APPENDIX B

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1 LETTERS AND NEWS RELEASES

1.1 Mohave Operating Permit Cancellation

ndep
NEVADA DIVISION OF ENVIRONMENTAL PROTECTION
protecting the future for generations

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

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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

FIN A0586
AP4911-1502

White Pine Energy Associates, LLC

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

ENVIRONMENTAL PROTECTION
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BAPC/BAQP

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

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

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NEVADA DIVISION OF ENVIRONMENTAL PROTECTION
protecting the future for generations

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

NVEnergy

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,

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
Brian Sandoval, Governor
Department of Conservation & Natural Resources
Leo M. Drozdoff, P.E., Director
DIVISION OF ENVIRONMENTAL PROTECTION
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

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

DAQEM

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 Gargras 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
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IS 347-0-0-0.2.25.8-2.F-Y153-N

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

February 20, 2008

VIA FACSIMILE AND U.S. MAIL

RECEIVED
08 FEB 25 P 2:00
EPA-DAQEM

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

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 Cooper 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 Zabel, Office of Regional Counsel, at 415-972-3902.

Sincerely,

Gerardo Rios
Chief, Permits Office

cc: Richard Bockstoad, DAQEM

1.6 Toquop Energy, LLC Withdrawal of Application for Toquop Project

Larry K.
FYI

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
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MIKE SOUMBENIOTIS
(1932-1997)

GEORGE V. ALLISON
OF COUNSEL

March 9, 2012

RECEIVED
MAR 12 2012
ENVIRONMENTAL PROTECTION

Nevada
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 [FN A0381, 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.
Robert Johnston, Esq.
Phil Williamson

PO BOX 646, CARSON CITY, NV 89702 • 402 N. DIVISION ST., CARSON CITY, NV 89703
TEL: (775) 687-0202 • FAX: (775) 882-7918 • WWW.ALLISONMACKENZIE.COM

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 CO_2 emissions in the electric power sector?**

   Questions for further discussion

   - *What actions are states, utilities, and power plants taking today that reduce CO_2 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 CO_2 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 CO_2 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 kWs 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 CO_2 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 downtown, 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 CO_2 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

NVEnergy

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.

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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.

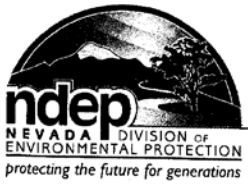
Sincerely,



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 Sate 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 PM_{10}, SO_2 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

Certified Mail # 9171 9690 0935 0012 2793 47

9171 9690 0935 0012 2793 47

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

ndep
NEVADA DIVISION OF ENVIRONMENTAL PROTECTION
protecting the future for generations

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.

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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

Certified Mail #9171 9690 0935 0011 8909 63

9171 9690 0935 0011 8909 63

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 (SO_2), and particulate matter less than 10 microns (PM_{10}) 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 SO_2 and PM_{10} control;
      - SO_2 emission limit of 0.05 lb/MMBtu (24-hour average);
      - PM_{10} emission limit of 0.03 lb/MMBtu (3-hour average);
      - Low NOx 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 SO_2 and PM_{10} control;
      - SO_2 emission limit of 0.05 lb/MMBtu (24-hour average);
      - PM_{10} emission limit of 0.03 lb/MMBtu (3-hour average);
      - Low NOx 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 SO_2 and PM_{10} 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 SO_2 and PM_{10} 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
(last viewed 6/13/2014)

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

Stipulation and Order accepting the Stipulation.

- Tracy Unit 1 will retire as of the BART compliance date. Attachment 1, section 2.C (page 3-4).
- Tracy Unit 2 will retire as of the BART compliance date. ORDER, section V.B.31 (page 13).
- 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 it relates to a new base load forecast, generating plant investments and retirements, and transmission projects.	)	Docket No. 12-08009

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.

