submit their comments or request in writing either in person, by postal service, or fax to Adele Malone at the NDEP address above, or by FAX at (775) 687-6396. ***A request for a hearing must be received by October 6, 2014. Written comments will be received by the NDEP until 5:00 PM PST, October 15, 2014 and will be retained and considered.***

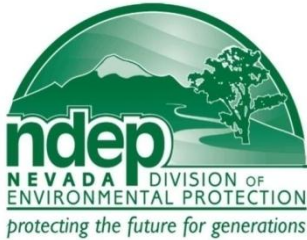
Upon receipt of a valid written request, the NDEP will hold a public hearing in Carson City on:

**October 15, 2014
10:00 am to 12:00 pm
Great Basin Conference Room, 4th Floor-South
901 South Stewart Street
Carson City, Nevada**

An agenda will be posted on the NDEP web site at least 3 working days prior to the hearing. Oral comments will be received at the Hearing. If no request for a public hearing is received by October 6, 2014, the hearing will be cancelled. Persons may check on the status of the hearing on the NDEP web site at http://ndep.nv.gov/admin/public.htm#air_gp, or you may call the NDEP Bureau of Air Quality Planning at (775) 687-9349.

This notice has been published in the Las Vegas Review-Journal and the Reno Gazette Journal newspapers. It has been posted at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada. Members of the public who are disabled and require special accommodations or assistance at the hearing are requested to notify Adele Malone (775-687-9356) no later than 3 full working days before the hearing. 9/10/2014

D.1.2 Notice of Cancellation of Hearing



STATE OF NEVADA

Department of Conservation & Natural Resources

DIVISION OF ENVIRONMENTAL PROTECTION

Brian Sandoval, Governor

Leo M. Drozdoff, P.E., Director

Colleen Cripps, Ph.D., Administrator

NOTICE OF CANCELLATION OF PUBLIC HEARING ON OCTOBER 15, 2014

Nevada Division of Environmental Protection
Bureau of Air Quality Planning

Pursuant to the public hearing provisions in Title 40 of the Code of Federal Regulations Part 51 section 102, the Nevada Division of Environmental Protection (NDEP) is cancelling the following public hearing because no request for a hearing was received:

October 15, 2014
10:00 a.m. to 12:00 p.m.
Great Basin Conference Room, 4th Floor
901 South Stewart Street
Carson City, Nevada

The draft *Nevada Regional Haze 5-Year Progress Report* and related materials are available on the NDEP website at <http://ndep.nv.gov/admin/public.htm>, click on “Air Quality Planning.” Persons may also check on the status of Nevada’s regional haze progress report by telephone at (775) 687-9356.

D.1.3 Newspaper Affidavits

Nevada
Environmental Protection

SEP 19 2014

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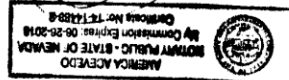
STATE OF NEVADA
COUNTY OF WASHOE

Being first duly sworn, deposes and says: That as the legal clerk of the Reno Gazette-Journal, a daily newspaper of general circulation published in Reno, Washoe County, State of Nevada, that the notice referenced below has published in each regular and entire issue of said newspaper between the dates: 9/15/2014 - 9/15/2014, for exact publication dates please see last line of Proof of Publication below.

Subscribed and sworn to before me

Signed:

Danielle Rasmussen



Proof of Publication

NOTICE OF PUBLIC COMMENT PERIOD BEGINNING SEPTEMBER 15, 2014 AND A PUBLIC HEARING ON OCTOBER 15, 2014, IF REQUESTED Conducted by the Nevada Division of Environmental Protection Bureau of Air Quality Planning Pursuant to the public hearing requirements in Title 40 of the Code of Federal Regulations Part 51 section 102, the Nevada Division of Environmental Protection (NDEP) is issuing the following notice. In 1977, Congress amended the Clean Air Act (CAA) establishing a national goal to protect visibility in Class I federal areas - primarily national parks and wilderness areas. The amendments called for the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." Nevada has one mandatory Class I area, the Jarbidge Wilderness Area, in the northeast corner of the state managed by the U.S. Forest Service. In 1999, the U.S. Environmental Protection Agency (USEPA) adopted the Regional Haze Rule (RHR) requiring each affected state to develop and adopt a plan to improve the haziest days and protect the clearest days at each mandatory Class I area in the state with a goal of returning to natural visibility conditions by the year 2064. The NDEP submitted a Regional Haze state implementation plan (SIP) to USEPA on November 18, 2009. The RHR requires periodic progress reports every five years after the initial SIP is

Ad Number: 2000040892

Page 1 of 2

submitted. The NDEP has prepared a draft "Nevada Regional Haze 5-Year Progress Report" (Report) to meet the requirements of the federal rule. The Report will be submitted to the USEPA by November 18, 2014. The draft Report and related materials are available on the NDEP website at: http://ndep.nv.gov/admin/public.htm#air_qp or <http://ndep.nv.gov/baqp/index.htm>. Access to the draft report may also be obtained by contacting Adele Malone at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9356; or e-mail to amalone@ndep.nv.gov. Persons wishing to comment on the draft 5-year progress report during the comment period or to request a public hearing should submit their comments or request in writing either in person, by postal service, or fax to Adele Malone at the NDEP address above, or by FAX at (775) 687-6396. A request for a hearing must be received by October 6, 2014. Written comments will be received by the NDEP until 5:00 PM PST, October 15, 2014 and will be retained and considered. Upon receipt of a valid written request, the NDEP will hold a public hearing in Carson City on: October 15, 2014 10:00 am to 12:00 pm Great Basin Conference Room, 4th Floor-South 901 South Stewart Street Carson City, Nevada. An agenda will be posted on the NDEP web site at least 3 working days prior to the hearing. Oral comments will be received at the Hearing. If no request for a public hearing is received by October 6, 2014, the hearing will be cancelled. Persons may check on the status of the hearing on the NDEP web site at http://ndep.nv.gov/admin/public.htm#air_qp, or you may call the NDEP Bureau of Air Quality Planning at (775) 687-9349. This notice has been published in the Las Vegas Review-Journal and the Reno Gazette Journal newspapers. It has been posted at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada. Members of the public who are disabled and require special accommodations or assistance at the hearing are requested to notify Adele Malone (775-687-9356) no later than 3 full working days before the hearing, 9/10/2014 No. 40892 September 15, 2014

**NOTICE OF PUBLIC COMMENT PERIOD BEGINNING SEPTEMBER 15, 2014
AND A PUBLIC HEARING ON
OCTOBER 15, 2014, IF REQUESTED**

Conducted by the Nevada Division of Environmental Protection
Bureau of Air Quality Planning
Pursuant to the public hearing requirements in Title 40 of the Code of Federal Regulations Part 51, section 102, the Nevada Division of Environmental Protection (NDEP) is issuing the following notice.

In 1977, Congress amended the Clean Air Act (CAA), establishing a national goal to protect visibility in Class I Federal areas, including national parks and wilderness areas. The amendments limited the "prevention of any future, and the remedying of any existing, results from manmade air pollution." Nevada has one Class I area, the Jarvis-Wheeler Wilderness Area, in the northeast corner of the state managed by the U.S. Forest Service.

In 1999, the U.S. Environmental Protection Agency (USEPA) adopted the Regional Haze Rule (RHR) requiring each affected state to develop and adopt a plan to provide the haziest days and protect the clearest days at each mandatory Class I area in the state with a goal of returning to natural visibility conditions by the year 2064. The NDEP submitted a Regional Haze Implementation Plan (RHIP) to USEPA on November 18, 2009. The RHIP requires periodic progress reports every five years after the 5-Year Progress Report (Report) to meet the requirements of the federal rule. The Report will be submitted to the USEPA by November 18, 2014.

The draft Report and related materials are available on the NDEP website at: http://ndep.nv.gov/admin/public.htm#air_qp or <http://ndep.nv.gov/baqp/index.htm>. Access to the draft report may also be obtained by contacting Adele Malone at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9356; or e-mail to amalone@ndep.nv.gov.

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No. 40892 September 15, 2014

Affidavit of Publication

STATE OF NEVADA)
COUNTY OF CLARK) SS:

NV DIVISION ENVIRONM PROT - AIR POLL
STE 4001 AIR POLLUTION CONTROL
901 S STEWART ST
CARSON CITY NV 89701-5267

Account # 22500
Ad Number 0000307541

Stacey M. Lewis, being 1st duly sworn, deposes and says: That she is the Legal Clerk for the Las Vegas Review-Journal and the Las Vegas Sun, daily newspapers regularly issued, published and circulated in the City of Las Vegas, County of Clark, State of Nevada, and that the advertisement, a true copy attached for, was continuously published in said Las Vegas Review-Journal and / or Las Vegas Sun in 1 edition(s) of said newspaper issued from 09/15/2014 to 09/15/2014, on the following days:

09 / 15 / 14

NOTICE OF PUBLIC COMMENT
PERIOD BEGINNING
SEPTEMBER 15, 2014 AND
A PUBLIC HEARING ON
OCTOBER 15, 2014,
IF REQUESTED

CONDUCTED BY THE NEVADA
DIVISION OF ENVIRONMENTAL
PROTECTION
BUREAU OF AIR QUALITY
PLANNING

Pursuant to the public hearing requirements in Title 40 of the Code of Federal Regulations Part 51 section 102, the Nevada Division of Environmental Protection (NDEP) is issuing the following notice.

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impairment results from manmade air pollution." Nevada has one mandatory Class I area, the Jarbidge Wilderness Area, in the northeast corner of the state managed by the U.S. Forest Service.

In 1999, the U.S. Environmental Protection Agency (USEPA) adopted the Regional Haze Rule (RHR) requiring each affected state to develop and adopt a plan to improve the haziest days and protect the clearest days at each mandatory Class I area in the state with a goal of returning to natural visibility conditions by the year 2064. The NDEP submitted a Regional Haze state implementation plan (SIP) to USEPA on November 18, 2009. The RHR requires periodic progress reports every five years after the initial SIP is submitted. The NDEP has prepared a draft "Nevada Regional Haze 5-Year Progress Report" (Report) to meet the requirements of the federal rule. The Report will be submitted to the USEPA by November 18, 2014.

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Persons wishing to comment on the draft 5-year progress report during the comment period or to request a public hearing should submit their comments or request in writing either in person, by postal service, or fax to Adele Malone at the NDEP address above, or by FAX at (775) 687-6396. A request for a hearing must be received by October 6, 2014. Written comments will be received by the NDEP until 5:00 PM PST, October 15, 2014 and will be retained and considered.

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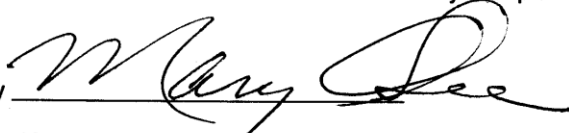
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PUB: September 15, 2014
LV Review-Journal


LEGAL ADVERTISEMENT REPRESENTATIVE

Subscribed and sworn to before me on this 15th day of September, 2014

Notary


MARY A. LEE
Notary Public State of Nevada
No. 09-8941-1
My Appt. Exp. Nov. 13, 2016

D.1. 4 SIP Approval Authority

ALLEN BIAGGI
Director

JIM GIBBONS
Assistant

KAY SCHERER
Deputy Director

State of Nevada
Department of Conservation and Natural Resources
Office of the Director
Richard H. Bryan Building
901 S. Stewart Street, Suite 5001
Carson City, Nevada 89701
Telephone (775) 684-2700
Facsimile (775) 684-2715
www.dcnr.nv.gov



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Division of Environmental Protection
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Division of State Lands
Division of State Parks
Division of Water Resources
National Heritage Program
Wild Dunes Program

STATE OF NEVADA
Department of Conservation and Natural Resources
OFFICE OF THE DIRECTOR

May 30, 2007

Wayne Nastri
Regional Administrator
ORA-1, USFPA Region 9
75 Hawthorne Street
San Francisco CA 94105

Dear Mr. Nastri:

Nevada Revised Statutes 445B.205 designates the Department of Conservation and Natural Resources (Department) as the air pollution control agency for the State of Nevada for the purposes of the Clean Air Act insofar as it pertains to State programs. Within the Department, the Division of Environmental Protection has responsibility to manage the air quality planning and air pollution control programs for the State of Nevada. Therefore, pursuant to Nevada Administrative Code 445B.053, I am hereby assigning the Administrator of the Nevada Division of Environmental Protection, or the Deputy Administrator acting on his behalf, to be my official designee for the purposes of the Clean Air Act, including, but not limited to, adoption, revision and submittal of state plans and state implementation plans.

Sincerely,

A handwritten signature in dark ink, appearing to read "Allen Biaggi".
Allen Biaggi
Director

cc Michael Dayton, Chief of Staff, Office of the Governor
Jodi Stephens, Deputy Chief of Staff, Office of the Governor
Leo Drozdoff, Administrator, NDEP
Colleen Cripps, Deputy Administrator, NDEP
Tim Porta, Deputy Administrator, NDEP
Deborah Jordan, Director, EPA Air Division, Region IX
Jefferson Wehling, ORC, EPA Region IX

SECTION D.2

PUBLIC COMMENTS AND NEVADA'S RESPONSES

On September 15, 2015, the Nevada Division of Environmental Protection (NDEP) opened a 30-day public comment period on the draft *Nevada Regional Haze 5-Year Progress Report* (Progress Report) with the opportunity for a public hearing in Carson City to be held upon public request. Pursuant to the public hearing provisions in Title 40 of the Code of Federal Regulations (CFR) Part 51 section 102, the NDEP cancelled the public hearing as no request for a hearing was received.

The NDEP received one set of written comments during the 30-day public comment period ending October 15, 2014. The single set of comments had signatories from the Sierra Club and National Parks Conservation Association and will be referred to as the non-governmental organization (NGO) comments in the remainder of this document. The NGO letter in its entirety follows the NDEP's response below.

D.2.1 Nevada's Response

SUMMARY OF COMMENTS

The NGO comments focus on the basis of Nevada's negative declaration that emissions management measures in the 2009 RH SIP are being implemented on schedule and visibility improvement appears to be consistent with reasonable progress goals. Specifically, the NGO comments focus on the following:

- The perceived need for a modeling demonstration that the significant emissions reductions that have and will occur at numerous EGUs in the State have significant visibility impacts on the Jarbidge Wilderness Area (Jarbidge WA);
- The assertion that Nevada's progress evaluation is based on a reasonable progress goal that purportedly used a flawed modeling analysis and an outdated emission inventory;
- The NGO's contention that visibility monitoring data do not show that the Jarbidge WA is on a path consistent with the reasonable progress goals; and
- The NGO's conclusion that Nevada should revise its haze plan to include new strategies to improve the progress towards remedying visibility impairment at the Jarbidge WA

NEVADA'S RESPONSE

The NDEP responds first to the general NGO comments as presented on the first two and half pages of the comment letter and summarized above, and then to the four specific comments detailed in the remainder of the letter.

