BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Annual Deferred Energy Accounting Adjustment Application of the Electric Division of Sierra Pacific Power Company d/b/a NV Energy for the 12-month period ending December 31, 2023, reset the Temporary Renewable Energy Development Charge, reset all components of the Renewable Energy Program Rate, reset the Base Energy Efficiency Program Rates, reset the Base Energy Efficiency Implementation Rates, reset the Energy Efficiency Program Amortization Rate, reset the Energy Efficiency Implementation Amortization Rate, and reset the Expanded Solar Access Program rate.	**Docket No. 24-03___**

VOLUME 5 OF 9

TESTIMONY AND TECHNICAL APPENDIX

DESCRIPTION **PAGE NUMBER**

TESTIMONY

TECHNICAL APPENDIX

VERNON TAYLOR

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Vernon Taylor

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Vernon Taylor. My current position is Director of Trading Operations for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company" and, together with Nevada Power, the "Companies"). My business address is 6226 West Sahara Avenue in Las Vegas, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have been employed by the Companies since 1991. My experience includes work in Generation, Engineering and Construction, Resource Planning, Business and Economic Development, Resource Optimization and Risk Control. From 2001 to 2010, I was the Manager of Short-term Analysis in the Resource Optimization department where I led the development of short-term energy supply plans, trading analytics and portfolio optimization activities in support of day-ahead and forward transactions. From October 2010 through December 2017, I served as the Company's Director of Risk Control with responsibility for all aspects of the Risk Control function as detailed in the Companies' risk policies and procedures. In December 2017, I returned to the Resource Optimization business unit in the role

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

of Director of Market Analytics. In June 2023, I accepted the position as the Director of Trading Operations in the Companies' Resource Optimization department. A Statement of Qualifications providing further detail on my education and professional background is attached as **Exhibit Taylor-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF TRADING OPERATIONS.

A. As Director of Trading Operations, my responsibilities include the economic scheduling of generating facilities, the optimization of power supply resources pursuant to a Joint Dispatch Agreement ("JDA"), real-time power trading, and the portfolio optimization of Participating Resources stemming from the Companies' active participation in the Western Energy Imbalance Market ("WEIM") that is operated by the California Independent System Operator ("CAISO").

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I have previously testified in proceedings before the Commission, most recently in Docket Nos. 23-03005 and 23-03006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I describe and support the Company's portfolio optimization of Participating Resources through active participation in the WEIM for the 12-month period ending December 31, 2023 (the "Deferral Period"). I also describe and support the Company's optimization of energy supply resources under the JDA for the Deferral Period. I describe and support the Company's calculation of benefits from WEIM transactions for the Deferral Period. I also support the Company's forward sales of wholesale electricity. Additionally, I describe and support the economic dispatch of the Company's generating assets during the Deferral Period. Finally, I describe and support activities performed as part of the Company's compliance with Commission orders from previous dockets related to wear and tear costs associated with joint dispatch, WEIM, and heat rate call options.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Taylor-Direct-1	Statement of Qualifications
Exhibit Taylor-Direct-2	CAISO EIM Benefit Methodology (Q1 2021)

The Resource Optimization Organization

7. Q. WHAT IS THE ROLE OF THE RESOURCE OPTIMIZATION DEPARTMENT?

A. The Resource Optimization department is responsible for the short-term (less than three years) purchase and sale of electric power, fuel, and financial products for the Companies, as well as the appropriate and efficient scheduling and optimization of the Companies' supply portfolio. Products are purchased and sold in accordance with the Commission approved Energy Supply Plans ("ESP") or ESP updates, and other governing documents (e.g., Commission stipulations and orders, and corporate policies and manuals). Resources are adjusted continuously based on many factors, including changes in expected load, system and market conditions, and system reliability needs. The Companies layer in purchases and sales over time, beginning a year or more prior to the delivery period and continuing until the hour of delivery.

8. Q. HOW DO RELIABILITY CONSIDERATIONS AFFECT THE COMPANY'S ACTIVITIES?

A. As Kim Whetzel explains in her testimony, short-term energy transactions or adjustments to planned transactions may be made in order to maintain the reliability of the system. Moreover, system conditions may require the Company to dispatch generating units in a specific manner, regardless of economics.

9. Q. WHY IS IT NECESSARY TO OPTIMIZE RESOURCES CONTINUOUSLY?

A. The Company must continuously match supply and demand on its electric system, and the Company strives to do so in the most cost-effective manner. The Company's optimization procedures recognize the uncertainty not only in system conditions (e.g., planned or unplanned outages of generating plants or transmission facilities) but also in regional energy markets organized across different commodities, locations, and trading timeframes. As conditions change and new information becomes available, the Company takes appropriate steps to balance supply and demand - buying and selling resources as appropriate, to account for changes in load, cost, volatility, reliability, and other commercial or technical factors.

10. Q. HOW DOES THE COMPANY BEGIN TO OPTIMIZE ITS RESOURCES MONTHS BEFORE DELIVERY?

A. The Company evaluates its capacity and energy positions for future months by taking into account planned unit outages, available resources, forecasted system loads, and forecasted reserve requirements. As approved in the Company's ESP and ESP updates, Docket Nos. 21-06001, 22-09002, and 23-09003 respectively, the

Company employs a power procurement laddering strategy to address capacity or energy short positions. If the evaluation shows that the Company is expected to be long in capacity in a specific period - for up to three future gas seasons - the Company may issue a Reverse Request for Proposal ("RRFP") to sell energy products or heat rate call options for capacity that is not expected to be needed to serve load.

Similarly, the Company acquires physical gas for future delivery months through laddered transactions across months or seasons when permitted by a Commission-approved ESP or ESP updates. As forecasts are updated, procurement targets are adjusted. In addition to the laddering strategy, on a monthly basis the Company evaluates its physical and financial gas portfolio for the current season and beyond; it then adjusts the portfolio as appropriate, depending on the difference between procurements and forecasted requirements as well as the number of transaction opportunities remaining.

11. Q. HOW DOES THE COMPANY OPTIMIZE ITS RESOURCES DAYS BEFORE DELIVERY?

A. On a daily basis, the Company forecasts the energy position and owned generation costs for the scheduling day. Owned generation costs are compared to energy market prices to identify and capture opportunities for mitigating the cost of providing electric service to the Company's customers. The Company's power traders determine energy market prices in real time by communicating with other power traders and by monitoring trading platforms. If the power market price is below the cost of owned generation, the Company's power traders purchase energy to reduce the cost to serve customers. If the market price is above the cost of owned generation not needed to serve load, the Company's power traders may make sales for the benefit of customers. The execution of a purchase or sale depends on economic and reliability considerations, such as transmission cost or availability; fuel cost or availability; owned generation unit flexibility for ramping up or down; or other commercial or technical factors.

12. Q. HOW DOES THE COMPANY OPTIMIZE ITS RESOURCES HOURS BEFORE DELIVERY?

A. On the day of delivery, the Company continues to compare owned-generation cost to energy market prices in order to identify and capture opportunities to reduce the cost of providing electric service to customers. The Company also optimizes fuel resources not needed to serve load by making sales, when possible, to reduce the overall cost of providing electric service.

Economic Utilization of Company Generation

13. Q. DID THE COMPANY APPROPRIATELY AND EFFICIENTLY UTILIZE ITS GENERATION RESOURCES TO REDUCE THE OVERALL COST OF PROVIDING ELECTRIC SERVICE TO ITS CUSTOMERS DURING THE DEFERRAL PERIOD?

A. Yes. The Company deployed its generation resources appropriately and efficiently, supplementing such internal resources as appropriate to serve customers, meet obligations, and mitigate costs to our customers when market power costs were more favorable than the costs to run the Company's owned generation. Ryan Atkins' prepared direct testimony includes the power and gas transactions that were entered into either immediately before or during the Deferral Period, and which also flowed during the Deferral Period. These transactions were entered into by the Company during the current and subsequent or "prompt" month.

14. Q. DID THE COMPANY ENGAGE IN ANY CONTINUOUS PERFORMANCE IMPROVEMENT ACTIVITY AS PART OF ITS RESOURCE OPTIMIZATION EFFORTS?

A. Yes. The Company continued to implement a post-analytics process to review its market operations and trading activities in order to identify opportunities for process improvement related to resource optimization activities.

15. Q. PLEASE EXPLAIN WHY THE COMPANY ENGAGES IN POST-ANALYSIS.

A. The Company believes that performing an after-the-fact review of its market operations and trading activities provides learning opportunities for its personnel engaged in those resource optimization activities, potentially leads to process improvement opportunities, and may be useful in establishing future performance targets. The Company believes that opportunities for process improvements to its resource optimization activities are also opportunities to save money for customers.

16. Q. PLEASE DESCRIBE THE TYPES OF POST-ANALYSES THAT THE COMPANY PERFORMS AS PART OF ITS CONTINUOUS PERFORMANCE IMPROVEMENTS.

A. The Company makes an after-the-fact determination on the economic benefits of sales and purchases, load forecasts, natural gas actuals versus natural gas windows, solar forecasts, and WEIM resource sufficiency tests. These results are reviewed with our real-time operating personnel. For example, we analyze WEIM resource sufficiency test failures and provide feedback to the GenDesk on how best to ensure passing the tests in the future. This analysis has led to progressive improvements in our passing rate. The inability to pass the tests, freezes our WEIM transfers at the previous hours' level for the intervals that were failed, preventing us from participating in the market. While a higher pass rate allows us to maximize our potential WEIM benefits. It is important to emphasize that these after-the-fact comparisons and determinations are not assessments of prudence.