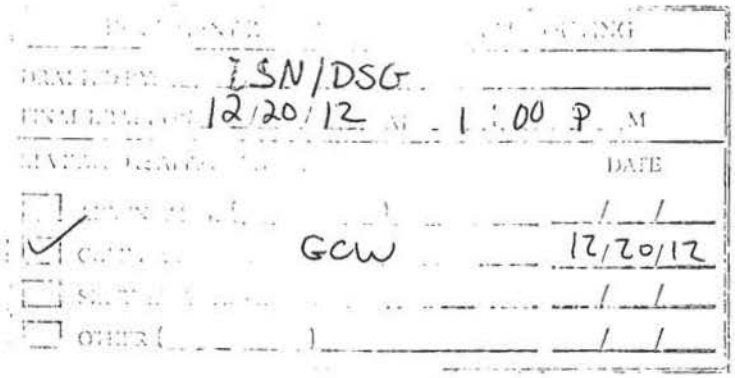
II. SUMMARY

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.


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• 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 1[1]

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") analyses[2], 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 ("SO_2"), mono-nitrogen oxides ("NOx"), 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 SO_2 and PM10, but additional controls will be needed for NOx 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 NOx BART compliance are low NOx 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 additional 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 increment[6] 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 2[7]

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 predomoinance 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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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)

PUBLIC UTILITIES COMMISSION OF NEVADA PUC

ATTACHMENT 1

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 11/27/2012

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

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

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

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

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

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

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

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

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

AGREEMENT OF THE PARTIES

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

1. Load Forecast.

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

i. NAC § 704.9321 because it is based on substantially accurate data and is adequately documented, justified demonstrated and defended,

ii. NAC § 704.9482 because the ESP Update uses a base load forecast, and

iii. NAC §§ 704.9482(7) and 704.922 because the technical appendices provide sufficient detail on how the Second Amendment Forecast was prepared and to evaluate the validity of the assumptions and the accuracy of the data used;

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

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

D. The Commission should order Sierra 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 forecasting purposes.

2. Generating Plant and Retirements.

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

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

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

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

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

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

3. Transmission.

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

4. Confidentiality.

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

5. General Points of Agreement.

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

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

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

[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").

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

REGULATORY OPERATIONS STAFF

By: _____ Dated: 11/27/12

Name: Jordan Pinjuv
Title: Assistant Staff Counsel

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

By: _____ Dated: 11/27/12

For Name: Elizabeth Elliot
Title: Associate General Counsel

OFFICE OF ATTORNEY GENERAL,
BUREAU OF CONSUMER PROTECTION

By: _____ Dated: November 27, 2012

Name: Paul Stuhff 12-08009
Title: Senior Deputy Attorney General

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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Michael Greene, Esq.
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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.

- 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 (last viewed 6/13/2014).
- 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 Plan of its 2013-2032 Integrated Resource Plan.	)	Docket No. 13-07002
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 Plan.	)	Docket No. 13-07005

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

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 10/9/2013

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.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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.

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

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

C. The Commission should find the base load forecast for 2014 and the low load forecast for 2015 through 2033 is suitable for making long-term planning decisions for the period between 2014 and 2033.[1]

2. Fuel and Purchased Power Forecast.

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

3. Supply Side Plan and Requests for Relief.

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

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

[1] Sierra, Staff and BCP entered into a stipulation in the Consolidated Dockets, which was filed with the Commission on September 16, 2013, whereby they agreed and recommended that the Commission find Sierra's 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.

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

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

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

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

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

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

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

3. With regard to prayer for relief 14, the construction of a second 345/120 kV transformer at Falcon; and,

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

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

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

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

I. 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.

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

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[2] Prayer for relief 18 in Sierra's Application.