General Comments

The NDEP appreciates the NGO's thorough review of Nevada's Progress Report and their comments. However, the NGO comments overlook some of the basic facts and science supporting Nevada's Progress Report. The NDEP maintains that the Progress Report fulfills every requirement set forth in the Regional Haze Rule (RHR) using the best data available at the time the report was

written. The report documents the first five years of progress for a 60-year planning horizon. 40 CFR 51.308(d)(1)(i)(B). Nevada will submit a full SIP revision in 2018 with an evaluation of progress likely informed by Regional Planning Organization (RPO) photochemical grid modeling for visibility assessment and source apportionment.

The NDEP emphasizes that three-quarters of visibility impairing emissions in Nevada are emitted by natural (non-anthropogenic) sources. 2009 RH SIP, Table 3-2. The Progress Report focuses on the major sources of anthropogenic emissions in Nevada, SO₂ and NO_x. Emissions of SO₂ and NO_x from Nevada point sources have decreased by 78 percent and 50 percent between 2002 and 2008, respectively, with additional reductions through 2011. Progress Report, Sections 3.1 and 5.5.

Nevada has one mandatory Class I area, the Jarbidge WA. The Progress Report demonstrates that Nevada's contribution to visibility impairment at Jarbidge WA is minimal. Five-year rolling averages of annual worst days visibility conditions from 2010 to 2012 (2006-2010, 2007-2011 and 2008-2012) show nitrate contributes between 3.5 and 4.2 percent, and sulfate contributes between 15.1 and 16.6 percent of total light extinction on the worst days at JARB1. Progress Report, Table 4-4. Source apportionment modeling (Table 2 and Table 3 below) shows that in the worst case scenario, Nevada NO_x and SO₂ emissions contribute at most only 0.6 and 0.9 percent, respectively, to total light extinction at the Jarbidge WA.¹ When emissions from only point sources are considered, the contributions drop to 0.3 and 0.6 percent, respectively.

The RHR requires each state to adopt a plan to improve the haziest days and protect the clearest days at each mandatory Class I area in the state. The Progress Report shows that from the baseline to the progress period, there is no degradation of the best days sulfate or nitrate light extinction at the Jarbidge WA. Figure 5, below. Furthermore, nitrate is not impeding worst days visibility progress at the Jarbidge WA. Five-year averages of annual worst days visibility conditions for nitrate show a persistent downward trend for the last six 5-year periods and are below the glidepath for nitrate for the last four 5-year periods. Progress Report, Figures 4-14 and 4-15; and Figure 3, below. Five-year averages of annual worst days visibility conditions for sulfate show a persistent downward trend consistent with the sulfate glidepath for the last seven 5-year periods, although the averages are above the glidepath. Significantly, three of the last six annual averages are on or below the glidepath for sulfate. Progress Report, Figures 4-12 and 4-13; and Figure 3, below. Trend analysis of the 2000 to 2012 nitrate and sulfate annual extinction values demonstrates that the slopes of the trend lines are comparable to (sulfate) or better than (nitrate) the speciated glide slopes for Jarbidge WA from baseline to natural conditions. Progress Report, Section 4.6.

The NGO comments suggest in several places that the significant emissions reductions achieved by Nevada do not equate to visibility improvement at both the Jarbidge WA as well as out-of-state Class I areas, but fail to present any hard data to substantiate these suggestions. The NDEP presents evidence to the contrary in our responses below. The 2018 regional haze SIP revisions are expected

¹ The NDEP calculated Nevada's contributions to visibility impairment at the Jarbidge WA using: 1) the monitoring data for sulfate and nitrate from JARB1; and 2) the WRAP's nitrate and sulfate source appointment modeling results for JARB1. The speciated contribution to the monitored light extinction was multiplied by Nevada's percent contribution according to the source apportionment modeling to calculate Nevada's contribution to sulfate and nitrate light extinction at JARB1. Essentially, Nevada's point sources contribute a percentage of a percentage.

to be supported by RPO modeling that will demonstrate how emissions reductions impact visibility impairment and will be the basis to further evaluate reasonable progress goals for the Jarbidge WA and impacts on out-of-state Class I areas.

In addition, the USEPA is proceeding with guidance and potential rule changes for the regional haze SIPs due in 2018. There are indications² the guidance and rule changes may include revisions to the four-factor analysis requirement and setting reasonable progress goals based on controllable emissions. There may also be consideration of a revised regional haze metric to replace the current metric of the deciview glidepath, as well as reconsideration of what natural conditions represent.

Specific Comments

NGO Comment 1: NDEP Must Revise Its Reasonable Progress Goal for Jarbidge Wilderness to Be Based on the WRAP's Revised Modeling with its 2018 PRPB Emissions Projections.

The NGOs support this comment with observations that Nevada's reasonable progress goal is based on modeling subsequently found to be in error and based on outdated 2018 emission projections. They further contend that emissions reductions in Nevada have not been demonstrated to impact or improve visibility at the Jarbidge WA, and the 2018 projected emission inventory does not include emissions for oil and gas development.

NDEP Response:

Page 1-6 of the Progress Report discusses Nevada's rationale for retaining its 2018 reasonable progress goal in light of the corrected modeling results noted by the NGO comments. The NDEP evaluated the status of control measures included in the 2009 RH SIP and changes in source activity that have occurred since then that would affect emissions included in corrected modeling. The NDEP presents evidence not only of emissions reductions from the control measures included in the 2009 RH SIP, but also further reductions from the full implementation of best available control technology (BART) and new state legislation. The NDEP notes the 2018 emissions projections included a large power plant that has since been decommissioned and three proposed power projects that are no longer viable. The Progress Report presents evidence that 2008 emissions from anthropogenic sources in Nevada are less than the 2018 emissions projections used by the WRAP in the 2018 visibility modeling. Based on these lines of evidence, the NDEP concluded that it was appropriate to retain the reasonable progress goal of 11.05 deciviews. The NDEP responds to the four components of this NGO comment below.

Modeling Error Assessment

Nevada's reasonable progress goal is based on the visibility modeling results as captured by the Plan02d and PRP18a emission inventories, which provided the best available information at the time the 2009 RH SIP was prepared and will be referred to as the original visibility modeling results in the discussion below. Note to Readers, 2009 RH SIP preface (noting cutoff date of January 5,

² National Association of Clean Air Agencies, Criteria Pollutants Committee September 24, 2014 conference call, agenda item 6 briefing by Rhea Jones, Group Leader, Geographic Strategies Group, Air Quality Policy Division. See also *Inside EPA's Clean Air Report*, November 6, 2014, page 16.

2009). Modeling results from the PRP18b emission inventory were not available until after this cutoff date. As noted in the NGO comments, the WRAP memorandum describing the modeling error was released in April 2011, a year and a half after Nevada submitted its initial regional haze SIP. Therefore, results based on PRP18b and the corrected modeling results were not evaluated for Nevada's original regional haze SIP.

In response to this comment, the NDEP evaluated how the visibility modeling results for the Jarbidge WA changed based on use of: 1) the corrected modeling, which is identified as modeling scenario Plan02d_rev, and 2) a second revision to the 2018 emissions inventory projections for point and area sources (or updated modeling) in the WRAP region identified as modeling scenario PRP18b. Table 1 presents the modeling results for the original visibility modeling, the corrected modeling, and the updated modeling.

Table 1. Comparison of Visibility Modeling Results for the Jarbidge WA

Modeling Scenarios by Emission Inventory	Deciview (dv)	Sulfate Extinction (Mm-1)	Nitrate Extinction (Mm-1)	POM Extinction (Mm-1)	EC Extinction (Mm-1)	Soil Extinction (Mm-1)	CM Extinction (Mm-1)	Sea Salt Extinction (Mm-1)
Plan02d/PRP18a (Original)	11.05	3.34	0.70	8.24	1.12	2.29	5.47	0.06
Plan02d_rev/PRP18a (Corrected)	11.82	3.57	0.77	9.88	1.48	2.67	5.47	0.06
Difference: Plan02d_rev/PRP18a - Plan02d/PRP18a	0.77	0.22	0.07	1.64	0.36	0.38	0	0
Percent change from correction	6.9%	6.7%	10.7%	19.9%	32.1%	16.6%	0%	0%
Plan02d_rev/PRP18b (Updated)	11.82	3.64	0.76	9.85	1.47	2.64	5.47	0.06
Difference: Plan02d_rev/PRP18b - Plan02d_rev/PRP18a	0.00	0.07	-0.01	-0.04	-0.01	-0.03	0	0
Percent change from update	0.0%	1.9%	-1.8%	-0.4%	-0.5%	-1.0%	0%	0%

Table 1 shows that visibility impairment, as measured in deciviews, increased by only seven percent due to correction of the modeling error (i.e., the difference between Plan02d_rev/PRP18a and Plan02d/PRP18a), with the greatest extinction increases occurring for elemental carbon (EC) at 32 percent, nearly 20 percent for particulate organic matter (POM,) and 17 percent for soil. These increases are primarily the result of non-anthropogenic emissions. Further, visibility impairment is only slightly impacted by the emissions inventory update from PRP18a to PRB18b (i.e., the difference between Plan02d_rev/PRP18b and Plan02d_rev/PRP18a) with no change to the haze index and the minor changes to speciated extinction noted in Table 1.

Based on this evaluation of the modeling results, the NDEP concludes: 1) the corrected modeling results suggest an increase in visibility impairment at the Jarbidge WA resulting mostly from large increases in non-anthropogenic sources; and 2) modeling based on the updated 2018 emissions projections did not change the visibility impairment as measured in deciviews, and most speciated extinction values declined slightly with a slight increase in sulfate extinction. Nevada stands by its evaluation of the status of control measures included in the 2009 RH SIP and the changes that have occurred that would affect emissions included in the 2018 visibility projections, as well as its decision to retain the reasonable progress goal of 11.05 deciviews.

Emissions Projections

As noted in the NGO comments, Nevada used modeling results based on projected 2018 emissions as captured by the PRP18a inventory to identify Nevada's reasonable progress goal. Since Nevada's reasonable progress goal was based on the PRP18a inventory, it makes sense to use this inventory as a basis of comparison (Progress Report, Table 5-1) to determine the emissions reductions achieved through the implementation of the measures included in Nevada's 2009 RH SIP. The NDEP also notes that the more refined PRP18b inventory, while reducing emissions from some source categories and increasing others, does not change the modeled visibility impacts (as measured in deciviews) at the Jarbidge WA, and all speciated light extinction improves with the exception of sulfate extinction (see Table 1, above).

The NDEP notes that all emission inventories are outdated immediately upon completion due to the changing nature of sources and their emissions. The PRP18b projections are no exception and do not reflect the changes noted in the Progress Report.

Impact of Emissions Reductions on Visibility at Jarbidge WA

The NGO comments acknowledge the significant reductions of anthropogenic emissions from Nevada sources documented in the Progress Report, but suggest these reductions do not improve visibility at the Jarbidge WA (i.e., emissions reductions have "not been shown to equate to an improvement in visibility impairment at the Jarbidge Wilderness Area") (NGO comment letter, page 4). The NGO comments also suggest that projected emissions from facilities that were included in the WRAP modeling inventory (PRP18a), but ultimately were not constructed, also have not been shown to impact visibility at the Jarbidge WA because of a lack of single source visibility modeling. The NGOs do not provide any evidence to support these suggestions. The NGOs further fault the NDEP for using PRP18a emissions projections in evaluating the adequacy of its reasonable progress goal.

The NDEP disagrees with this assessment. The RHR was established to address "widespread haze from a multitude of sources which impairs visibility in every direction over a large area." 40 CFR 51.300 (a). The NDEP purports that although Nevada's point source contribution to haze at Jarbidge WA is small, the significant reductions in SO₂ and NO_x emissions during the progress period are reflected in visibility improvement at Jarbidge WA.

First, Table 1 above shows no change in visibility impairment at Jarbidge WA, as measured in deciviews, resulting from the update to the 2018 emissions projections. It shows only small decreases in the speciated light extinction, except for a slight increase in light extinction due to sulfate. The SO₂ emissions increases and NO_x decreases noted in the April 29, 2009 (revised October 16, 2009) technical memorandum from Eastern Research Group (ERG),³ *WRAP PRP18b Emissions Inventory – Revised Point and Area Source Projections*, may account for the increase in modeled sulfate concentrations and the decrease in modeled nitrate concentrations at the Jarbidge

³ *WRAP PRP18b Emissions Inventory – Revised Point and Area Source Projections*. April 29, 2009 (Revised October 16, 2009). Technical Memorandum from Marty Wolf and Paula Fields, Eastern Research Group, to the WRAP staff. http://www.wrapair.org/forums/ssjf/documents/Pivot_Tables/PRP18b/Final_PRP18b_point_area_source_memo_erg_101609_revised.pdf (last viewed 11/5/2014)

WA. Table 8e of the ERG memorandum shows an increase in Nevada SO₂ point source emissions of 13,532 tons per year from the PRP18a to PRP18b inventories, as well as a decrease of 8,876 tons per year of NO_x point source emissions. Table 9e shows no changes to the area source inventory for NO_x or SO₂, indicating that all of the changes in model results are due to changes in the point source inventory.

The NDEP notes that the emissions changes between PRP18a and PRP18b may not reflect actual changes in facility emissions. The changes were made to address certain changes in projections and corrections that were identified since the January 2007 revision to the 2018 projection inventory.⁴ Note that many of the facilities or units at the facilities listed below were not built, have been or are scheduled to be shut down, or will be converted from coal-fired to natural gas before 2018. For example, the Ely Energy Center, Toquop and the White Pine Energy Center all modeled with increases in NO_x and SO₂ in the PRP18b update, however, none of those facilities were permitted; therefore, the projected increases in emissions are unreal. Progress Report, pages 2-7, 2-8 and 3-3, 3-4. In addition, the NO_x and SO₂ decreases for Mohave are underestimates, because they are based on BART limits, whereas the facility was actually shut down at the end of 2005.