17. Q. PLEASE EXPLAIN WHY THESE ANALYSES ARE NOT APPROPRIATE FOR ASSESSING PRUDENCY.

A. As Eugene T. Meehan and Kurt Strunk explain in their respective prefiled direct testimonies, the standard for what constitutes prudency is determined from an analysis of the range of options available at the time the decision was made, judged in light of the circumstances, information and options available at the time, without the benefit of hindsight. Post-analysis necessarily relies on information and options that were not available at the time the Company made its optimization decision. Because post-analysis relies on hindsight, one cannot use post-analysis to assess the prudence of the Company's optimization and dispatch activities.

Joint Dispatch Agreement

18. Q. WHAT IS THE PRIMARY PURPOSE OF THE JDA?

A. The primary purpose of the JDA is to provide a contractual basis for the joint dispatch of the power supply resources of both Nevada Power and Sierra to efficiently and effectively serve the customers of both Companies. The JDA provides a mechanism to leverage the diverse portfolio of power supply resources of both Companies for the benefit of all customers.

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

19. Q. PLEASE DESCRIBE HOW THE COMPANY PERFORMS JOINT DISPATCH OPTIMIZATION.

A. The Company forecasts the native load requirements for both Nevada Power and Sierra. These native load requirements are inputs into a short-term optimization production cost model along with commercial and technical factors such as fuel price, generation availability, contractual obligations, and transmission availability over the One Nevada Transmission Line ("ON Line"). The Company then uses the production model to forecast its energy position and owned generation costs of the combined resource portfolio for the relevant upcoming period (e.g., the next day). These costs are then compared to market alternatives. If the market price is below the cost of the owned combined generation portfolio, the Company purchases energy to reduce the cost to serve the combined native load. Similarly, if the market price is above the cost of the owned combined generation portfolio, the Company seeks opportunities to make economic sales to benefit the native load customers of both Nevada Power and Sierra.

20. Q. PLEASE EXPLAIN HOW VARIABLE OPERATIONS AND MAINTENANCE ("VOM") COSTS ARE RECOVERED FROM THE RESPECTIVE UTILITY (E.G., NEVADA POWER RECOVERS VOM FROM SIERRA AND VICE-VERSA) THROUGH THE JOINT DISPATCHING COST ALLOCATION.

A. The JDA provides for transfer payments between Nevada Power and Sierra to compensate each company for its respective VOM costs attributable to the energy transferred between the Companies. The transfer payment captures the production cost difference between what each company would have incurred through standalone dispatch as compared to what each company incurred through joint dispatch. This production cost difference includes VOM expenses either company incurred from operating its generating units to serve the other company. Stated differently, if Nevada Power's generating units increased its production to serve Sierra, then the increased production costs incurred by Nevada Power would be captured in the production cost difference and resultant transfer payment between Sierra and Nevada Power. The transfer payment is the mechanism that allows each company to recover its respective VOM costs.

21. Q. PLEASE EXPLAIN TO WHAT EXTENT THE CAPITALIZED COSTS ASSOCIATED WITH GENERATION MAINTENANCE ARE USED IN DETERMINING JOINT DISPATCH OPTIMIZATION AND COST ALLOCATION.

A. As further explained below in Q&A 33, capitalized maintenance costs are not utilized in the joint dispatch optimization and cost allocation.

Energy Imbalance Market

22. Q. BRIEFLY DESCRIBE THE WEIM.

A. The WEIM is an expansion of the CAISO's real-time market enabling economic dispatch of inter-regional resources throughout the WEIM footprint to efficiently manage imbalances caused by variations between forecast and actual energy (both load demand and generation production) within the operating delivery hour. The WEIM leverages geographic diversity of regional supply and demand portfolios to manage imbalances more efficiently, which each Balancing Authority ("BA") previously managed through stand-alone dispatch of resources owned or controlled within each individual Balancing Authority Area ("BAA"). The WEIM also facilitates economically efficient transactions between BAAs.

23. Q. PLEASE DESCRIBE RESOURCE OPTIMIZATION'S ROLE IN THE COMPANIES' WEIM PARTICIPATION.

A. Resource Optimization serves as the Companies' Participating Resource Scheduling Coordinator ("PRSC"). As such, Resource Optimization performs a myriad of WEIM related workflows including, but not limited to reporting generation outages or changes in availability from the Companies' WEIM Participating Resources; submitting economic bids for WEIM purchase and sale transactions; providing forecast and operating data such as native load obligations and interchange schedules; and submitting resource plans (or "base schedules") of how the Companies plan to economically serve native load obligations.

24. Q. PLEASE DESCRIBE THE DAILY MARKET OPERATIONS FUNCTIONS THAT RESOURCE OPTIMIZATION PERFORMS AS A PRSC.

A. First, it is important to note functions within Resource Optimization that were not affected by the WEIM. The WEIM does not affect portfolio optimization activities beyond the real-time market operating horizon, such as day-ahead and forward operational planning and forward purchase and sales transactions. Resource Optimization continues to execute those functions independent of the WEIM with some modifications to communication protocols related to outage notification and communication of forecast data. Additionally, the WEIM does not alter or otherwise conflict with the Companies' BA functions of ensuring resource adequacy, reserve obligations, reliable dispatch of generation, or compliance with reliability standards to meet the Companies' native load and other non-WEIM obligations. Resource Optimization continues to develop operational plans that factor in these reliability constraints as further described below.

The real-time market functions associated with a PRSC begin with the development of a balanced schedule. The balanced schedule represents Resource Optimization's economic resource plan for the optimization of the Companies' power supply resources to meet native load requirements, operating reserve requirements, and any pre-existing obligations (e.g., wholesale bilateral transactions with third parties). Resource Optimization submits this balanced schedule to the Transmission Organization (i.e., the WEIM Entity) up to 57 minutes prior to the operating delivery hour ("T-57"). These balanced schedules serve to advise the WEIM Entity (also the BA) of the PRSC's economic resource plan for the operating delivery hour. The BA, in its capacity as the WEIM Entity, makes necessary modifications to these advisory schedules between T-57 and up to 40 minutes prior to the operating delivery hour ("T-40") to ensure the reliable and safe operations within the Companies' BAA. At T-40, these advisory schedules, as modified by the WEIM Entity, become financially-binding "base schedules" from which the CAISO will assess imbalance charges or payments for any deviations.

25. Q. IS IT REASONABLE TO ASSUME THAT THERE WILL BE DEVIATIONS FROM THE BASE SCHEDULE IN EVERY HOUR?

A. Yes. It is inherent to all operating circumstances for there to be continuous variations between forecasted and actual operating conditions, which the WEIM refers to as deviations from the base schedule. This operating phenomenon, imbalance, existed prior to the Companies' participation in the WEIM and was recognized as a service that the Companies provided their customers (both retail and Federal Energy Regulatory Commission jurisdictional) to account for deviations between scheduled and actual energy (both load demand and generation production). For certain non-native load customers, the Companies' Transmission

Organization issues bills for the provision of imbalance service under its federally-approved Open Access Transmission Tariff (commonly referred to as the "OATT"). The Companies' participation in the WEIM does not alleviate the BA's obligation to provide this service to customers. Instead, the Companies' participation in the WEIM merely adds transparency to the provision of this service to customers through market invoices and settlement statements. Lastly, the Companies' participation in the WEIM does not change the underlying factors which lead to deviations from forecast and actual operating conditions. Rather, it is the existence of this inherent characteristic of operating an electric system that is the foundation of the WEIM market design and the portfolio optimization opportunities realized through Resource Optimization's submittal of economic bids and resulting WEIM transactions.

26. Q. PLEASE DESCRIBE RESOURCE OPTIMIZATION'S PROCESSES RELATED TO THE SUBMITTAL OF ECONOMIC BIDS AND WEIM TRANSACTIONS.

A. As described above, Resource Optimization continues its prior practice of developing a balanced schedule representing the economic optimization of the Companies' power supply resources to serve native load requirements, operating reserve requirements, and other pre-existing obligations (e.g., bilateral transactions with third parties). This balanced schedule reflects the outcome of other portfolio optimization activities that have not changed as a result of WEIM operations. These activities involve the forecasting of native load requirements, the production cost modeling of commercial and technical factors such as fuel price, generation availability, contractual obligations, and transmission availability over the ON Line, the market comparison of owned generation costs and the capturing of market

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

opportunities through bilateral transactions, and the joint dispatch of the combined resource portfolios of both Companies.

This balanced schedule is the basis for Resource Optimization's economic bid submittal for potential transactions. Meaning, the Companies' balanced schedule also serves to identify both utility resources that are eligible to be dispatched by the WEIM and at what bid ranges Resource Optimization will utilize to submit economic bids for those Participating Resources.

Based on the anticipated utilization of resources to serve native load and other non-WEIM obligations, Resource Optimization's real-time power traders submit economic bid ranges. The bid ranges primarily reflect an incremental or decremental change in resource production levels that the Companies voluntarily provide as resources that will respond to a market dispatch instruction by the CAISO. The CAISO refers to such market dispatch as instructed imbalance energy awards, which are awards to sell into or remove from the market offered megawatts and are considered to be sales and purchases in the WEIM.

27. Q. DID THE COMPANY PERFORM THESE WEIM FUNCTIONS IN A REASONABLE MANNER?

A. Yes, Resource Optimization's implementation of market operational workflows associated with outage management, submissions of forecast data (e.g., base schedules), and submission of economic bids enabled the Company to perform WEIM functions in a reasonable manner.