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

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

4. Confidentiality.

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

5. General Points of Agreement.

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

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

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

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

Regulatory Operations Staff

By: Jermaine Grubbs Dated: 10/8/2013

Name: Jermaine Grubbs
Title: Assistant Staff Counsel

Sierra Pacific Power Company d/b/a NV Energy

By: Shawn M. Elicegui Dated: 10/09/2013

Name: Shawn Elicegui
Title: Associate General Counsel

Office of the Attorney General,
Bureau of Consumer Protection

By: David Norris Dated: 10/8/13

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: _____ Dated: _____

Name:
Title:

Nevadans for Clean Affordable Reliable Energy (Does Not Oppose)

By: _____ Dated: _____

Name:
Title:

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

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Name: David Norris
Title: Senior Deputy Attorney General

Apple Inc. (Does Not Oppose)

By: _____ Dated: 10/9/13
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:

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

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By: _____ Dated:_____
Name:
Title:

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

By: _____ Dated:_____
Name:
Title:

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

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

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

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By:_____ Dated:_____
Name:
Title:

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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

By: Patrick V. Fogg Dated: 10/9/13

Name:

Title:

Northern Nevada Industrial Electric Users (Does Not Oppose)

By: Patrick V. Fogg Dated: 10/9/13

Name:

Title:

Nevada Power Company and Sierra Pacific Power Company d/b/a NV Energy

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

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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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

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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.

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[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 CAPACITY[7]

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.

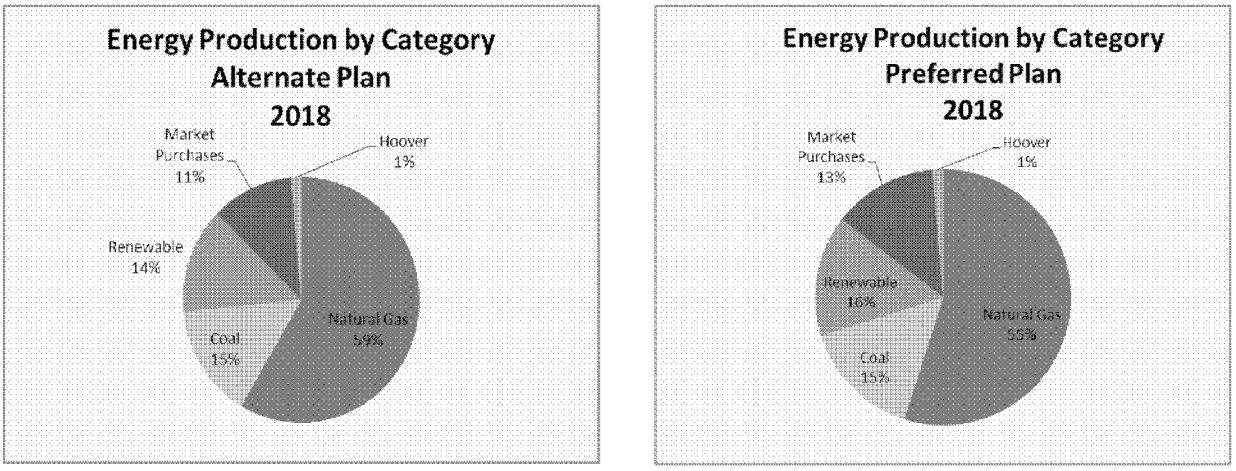
Fuel (or production) diversity refers to the type of fuel or process that a given unit uses to produce electricity. More specifically, fuel diversity – that is, the development of a portfolio of generation resources that rely on different means of generating electricity – has the potential to reduce 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