Nevertheless, the data demonstrate that changes in Nevada's point source inventory do impact Jarbidge WA. The data in Tables 5 and 6 of the ERG memorandum show increases in SO₂ emissions and significant decreases in NO_x from Reid Gardner, Fort Churchill, and Tracy, as well as large reductions in NO_x and SO₂ from Mohave, as a result of updates to BART. Additional documentation of the inventory changes between the PRP18a and PRP18b inventories is presented in the Nevada – Point Sources table, which incorporates the changes noted in tables 5 and 6, in Attachment 1 of the ERG memorandum. The Nevada – Point Sources table shows:

- NO_x and SO₂ increases for Ely Energy Center, Toquop, TS Power (Newmont Nevada Energy Investment), North Valmy, and White Pine Energy Center;
- NO_x increases for Graymont Western and Nevada Cement;
- SO₂ increases at Reid Gardner;
- NO_x and SO₂ decreases for Mohave; and
- NO_x decreases for Reid Gardner, Fort Churchill, and Tracy.

These data and the data in Table 1 of this response suggest that emissions reductions from facilities across the state, including those in southern Nevada, do contribute to visibility improvement at the Jarbidge WA, since approximately half of the listed facilities are not located in northern Nevada.

The WRAP conducted source apportionment modeling that included regional contributions to modeled sulfate and nitrate concentrations at the Jarbidge WA, including emissions from all Nevada point sources. The percent contribution to modeled sulfate on the worst 20 percent visibility days by region and source category is presented in Table 2, while the contribution to modeled nitrate for the worst 20 percent visibility days is presented in Table 3. Tables 2 and 3 show Nevada's point source emissions contribute 2.7 percent and 3.5 percent to the total modeled sulfate concentration in 2002 and 2018, respectively, and 3.9 percent and 6.3 percent to the total modeled nitrate

⁴ See supra n.3.

concentration in 2002 and 2018, respectively.⁵ Recalling that light extinction due to sulfate accounts for approximately 15 percent and nitrate for 3.5 percent of total light extinction on worst days at Jarbidge WA (Progress Report, Table 4-4, 2008-2012 5-year average), overall contributions by Nevada point sources to worst days visibility impairment is about 0.5 percent and 0.2 percent for sulfate and nitrate, respectively.⁶ The NDEP contends that the large reductions in point source emissions of SO₂ and NO_x during the progress period do contribute to visibility improvement at the Jarbidge WA; however, Nevada's overall point source contribution to light extinction at Jarbidge WA is small, while other source category contributions have a larger impact. Clearly, emissions from the North Valmy Generating Station are not a significant source of visibility impairment at the Jarbidge WA.

Table 2. Percentage Contribution to Modeled Worst Days Sulfate Concentration at the Jarbidge WA by Source Region and Category for 2002 (plan02c) and 2018 (base18b)

	Point	Anthro Fire	Mobile	Natural Fires and Biogenics	Area	Total
2002						
Canada	2.3%	0%	0.2%	0%	1.9%	4.3%
Central US	1.5%	0%	0.2%	0%	0.2%	1.9%
Eastern US	2.6%	0%	0%	0%	0.2%	2.8%
Mexico	2.1%	0%	0%	0%	0.4%	2.6%
Outside Domain*	n/a	n/a	n/a	n/a	n/a	41.8%
Pacific Offshore	0.8%	0%	0.4%	0%	5.3%	6.6%
WRAP	18.8%	0.5%	6.4%	10.1%	4.3%	39.9%
WRAP States						
AZ	0.6%	0%	0.1%	0%	0%	0.7%
CA	2.1%	0%	0.6%	1.3%	0.6%	4.6%
CO	0.4%	0%	0%	0%	0.0%	0.4%
ID	2.3%	0.1%	1.1%	5.1%	0.9%	9.5%
MT	0.1%	0%	0.1%	0%	0.1%	0.3%
NV	2.7%	0%	0.3%	0.9%	0.6%	4.5%
NM	0.3%	0%	0%	0%	0%	0.4%
ND	0.1%	0%	0%	0%	0%	0.1%
OR	2.9%	0.2%	1.5%	2.1%	1.0%	7.7%
SD	0%	0%	0%	0%	0%	0%
UT	1.0%	0%	0.4%	0.1%	0.1%	1.6%
WA	5.4%	0.1%	2.1%	0.1%	0.8%	8.6%

⁵ To replicate the data in Tables 2 and 3, enter the TSS website at <http://vista.cira.colostate.edu/TSS/>. Under the "Resources" tab on the left select: Haze Planning. On the map select the Jarbidge WA, then click on "Emissions and Source Apportionment". Under the "Source Apportionment Results" select "Sulfate/SO_x Tracer – All Source Regions". Here you can switch between Nitrate/NO_x and Sulfate/SO_x "parameter choices. Narrow the selection to Nevada. The data can then be expanded below the figure under "Show Data."

⁶ See supra n.1.

	Point	Anthro Fire	Mobile	Natural Fires and Biogenics	Area	Total
WY	1.0%	0%	0%	0.3%	0.1%	1.5%
2018						
Canada	2.4%	0%	0.2%	0%	2.0%	4.3%
Central US	1.2%	0%	0%	0%	0.2%	1.4%
Eastern US	1.2%	0%	0%	0%	0.2%	1.4%
Mexico	2.2%	0%	0%	0%	0.6%	2.8%
Outside Domain*	n/a	n/a	n/a	n/a	n/a	43.8%
Pacific Offshore	1.0%	0%	0.2%	0%	5.5%	6.9%
WRAP	22.3%	0.3%	1.4%	10.5%	4.9%	39.4%
WRAP States						
AZ	0.7%	0%	0%	0%	0%	0.7%
CA	2.5%	0%	0.4%	1.4%	0.7%	5.0%
CO	0.3%	0%	0%	0%	0%	0.3%
ID	3.6%	0.1%	0.3%	5.3%	1.0%	10.3%
MT	0.2%	0%	0%	0%	0.1%	0.3%
NV	3.5%	0%	0.1%	1.0%	0.8%	5.4%
NM	0.3%	0%	0%	0%	0.1%	0.4%
ND	0.1%	0%	0%	0%	0%	0.1%
OR	3.7%	0.1%	0.2%	2.2%	0.9%	7.2%
SD	0%	0%	0%	0%	0%	0%
UT	1.5%	0%	0.1%	0.1%	0.1%	1.8%
WA	4.5%	0%	0.2%	0.1%	1.0%	5.9%
WY	1.5%	0%	0%	0.3%	0.1%	2.0%

* n/a means not available

Source: <http://vista.cira.colostate.edu/tss/>, last viewed 11/07/2014

Table 3. Percentage Contribution to Modeled Worst Days Nitrate Concentration at the Jarbidge WA by Source Region and Category for 2002 (plan02c) and 2018 (base18b)

	Point	Anthro Fire	Mobile	Natural Fires and Biogenics	Area	Total
2002						
Canada	0.3%	0%	1.0%	0%	0.3%	1.9%
Central US	0%	0%	0%	0%	0%	0%
Eastern US	0%	0%	0%	0%	0%	0%
Mexico	0%	0%	0%	0%	0%	0%
Outside Domain*	n/a	n/a	n/a	n/a	n/a	20.8%
Pacific Offshore	0%	0%	0.3%	0%	0.6%	1.0%
WRAP	13.1%	1.5%	43.2%	8.2%	10.2%	76.3%

	Point	Anthro Fire	Mobile	Natural Fires and Biogenics	Area	Total
WRAP States						
AZ	0%	0%	0.1%	0%	0%	0.2%
CA	0.6%	0.1%	5.3%	0.5%	0.9%	7.3%
CO	0%	0%	0%	0%	0%	0%
ID	3.2%	0.3%	16.1%	3.9%	8.2%	31.7%
MT	0.1%	0%	0.3%	0.1%	0%	0.5%
NV	3.9%	0%	6.0%	1.6%	0.2%	11.6%
NM	0%	0%	0%	0%	0%	0.1%
ND	0%	0%	0%	0%	0%	0%
OR	0.8%	0.4%	3.0%	0.7%	0.2%	5.1%
SD	0%	0%	0%	0%	0%	0%
UT	4.0%	0%	7.8%	0.6%	0.3%	12.8%
WA	0.4%	0.6%	4.6%	0.8%	0.3%	6.7%
WY	0.1%	0%	0.1%	0%	0%	0.2%
2018						
Canada	0.4%	0%	1.3%	0%	0.4%	2.1%
Central US	0%	0%	0%	0%	0%	0%
Eastern US	0%	0%	0%	0%	0%	0%
Mexico	0%	0%	0%	0%	0%	0%
Outside Domain*	n/a	n/a	n/a	n/a	n/a	27.5%
Pacific Offshore	0%	0%	0%	0%	0.8%	1.3%
WRAP	18.9%	0.9%	23.2%	9.5%	16.5%	69.2%
WRAP States						
AZ	0.1%	0%	0.1%	0%	0%	0.2%
CA	0.8%	0.1%	2.6%	0.6%	1.0%	5.1%
CO	0%	0%	0%	0%	0%	0%
ID	4.6%	0.2%	7.4%	4.5%	13.6%	30.3%
MT	0.1%	0%	0.2%	0.1%	0%	0.4%
NV	6.3%	0%	4.5%	1.9%	0.3%	13.1%
NM	0%	0%	0%	0%	0%	0.1%
ND	0%	0%	0%	0%	0%	0%
OR	1.2%	0.4%	1.9%	0.8%	0.3%	4.6%
SD	0%	0%	0%	0%	0%	0%
UT	5.0%	0%	4.3%	0.8%	0.6%	10.6%
WA	0.6%	0.3%	2.2%	0.9%	0.4%	4.4%
WY	0.1%	0%	0%	0%	0.1%	0.3%

* n/a means not available

Source: <http://vista.cira.colostate.edu/tss/>, last viewed 11/07/2014

Failure to Include Emissions from Oil and Gas Development

The NGO comments contend that emissions resulting from oil and gas development were included in the 2002 inventory for Nevada, but Nevada did not report oil and gas emissions for 2008 and the assumption of zero emissions for 2008 is at odds with publicly reported information. In fact, Nevada did not report oil and gas emissions in either 2002 or 2008. Sections 5.3 and 5.4 of the Progress Report have been revised to make this clear. Like many other states, Nevada does not report oil and gas emissions directly to the NEI, relying on USEPA for this portion of the area source inventory in the NEI.

The fact that Nevada did not report oil and gas emissions does not necessarily mean that there were no estimates. The NDEP notes that emissions resulting from oil and gas development were projected for Nevada's PRP18a inventory (2009 RH SIP, Tables 3-7, 3-8, and 3-9) and, therefore, incorporated in Nevada's reasonable progress goal. For the 2002 baseline inventory, the WRAP built on the 2002 NEI and developed a robust inventory that included oil and gas emissions estimates for Nevada. For the WestJump2008 inventory, the WRAP built on the 2008 NEI. Although the WRAP developed robust oil and gas inventories for other areas within the WRAP region, it did not conduct the same for Nevada. Progress Report, Sections 5.3 and 5.4. Nonetheless, such emissions must be put into perspective: in 2002 only 63 tons per year (tpy) of NO_x and 129 tpy of VOC emissions were reported compared to a state-wide 2002 inventory of 162,397 tpy of NO_x and 897,102 tpy VOC and the state-wide 2008 inventory of 118,766 tpy NO_x and 351,142 tpy VOC. Progress Report, Table 5-7 and Table 5-10.

The NDEP is aware of the limited oil and gas exploration efforts in northeastern Nevada to assess potential targets suitable for enhanced oil recovery methods such as fracking (see [BLM Environmental Assessment for Huntington Valley Oil and Gas Exploration Project DOI-BLM-NV-E020-2014-0003-EA](#)). In Nevada, oil and gas development and production, as reflected by rig counts, is either declining or steady. Table 4 shows annual average rig counts by state from 2000 to 2013 and demonstrates that Nevada is not experiencing any sort of oil and gas development boom as are some western states such as North Dakota or Utah. Figure 1 shows a steady decline in Nevada's oil and gas production from 1990 to 2013. These data suggest that oil and gas development and production is not a significant activity in Nevada. The NDEP notes that oil and gas development and production in Nevada is currently subject to permitting requirements.

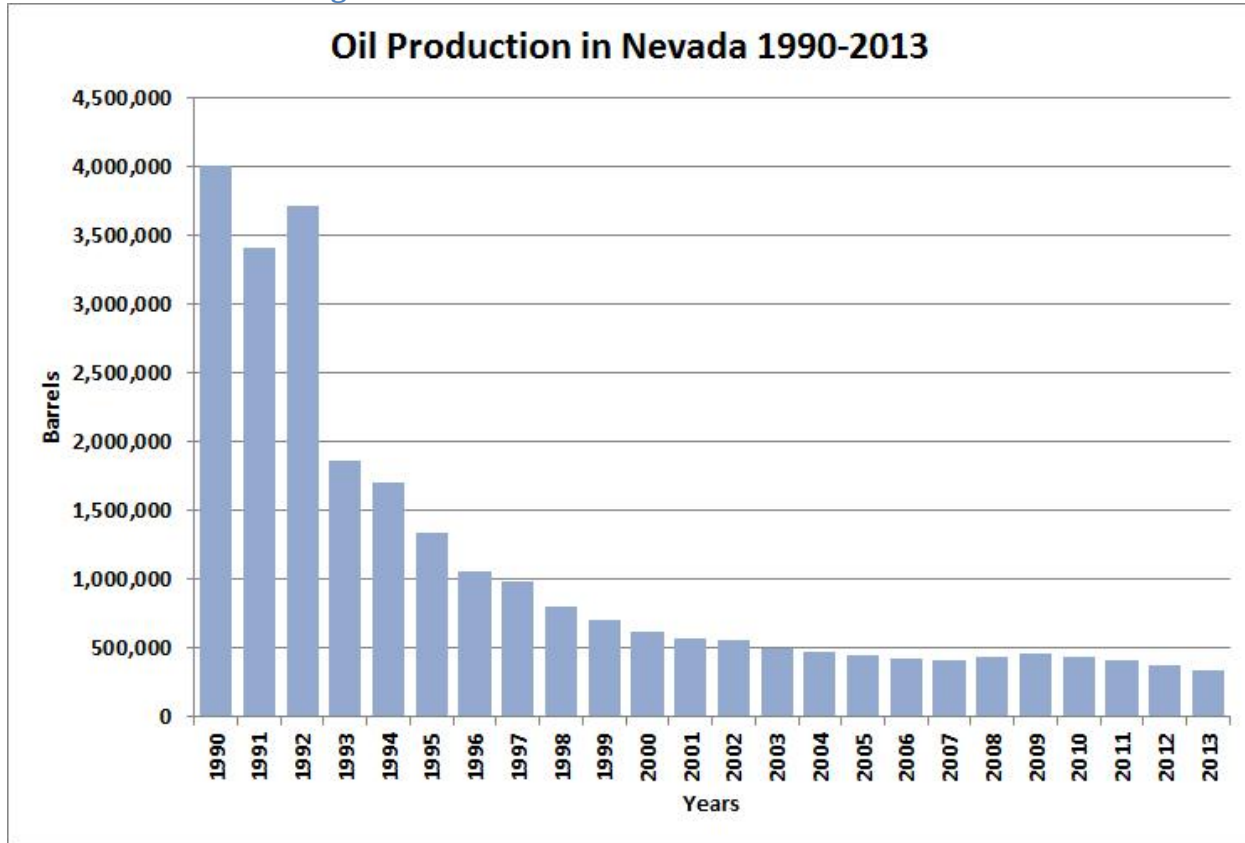
Table 4. Baker Hughes Rotary Rig Count Annual Averages by State⁹

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Colorado	18	32	28	39	54	74	89	107	114	50	58	72	65	63
Montana	7	10	8	14	20	24	22	17	11	3	7	9	20	12
Nevada	0	0	0	1	2	2	1	2	3	3	6	3	1	3
New Mexico	68	68	42	65	67	83	94	78	78	44	62	79	84	77
N Dakota	13	14	10	14	15	21	32	39	68	50	114	168	188	173

⁹ Modified from information downloaded from <http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother> on October 23, 2014.