28. Q. PLEASE DESCRIBE THE COMPANY'S METHODOLOGY FOR ASSESSING BENEFITS ATTRIBUTED TO THOSE TRANSACTIONS.

A. It is important to note and as stated above that these transactions occurred sub-hourly (in both five and 15-minute trading intervals). Due to the heavy computational burden associated with this granular level of data, it is not technically feasible to execute production cost model studies from which comparison cases could be made between an actual and a counterfactual case. Rather, the Companies' production cost software has been configured to enable after-the-fact determinations of economic benefits derived from purchase and sale transactions by comparing the sub-hourly costs of WEIM participating resources to sub-hourly transactions (five and 15-minute market awards). This provides a direct comparison of the affected resource's cost to the affected resource's market awards with comparable granularity.

Through this assessment, a transaction provides an economic benefit if it results in either an avoided costs savings or a positive sales margin. For example, if the five-minute decremental price of a given resource was \$30/MWh and the WEIM purchase transaction during that same transaction interval was \$25/MWh, then the transaction saves the Companies' customers \$5/MWh by avoiding the production costs associated with producing energy of an equivalent amount to the WEIM transaction (avoided costs savings). Likewise, if the incremental cost of a given resource was \$30/MWh and the WEIM sales transaction was \$37/MWh, then the transaction provides the Companies' customers with economic benefits of \$7/MWh by capturing the marginal price difference between the Companies' production costs and the WEIM sales transaction of an equivalent amount of energy (positive sales margin).

The Companies performed this analysis for all WEIM transactions in the Deferral Period to determine economic benefits realized on behalf of its customers through active participation in the WEIM.

29. Q. WHAT WERE THE OUTCOMES OF THIS TRANSACTIONAL BENEFIT ANALYSIS?

A. The analysis indicates that the Companies' customers have realized $279.1 million of transactional benefits from participating in the WEIM since entering the market in December 2015, of which $73.7 million was realized by Sierra's customers. During the Deferral Period, the Companies' benefits were approximately $75.7 million, of which approximately $20.9 million was realized by Sierra's customers.

It is important to note that the Companies' calculation of transactional benefits utilizes market data from the CAISO that is subject to change. Such changes are consistent with the CAISO market settlement timelines and not controllable by the Companies. As such, the transactional benefits contained in this testimony may differ from benefits previously reported to the Commission and may again differ in future benefit estimates that the Company reports to the Commission.

30. Q. IS IT REASONABLE TO ASSUME THAT ALL WEIM TRANSACTIONS WILL HAVE POSITIVE BENEFITS?

A. No. Like non-WEIM transactions, a WEIM transaction always has the potential to have negative economic results when assessed after-the-fact. Such instances are attributed to inherent changes between forecast and actual operating conditions which occurred during the operating hour such as variances in load and resource production.

31. Q. SHOULD AN AFTER-THE-FACT ECONOMIC DETERMINATION OF TRANSACTIONAL BENEFITS WEIGH IN THE ASSESSMENT OF PRUDENCY FOR WEIM TRANSACTIONS?

A. No. For the reasons previously described in Q&As 16 and 17, it is again important to emphasize that after-the-fact comparisons and determinations are not assessments of prudence. As Mr. Meehan and Mr. Strunk explain in their respective testimonies, the standard for what constitutes prudency is determined from an analysis of the range of options available at the time the decision was made, judged in light of the circumstances, information and options available at the time, without the benefit of hindsight. As with similar post analysis efforts, after-the-fact assessments of economic benefits stemming from WEIM transactions necessarily rely on information and options that were not available at the time the Company made its optimization decision. Because it relies on hindsight, one cannot use it to assess the prudence of the Company's optimization and dispatch activities in the WEIM.

32. Q. DOES THE CAISO PERFORM AN INDEPENDENT ANALYSIS OF THE COMPANIES' BENEFITS ATTRIBUTED TO THEIR WEIM PARTICIPATION?

A. Yes. At the writing of this testimony, the CAISO published reports indicate that customers within the Companies' Balancing Authority Area ("BAA") realized \$455.3 million of benefits since December 2015. For the Deferral Period, the CAISO reports that customers within the Companies' BAA realized \$176.1 million of benefits. The CAISO benefit report does not include a breakdown of benefits specific to Sierra.

33. Q. WHAT ARE UNDERLYING CAUSES FOR THE DIFFERENCES BETWEEN THE COMPANIES' BENEFIT RESULTS AND THE RESULTS REPORTED BY THE CAISO?

A. Differences between the CAISO and the Companies' benefit results are attributed to varied approaches for measuring economic benefits. As described above, the Companies' benefit analysis measures economic benefits of transactions due to avoided cost savings (WEIM purchases) and marginal production cost differences (WEIM sales). Further, the Companies' transactional benefit analysis focuses solely on benefits attributed to the Companies' native load customers from their participating WEIM resources.

The CAISO's analysis is intended (in part) to capture economic benefits of actual versus counterfactual dispatch and net interchange transfers. In doing so, the CAISO's analysis includes additional benefits that are not currently included in the Companies' transactional benefit analysis. More specifically, the CAISO's analysis captures benefits from addressing load imbalances and from the optimization of base schedules by the Market Operator. Additionally, the CAISO's benefit analysis is representative of all customers within the Companies' BAA not just native load. Together, the CAISO's methodology provides a more inclusive approach of measuring benefits with potential for higher magnitudes than the Companies' transactional benefit analysis. A more detailed description of the methodology that the CAISO utilizes to calculate WEIM benefits is provided in **Exhibit Taylor-Direct-2**, which describes the methodology that the CAISO utilized for reporting the WEIM benefits for the 2023 Deferral Period.

34. Q. IN COMPLIANCE WITH THE COMMISSION'S ORDERS FROM DOCKET NOS. 16-03003 AND 17-03001, PLEASE DESCRIBE THE COMPANY'S CONSIDERATION OF COSTS ASSOCIATED WITH WEAR AND TEAR OF GENERATING UNITS IN THE PRICING OF ALL WHOLESALE TRANSACTIONS INCLUDING BUT NOT LIMITED TO TRANSACTIONS ASSOCIATED WITH JOINT DISPATCH, WEIM AND HEAT RATE OPTIONS.

A. The answer to the above question will be addressed in three parts. First, in reference to joint dispatch, the Company has not identified any circumstances in which a generating unit owned by Sierra was committed and used solely for the purpose of serving Nevada Power's customers. As such, the Company's actual operating experience did not indicate that a change was warranted to add capital operating and maintenance costs for wear and tear of generating units related to unit start-ups. The Company, therefore, continues to utilize non-capital variable generation operation and maintenance costs in its wholesale transactions associated with joint dispatch.

Second, for WEIM transactions, the Company's bid price utilized for WEIM transactions includes capital operating and maintenance costs associated with generation unit starts. In doing so, the Company receives payments from the CAISO that are intended to reimburse the Company for circumstances in which the Companies' generating units are committed and used solely for the purpose of completing WEIM transactions. The Company's actual operating experience indicates that its current pricing of wholesale transactions in the WEIM provides an appropriate mechanism for recovering costs associated with wear and tear of generating units from unit start-ups. The Company intends to continue utilizing the capital operating and maintenance costs associated with generation units starts by the WEIM Market Operator.

Third, with regard to heat rate options, the Company has not identified any circumstances in which a generating unit owned by Nevada Power was committed and used solely for the purpose of serving a heat rate option sale transaction. As such, the Company's actual operating experience did not indicate that a change was warranted to add capital operating and maintenance costs for wear and tear of generating units related to unit start-ups. The Company, therefore, continues to utilize non-capital variable generation operation and maintenance costs in its wholesale transactions associable with heat rate call options.

Forward Sales of Wholesale Electricity

35. Q. DID THE COMPANY SEEK TO MAKE FORWARD SALES DURING THE DEFERRAL PERIOD?

A. No. The Company did not seek to make forward sales during the Deferral Period. There are several reasons the Company did not seek forward sales through the RRFP process. Over the last several years, the Company was not seeing a strong response from its forward sales trading activity. Feedback from counterparties was that the amount of solicitations was simply becoming overwhelming and the RRFP was not a priority. In addition, with the growth of the WEIM, western counterparties are primarily focused on maximizing their profits in the WEIM and not in the forward market where risks are higher. As evidenced by the WEIM benefits, the Company has been able to provide significant benefits to customers by maximizing participation in the WEIM.

36. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

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

EXHIBIT TAYLOR-DIRECT-1

QUALIFICATIONS OF WITNESS

Vernon W. Taylor
Director, Trading Operations
6226 West Sahara Ave.
Las Vegas, NV 89151-001
(702) 402-5864

Employment History

NV Energy, Las Vegas, NV
Director, Trading Operations – Resource Optimization
June 2023 – Present

- Lead the functions related to the hourly economic unit commitment and economic dispatch planning used to serve the Companies' native load requirements.
- Oversee the functions related to the Companies' real-time participation in the California Independent System Operator's Energy Imbalance Market.
- Oversee the real-time power trading function.

NV Energy, Las Vegas, NV
Manager, Portfolio Analytics – Resource Optimization
April 2021 – May 2023

- Oversaw functions related to the optimization of energy supply resources from month-ahead planning to forward optimization, forward purchases, and forward sales transactions.
- Managed the development and execution of strategies to optimally dispatch the power portfolio and sell surplus capacity and energy.
- Oversaw the development of trading analytics and commercial operations trading support for energy marketing and origination.