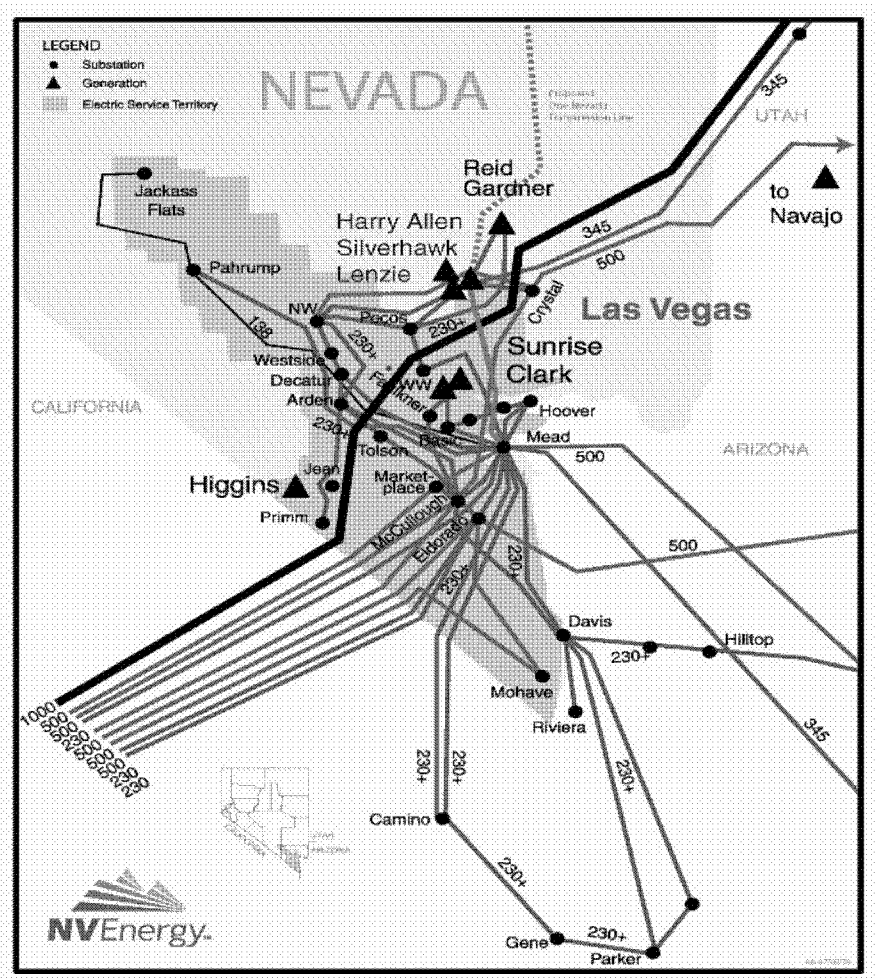
B. SUMMARY VOLUME REQUIREMENTS[12]

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

	Load	Fuel	GHG
1		BASE	MID C
2	BASE	LOW	MID C
3		HIGH	MID C
4	HIGH	BASE	MID C
5	LOW	BASE	MID C
6		BASE	NO C
7	BASE	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.

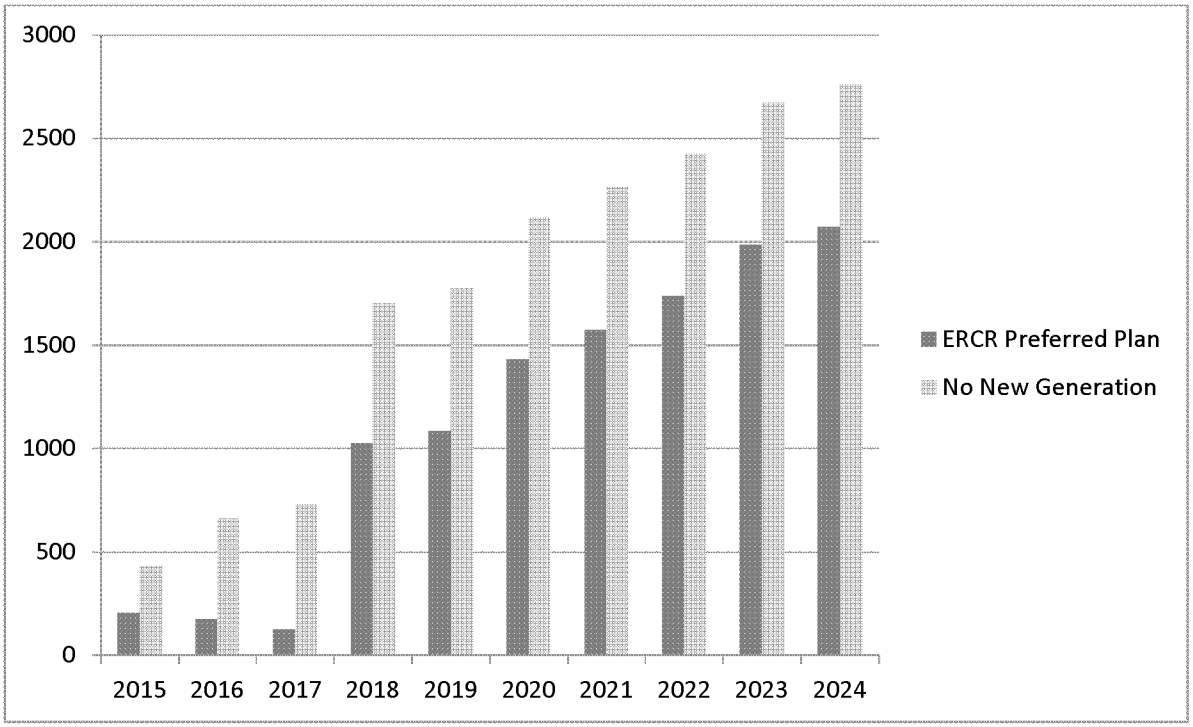
TABLE S-6
CAPACITY ELIMINATIONS 2013-2022