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Utah	16	21	13	14	22	28	40	42	42	18	27	28	37	29
Wyoming	41	55	40	54	74	78	99	74	74	40	40	48	47	48

Figure 1. Oil Production in Nevada 1990 to 2013.¹⁰



The NDEP considered the applicable RHR requirements and available data in reaching the conclusion to retain the reasonable progress goal of 11.05 deciviews for the Jarbidge WA. The NDEP acknowledges the modeling error, but notes the update to the emission inventory demonstrates that state-wide reductions in Nevada point source emissions have reduced visibility impairment at the Jarbidge WA. Emissions from Nevada's oil and gas development are not a significant emissions source and are not likely to have significant influence on visibility at the Jarbidge WA. Nevada stands by its conclusion to retain the reasonable progress goal of 11.05 deciviews.

The only change made to the Progress Report based on this NGO comment was to clarify the discussion of oil and gas emissions reporting, as noted above.

¹⁰ Figure downloaded from http://minerals.nv.gov/uploadedImages/mineralsnvgov/content/Programs/Oil_and_Gas/OilProdInNV1990-2013.jpg October 23, 2014

NGO Comment 2: NDEP Must Consider and Evaluate Reasonable Progress Measures for the Jarbidge Wilderness and Other Class I Areas Impacted by Nevada Sources.

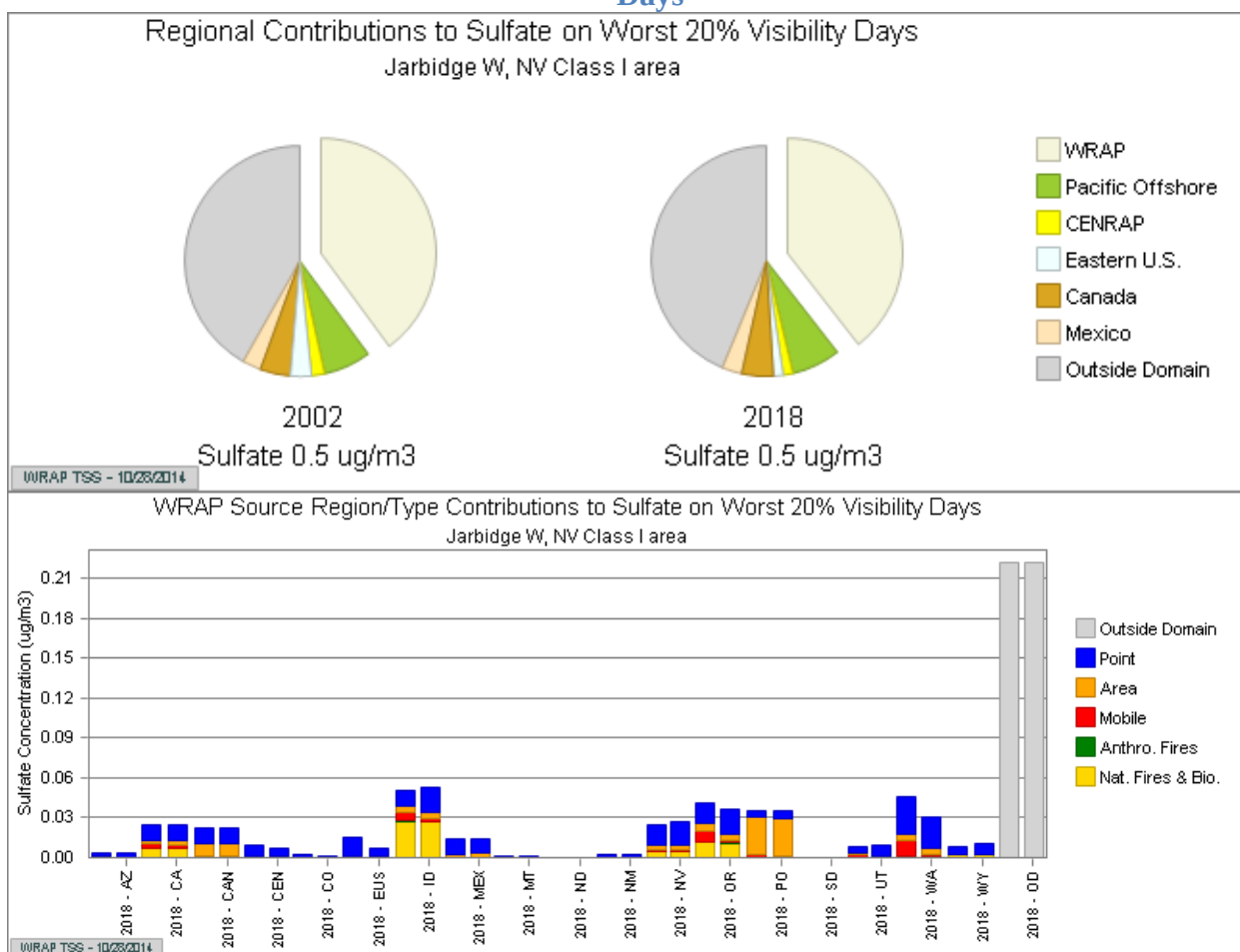
This NGO comment hinges on the opening statement that the NDEP must find its implementation plan “is or may not be adequate to ensure reasonable progress due to emissions from sources within the State.” NGO comment letter, page 6. The NGOs suggest that NO_x and SO₂ emissions from Nevada point sources have significant contributions to visibility impairment at the Jarbidge WA and that Nevada should consider emission control requirements for the North Valmy Generating Station as well as potential visibility impacts from oil and gas development in Nevada.

NDEP Response: The NDEP maintains Nevada’s implementation plan is adequate to ensure reasonable progress due to emissions from sources within the State. Nevada’s initial regional haze progress report focuses on controllable anthropogenic emission sources. The Progress Report documents progress for the first five years of a 60-year planning horizon and not all controls identified in the State’s 2009 RH SIP have been implemented because they are not required to do so until 2015 (Progress Report, Section 2.5.2). Furthermore, the majority of visibility impairing emission sources at the Jarbidge WA are out of Nevada’s jurisdiction (Progress Report, Section 4.4 and 2009 RH SIP, Section 4.3). Long-term monitored light extinction trends are either better than or comparable to the speciated glide slopes for nitrate and sulfate (Progress Report, Section 4.6). Finally, the 5-year annual average nitrate extinction on the worst days is below the nitrate glide slope, and there is no degradation of visibility resulting from nitrate or sulfate on the best days.

Nevada Point Source Contributions to Visibility Impairment

Emissions from outside of Nevada contribute more to visibility impairment at Jarbidge WA than Nevada point sources. The sulfate modeling results for Nevada’s point sources are presented graphically in Figure 2. Coupled with the information presented in Table 2, the data show that for 2002, Canada, Eastern US, Pacific Offshore, and Outside Domain each contribute more to modeled worst days sulfate concentrations at the Jarbidge WA than do emissions from Nevada point sources. Similarly, point sources in Oregon and Washington contribute more than Nevada point sources, while point sources in Idaho contribute nearly as much. When total state-wide emissions are considered, California, Idaho, Oregon and Washington all contribute more to modeled sulfate concentrations at Jarbidge than do Nevada’s state-wide emissions.

Figure 2. Contributions to Modeled Sulfate Concentrations at the Jarbidge WA on the Worst Days



For 2018, a similar situation exists. Emissions from Canada, Pacific Offshore and Outside Domain each contribute more to the modeled worst days sulfate concentration than emissions from Nevada point sources, as do point sources in Idaho, Oregon, and Washington. When state-wide emissions are considered, Idaho, Oregon, and Washington each contribute more than Nevada's state-wide emissions with California contributing nearly as much as Nevada. The source apportionment modeling supports Nevada's conclusion that the IMPROVE monitor for the Jarbidge WA is "likely more strongly impacted by emissions originated from within the Snake River Basin than those emitted from within the Great Basin" (Progress Report, page 9-3) and emissions from sources within the State are not impeding reasonable progress at the Jarbidge WA. As noted in the NDEP's response to the NGO comment 1, emissions from the North Valmy Generating Station are clearly not a significant source of visibility impairment at the Jarbidge WA.

Emissions from Outside Domain and Pacific Offshore contribute approximately 50 percent of modeled sulfate at Jarbidge with all sources outside of the WRAP contributing approximately 60 percent of modeled concentration. WRAP states, excluding Nevada, contribute approximately 35 percent. The source apportionment modeling demonstrates the majority of emission sources

contributing to sulfate visibility impairment at Jarbidge are outside the jurisdiction of Nevada or its WRAP co-regulators. As noted in Section 4.6 of the Progress Report, monitored sulfate extinction for the worst days at the Jarbidge WA is trending downward, both on an annual and five-year average basis.

The NDEP is unsure why the NGOs commented on nitrate extinction at Jarbidge WA and the need for further emission controls when, as shown by Figure 3, five-year rolling averages of worst days nitrate extinction for the last 4 years (2006-2010, 2007-2011, 2008-2012, and 2009-2013) are below the nitrate glideslope. Figure 4 graphically shows the contributions to modeled worst days nitrate concentrations at Jarbidge WA. Regarding the NGO comments about Nevada's contributions to the best days, there is no degradation in visibility resulting from sulfate or nitrate for the least impaired (best) days at the Jarbidge WA over the current planning period (Figure 5).

Figure 3. Baseline and Five-Year Rolling Averages of Worst Days Sulfate and Nitrate Light Extinction at the Jarbidge WA.

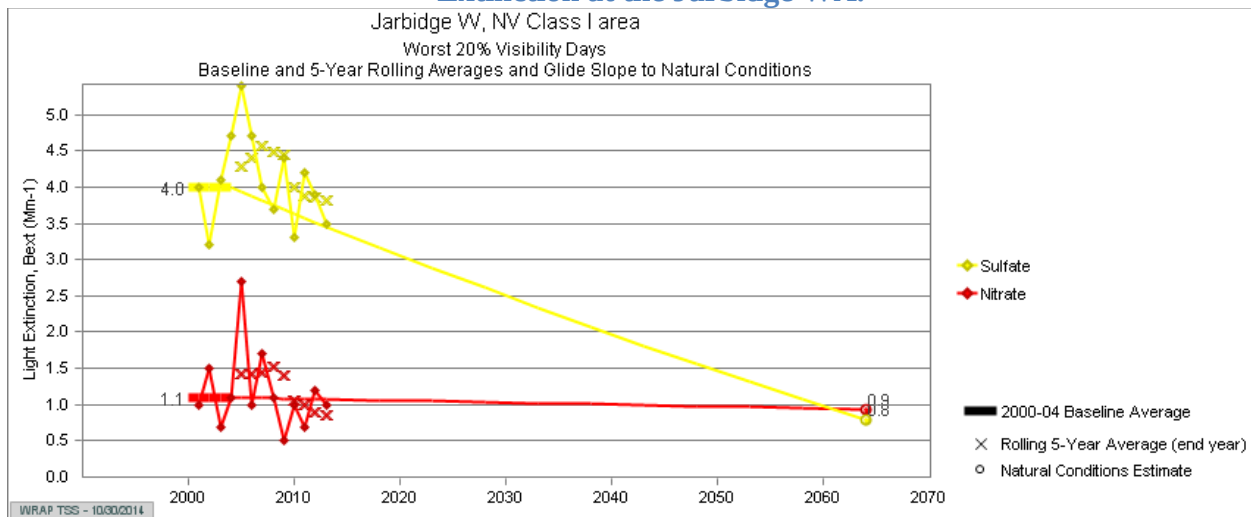


Figure 4. Contributions to Modeled Nitrate Concentrations at the Jarbidge WA on the Worst Days