NV Energy, Las Vegas, NV
Director, Market Analytics – Resource Optimization
January 2018 – March 2021

- Directed the development and execution of trading strategies to maximize the value of the Company's energy supply portfolio.
- Evaluated proposed market rules and market design changes that impact Resource Optimization's commercial operations including but not limited to the evolving energy imbalance market and potential organized market expansion.
- Evaluated proposed changes to tariffs, business practices, market policy and strategy that impact Resource Optimization's commercial operations.
- Coordinated with the Company's state and regulatory teams and legal counsel to develop and execute strategies.
- Developed comments and proactively participated in tariff, stakeholder, and other regulatory proceedings to advance market rules and market design changes.
- Represented Resource Optimization in public forums and regulatory proceedings to support justifications for energy transactions.

NV Energy, Las Vegas, NV
Director, Risk Control
November 2010 – December 2017

- Led the development, implementation, and periodic review of energy risk management policies and procedures.
- Establishing uniform standards within the corporation for risk assessment and measurement, including reporting requirements and evaluation techniques.
- Monitored compliance with policies and guidelines and communicated any deviations and exceptions to the appropriate authority.
- Presented and reported on the status of risk management initiatives to the Chief Risk Officer/Senior Leadership on a monthly basis and as developments occurred.
- Supported Nevada Power Company's and Sierra Pacific Power Company's Deferred Energy Accounting Adjustment Filings.

NV Energy, Las Vegas, NV
Manager, Short-Term Analysis - Resource Procurement
August 2001 – October 2010

- Led a team responsible for the development of strategies to optimally dispatch Nevada Power Company's and Sierra Pacific Power Company's power portfolio and sell surplus capacity and energy.
- Led a team responsible for the unit commitment and economic dispatch modeling of Nevada Power Company and Sierra Pacific Power Company's resource portfolio.
- Supported development of the Energy Supply Plan section of the Company's 20-year Integrated Resource Plan fillings.
- Supported Nevada Power Company's and Sierra Pacific Power Company's Deferred Energy Accounting Adjustment Filings.

Nevada Power Company, Las Vegas, NV
Senior Engineer - Resource Planning
July 2001 – August 2001

- Supported development of the Supply Side section of Nevada Power Company's and Sierra Pacific Power Company's 20-year Integrated Resource Plan filings.
- Conducted technical and economic evaluations of supply alternatives using supply-side planning methods and computer models.
- Updated and documented inputs to supply-side production costing and integrated corporate planning computed models.
- Contributed to NPC's and SPPC's annual team effort to purchase resources for the summer seasons by analyzing and evaluating purchase power proposals.

Nevada Power Company, Las Vegas, Nevada
Consultant - Business Planning and Growth
March 2000 – July 2001

- Senior analytical member of a new department created during corporate merger to align economic development with tactical planning and business analysis.

- Responsible for presenting the company's rate structure, corporate vision, and corporate goals to senior leadership of companies who were considering relocating their commercial businesses to southern Nevada.
- Coordinated commercial customer's plans to connect to Nevada Power Company's distribution system by working with the Distribution Planning Department all in an effort to reduce the customer's connection costs.

Sierra Pacific Energy Company, Las Vegas, NV
Structuring Analyst
September 1999 – March 2000

- Part of a small start-up group tasked with persuading eligible customers to switch energy providers under Nevada law (AB 661) which allowed eligible customers to purchase their energy and ancillary service requirements from an alternative provider.
- Made presentations to eligible customers explaining the provisions of the new law and how we could serve their needs.
- Analyzed customer load profiles and analyzed energy, capacity, and ancillary service requirements necessary to serve the potential customers.

Nevada Power Company, Las Vegas, NV
Supply-Side Planning Engineer – System Planning
June 1995 – September 1999

- Performed daily unit commitment analysis for the purpose of providing NPC fuels department day gas nominations and assessment of resource needs.
- Updated and documented inputs to supply-side production costing and integrated corporate planning computer models.
- Contributed to NPC's team effort to purchase resources on a monthly basis by analyzing, evaluating, and recommending system resource needs.
- Responsible for developing economic recommendations related to supply-side resource alternatives using PROMOD and other computer models.
- Responsible for the analysis, evaluation, recommendation, and documentation of Nevada Power Company's Summer Season Purchase Power RFP.
- Supported the development of the supply-side section of Nevada Power Company's Integrated Resource Plan filings.

Nevada Power Company, Las Vegas, NV
Engineer I, II, and III – Generation, Engineering, and Construction
November 1991 – June 1995

- Responsible for the activities related to the design, construction, and modification of Company power generating facilities.
- Supervised project installations, troubleshooting, and project startups.
- Designed the electrical system and controls system for the addition of the Seal Water Booster Pumps to the Reid Gardner 1-3 Ash Water System.
- Accountable for the design, bid preparations, bid evaluation and supervision of field installation of new construction and maintenance projects.

General Dynamics Corp., Pomona California
Test Requirements Engineer
June 1989 - March 1991

- Developed and implemented test requirements for the Phalanx Close-In Weapons System.
- Provided systems engineering support to enhance reliability, maintainability and performance of the Phalanx Close-in Weapons System and performed engineering analyses to determine the cause of fleet and factory test problems.
- Analyzed factory test data to identify potential mavericks and improve tolerance allocations.
- Wrote an instruction manual for the Phalanx Parameters Document Database Program and interfaced with Navy personnel by assisting the Phalanx Program Management Office.

Urban Chamber of Commerce – Board Member
January 2020 - Present

EDUCATION

- University of Nevada Las Vegas, Las Vegas, Nevada
  Master of Business Administration, May 1999

- Arizona State University
  Bachelor of Science, Electronic Engineering Technology, August 1988

CERTIFICATES

- Willamette University, Atkinson Graduate School of Management
  Utility Management Certificate Program, November 2006
- University of Idaho, Utility Executive Course, June 2013

EXHIBIT TAYLOR-DIRECT-2

EIM Quarterly Benefit Report Methodology

Effective with Q1 2021 EIM benefits report

Prior to the creation of this document, the methodology for the benefits calculation was posted in a technical bulletin and in the benefit report itself. This document consolidates these prior materials into a concise paper for easier understanding of how the EIM benefits are calculated.

The total EIM benefit is the cost saving of the EIM dispatch compared with a counterfactual (CF) without EIM dispatch. The counterfactual dispatch meets the same amount of real-time load imbalance in each BAA without EIM transfers between neighboring EIM BAAs. For an EIM BAA, the benefit can take the form of cost savings or profit or their combination. A BAA will be likely to have energy cost savings when the BAA is importing energy economically, or its base schedules are being optimized by the EIM. To the extent an entity base schedule is optimized prior its submission into the EIM, the benefits may be lessened when compared to an entity that has not submitted optimized base schedules into the EIM. A BAA will be likely to have an energy profit when the BAA is exporting energy economically to other BAAs and being paid a price higher than the bid cost. A BAA other than the ISO may also have a GHG profit when the resource is allocated GHG MWs and is receiving GHG revenue based on marginal GHG cost that is likely higher than its own GHG bid cost.

For each 5-minute interval, the **EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost.** The 5-minute level EIM benefits are then aggregated each month with a multiplier 1/12 to convert ($/5 min) to a dollar amount.

EIM Benefit Calculation Components

EIM Dispatch Cost

The total dispatch cost for a BAA for an interval is the sum of all the unit level EIM dispatch costs for that BAA for that interval.

For all BAAs other than CAISO, the dispatch cost only includes variable dispatch cost, i.e. the bids submitted by the corresponding Scheduling Coordinator.

For the ISO's long start units, we only consider variable dispatch cost. For the ISO's short start units, we use a generic cost formula, which includes variable dispatch cost, no load cost, and startup cost. Specifically, the three-part cost for short start units includes:

- The variable dispatch cost of RTD, which is equal to the bid cost associated with the delta instruction above or below the base schedule for each interval,
- the no load cost associated with the incremental dispatch, which is equal to the no load cost divided by Pmax, then multiplied by the delta instruction from the base schedule,
- The startup cost associated with the incremental dispatch, which is equal to the startup cost divided by the minimum online hours, then multiplied by the delta instruction from base schedule divided by the Pmax.

The purpose of this generic cost formula is to evaluate cost differences between EIM dispatches and counterfactual dispatches without performing sophisticated unit commitment simulations. Prior to Q1 2016, only variable dispatch cost was considered in the EIM benefit calculation. With NV Energy joining EIM and improving the transfer capabilities from and to the ISO, we observed a significantly increased transfer volume in EIM. The higher transfer volume cannot be sufficiently replaced by resources online in EIM without committing or de-committing resources, and hence the ISO adopted a three-part cost formula as of Q1 2016 to allow for unit commitment decisions to better evaluate the production difference between EIM and the counterfactual dispatch of the ISO. The unit commitment decisions were made only for short start units that were not combined cycle units. The combined cycle units have complicated models in EIM, so their counterfactual commitment status is fixed at the EIM commitment status to avoid oversimplification.

We approximate the ISO's commitment costs by converting the startup cost and no load cost into variable dispatch cost, assuming a committed short start resource will be fully loaded for minimum online hours. For each supply segment, the corresponding three-part variable cost is equal to

bid_price + no_load_cost/Pmax + startup_cost/min_up_hour/Pmax

Note the formula above converts startup cost (in unit $) and no load cost (in unit $/h) into variable dispatch cost (in unit $/MWh). By doing this, the commitment for the ISO's short start units can be determined based on the economic metric order of the three-part variable cost.