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

	SALES (GWH) WITH DSM			SALES (GWH) WITHOUT DSM/DR		
Year	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

	PEAK DEMAND (MW) WITH DSM			PEAK DEMAND (MW) WITHOUT DSM/DR		
Year	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 L0AD 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	70.5	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	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	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	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	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	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	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	25.6	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	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	128
Total MW	107	174	206	233	259	286	313	339	365	390	415	439	462	485	504	518	526	526	527	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
	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
	DSM	51	78	105	131	158	185	211	237	262	287	311	334	357	376	390
	Net Metering	15	23	27	35	41	49	52	52	53	53	54	56	57	57	58
	Demand Response	238	243	243	243	243	243	243	243	243	243	243	243	243	243	243
	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
	SNWA Obligation	125	125	125	125	-	-	-	-	-	-	-	-	-	-	-
	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
	Planning Reserve Requirement (12%)	690	693	701	710	706	716	725	733	742	751	759	768	778	788	797
	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
	RESOURCES (Itemized)															
	Existing Internal Generation Facilities (Retire Date, 12/31/xx)															
	Clark 4 (2020)	54	54	54	54	54	54	-	-	-	-	-	-	-	-	-
	Clark 9,10 (9 - 2033, 10 - 2034)	430	430	430	430	430	430	430	430	430	430	430	430	430	430	430
	Clark Peakers 11-22 (2038)	619	619	619	619	619	619	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)	72	72	72	72	72	72	72	72	72	72	72	-	-	-	-
	Harry Allen 4 (2036)	72	72	72	72	72	72	72	72	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	530	530	530	530	530
	Lenzie 1 (2041)	551	551	551	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	551	551	551
	Reid Gardner 1,2,3 (2014)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reid Gardner 4 - Base (2017)	257	257	257	-	-	-	-	-	-	-	-	-	-	-	-
	Silverhawk (75% Share) (2039)	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
	Sunpeak 3,4,5 (2026)	222	222	222	222	222	222	222	222	222	222	222	222	-	-	-
		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
	Existing Generation Requiring or Affecting Imports															
	Hoover	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Navajo 1,2,3 (2019)	255	255	255	255	255	-	-	-	-	-	-	-	-	-	-
IMP		455	455	455	455	455	200	200	200	200	200	200	200	200	200	200
	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
	Planned Internal Generation Facilities															
	15 MW PV_2016 (COD 1/1/2016)	-	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
	35 MW PV_2021 (COD 1/1/2021)	-	-	-	-	-	-	13	13	13	13	13	13	13	13	13
	3x_7EA_27	-	-	-	-	-	-	-	-	-	-	-	-	213	213	213
	2x1_CC_20	-	-	-	-	-	597	597	597	597	597	597	597	597	597	597
		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Planned Internal Generation	-	6	82	82	82	679	692	692	692	692	692	692	905	905	905
	Planned Generation Facilities Requiring Import Rights															
	1x1_CC_22	-	-	-	-	-	-	-	-	273	273	273	273	273	273	273
	3x_7EA_23	-	-	-	-	-	-	-	-	-	213	213	213	213	213	213
	2x1_CC_24	-	-	-	-	-	-	-	-	-	-	597	597	597	597	597
	3x_LMS 100_30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3x_LMS 100_32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2x1_CC_35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3x_LMS 100_36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1x1_CC_38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2x1_CC_39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2x1_CC_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3x_LMS 100_40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1x1_CC_41	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Planned Generation Requiring Imports	-	-	-	-	-	-	-	-	273	486	1,083	1,083	1,083	1,083	1,083
	Total Planned Generation	-	-	6	82	82	82	679	692	965	1,178	1,775	1,775	1,775	1,988	1,988
	Less Scheduled Maintenance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	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
		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	-	-	-	-	-	-	-