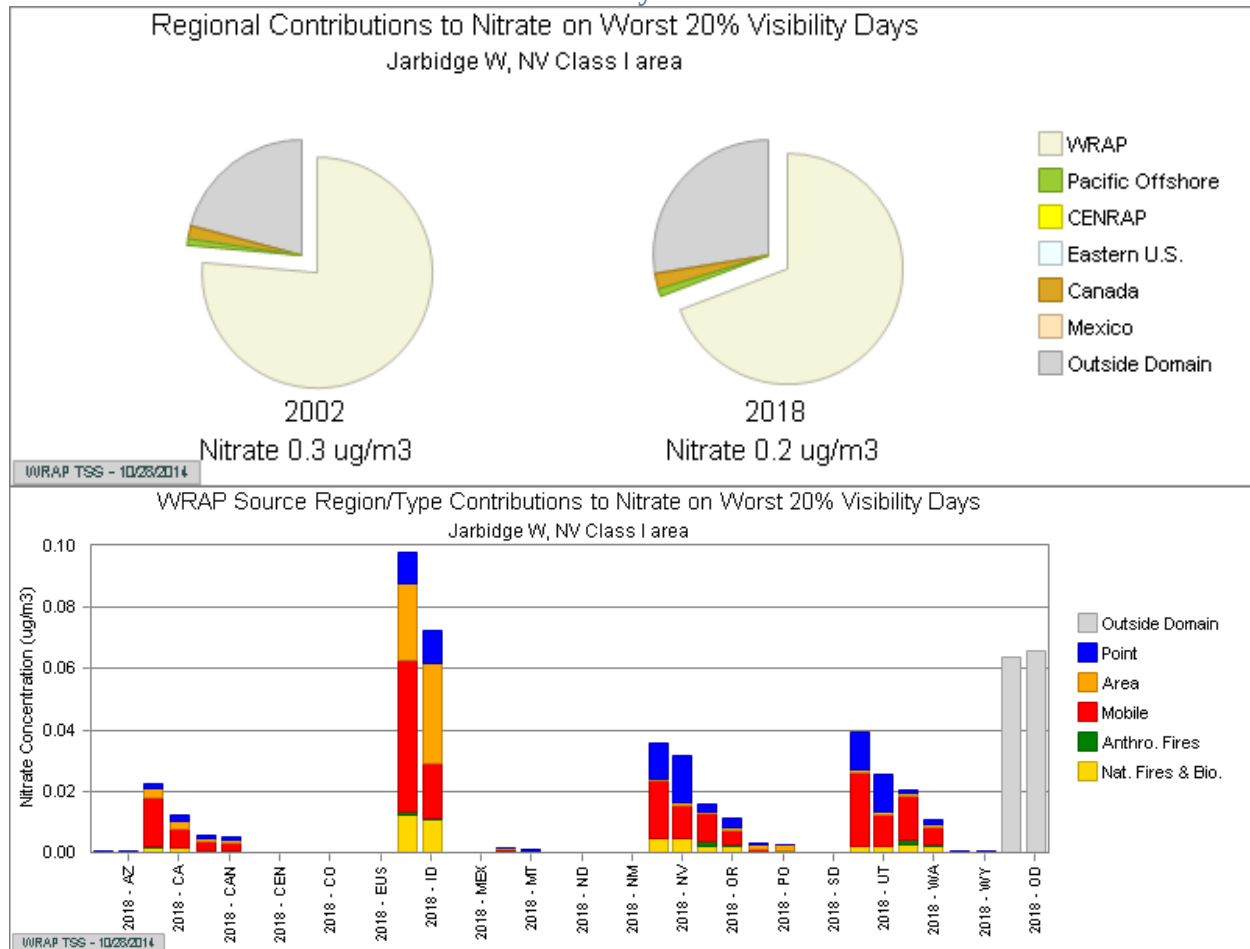
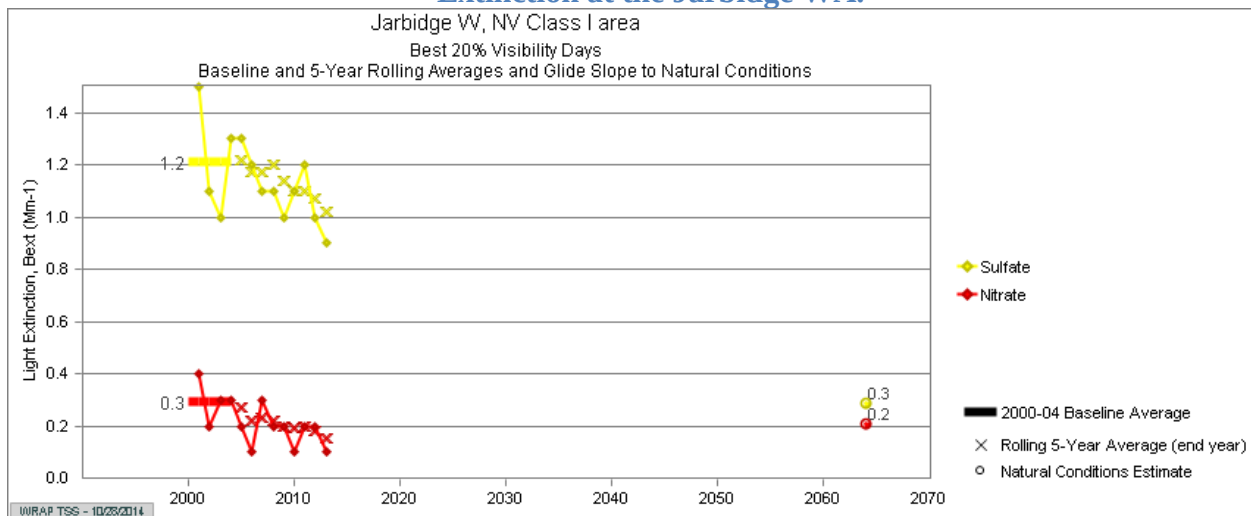


Figure 5. Baseline and Five-Year Rolling Averages of Best Days Sulfate and Nitrate Light Extinction at the Jarbidge WA.



Consideration of Emissions from Oil and Gas Development

The NGO comments state Nevada must consider emissions from oil and gas development and the potential visibility impact, using information from a couple of newspaper articles to suggest oil development could be increasing, as it has in recent years in Utah. However, as discussed under the first NGO comment, the data in Table 4 shows that oil and gas development in Nevada has a considerably slower pace than other oil and gas areas in the western US, and the data in Figure 1 show that Nevada's oil production has been in a state of steady decline since the 1990s. The NDEP continues to monitor the pace of oil and gas development in Nevada and will evaluate emissions sources resulting from increased activity as warranted. However, given the very limited oil and gas activity to date, implementation of additional emission controls on this sector at this time would be premature.

Nevada's 2009 RH SIP focused on impairment resulting from Nevada's anthropogenic emissions of SO₂ and NO_x, the precursors of sulfate and nitrate, respectively. Source apportionment modeling demonstrates Nevada emissions do not make a large contribution to overall visibility impairment at Jarbidge WA. The bulk of impairment results from emissions beyond Nevada's jurisdiction. Monitoring data show that the Jarbidge WA is achieving levels of improvement in visibility impairment necessary to achieve natural background conditions by 2064 for impairment resulting from nitrate and sulfate extinction in this first 5-year planning period. To the extent that SO₂ and NO_x emissions from point sources in Nevada contribute to visibility impairment at Jarbidge WA, Nevada's progress report documents significant SO₂ and NO_x emissions reductions from sources within the State (see Table 5-1 of the Progress Report).

In summary, the NDEP has fully justified Nevada's negative declaration (i.e., emissions from sources within the State are not preventing Nevada from achieving its reasonable progress goal) and deems its 2009 RH SIP adequate to ensure reasonable progress towards the national visibility goal for sulfate and nitrate resulting from anthropogenic emissions.

No changes were made to the Progress Report as a result of this NGO comment.

NGO Comment 3: NDEP Must Revise Its Assessment of Contribution to Visibility Impairment at Class I Areas Impacted by its Sources to Be Based on the WRAP's Revised Modeling with its 2018 PRPb Emissions Projections.

This NGO comment contends that Nevada's assessment of its sources' impacts on Class I areas outside Nevada is based on erroneous source appointment modeling, which in turn is based on an outdated PRP18a emissions projection. The NGO comments go on to suggest that Nevada's conclusions regarding emissions reductions should be informed not by the 2008 inventory data, but by the 2011 NEI and more recent CAMD data. Further, the NGO comments suggest that emissions reductions in Nevada may not account for Nevada's portion of impairment in some Class I areas, and Nevada must revise its analysis of Nevada's impacts on out-of-state Class I areas.

NDEP Response: A comprehensive review of the Nevada regional haze SIP and Progress Report and the WRAP's modeling efforts that supported Nevada's regional haze submissions belie this comment.

Modeling Assessment

Table 4-3 and Table 4-4 of the 2009 RH SIP present Nevada's contributions to light extinction at Class I areas in the five states adjacent to Nevada based on the WRAP's source apportionment modeling. Sections 1.3.2.2, 1.3.3.2 and 4.3 of the 2009 RH SIP describe the modeling framework and emissions scenarios utilized for this modeling effort by the WRAP, which relied on the Plan02c and Base18b emission inventories. To the NDEP's knowledge, there has been no indication by any party that this source apportionment modeling is erroneous or not fully acceptable. This is the most comprehensive and current regional haze source apportionment data available for the WRAP region.

Table 7-6 of the 2009 RH SIP provides a summary of visibility impairment at nearby Class I areas and Nevada's emissions reductions, which the NGO comments suggest is based on erroneous modeling. However, as noted in Section 7.9.3.2 of the 2009 RH SIP, the information in the table is based on monitored baseline light extinction (2000-2004), the uniform rate of progress for 2018 (i.e., the glideslope value for 2018), and Nevada's contributions to sulfate and nitrate based on the WRAP's source apportionment modeling. Nevada's emission reduction share is calculated by multiplying the extinction reduction needed at any given Class I area by the 2018 pollutant contribution by Nevada. Nevada's share is independent of the WRAP's corrected visibility modeling.

Emissions Assessment

The NGOs suggest that the analysis should be informed by 2011 NEI data and recent CAMD data, but later acknowledge that the NDEP did present and evaluate both 2011 NEI and CAMD data through 2013. Tables 5-5 and 5-7 of the Progress Report compare 2002 baseline emissions as represented by the Plan02d inventory and 2008 progress period emissions as represented by WestJump2008. However, Tables 5-6 and 5-8 present 2011 NEI data from the major anthropogenic source categories (point, on-road mobile and off-road mobile) and show further reductions in SO₂ and NO_x emissions from 2008 to 2011. In addition, Table 3-2 and Figure 3-1 of the report present CAMD data through 2013 for annual EGU emissions. Figures 3-2 through 3-7 present SO₂ and NO_x CAMD data for specific EGUs through 2013. The 2011 NEI and recent CAMD emissions data have been evaluated by the NDEP and further support Nevada's emission reduction conclusions, contrary to statements in the NGO comments.

Out of State Impact Assessment

The NGO comments suggest that the significant emissions reductions in Nevada may not account for Nevada's portion of impairment at out-of-state Class I areas and use the Sawtooth Wilderness Area as an example. Baseline nitrate extinction at the Sawtooth Wilderness Area is better than the natural conditions estimate (0.63 Mm⁻¹ for baseline and 0.65 Mm⁻¹ for natural conditions), so the extinction reduction needed and Nevada's emissions reduction share are both negative in Table 7-6 of the 2009 RH SIP. The NDEP notes that Table 7-6 shows that Nevada's emission reduction share is 0.5 percent for sulfate while the difference between the Base02d and PRP18a inventories is 33.0

percent for SO₂ and 16.6 percent for NO_x. Table 5-5 of the Progress Report shows state-wide SO₂ emission reductions of 75 percent between 2002 and 2008 with additional reductions shown in Table 5-6 between 2008 and 2011. Table 5-7 shows state-wide NO_x emissions reductions of 26 percent between 2002 and 2008, which are slightly offset by the emissions growth shown in Table 5-8 between 2008 and 2011. The percentage reductions in Nevada's NO_x and SO₂ emissions are much greater than Nevada's emissions reduction share presented in Table 7-6 of the 2009 RH SIP.

Figure 6 below shows the annual worst days monitoring data for the Sawtooth Wilderness Area with 5-year rolling averages, natural conditions, and the glideslopes for each species. This figure demonstrates that visibility impairment due to sulfate and nitrate are not preventing reasonable progress at the Sawtooth Wilderness Area, even though this site is not achieving the uniform rate of progress for sulfate and nitrate as shown by Figure 7. Figure 6 shows particulate organic matter (resulting from fire emissions) is the principle driver of visibility impairment at this Class I area.

Figure 6. Baseline and Five-Year Rolling Averages of Worst Days Visibility Conditions at the Sawtooth Wilderness Area.

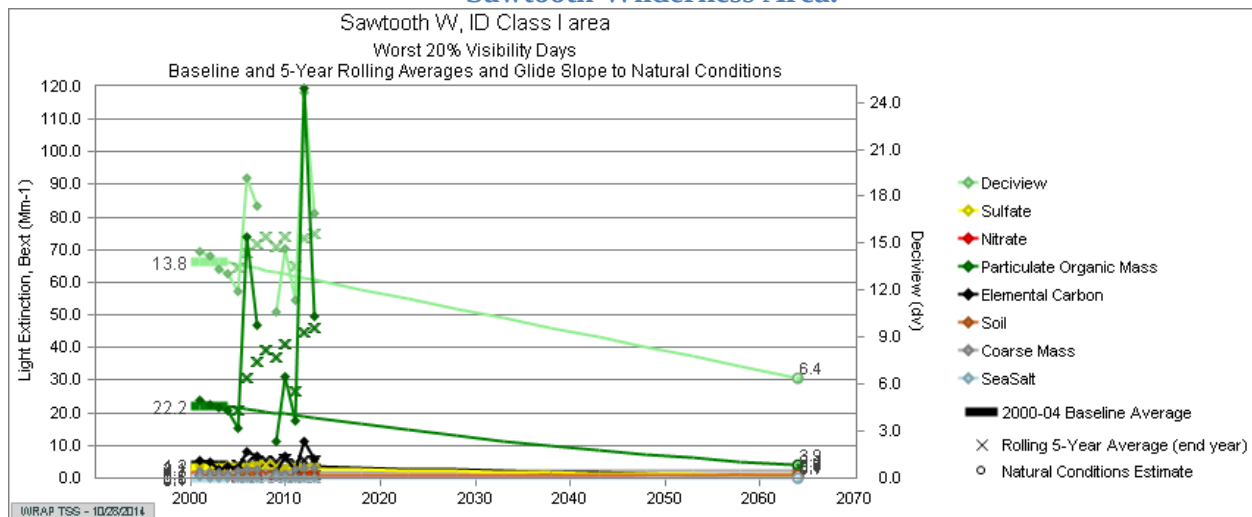


Figure 7. Baseline and Five-Year Rolling Averages of Worst Days Sulfate and Nitrate Visibility Impacts at the Sawtooth Wilderness Area.