Transfer Cost

As a convention, select the importing direction as the default direction for a transfer, so the importing transfer is positive and the exporting transfer is negative. The transfer cost is equal to the transfer MW times the transfer price. For transfers involving the ISO in either the importing direction or the exporting direction, the transfer price is the other BAA's LMP plus the shadow price of the transfer. In doing this, the congestion rent on the transfer will be fully attributed to the other BAA. For transfers involving two BAAs that are not the ISO, the transfer price will split the congestion shadow price on the transfer in half. For an importing BAA, the transfer price is the LMP of the BAA minus half of the absolute value of the transfer shadow price. For an exporting BAA, the transfer price is the LMP of the BAA plus half of the absolute value of the transfer shadow price. The transfer could occur in both the 15-minute market and the 5-minute market. In this case, the transfer cost is 15-minute transfer * 15-minute transfer price + (5-minute transfer – 15-minute transfer) * 5-minute transfer price for each 5-minute interval.

For the prices (LMPs) used in the EIM benefits, the calculation uses the corresponding ELAP prices of each EIM area. For CAISO prices, the calculation uses the prices associated at the corresponding scheduling points at the Malin, Palo Verde, El Dorado or Rancho Seco interties. The specific scheduling price to be used among these intertie locations is in relationship to the benefit calculated to a specific EIM area. For instance, when calculating the benefits between PAC West and CAISO, the calculation will use Malin scheduling point price (CAISO side).

Flex Ramp Transfer Cost

In 2016, the ISO implemented the flexible ramping products to replace flexible ramping constraints. The flexible ramping products are available capacities to handle future load and generation uncertainties, and include both the upward ramping capacity and downward ramping capacity. They may be put aside in RTD to enhance dispatch flexibility. One BAA's flexible ramping capacities in RTD may be helping other BAAs. In this case, the BAA that exports flexible ramping products should receive payment from other BAAs to compensate the dispatch cost of keeping flexible ramping capacities, and the BAA that imports flexible ramping products should pay other BAAs to reflect its dispatch cost to handle future uncertainties. This is similar to how energy transfer is treated in the EIM benefit calculation. Energy transfer is explicitly modeled in EIM, while flexible ramping transfer is not. We need to calculate a BAA's flexible ramping transfer. First, we allocate the system flex ramp award to each BAA in proportion to its individual BAA requirement. Then we calculate the flex ramp transfer as the BAA's RTD flexible ramping award minus its allocated share. The flex ramp transfer cost is equal to the flex ramp transfer multiplied by the EIM whole footprint flex ramp shadow price.

Counterfactual Dispatch Cost

The counterfactual dispatch for an EIM BAA mimics the market operations without importing or exporting through the EIM transfers. The counterfactual dispatch moves units inside the BAA to meet the same real-time load imbalance as the EIM dispatch based on economic merit order without considering transmission constraints. For PacifiCorp, the transfer limit between PACE and PACW is enforced in the counterfactual dispatch.

Neglecting transmission constraints in a BAA tends to underestimate the EIM benefit. The magnitude depends on how significant the congestion is. Severe congestion impacting EIM benefits was not observed until October 2017, where transmission congestion happened between the generation in Wyoming and PACE's load in PacifiCorp. The impact of this congestion to the EIM benefit calculation can be demonstrated with the following example.

Assume in PACE, load increased 10 MW from the base schedule, generation decreased 100 MW from the base schedule, and PACE imported 110 MW in EIM. Note that energy is balanced in PACE with 110 MW of transfer import replacing 100 MW of generation and serving 10 MW of load above the base schedule. Assume the decremented generation cost is $20/MWh, and the import cost is $120/MWh. From an economic standpoint, the EIM dispatched the resources out-of-merit with high cost supply being incremented and low cost supply being decremented. If we were to calculate the EIM benefit ignoring the congestion effect, the benefit will be negative. The calculation is as follows:

> EIM dispatch cost = -100 MW * $20 = –$2,000.
>
> EIM transfer cost = 110 MW * $120 = $13,200.
>
> Counterfactual dispatch cost = 10 MW * $20 = $200.
>
> For simplicity, ignore flex ramp and GHG. The EIM benefit is calculated as $200 – (–$2,000 + $13,200) = –$11,000.

To better understand the root cause of the negative benefit, we break the calculated benefit into two components: infeasible base schedule and infeasible counterfactual.

1. Infeasible base schedule: In the EIM, the imported $120 transfer replaced 100 MW of $20 internal generation, and produced a negative benefit equal to 100*($20-$120) = -$10,000. The extra dispatch cost in EIM is not due to economics, but due to infeasible base schedules for certain constraints, which forces the EIM to mitigate congestion, and incurs additional cost. For this reason, we need to add the congestion management cost to the counterfactual dispatch cost to reflect the need to perform the same congestion management dispatch as in the EIM. In the example, we add $10,000 to the counterfactual dispatch cost.

2. Infeasible counterfactual: In the counterfactual, the merit order dispatch did not know that dispatching up the $20 generation would overload the transmission, and produced a negative benefit equal to 10*($20-$120) = -$1,000. The counterfactual should recognize the economic $20 supply is subject to transmission congestion, and cannot be dispatched. Therefore, in the counterfactual dispatch, for increased net load, we dispatch only supply offers with a bid price >= the transfer LMP. For decreased net load, we dispatch down only supply offers with a bid price <= the transfer LMP. In the example, the net load is 10 MW, so we only dispatch resources that bid above $120, assume these supplies cost $125/MWh.

With these two enhancements, we revise the benefit calculation as follows:

EIM dispatch cost = -100 MW * $20 = –$2,000.

EIM transfer cost = 110 MW * $120 = $13,200.

Counterfactual dispatch cost = 10 MW * $125 + $10,000 = $11,250.

The new EIM benefit is calculated to be $11,250 – (–$2,000 + $13,200) = $50.

These enhancements only apply when we detect significant congestion indicated by the LMP difference between the BA's ELAP and DGAP greater than a tolerance setting. Currently, the tolerance is set to $5/MWh.

The counterfactual dispatch makes unit commitment decisions only for the ISO's short start units. The unit commitment decisions are based on the generic three-part variable cost formula, which has converted startup cost and no load cost into variable dispatch cost, so unit commitment can be determined by the economic metric order of the three-part cost.

Prior to the 2016 Q4 report, we used the resources' RTD dispatching limits from the EIM in the counterfactual. The EIM dispatching limits are 10-minute ramp limited in RTD, and they may be overly constraining for the counterfactual theoretically. The counterfactual will replace the transfers with internal dispatches, but it does not need to do it within 10-minute timeframe. When EIM transfer volumes are moderate relative to the EIM dispatching range, this limitation may not be a real problem, because the EIM dispatch range is mostly sufficient to replace the transfers. As the EIM footprint increases, the transfer volume between BAAs also increases. We observed that some EIM transfers exceeded 1,000 MW frequently. The EIM dispatching range started to show its limitation. In Q4 of 2016, we expanded the resources' dispatching range to base schedule and FMM dispatching limits. From Q2 of 2017, we decided not to use EIM calculated limits. Instead, the dispatching range is constructed based on the resource's economic bid range in the following way:

a) Start with the resource's bid range [bid_MW_min, bid_MW_max]
b) Block the ancillary service provisions, so the new range is [bid_MW_min+reg_down, bid_MW_max – reg_up – spin – nonspin]
c) If the resource is a wind or solar resource, limit its upper limit by the forecasted output, so the new range is [bid_MW_min+reg_down, min(bid_MW_max – reg_up – spin – nonspin, wind or solar forecast)]

In cases where a counterfactual dispatch does not have sufficient supply offers to meet net load imbalance, we assign a penalty cost for procuring more energy. If the BA does not import from EIM, we extend its last economic bid segment. If the BA imports from EIM, we compare its last economic segment against the EIM LMP, and set the penalty price to the higher of the two. In summary, the penalty price per MWh is

- The highest offer price from the BA if the BA does not import from EIM,
- Max (the highest offer price from the BA, the transfer LMP) if the BA imports from EIM.

An EIM BAA may restrict the pool of dispatchable units in the counterfactual dispatch if that the BAA's practice prior to joining EIM was to balance real-time load from a limited pool.

ISO Counterfactual Dispatch

The ISO would need to meet load without EIM transfers in the counterfactual dispatch. The counterfactual dispatch is constructed in the following way:

1. Calculate the ISO's net EIM transfer;
2. Economically dispatch resources from the ISO to replace the transfer
   A. If the ISO is importing from the EIM,
      a. Find the ISO's undispatched supply with the variable cost (bid and three-part converted) greater than or equal to the reference transfer price;
      b. Sort and stack the supply by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the transfer megawatts
   B. If the ISO is exporting to the EIM,
      a. Find the ISO's dispatched supply with the variable cost (bid and three-part converted) less than or equal to the reference FMM transfer price;
      b. Sort and stack them by the variable cost from high cost to low cost; and

c. Clear the supply stack from high cost to low cost up to the transfer megawatts

The reference transfer price for the ISO is the maximum price of the incoming transfer points if the ISO is a net transfer importer, and the minimum price of the outgoing transfer points if the ISO is a net transfer exporter in RTD. Undispatched supply at lower bid cost than the reference price is dispatched out of merit when the ISO is importing transfer at the reference price. Dispatched supply at higher bid cost than the reference price is also dispatched out of merit when the ISO is exporting transfer at the reference price. The ISO has complex networks and constraints that are modeled in the EIM but not in the counterfactual. For example, supplies can be locally transmission constrained and undispatched in the EIM, which have available supply at lower bid cost than the LMP of the rest of the ISO. They should remain undispatched in the counterfactual even they have lower supply cost, because they are constrained by transmission. In the ISO's counterfactual dispatch, we only consider supplies above the reference transfer price to replace incoming transfer into the ISO, and thus preventing the transmission constrained lower cost supply being dispatched. Vice versa for the supplies below the reference transfer price to replace outgoing transfer. The counter factual dispatch (applies for whole EIM, not just the ISO) was based on 5-minute dispatch capability, and the reference price is the RTD price.