		Saguaro (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)															
	IMP	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
	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	**JsyValNP**	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	TRN	**DsrtPkNP**	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	TRN	**(Blue Mountain) FlknerNP**	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	TRN	**Gal2NP**	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	TRN	**SltWelNP**	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	TRN	**StlWtrNP (PV & GEO)**	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
	TRN	**Tuscarora**	15	15	15	15	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
	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
		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
	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
		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
	TRN	**51 MW GEO_2019**	-	-	-	-	17	17	17	17	17	17	17	17	17	17	17
	TRN	**102 MW GEO_2033**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	TRN	**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
		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
	IMP	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	1,958	1,957	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)															
	Existing Internal Generation Facilities (Retire Date, 12/31/xx)															
	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
	Existing Generation Requiring or Affecting Imports															
	Hoover	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Navajo 1,2,3 (2019)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IMP		200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Total Existing Generation	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
	Planned Internal Generation Facilities															
	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
	Planned Generation Facilities Requiring Import Rights															
	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
	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	597	597	597
	2x1_CC_42	-	-	-	-	-	-	-	-	-	-	-	-	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)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Saguaro (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)															
	IMP	Griffith	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		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	**JsyValNP**	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
	TRN	**DsrtPkNP**	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	TRN	**(Blue Mountain) FlknerNP**	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	TRN	**Gal2NP**	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
	TRN	**SltWelNP**	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	TRN	**StlWtrNP (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
		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
	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
	TRN	**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
		25 MW PV_2034	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10
		25 MW PV_2035	-	-	-	-	-	-	-	10	10	10	10	10	10	10	10
	TRN	**25.5 MW GEO_2037**	-	-	-	-	-	-	-	-	19	19	19	19	19	19	19
		25 MW PV_2038	-	-	-	-	-	-	-	-	-	10	10	10	10	10	10
		25 MW PV_2039	-	-	-	-	-	-	-	-	-	-	10	10	10	10	10
		50 MW PV_2040	-	-	-	-	-	-	-	-	-	-	-	19	19	19	19
		25 MW PV_2041	-	-	-	-	-	-	-	-	-	-	-	-	19	19	19
		25 MW PV_2041	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
		50 MW PV_2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	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	7,759	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)	(3,568)	(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 (SRSG) 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	$1,262,554

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 Two[21] 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	TOTAL[26]
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 BUDGET[27]
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
Subtotal Generation	$ 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
Subtotal Renewables	$ 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
previously approved					
ON Line (Nevada Power's portion 95%)			$ 0.12		
WestConnect membership			$ 0.15		
Subtotal transmission	$ 48.40	$ -	$ 2.91	$ 45.77	
Demand Side					
Per Approved DSM Plan			$ 53.05		12/31/2015
Subtotal DSM	$ -	$ -	$ 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.