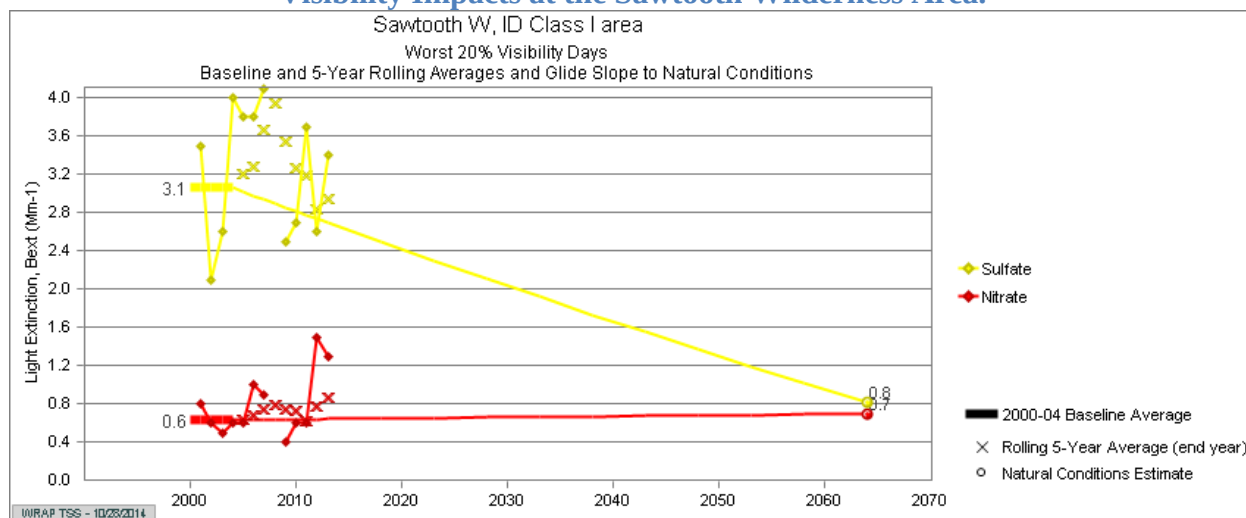


Figure 8 and Figure 9 show the regional as well as the WRAP source region and source type contributions to modeled sulfate and nitrate respectively at the Sawtooth Wilderness Area. These Figures show how little Nevada emissions sources contribute to visibility impairment at the Sawtooth Wilderness Area.

Figure 8. Contributions to Modeled Sulfate Concentrations at the Sawtooth Wilderness Area on the Worst Days

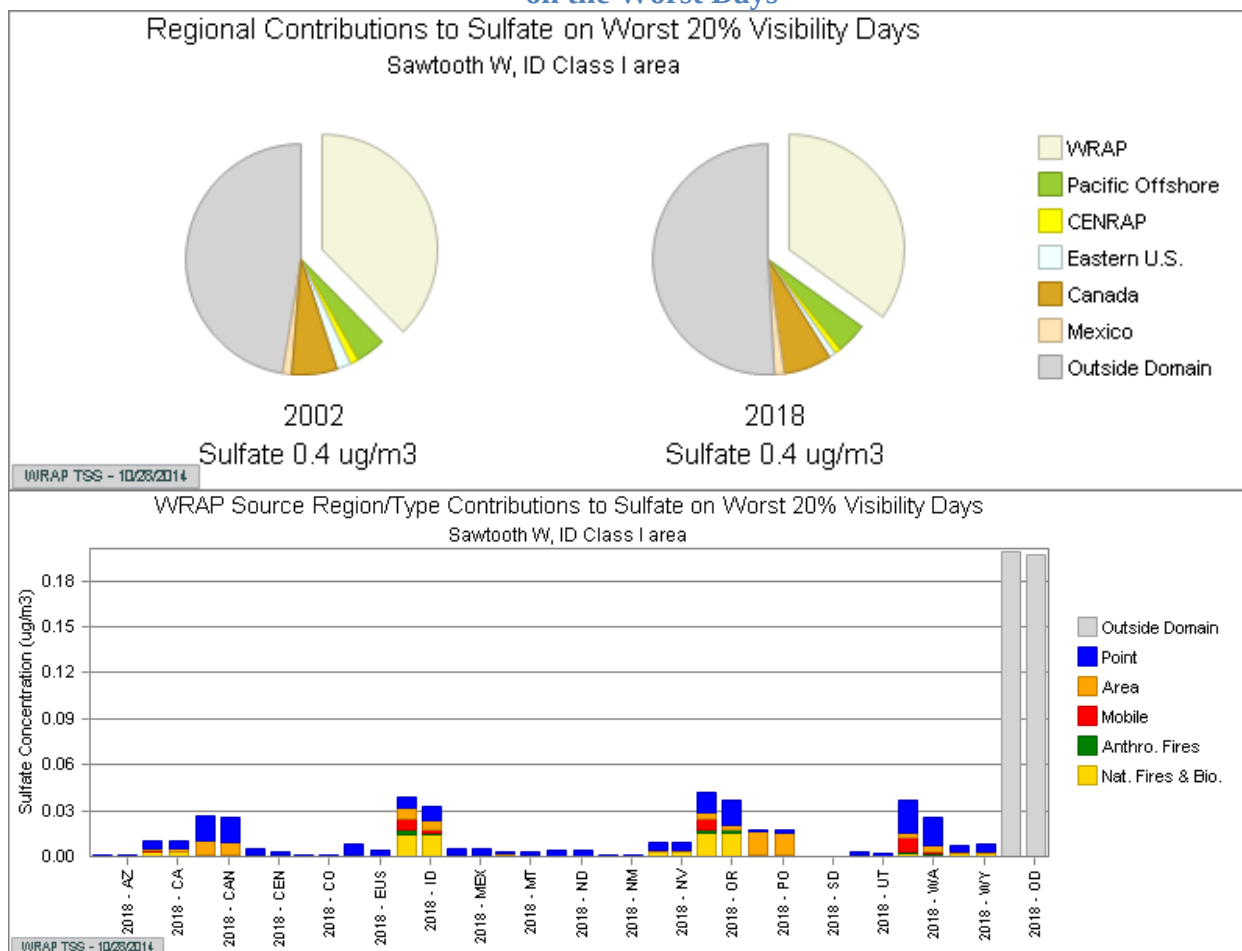
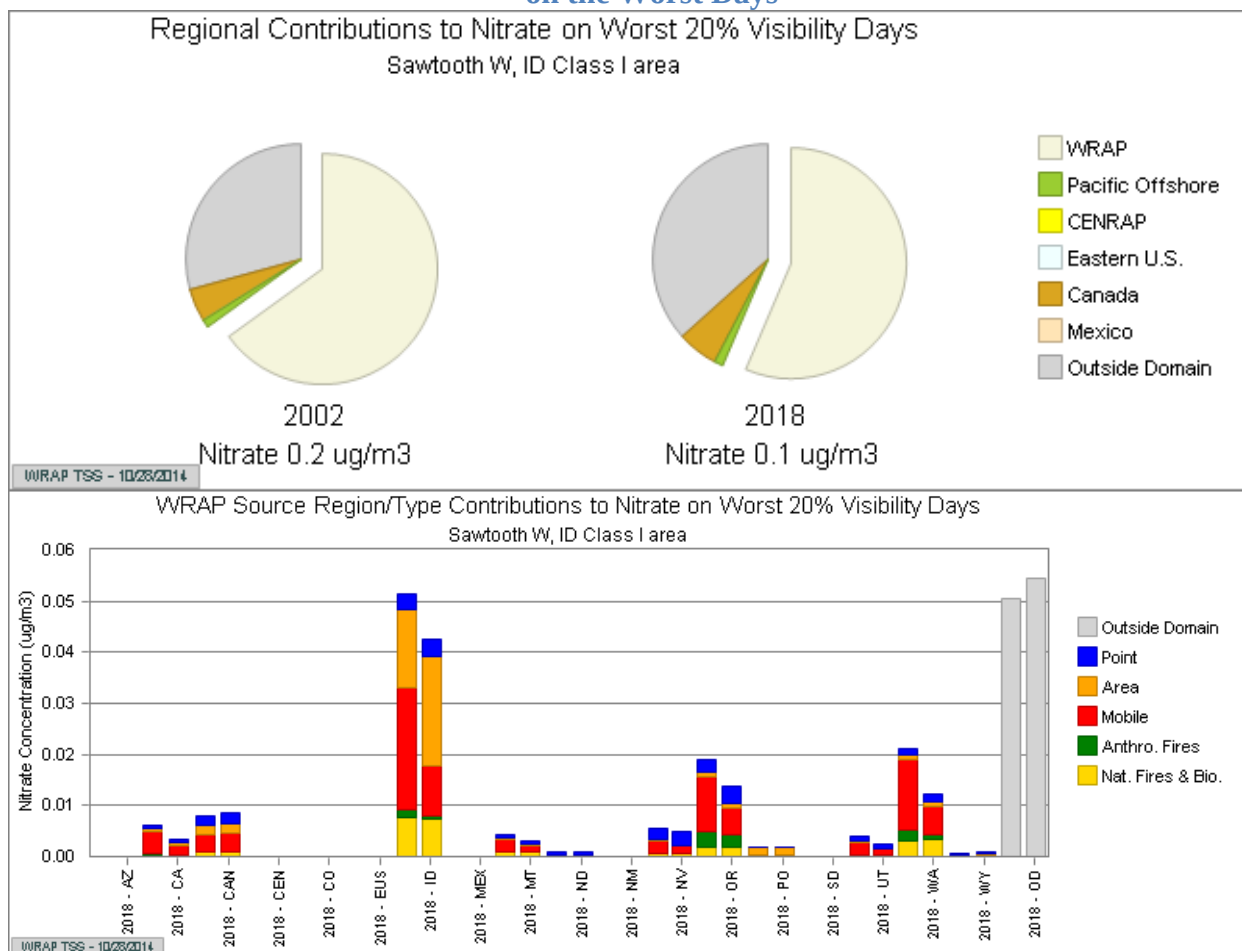


Figure 9. Contributions to Modeled Nitrate Concentrations at the Sawtooth Wilderness Area on the Worst Days



In summary, WRAP visibility modeling based on the PRP18b emission inventory has no bearing on the NDEP's assessment of Nevada's contribution to visibility impairment at Class I areas impacted by Nevada emission sources. The NDEP's emissions reductions conclusions are based on the most recent commonly available emissions data as represented by the WestJump2008, 2011 NEI, and CAMD data through 2013, as requested by the NGO comments. Nevada's emission reductions far exceed Nevada's contributions to visibility impairment at Class I areas impacted by Nevada sources. Emissions from Nevada are not impeding reasonable progress at the Sawtooth Wilderness Area or other out-of-state Class I areas.

The NDEP has not revised its determination regarding the adequacy of its plan with respect to Nevada's impacts on out-of-state Class I areas based on this comment, and no changes were made to the Progress Report.

NGO Comment 4: NDEP Must Revise Its Proposed Progress Report to Meet §51.308(g)(2) and §51.308(g)(4).

The NGOs comment that the Progress Report fails to detail the specific reductions achieved through the implementation of the enforceable measures required by the SIP and request that Nevada include such estimates and revise its assessment of the adequacy of its SIP on this basis. They question whether the significant decrease in SO₂ and NO_x emissions from EGUs is due to enforceable measures and point to the increase in 2013 SO₂ and NO_x emissions at Reid Gardner and NO_x emissions at Fort Churchill (Progress Report Figures 3-2, 3-3 and 3-7) as support. They further comment that the use of 2011 NEI data in Chapter Five is not a sufficient basis for evaluating the most recent emissions trends in Nevada. They request the NDEP discuss the EGU emissions from USEPA's CAMD database in Chapter Five as well as Chapter Three of the report and also use in-state inventories and Title V reporting from 2008 to at least 2012 to discuss emission trends. Finally, the NGOs suggest that to the extent the NDEP is relying on measures not included in the 2009 RH SIP to meet its reasonable progress goal, using SB 123 as an example, it should adopt those requirements as enforceable measures in its regional haze SIP.

NDEP Response: The 2009 RH SIP requires the implementation of BART as a major enforceable control measure for the first planning period, 2008 - 2018. All applicable BART requirements have been adopted and incorporated into the Nevada Administrative Code, approved by USEPA into Nevada's applicable SIP and are enforceable by the State and USEPA. Chapters Two and Three of the Progress Report discuss BART implementation. Table 2-3 of the report details the status of BART implementation in Nevada, showing that all BART control measures will be installed and operating by January 1, 2015 with the exception of NO_x controls at Reid Gardner, which has a compliance date of June 30, 2016. Thus, since the controls have not been fully implemented at this time, specific reductions are not yet fully realized. Chapter Five of the 2009 RH SIP, specifically Tables 5-4, 5-5, 5-6 and associated text, provide expected emissions reductions following full implementation of BART controls. Section 3.4.2 of the Progress Report notes that NV Energy plans to shut down Units 1 through 4 at Reid Gardner and specifies associated emissions reductions.

Chapter Three of the Progress Report discusses the most recent CAMD EGU emissions data through 2013. The fact that there is a small increase in EGU emissions from 2012 to 2013 is diminished by the overall steady decline in EGU emissions, with the exception of increased emissions at Tracy and Fort Churchill during the Energy Crisis of 2000-2001. Indeed, electrical generation demand varies across fleet facilities and could account for the increased emissions in 2013. The NDEP finds the NGOs' speculation that the miniscule increase in 2013 may indicate that the control measures included in the 2009 RH SIP may be inadequate is unsubstantiated.

Chapter Five of the Progress Report includes 2011 NEI Nevada point and mobile source emissions in Tables 5-6, 5-8, and 5-11 for SO₂, NO_x, and VOC, respectively. 2012 NEI data was not used because it only includes the larger point source data and does not include mobile source data. Thus, it would not provide a complete picture of emissions in Nevada. In addition, 2012 in-state emissions data was neither quality checked nor available at the time of preparation of the Progress Report. Thus, the WestJump2008 and 2011 NEI inventories provide the most recent data available to the NDEP at the time of the Progress Report. The next SIP submission is expected to include new modeling results using the most current available emissions data for use in assessing the adequacy of Nevada's SIP.

Lastly, the NGOs suggest Nevada adopt SB123 as an enforceable measure of its regional haze SIP. The NDEP as part of its reasonable progress update reviewed all available sources of emission reductions and planned control measures. The NDEP maintains that it is appropriate to include an assessment of the impact of all emissions reduction measures occurring since the 2009 RH SIP was adopted. The NDEP did not, however, rely on the emission reductions in SB123 in making its determination that Nevada is making adequate progress overall in improving visibility. It is unnecessary to incorporate SB123 in to the Nevada SIP.

No revisions have been made to the Progress Report as a result of this comment.