Counterfactual Dispatch

All EIM entities, with the exception of Pacificorp, have their counterfactual dispatch constructed in the following way. We will use NVE as an example.

1. Calculate the real-time net load imbalance for NVE;
2. Economically dispatch resources from NVE on top of the base schedules to meet NVE's net load imbalance
   - A. If the net load imbalance is positive,
     - a. Dispatch NV Energy's bid-in supply above base schedules;
     - b. Sort and stack them by the variable cost from low cost to high cost; and
     - c. Clear the supply stack from low cost to high cost up to the net load imbalance.
   - B. If the net load imbalance is negative,
     - a. Dispatch NV Energy's bid-in supply below base schedules;
     - b. Sort and stack them by the variable cost from high cost to low cost; and
     - c. Clear the supply stack from high cost to low cost up to the net load imbalance.

PacifiCorp Counterfactual Dispatch

PacifiCorp East BAA and PacifiCorp West BAA would need to meet demand without intra-hour transfers between PacifiCorp and the ISO, but transfers could occur between PACE and PACW in the counterfactual dispatch. The PacifiCorp counter factual dispatch will be constructed in the following way:

1. Calculate the real-time net load imbalance for each BAA;
2. Economically dispatch resources from PacifiCorp on top of the base schedules to meet net PacifiCorp load imbalance without violating the transfer limitations between PACE and PACW.
   A. If the net load imbalance is positive,
      a. Find PacifiCorp's bid-in supply above base schedules;
      b. Sort and stack them by the variable cost from low cost to high cost; and
      c. Clear the supply stack from low cost to high cost up to the net load imbalance subject to the transfer limit between PACE and PACW
   B. If the net load imbalance is negative,
      a. Find PacifiCorp's bid-in supply below base schedules;
      b. Sort and stack them by the variable cost from high cost to low cost; and
      c. Clear the supply stack from high cost to low cost up to the net load imbalance subject to the transfer limit between PACE and PACW

GHG Revenue

Greenhouse gas (GHG) revenue for a resource is equal to its GHG allocation MW times the GHG price.

GHG Cost

GHG cost for a resource is equal to its GHG allocation MW times its GHG bid.

Example

This example illustrates how the EIM benefit is calculated.

The transfers out of the EIM optimization are listed in Table 1. Base scheduled transfers have been excluded in the FMM transfers and RTD transfers.

From BAA	To BAA	FMM transfer	FMM transfer price	RTD incremental transfer	RTD transfer price	Transfer cost
PACE	NEVP	140	$26	10	$25	$3,890
NEVP	CISO	160	$26	20	$30	$4,760
PACE	PACW	190	$26	10	$25	$5,190

PACW	CISO	110	$26	-10	$30	$2,560

Table 1. An example of BAA to BAA transfers and prices

Assume the EIM energy imbalance and prices are as follows. Every BAA is balanced with Gen + Transfer – Load = 0. Assume the EIM optimization results in $1 GHG price, which means the ISO's LMP is $1 higher than the neighboring BAA (NEVP and PACW), because there is no congestion going into the ISO in the example. In the table below, positive transfer MW means the BAA is importing and negative transfer MW means it is exporting. Also, transfers in the table are sum of the transfers occur in both the FMM and the RTD with base scheduled transfer being excluded.

BAA	Gen	Load	Net transfer in MW	LMP	GHG price
CISO	0	280	280	$31	$1
NEVP	50	20	-30	$30	
PACE	150	-200	-350	$20	
PACW	100	200	100	$30	

Table 2. EIM energy imbalance and prices by BAA for one 5-minute interval

Transfer Cost

The transfers occur in both FMM and RTD, and their volume and prices are listed in Table 3. They are calculated from applying the convention that importing is positive and exporting is negative the BAA to BAA transfers, and summing them over all the neighboring BAAs.

BAA	transfer cost
CISO	$7,320 = $4,760+$2,560
NEVP	($870) = $3,890-$4,760
PACE	($9,080) = -$3,890-$5,190
PACW	$2,630 = $5,190-$2,560

Table 3. EIM transfer cost by BAA

For flex ramp, we calculate its transfer and transfer cost in Table 4.

BAA	Direction	Req.	Award	Allocation	Flex ramp transfer in	Flex ramp price	Flex ramp transfer cost

CISO	upward	150	100	75	-25	$1	-$25
NEVP	upward	10	0	5	5	$1	$5
PACE	upward	20	0	10	10	$1	$10
PACW	upward	20	0	10	10	$1	$10
CISO	downward	0	0	0	0	$2	$0
NEVP	downward	10	10	2	-8	$2	-$16
PACE	downward	20	0	4	4	$2	$8
PACW	downward	20	0	4	4	$2	$8

Table 4. Flex ramp transfer example

EIM Dispatch Cost

Now calculate the total bid cost associated with the EIM dispatches (delta from base schedules). The EIM dispatch costs are listed in Table 5.

BAA	Gen_EIM	EIM dispatch cost
CISO	0	$0
NEVP	50	$1,450
PACE	150	$2,700
PACW	100	$2,800

Table 5. EIM dispatch cost by BAA

Counterfactual Dispatch Cost

Then construct the counterfactual dispatches as described in the previous section, and sum up the counter factual dispatch cost for each BAA as shown in Table 6.

BAA	Gen_CF	Counterfactual dispatch cost
CISO	280	$9,240
NEVP	20	$640
PACE	-200	($3,800)

PACW	200	$6,200

Table 6. Counterfactual dispatch cost by BAA

GHG Cost and Revenue

The GHG costs associated with the 280 MW of importing transfer into CISO, and the revenues received by the GHG allocated MWs in both FMM and RTD are listed in Table 7.

BAA	GHG FMM MW	GHG RTD MW	GHG cost	GHG revenue
CISO	270	280	$0	-$280
NEVP	0	0	$0	$0
PACE	200	200	$20	$200
PACW	70	80	$75	$80

Table 7. GHG cost and revenue by BAA

EIM Benefit

With all the cost and revenue for each BAA available, we can use the formula EIM benefit for a BAA = counterfactual dispatch cost – (EIM dispatch cost + transfer cost + flex ramp transfer cost) + GHG revenue – GHG cost to calculate EIM benefit for each BAA. The results are shown in Table 8.

BAA	CF dispatch cost	EIM dispatch cost	Transfer cost	Flex transfer cost	GHG cost	GHG revenue	EIM benefit
CISO	$9,240	$0	$7,320	($25)	$0	($280)	**$1,665**
NEVP	$640	$1,450	($870)	($11)	$0	$0	**$71**
PACE	($3,800)	$2,700	($9,080)	$18	$20	$200	**$2,742**
PACW	$6,200	$2,800	$2,630	$18	$75	$80	**$757**

Table 8. EIM benefit for one 5-minute interval

This calculation is performed for each 5-minute interval with unit $/hr. We convert the $/hr benefit into the dollar benefit by multiplying 1/12. Then the 5-minute interval benefits in dollar amount can be aggregated into the monthly benefit by summing all the 5-minute intervals in the month.

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, VERNON W. TAYLOR, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2024

VERNON W. TAYLOR

VINCENT VITIELLO

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Vincent Vitiello

1. Q. PLEASE STATE YOUR NAME, JOB TITLE, EMPLOYER, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Vincent Vitiello. I am the Gas Supply Planning Lead for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra" or the "Company" and together with Nevada Power, the "Companies" or "NV Energy"). My business address is 6226 West Sahara Avenue, Las Vegas, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. My professional experience includes more than 30 years in the utility and power generation industries. I have a Bachelor of Engineering degree with a concentration in mechanical engineering and have worked for the Companies since 2006.

Prior to joining the Companies, I was employed for six years by Chevron Corporation ("Chevron") as the Assistant Executive Director at Nevada Cogeneration Associates #1 and Nevada Cogeneration Associates #2. Prior to that, I worked at Southwest Gas Corporation ("SWG") for 14 years, in the major accounts and engineering departments. Prior to that, my first career position was as an engineer at Exxon Company, U.S.A. in the refining and oil and natural gas production areas. More details regarding my background and experience are provided in **Exhibit Vitiello-Direct-1.**

3. Q. WHAT ARE YOUR RESPONSIBILITIES AS GAS SUPPLY PLANNING LEAD?

A. As the Gas Supply Planning Lead, I am primarily responsible for the short and long-term planning of the Companies' natural gas transportation and storage assets necessary to ensure the adequate supply of natural gas to the Companies' generation plants and to Sierra's gas distribution system. I am also responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions.

4. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, I support the Company's portfolio of gas transportation assets for the period of January 1, 2023, through December 31, 2023 (the "Deferral Period").

5. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Vitiello-Direct-1	Statement of Qualifications
Exhibit Vitiello-Direct-2	Gas Transportation Contract Summary

6. Q. DID THE COMPANY HAVE ADEQUATE GAS TRANSPORTATION ASSETS FOR THE DEFERRAL PERIOD?

A. Yes, a list of the Company's gas transportation agreements is provided in **Exhibit Vitiello-Direct-2**. The Company's primary points of delivery for gas supplies were from Great Basin Gas Transmission Company ("Great Basin"), formerly Paiute Pipeline Company, and TC Energy-Tuscarora Pipeline ("Tuscarora"). Great Basin interconnects upstream to Williams Gas Pipelines-Northwest ("Northwest") for gas supplies. Northwest derives its gas supplies from the San Juan and Rocky Mountain gas supply basins in New Mexico, Wyoming, Utah and Colorado, as well as Canadian gas supplies sourced from British Columbia, Canada. Tuscarora receives gas supplies from TC Energy-Gas Transmission Northwest Pipeline ("GTN"), which is connected to the gas-producing regions of Alberta, Canada. The TC Energy-Alberta System ("Alberta") carries supplies from the producing areas to the Alberta/British Columbia border. From there, the Alberta System interconnects with the TC Energy- Foothills System ("Foothills"), and then to GTN at the U.S.-Canada border near Kingsgate, Idaho. Sierra also has natural gas storage capacity at the Jackson Prairie Storage Facility and gas transportation assets in and around the Jackson Prairie Storage Facility. The Jackson Prairie Storage is on the Northwest Pipeline.

The Company's gas transportation and storage agreements ensure reliability and adequate access to a diverse mix of gas supply basins while gas storage allows the Company to respond quickly to real time weather-related load conditions in a reliable manner. The Company used these transportation and storage assets in an efficient and appropriate manner to provide service to its customers during the Deferral Period.

7. Q. DID THE COMPANY EXTEND ANY OF ITS GAS TRANSPORTATION AGREEMENTS FOR A PERIOD OF MORE THAN ONE YEAR?

A. Yes, the Company renewed its evergreen natural gas transportation agreements with Northwest Pipeline which require yearly renewal. Evergreen is a contract provision that automatically renews the agreement for a predetermined period, unless notice for terminations is given.

8. Q. DID THE COMPANY ADD ANY GAS TRANSPORTATION AGREEMENTS DURING THE DEFERRAL PERIOD?

A. No.

9. Q. DID ANY OF THE PIPELINES SIERRA HAS GAS TRANSPORTATION AGREEMENTS WITH CONCLUDE A RATE CASE DURING THE DEFERRAL PERIOD?

A. Yes, Tuscarora Pipeline filed a rate case at FERC on July 29, 2022. A settlement agreement in principle was reached between Tuscarora, the Company and other stakeholders on March 1, 2023. The settlement decreased Tuscarora's existing base firm transportation rate by 6 percent with the lower rate effective February 1, 2023. The settlement also establishes a rate moratorium through December 1, 2028 and a comeback requirement date of November 1, 2030.

10. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT VITIELLO-DIRECT-1

Vincent J. Vitiello
6226 West Sahara Avenue
Las Vegas, Nevada 89146
(702) 402-2991

Employment History

NV ENERGY

GAS SUPPLY PLANNING LEAD – RESOURCE OPTIMIZATION – LAS VEGAS, NV
2019 – Present

- Responsible for short and long-term planning of the Company's natural gas transportation and storage assets necessary to ensuring adequate gas supply to the Company's generation plants and to Sierra's gas distribution system.
- Responsible for reviewing and monitoring pipeline filings, negotiating rate case settlements, and supporting related efforts before the Federal Energy Regulatory Commission (FERC) and state regulatory commissions.

STAFF ANALYST/ ENGINEER – RESOURCE PLANNING DEPARTMENT – LAS VEGAS, NV
2007 – 2019

- Perform technical analysis and evaluation of the capital cost, production cost, and reliability of various transmission, generation, purchase power, and demand side alternatives being considered by the Company.
- Project management of regulatory filings submitted to the Public Utilities Commission of Nevada. Assist in the preparation of testimony and exhibits and respond to data requests.

SENIOR COMPLIANCE CONSULTANT – COMPLIANCE DEPARTMENT – LAS VEGAS, NV
2006 – 2007

- Assisted in the establishment, implementation and monitoring of an effective compliance program.
- Audited several departments to insure Sarbanes-Oxley compliance.

CHEVRON CORPORATION

ASSISTANT EXECUTIVE DIRECTOR – NEVADA COGENERATION ASSOCIATES #1 AND #2
LAS VEGAS, NEVADA
2000 – 2006

- Responsible for the engineering activities of two 85 MW cogeneration facilities which provided electricity to Nevada Power Company under long-term contracts.
- Coordinated all environmental compliance, including Title V air permits.
- Assisted in the operations and maintenance of the facilities to insure safe operations and optimized plant performance.

SOUTHWEST GAS CORPORATION

SUPERVISOR – MAJOR ACCOUNTS DEPARTMENT – LAS VEGAS, NV
1993 – 2000
- Supervised the activities of Industrial Gas Engineers in Nevada, Arizona and California.
- Coordinated and administered natural gas supplies and interstate transportation service to power generation, large industrial and commercial customers.
- Developed programs to maintain or increase the corporate margin from power generation, large industrial and commercial customers.

INDUSTRIAL GAS ENGINEER – MAJOR ACCOUNTS DEPARTMENT – PHOENIX, AZ
1989 – 1993
- Maintained contact and provided technical assistance for power generation, large industrial and commercial gas customers.
- Negotiated contracts for customers served under transportation and optional fuel rate schedules.
- Promoted natural gas technology including cogeneration, natural gas air-conditioning and compressed natural gas vehicles.

ENGINEER – ENGINEERING DEPARTMENT – PHOENIX, AZ
1986 – 1989
- Designed gas distribution facilities including high pressure and distribution gas piping, regulating stations, meter sets and telemetry.
- Provided work direction and conducted the performance reviews for several Engineering Technicians and Drafters.
- Special projects included an emergency valve isolation plan and over-pressure protection review.

EXXON COMPANY, U.S.A.

SENIOR PROJECT ENGINEER – PRODUCTION DEPARTMENT – CORPUS CHRISTI, TX
1982 – 1986
- Designed oil and gas production facilities including gathering lines, oil storage sites and separation and metering stations. Responsible for the design, material specification, cost estimating and project management necessary during construction.

MECHANICAL CONTACT ENGINEER – REFINING DEPARTMENT – BAYTOWN, TX
1980 – 1982
- Responsible for maintaining the operation of several refinery process units. Duties included solving daily maintenance problems as well as designing and implementing quality and production improvements. This assignment provided extensive experience with heat exchangers, furnaces, pumps and compressors.

EDUCATION

STEVENS INSTITUTE OF TECHNOLOGY – HOBOKEN, NEW JERSEY
- Bachelor of Engineering – with Honor, awarded May 1980
- Major: Mechanical Engineering

EXHIBIT VITIELLO-DIRECT-2

Sierra Pacific Power Company d/b/a NV Energy
Gas Transportation and Storage Agreements

Contract Type	Counterparty	Contract #	Termination Date (as of 12/31/2023)	Units	Maximum Daily Quantity Annual	Winter	Summer
TSA							
	TC Energy - Alberta System						
		2010-447962	10/31/2025	GJ/Day	18,583		
		2010-447963	10/31/2025	GJ/Day	92,918		
		2010-447964	10/31/2025	GJ/Day	25,993		
					137,494		
	TC Energy - Foothills System						
		SPP-F1	10/31/2025	GJ/Day	32,444		
		SPP-F2	10/31/2025	GJ/Day	2,143		
		SPP-F3	10/31/2025	GJ/Day	5,572		
		SPP-F4	10/31/2025	GJ/Day	16,220		
		SPP-F5	10/31/2025	GJ/Day	10,920		
		SPP-F6	10/31/2025	GJ/Day	866		
		SPP-F7	10/31/2025	GJ/Day	26,233		
		SPP-F8	10/31/2025	GJ/Day	10,000		
		SPP-F9	10/31/2025	GJ/Day	15,826		
		SPP-F10	10/31/2025	GJ/Day	15,807		
					136,031		
	TC Energy - GTN						
		F-02842	10/31/2029	MMBTU/Day		60,000	30,000
		F-02843	10/31/2029	MMBTU/Day		20,270	10,000
		F-07027	4/30/2031	MMBTU/Day		20,000	
		F-07328	10/31/2029	MMBTU/Day	14,000		
		F-07370	10/31/2035	MMBTU/Day	15,000		
		F-07371	10/31/2035	MMBTU/Day	10,099		
		F-07567	10/31/2035	MMBTU/Day	800		
					39,899	100,270	40,000
	Northwest Pipeline						
		10046	6/30/2024	MMBTU/Day	59,696		
		10061	3/31/2024	MMBTU/Day	9,000		
					68,696		
	Great Basin Gas Transmission						
		F-29	11/30/2024	MMBTU/Day		68,696	61,044
		F-32	3/31/2025	MMBTU/Day		23,000	
						91,696	61,044
	TC Energy - Tuscarora						
		F001	12/31/2032	MMBTU/Day	105,750		
		F019	12/31/2032	MMBTU/Day	10,000		
		F024	12/31/2032	MMBTU/Day	5,661		
		F025	12/31/2032	MMBTU/Day	5,690		
		F030	12/31/2032	MMBTU/Day	5,722		
		F097	9/30/2030	MMBTU/Day	40,000		
		369	9/30/2030	MMBTU/Day	760		
					173,583		
Storage							
	Northwest Pipeline						
		126544 Storage Capacity	3/31/2046	MMBTU	281,242		
		126544 Storage Withdraw	3/31/2046	MMBTU/Day	12,687		
	Great Basin Gas Transmission						
		S-6 LNG Stor Cap	3/31/2025	MMBTU	303,604		
		S-6 LNG Daily Del Cap	3/31/2025	MMBTU/Day		23,000	

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, VINCENT VITIELLO, states that he is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2024

VINCENT VITIELLO

KIM WHETZEL

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy (Electric)
Docket No. 24-03___
2024 Deferred Energy Proceeding
Prepared Direct Testimony of

Kim Whetzel

I. <u>INTRODUCTION AND PURPOSE OF TESTIMONY</u>

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Kim Whetzel. My current position is Director, Grid Operations and Reliability, for Nevada Power Company d/b/a NV Energy ("Nevada Power") and Sierra Pacific Power Company ("Sierra" or the "Company" and, together with Nevada Power, the "Companies"). My business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I have been employed by the Companies for 24 years. I received my Bachelor of Applied Science degree in Energy Management in 2015 from Bismarck State College, North Dakota. I began my career at the Companies as a Clerical Specialist in 1999 in Land Operations. Since then I have worked as an Accounts Payable Representative, Utility Material Specialist, Transmission/Distribution System Operator, and Manager of Transmission & Distribution Operations. I am currently working as the Director of Grid Operations and Reliability. A copy of my statement of qualifications is provided as **Exhibit Whetzel-Direct-1**.