D.2.2 Sierra Club-National Parks Conservation Association Comment Letter

SIERRA CLUB TOIYABE CHAPTER
P.O. Box 8096 Reno, NV 89507

NATIONAL PARKS CONSERVATION ASSOCIATION
10161 Park Run Drive, Ste. 150, Las Vegas, NV 89145

Nevada
Environmental Protection

OCT 16 2014

BAPC/BAQP

October 8, 2014

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ENVIRONMENTAL PROTECTION

OCT 16 2014

Adele Malone
Bureau of Air Quality Planning
Nevada Division of Environmental Protection
901 S Stewart Street, Suite 4001
Carson City, Nevada 89701

RE: Comments on the Nevada Regional Haze 5-Year Progress Report

Dear Ms. Malone,

Sierra Club and National Parks Conservation Association submit the following comments on the Nevada Regional Haze 5-Year Progress Report.

The purpose of the regional haze 5-year progress reviews is to provide an analysis of the progress made in implementing the regional haze SIP and also, if necessary, make mid-course corrections to the regional haze SIP. According to the preamble to the EPA's 1999 regional haze regulations, states may submit a negative declaration "if the state finds that the emission management measures in the SIP are being implemented on schedule, and visibility improvement appears to be consistent with reasonable progress goals." 64 Fed.Reg. 35747 (July 1, 1999). See also 40 C.F.R. §51.308(h)(1). The Nevada Department of Environmental Protection (NDEP) proposes such a negative declaration in its 5-Year Progress Report. See Section 9.1 of the proposed Nevada Regional Haze 5-Year Progress Report. However, visibility improvement at the state's only Class I area, the Jarbidge Wilderness, is not projected to improve in a manner consistent with achieving reasonable progress toward the national visibility goal of reaching natural background visibility conditions by 2064.

In making its negative declaration, NDEP relies heavily on the emission reductions that have occurred due to the shutdown of the Mohave Generating Station in 2005 and the emission reductions that will occur due to the shutdown of Reid Gardner Units 1-3 in 2014 and of Reid Gardner Unit 4 in 2017, the shutdown of Tracy Generating Station Units 1 and 2, and the BART requirements that Tracy Unit 3 and Fort Churchill Units 1 and 2 no longer burn oil by December of 2014. Sierra Club supports and applauds Nevada in its efforts to significantly reduce emissions of air pollutants with the shutdown of the large fossil-fuel fired power plants and/or the conversion to natural gas. These source shutdowns and reductions in emissions will undoubtedly provide significant visibility benefits for the Class I areas that these sources impact,

1

including Grand Canyon National Park and other Colorado Plateau national parks and wilderness areas, as well as national parks and wilderness areas like Joshua Tree National Park in eastern California. Moreover, these reductions will also benefit public health and non-Class I areas like Great Basin National Park. However, there is no modeling demonstrating whether and to what extent any of these sources have significant impacts on the Jarbidge Wilderness Area.

Further, the entire premise for NDEP's current 5-year progress evaluation for the Jarbidge Wilderness is based on a reasonable progress goal and a Nevada emissions inventory in a WRAP modeling effort that was subsequently revised and found to be in error. As noted in EPA's June 2011 proposed partial approval of the Nevada Regional Haze SIP, the WRAP issued a report in April 2011 regarding errors in its visibility projections for about 15 Class I areas in the West including the Jarbidge Wilderness in Nevada and also including Class I areas impacted by Nevada emissions including the Hells Canyon Wilderness (in Oregon and Idaho), Crater Lake National Park (in Oregon), and Domelands Wilderness (in California).¹ In approving the reasonable progress goals of the Nevada Regional Haze SIP, EPA acknowledged this error, but did not require new modeling be done by NDEP at that time. Instead, EPA stated that the 5-year progress report and adequacy determination required by 40 C.F.R. §51.308(g) and (h) would provide the opportunity to determine whether Nevada's SIP is adequately ensuring reasonable progress toward the national visibility goal. 76 Fed.Reg. 36464 (June 22, 2011) at fn 18.

As part of its 5-Year Progress Report, NDEP has proposed to find that it is not necessary to revise its reasonable progress goals. See Chapter 1 of the proposed Nevada Regional Haze 5-Year Progress Report at 1-6. This was based primarily on a review of the emission reductions from the control measures in Nevada's 2009 regional haze SIP, the shutdown of the Mohave Generating Station, and also from the new state legislation that will result in the shutdown of the Reid Gardner units. *Id.* However, as NDEP has acknowledged, the reduction in emissions from the southern Nevada sources (i.e., Reid Gardner and Mohave power plants) may not be reflected in visibility improvements at Jarbidge Wilderness that is in northeastern Nevada. See Chapter 9 of the proposed Nevada Regional Haze 5-Year Progress Report at 9-3. NDEP's basis for its finding that it does not need to revise its reasonable progress goals does not justify its proposed decision.

Although there has been some improvement in visibility in the Jarbidge Wilderness area, the IMPROVE visibility monitoring data do not show that the Jarbidge Wilderness is on the path consistent with the reasonable progress goals. See Chapter 4 of the Nevada Regional Haze 5-Year Progress Report. Further, EPA's guidance for the 5-year progress reviews is that negative declarations can be submitted when both visibility trends and emissions data indicate "a **significant** overall downward trend."² Rather than showing a significant downward trend in both emissions and visibility impairment to justify its negative declaration, NDEP focuses mainly on the planned emission reductions for sources in Nevada. See Chapter 9 of the

¹ See April 27, 2011 Correction of WRAP region Plan02d CMAQ visibility modeling results on TSS for Regional Haze Planning, in docket for EPA rulemaking on Nevada Regional Haze SIP at EPA-R09-OAR-2011-0130-0011 (Ex. 1).

² See U.S. EPA, General Principles for the 5-Year Regional Haze Progress Reports for the Initial Regional Haze State Implementation Plans (Intended to Assist States and EPA Regional Offices in Development and Review of the Progress Reports) at 15 [emphasis added].

proposed Nevada Regional Haze 5-Year Progress Report at 9-3. This is not adequate justification for a negative declaration. Given that the revised WRAP modeling shows that the Jarbidge Wilderness is not on the glide path to achieve natural background conditions by 2064 and given that the emission reductions in southern Nevada sources will not likely improve visibility conditions at the Jarbidge Wilderness, NDEP should amend its proposal and determine that additional actions are necessary to achieve the level of progress committed to by the state for Jarbidge Wilderness and revise its haze plan accordingly. Such a revision should include the evaluation of new strategies for its regional haze plan to significantly improve the progress towards remedying visibility impairment at the Jarbidge Wilderness Area.

Such strategies should include an assessment of pollution controls at the North Valmy Generating Station. The North Valmy plant is the largest emitter of sulfur dioxide (SO₂) and the second largest emitter of nitrogen oxides (NO_x) in the state³. Unlike the Reid Gardner and Mohave power plants, this coal-fired power plant is not subject to emission reductions under Nevada's SB 123, and Nevada's 5-Year Progress Report does not mention any planned pollution controls for this plant. Further, it appears likely that the North Valmy Generating Station does contribute to visibility impairment at the Jarbidge Wilderness area, given its emissions and the fact that it is within 160 kilometers from the Jarbidge Wilderness. Thus, the North Valmy Generating Station is an obvious candidate for reasonable progress measures under the Nevada Regional Haze plan.

The following discussion provides more detailed comments on these deficiencies in the Nevada Regional Haze 5-Year Progress Review.

1. NDEP Must Revise Its Reasonable Progress Goal for Jarbidge Wilderness to Be Based on the WRAP's Revised Modeling with its 2018 PRPB Emissions Projections.

As stated above, NDEP's reasonable progress goal for the Jarbidge Wilderness was based on modeling done by the WRAP that was subsequently found to be in error. 76 Fed.Reg. 36464 (June 22, 2011) at fn 18. The error in the WRAP's modeling was not at all minor. Specifically, as discussed in an April 27, 2011 WRAP memo, the WRAP determined that the CMAQ model extracted gridded emissions that were off by one grid cell for 9 IMPROVE site locations in the WRAP region, which affected a total of 15 different Class I areas in 8 states including the Jarbidge Wilderness area and other Class I areas impacted by Nevada sources⁴.

Not only was NDEP's reasonable progress goal for the Jarbidge Wilderness based on a flawed modeling analysis, but it was also based on the WRAP's preliminary reasonable progress emissions projections for 2018 (i.e., the WRAP's PRP18a emission projections). See the Nevada Regional Haze State Implementation Plan at 6-2. In 2009, the WRAP updated the 2018 emission projections to reflect changes to future emissions projections since January 2007 including BART determinations, 2018 federal electrical generation demand forecasts, new rulemaking,

³ According to stationary source emissions data for Nevada in EPA's 2011 National Emissions Inventory, available at <http://www.epa.gov/ttn/chieff/net/2011inventory.html>.

⁴ See Tom Moore, Correction of WRAP region Plan02d CMAQ visibility modeling results on TSS for Regional Haze Planning, April 27, 2011 at 2 (in in docket for EPA rulemaking on Nevada Regional Haze SIP at EPA-R09-OAR-2011-0130-0011) (Ex. 1).

permit limits, consent decrees, and other issues⁵. The revised emission inventory took into account expected emission reductions due to BART that were known at that time at the Reid Gardner and Mohave units.⁶

The April 27, 2011 memo regarding the revised CMAQ modeling shows the differences in the flawed modeling relied upon for the Nevada Regional Haze plan and the revised/corrected modeling. For the Jarbidge Wilderness area, the flawed modeling predicted visibility conditions in 2018 of 11.1 dv, and the corrected modeling predicted visibility conditions in 2018 of 11.8 dv.⁷ Both of these modeling results were based on the WRAP's PRP2018b revised emission inventory.⁸ The Nevada Regional Haze SIP adopted an even lower reasonable progress goal of 11.05 dv, which was presumably based on modeling done with the earlier PRP2018a emission inventory. See the Nevada Regional Haze State Implementation Plan at 6-2, 6-15. This was lower than the 11.09 dv value that reflects the 2018 uniform rate of progress, and thus Nevada's Regional Haze SIP is premised on the concept that the Jarbidge Wilderness Area is on the glide path to reach natural background visibility conditions by 2064. *Id.* However, this predicted level of progress is based on flawed modeling and thus NDEP cannot continue with the assumption that no further measures are needed until 2018 to ensure the visibility improvements at Jarbidge Wilderness are meeting the uniform rate of progress.

In fact, the WRAP's revised modeling based on the 2018PRPb emission projections shows that the Jarbidge Wilderness Area will be significantly off the glide path in 2018. Our calculations show that if visibility improvement continues at the same rate as shown by the WRAP's April 27, 2011 revised modeling results, the Jarbidge Wilderness won't attain natural background visibility conditions until 2210, which is 146 years later than required. This is not acceptable reasonable progress towards the national visibility goal.

NDEP's rationale for not revisiting its reasonable progress goal is that emissions from anthropogenic sources in Nevada are less than emissions projections used by the WRAP in the 2018 modeling. See Chapter 1 of the proposed Nevada Regional Haze 5-Year Progress Report at 1-6. See also Chapter 5 of the 5-Year Progress Report. However, the comparison made by NDEP was based on the WRAP's PRP18a emissions projections. NDEP should have instead compared to the WRAP's PRP18b emissions projections.

Moreover, while the 2008 emission inventory is lower than the WRAP's 2018a inventory as shown in Table 5-1 of the Nevada 5-Year Progress Report, this reduction in emissions has not been shown to equate to an improvement in visibility impairment at the Jarbidge Wilderness Area. In fact, the majority of the anthropogenic sources that have reduced emissions but were included in the WRAP's 2018 emission inventory have never been shown to impact visibility at the Jarbidge Wilderness Area.

⁵ See April 29, 2009 ERG Technical Memorandum – Final, From Marty Wolf and Paula Fields to Lee Briovicz and Tom Moore, WRAP staff (Ex. 2).

⁶ *Id.* at 8.

⁷ See Tom Moore, Correction of WRAP region Plan02d CMAQ visibility modeling results on TSS for Regional Haze Planning, April 27, 2011 at 11 (Ex. 1).

⁸ *Id.*

Specifically, NDEP's 5-Year Progress Report discusses the emission reductions that have occurred or will occur at Tracy Generating Station, Fort Churchill Generating Station, Reid Gardner Generating Station, and the Mohave Generating Station. *See* Chapter 3 of the proposed Nevada Regional Haze 5-Year Progress Report. However, none of these sources were modeled to have an impact on visibility at the Jarbidge Wilderness Area, presumably because the Jarbidge Wilderness Area is quite far from these facilities.⁹ Specifically, the Mohave Generating Station was approximately 750 km from the Jarbidge Wilderness Area, the Reid Gardner Generating Station is approximately 580 km from the Jarbidge Wilderness Area, and the Tracy and Fort Churchill Generating Stations are approximately 450 km away. Given these distances and the fact that there is no modeling showing otherwise, it does not appear that the reduction in emissions at these facilities will significantly improve visibility at the Jarbidge Wilderness Area. NDEP has also acknowledged this in its 5-Year Progress Report. *See* Chapter 9 of the proposed Nevada Regional Haze 5-Year Progress Report at 9-3.

NDEP also relies on the fact that the WRAP included emissions for proposed power plants in the 2018 inventory which are no longer being proposed for construction. *See* proposed Nevada Regional Haze 5-Year Progress Report at 3-3 to 3-4 and Appendix B. Those power plants included the White Pine power plant to be located near Ely, Nevada, the Toquop Energy Center, to be located in Mesquite, Nevada, and the Copper Mountain Power Plant to be located in Clark County, Nevada.¹⁰ Of these three proposed power plants, only one power plant was modeled for visibility impacts on the Jarbidge Wilderness Area as part of its air permit, and that is the proposed White Pine Energy Center. It does not appear that any modeling was conducted to evaluate the impacts from the proposed Toquop and Copper Mountain power plants on the Jarbidge Class I area as part of any air permit for the proposed facilities.

Thus, while as a whole, 2018 emissions from power plants in Nevada will be much lower than modeled by the WRAP in 2018, the bulk of those cancelled emissions and emission reductions will not likely have much impact on the modeled 2018 visibility conditions at the Jarbidge Wilderness.

Further, the 2008 Nevada emission inventory that NDEP compared to WRAP's modeled 2018 emission projections does not include any emissions for oil and gas development, even though emissions from oil and gas development sources were included in the 2002 emissions inventory for Nevada. *See* Proposed Nevada Regional Haze 5-Year Progress Report at 5-9, 5-12, 5-16. Yet, NDEP stated that Nevada did not report oil and gas emissions for 2008. *Id.* at 5-6. NDEP did not provide justification for assuming zero emissions from oil and gas development in Nevada. This is at odds with publicly reported information related to oil exploration that may be on the rise in Nevada, especially in the northeastern part of the state.¹¹

⁹ *See* April 24, 2007, Summary of WRAP RMC BART Modeling for Nevada, Draft #7, April 24, 2007 (Ex. 3).

¹⁰ NDEP also cites to the withdrawal of the Ely Energy Center, which was proposed for Ely, Nevada, but NDEP stated that emissions for this power plant were not included in the WRAP's 2018 emissions projections. *See* the Nevada 5-Year Progress Report, Chapter 2 at 2-7 and at Appendix B, Section 1.4. It appears that emissions for this power plant were included in the WRAP's 2018 PRPb emissions projections.

¹¹ *See* "Far-Flung Noble Energy Believes in Oil and Gas 'Diversification'," *Forbes* magazine, December 18, 2013, available at <http://www.forbes.com/sites/christopherhelman/2013/12/18/far-flung-noble-energy-believes-in-oil-and-gas-diversification/>; *See also* "Fracking comes to Nevada," *Las Vegas Review-Journal*, January 8, 2013, available at <http://www.reviewjournal.com/business/energy/oilgas-search-fracking-comes-nevada>.

In summary, NDEP's proposed rationale for not revising the reasonable progress goal for the Jarbidge Wilderness Area does not justify retaining a reasonable progress goal for the area that is based on the WRAP's flawed modeling, especially when the flawed and unjustified reasonable progress goal misleads the public and regulators to find that the Jarbidge Wilderness is on the glide path to achieve natural background visibility conditions by 2064. Instead, NDEP must revise its reasonable progress goal to be 11.8 dv, based on the revised WRAP modeling¹². While it is true that emissions from Nevada sources are lower than the emissions modeled for Nevada sources in the WRAP's PRB2018b modeling effort, most of those facilities were so far removed from the Jarbidge Wilderness that their emissions were not likely having significant effects on visibility in Jarbidge Wilderness. Thus, NDEP must adopt a revised reasonable progress goal for the Jarbidge Wilderness.

2. NDEP Must Consider and Evaluate Reasonable Progress Measures for the Jarbidge Wilderness and Other Class I Areas Impacted by Nevada Sources.

Because the Jarbidge Class I area is not expected to achieve the level of improvement in visibility impairment necessary to achieve natural background conditions by 2064, NDEP has no justification for its proposed negative declaration finding that its implementation plan is adequate to achieve reasonable progress towards the national visibility goal. Accordingly, NDEP must find that its implementation plan "is or may not be adequate to ensure reasonable progress due to emissions from sources within the State" and commit to revise its implementation plan within one year pursuant to 40 C.F.R. §51.309(h)(4).

While NDEP's Progress Report claims that visibility impairment in the Jarbidge Wilderness is "likely more strongly impacted by emissions originating from within the Snake River Basin than those emitted from within the Great Basin,"¹³ source apportionment analyses show that point sources in Nevada contribute a significant portion to visibility impairment in the Jarbidge Wilderness area. According to WRAP source apportionment data for 2002 presented in the Nevada Regional Haze SIP, Nevada point sources contributed significantly more sulfate than any other state on the 20% best days at the Jarbidge Wilderness, and Nevada point sources were the second biggest contributor of sulfates (after Washington state point sources) on the 20% worst days.¹⁴ Point sources of NO_x in Nevada also appear to be the second largest contributor to nitrates on the 20% worst days in the Jarbidge Wilderness (after Utah), and Nevada point sources are by far the largest contributor to nitrates in the Jarbidge Wilderness on the 20% best days.¹⁵

A review of point source emissions data in EPA's 2011 National Emission Inventory database shows that the North Valmy Generation Station located near Valmy, Nevada is the largest emitter of SO₂ in the state of Nevada, accounting for almost 54% of all SO₂ emissions in the state in 2011.¹⁶ The North Valmy plant was the second largest point source for emissions of

¹² See Tom Moore, Correction of WRAP region Plan02d CMAQ visibility modeling results on TSS for Regional Haze Planning, April 27, 2011 at 11 (Ex. 1).

¹³ See Proposed Nevada Regional Haze 5-Year Progress Report at 9-3.

¹⁴ See October 2009 Nevada Regional Haze State Implementation Plan at 4-10 through 4-11.

¹⁵ *Id.* at 4-12 to 4-13.

¹⁶ Based on 2011 data from EPA's National Emission Inventory database for 2011, available at <http://www.epa.gov/ttn/chiefsnet/2011inventory.html>.

NOx in Nevada, accounting for 18% of the point source NOx emissions in Nevada in 2018¹⁷. And the North Valmy Generation Station likely contributes to visibility impairment at the Jarbidge Wilderness Area, as the facility is only about 160 kilometers from the Jarbidge Wilderness¹⁸.

The North Valmy Generating Station consists of two coal-fired units, and in 2013 the two units combined emitted a total of 6,358 tons of SO₂ and 3,769 tons of NO_x according to EPA's Clean Air Markets Database. These units are not equipped with the best air pollution controls for SO₂ and NO_x. Unit 1 is a 254 MW unit with no SO₂ controls, low NO_x burners and overfire air for NO_x control, and a baghouse¹⁹. Unit 2 is a 268 MW unit with a dry scrubber that is only required to achieve 70% SO₂ control, low NO_x burners and overfire air for NO_x control, and a baghouse²⁰. If a new SO₂ scrubber was installed at Unit 1 to achieve 95% control, that would reduce SO₂ emissions by almost 4,500 tpy (assuming operations at the same level as in 2013) just from Unit 1. If both North Valmy units were equipped with new SO₂ scrubbers to achieve 95% control, SO₂ emissions would be reduced from a total of 6,358 tons per year to 531 tons per year (based on 2013 operation levels), which would mean over 5,800 tons per year of SO₂ would be reduced from this facility. If the two North Valmy units were equipped with selective catalytic reduction (SCR) for NO_x control, NO_x emissions could be reduced by approximately 3,000 tons per year. Such emission reductions are readily achievable with available technology and would likely have significant benefits for visibility improvement at the Jarbidge Wilderness Area and other nearby Class I areas that are likely being impacted by emissions from northern Nevada. NDEP must consider emission control requirements for the North Valmy Generating Station as measures to ensure reasonable progress towards the national visibility goal at the Jarbidge Wilderness Area.

NDEP must also consider the potential visibility impacts from oil and gas development in the region near the Jarbidge Wilderness. Recent news articles seem to indicate that oil development could be increasing in Nevada, as it has in recent years in Utah²¹. To minimize impacts on air quality, NDEP should identify any appropriate regulatory tools in place to address the air emissions from the emission sources associated with oil and gas development. One regulatory tool that has proven to be very useful in regulating air emissions from these sources is a minor source best available control technology (BACT) requirement. Since most of the

¹⁷ *Id.*

¹⁸ The proposed White Pine power plant was to be located approximately 260 km to the south/southeast of the Jarbidge Wilderness Area, and it was projected to have noticeable visibility impacts on the Jarbidge Wilderness Area. The White Pine facility's maximum SO₂ and NO_x emissions were expected to be in a similar range as the actual emissions from the North Valmy Generating Station. See Bureau of Land Management, Ely Field Office/Nevada, Final Environmental Impact Statement for the White Pine Energy Station Project, August 2008, Volume 2 at 4-102-4-103, 4-114, and 4-122. Given the proposed White Pine power plant's impacts, it seems very likely that modeling of the North Valmy Generating Station, which is 100 km closer to the Jarbidge Wilderness, would show similar or greater impacts to visibility at the Jarbidge Wilderness.

¹⁹ See Nevada Bureau of Air Pollution Control Class I Air Quality Operating Permit, Permit No. AP4911-0457.01 at Section VI.A.1.a.

²⁰ *Id.* at Section VI.B.1.a.

²¹ See "Far-Flung Noble Energy Believes in Oil and Gas 'Diversification'," *Forbes* magazine, December 18, 2013, available at <http://www.forbes.com/sites/christopherhelman/2013/12/18/far-flung-noble-energy-believes-in-oil-and-gas-diversification/>; See also "Fracking comes to Nevada," *Las Vegas Review-Journal*, January 8, 2013, available at <http://www.reviewjournal.com/business/energy/oilgas-search-fracking-comes-nevada>.

sources associated with oil and gas development are often not considered major sources under the prevention of significant deterioration (PSD) permitting program, a minor source BACT requirement can give the state the regulatory authority to require controls on air pollution from these sources. Alternatively, NDEP should consider a SIP regulation requiring appropriate pollution controls and emission limits on these sources. Examples of pollution controls for these sources are available from other western states that have been experiencing a boom in development, such as Wyoming, Colorado and New Mexico. All of these states either have a minor source BACT program, emissions control regulations, and/or guidance to minimize air emissions from these sources.

In summary, NDEP does not have adequate justification for its negative declaration. Given that revised, corrected modeling from the WRAP shows that the Jarbidge Wilderness is not on the glide path to achieve natural background conditions in 2064, NDEP must acknowledge that its regional haze SIP is not adequate to ensure reasonable progress towards the national visibility goal. Further, NDEP must commit to revising its SIP to evaluate additional controls to achieve reasonable progress within one year pursuant to 40 C.F.R. §51.309(h)(4).

3. NDEP Must Revise Its Assessment of Contribution to Visibility Impairment at Class I Areas Impacted by its Sources to Be Based on the WRAP's Revised Modeling with its 2018 PRPb Emissions Projections.

Nevada's assessment of the adequacy of its plan with regard to the reasonable progress goals set for out-of-state Class I areas impacted by its sources is flawed in similar ways to its analysis for the Jarbidge Wilderness. Its assessment is based on its percent contribution as identified by WRAP's erroneous modeling that itself relies on WRAP's outdated PRP18a emission projections. See Chapter 6 of the proposed Nevada Regional Haze 5-Year Progress Report at 6-6, 6-7 and the Nevada Regional Haze State Implementation Plan at 4-15, 4-17, 7-21. Additionally, Nevada bases its emission reduction conclusions on the WestJump 2008 emissions inventory; its analysis of the changes in statewide emissions should be informed with the more updated 2011 NEI and recent CAMD data available to the extent possible.

As at the Jarbidge Wilderness, it is not clear that emissions reductions on a statewide basis will be sufficient to prevent Nevada's sources from impeding reasonable progress in out-of-state Class I areas. If the majority of emissions reductions come from sources in the southern part of the state, they may not account for Nevada's portion of impairment at, for instance, the Sawtooth Wilderness in Idaho. Thus, NDEP must revise its analysis of the adequacy of its plan with regard to its potential to impede reasonable progress in out-of-state Class I areas.

4. NDEP Must Revise Its Proposed Progress Report to Meet §51.308(g)(2) and §51.308(g)(4)

§51.308(g)(2) requires states to include estimates of emissions reductions associated with its SIP measures. The Progress Report describes the emissions reductions achieved in and near Nevada since the baseline for the SIP; however, it fails to detail the specific reductions achieved

through the implementation of the enforceable measures required by the SIP. This makes it impossible to tell whether the reductions are a result of the SIP or other actions, and hence doesn't demonstrate whether or not the SIP measures are working.

For instance, the Progress Report outlines a significant decrease in SO₂ and NO_x from electric generating units (EGUs). However, it is not clear how, or if, all of these reductions are enforceably linked to SIP requirements. Nevada notes a "steady decrease" in emissions from several EGUs, but in both instances, emissions actually increased from 2012-2013. See Chapter 6 of the proposed Nevada Regional Haze 5-Year Progress Report at 3-6 through 3-10. This may be due to variations in operating time or other non-enforceable factors at the facilities in question. If the reductions are not enforceable, they cannot be relied upon.

40 C.F.R. §51.308(g)(2) specifically requires an analysis of emissions reductions achieved through the SIP reduction measures, and this is set apart from the separate regulatory requirement to track emissions more generally from all sources in the State in §51.308(g)(4). We ask Nevada to include estimates of reductions due to enforceable SIP measures and revise its assessment of the adequacy of its SIP on this basis.

Likewise, §51.308(g)(4) requires an analysis of emissions trends across the entire inventory, covering the applicable 5-year period "based on the most recent updated emissions inventory, with estimates projected forward as necessary and appropriate." Nevada's analysis includes a description of the differences between the 2002 inventory and the WestJump inventory, which was for base year 2008. It also describes the differences between WestJump's inventory and the 2011 NEI in some source categories.

However, this does not fully address the regulatory requirement to include "estimates projected forward as necessary and appropriate." In this case, 2008 is 6 years ago. While the WestJump inventory and NEI comparison are helpful, it does not provide a picture of what is happening today with which to assess the sufficiency of Nevada's SIP.

We ask Nevada to additionally discuss in this section of its progress report: 1) up-to-date EGU emissions from EPA's Clean Air Markets Database (these are discussed elsewhere in the report but are not included here); and 2) descriptions of general trends in in-state emissions from 2008 to at least 2012 by pollutant and source category (preferably quantitative), derived from available state emissions inventories and Title V annual reporting and similar data collection endeavors. Without this information it is difficult to determine the impact of Nevada's SIP measures.

Last, to the extent that NDEP is relying on emission reductions that go beyond what is required by its Regional Haze SIP, such as SB123, NDEP should adopt those requirements as enforceable measures of its state implementation plan for regional haze.

Thank you for considering these comments.

Sincerely,

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Exhibits 1-3 attached

The NGO comment letter was accompanied by three exhibits. Because of the length of the exhibits, the NDEP has not included them in this appendix, but is providing links to these documents on the internet.

1. *Correction of WRAP region Plan02d CMAQ visibility modeling results on TSS for Regional Haze Planning*. April 27, 2011. The final version of the document is available at <http://vista.cira.colostate.edu/TSS/Planning/InformationExchange.aspx> (See [Revised Plan 02d CMAQ Modeling Results \(June 2011\)](#), last viewed 11/10/2014)
2. *WRAP PRP18b Emissions Inventory – Revised Point and Area Source Projections*. April 29, 2009. Technical Memorandum from Marty Wolf and Paula Fields, Eastern Research Group, to the WRAP staff. http://www.wrapair.org/forums/ssif/documents/Pivot_Tables/2009-04x_Final_PRP18b_memo_4-29.pdf (last viewed 11/10/2014)
3. *Summary of WRAP RMC BART Modeling for Nevada*. Draft#7. April 24, 2007. http://www.ndep.nv.gov/baqp/planmodeling/docs/NV_Bart_summary_v7_Apr24_2007.doc

These exhibits are also available on request from the NDEP Bureau of Air Quality Planning at 901 South Stewart Street, Carson City, Nevada 89701 or 775-687-9349.