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR, GRID OPERATIONS AND RELIABILITY.

A. As the Director of Grid Operations and Reliability, my responsibilities include administration of the Companies' Balancing, Transmission, Distribution, Scheduling and Trouble Operations. This includes safe, reliable, and compliant operation of the Companies' electric transmission and distribution systems conducted through electric system control centers, balancing authority operations, operations engineering, network engineering and outage management. I am also responsible for some of the Companies' California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM") activities. Specifically, I am responsible for the Companies' EIM Entity functions. The EIM Entity is responsible for facilitating EIM participation while managing the Companies' safety, reliability, and mandatory compliance.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("COMMISSION")?

A. Yes. I previously testified in the Companies' deferred energy proceedings in 2023, in Docket Nos. 23-03005 and 23-03006.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I explain the procedures that the Company has in place to balance loads and resources, and I support the prudence of those procedures and activities completed pursuant to those procedures. I also discuss the Company's participation in the EIM. Finally, I discuss operational changes as a result of the EIM operations.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

Exhibit Whetzel-Direct-1	Statement of Qualifications
Exhibit Whetzel-Direct-2	NV Energy NERC Reliability Compliance Plan[1]
Exhibit Whetzel-Direct-3	NERC CMEP Implementation Plan[2]

II. <u>SHORT-TERM TRADES MADE TO SUPPORT SYSTEM RELIABILITY</u>

7. Q. PLEASE EXPLAIN THE SEPARATION BETWEEN THE COMPANY'S RESOURCE OPTIMIZATION DIVISION AND ITS TRANSMISSION DIVISION.

A. The separation dates back to 1996 when the Federal Energy Regulatory Commission ("FERC") issued Order Nos. 888 and 889. FERC Order No. 888 required all public utilities that own transmission facilities used for the transmission of electric energy in interstate commerce to file an Open Access Transmission Tariff ("OATT") for the provision of non-discriminatory transmission service. The order did not require corporate restructuring but did require the functional unbundling of wholesale power marketing from transmission. Order No. 889 required public utilities to create an Open Access Same-Time Information System ("OASIS") and to implement Standards of Conduct. FERC explained that open access transmission service requires that information about the transmission system be made available to all transmission customers at the same time.

In accordance with these FERC orders, the Resource Optimization organization is functionally separated from the Transmission function. Resource Optimization

[1] NERC refers to the North American Electric Reliability Corporation, which is an institution that oversees and regulates the reliability of the North American electrical grids.

[2] CMEP refers to NERC's compliance monitoring and enforcement program.

reports to the Vice President, Resource Optimization, while Transmission reports to the Vice President, Transmission. Resource Optimization schedules its wholesale transactions through OASIS and obtains transmission information in the same manner as other transmission customers. Resource Optimization also participates in the EIM as a Participating Resource Scheduling Coordinator for Company-owned and operated generation resources, and bids those resources into the EIM independent of EIM Entity activities performed by the Transmission business unit.

8. Q. PLEASE GENERALLY DESCRIBE THE FERC STANDARDS OF CONDUCT.

A. The FERC Standards of Conduct established by Order No. 889 were designed to ensure that a public utility's employees, engaged in transmission system operations, function independently from the public utility's employees engaged in wholesale purchases and sales of electric energy. The Standards of Conduct prohibit the Transmission function from disclosing non-public information about the transmission system to its wholesale power marketing group through non-public communications conducted off the OASIS. There was litigation surrounding FERC Order 889, and questions were raised as to whether the Standards of Conduct would interfere with system reliability. FERC stated that it was not the purpose of these rules to compromise reliability and that, in emergency circumstances affecting system reliability, transmission system operators would be permitted to take whatever steps were necessary to keep the system in operation, even if these steps would otherwise constitute a violation of the Standards of Conduct.

9. Q. WHO IS RESPONSIBLE FOR SYSTEM RELIABILITY?

A. As a Balancing Authority ("BA") and Transmission Operator ("TOP"),[3] the Company's Transmission function is responsible for reliable system operation. The Energy Policy Act of 2005 gave FERC new responsibilities regarding the establishment of mandatory reliability standards. In response, in Order No. 672 FERC certified the North American Electric Reliability Corporation ("NERC") as the Electric Reliability Organization responsible for developing and enforcing mandatory reliability standards. NERC developed (and FERC accepted in Order No. 693) various mandatory reliability standards as well as NERC's Glossary of Terms used in Reliability Standards. The BA is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a specific metered area (known as the Balancing Authority Area or BAA) and supports interconnection frequency in real time. The BAA is the collection of generation, transmission and loads within specific metered boundaries over which the BA has responsibility.

10. Q. PLEASE EXPLAIN THE "SYSTEM RELIABILITY" CRITERIA WITH WHICH THE COMPANY MUST COMPLY IN OPERATING ITS TRANSMISSION SYSTEM AND BA AREA.

A. The Company is recognized by NERC and the Western Electricity Coordinating Council ("WECC") as performing numerous functions defined in the NERC Functional Model pertaining to the operation of the North American Bulk Electric System. Accordingly, the Company is legally required to comply with all NERC and WECC Reliability Standards applicable to the functions for which the

---

[3] A Transmission Operator refers to the entity that is responsible for the reliability of its "local" transmission system and the entity that operates or directs the operations of transmission facilities.

Company is registered. In the context of this discussion, the most pertinent among these functions are TOP and BA functions.

Within the TOP and BA functional areas, the Company complies with the Reliability Standards, which require, among other things, the following:

1) Continuous balancing of BAA load and resources;
2) Maintenance of a minimum amount of operating reserves;
3) Re-establishment of balance within 15-minutes following a sudden loss of generating resources;
4) Operation of transmission facilities within established operating limits; and
5) Operation such that grid instability, uncontrolled separation or cascading outages shall not result from the most severe single contingency.

11. Q. PLEASE DESCRIBE THE CIRCUMSTANCES UNDER WHICH IT MAY BECOME NECESSARY FOR THE COMPANY TO EXECUTE SHORT-TERM TRADES TO SUPPORT SYSTEM RELIABILITY.

A. From a transmission system reliability standpoint, a number of circumstances may necessitate the execution of short-term energy transactions or adjustments to planned transactions. These circumstances include unexpected loss of generation due to forced outages or capacity constraints, actual loads being higher than forecasted and transmission constraints due to forced outages or other unanticipated contingencies concerning transmission facilities inside or outside the Company's transmission network. Additionally, due to larger concentrations of renewable generation, primarily solar, occasional seasonal oversupply can occur during low load conditions.

In any of these circumstances, the transmission system may enter a condition where, absent an adjustment to short-term transactions, one or more of the requirements of the NERC Reliability Standards will be violated. Operation in violation of the NERC Reliability Standards poses undue risk to the reliable and secure operation of the Bulk Electric System, and also can result in monetary sanctions for non-compliance. When there is a negative imbalance between load and resources, and generating unit output cannot be increased, the Company procures additional resources to regain such balance and restore the required reserve margins. On the other hand, when resources exceed actual load, and generating unit output cannot be lowered, the Company may curtail the delivery of purchased energy to restore balance, or the Company may have to sell surplus resources to regain balance. When such imbalances occur within the hour, the Company may restore balance through its participation in the EIM when established resource sufficiency tests have been met.

12. Q. PLEASE PROVIDE EXAMPLES OF SHORT-TERM TRANSACTIONS OR ADJUSTMENTS THAT WOULD HAVE BEEN TYPICAL FOR THE COMPANY TO EXECUTE FOR RELIABILITY REASONS DURING THE DEFERRAL PERIOD.

A. Listed below are several typical examples of situations where system reliability issues have necessitated the execution of short term transactions:

Shortage of Operating Reserve: Occurring during real-time system operation, the generation and purchased power resources currently in use are insufficient to uphold the amount of Operating Reserve required by the NERC ("BAL") Standards. The Company's transmission system can enter this state for a variety of reasons including: higher actual load compared to forecast, generating units not being available as planned or pre-scheduled, unexpected generating unit outages, unexpected deviations from forecasted production of renewable resources, or energy transaction curtailments. In order to promptly restore the required Operating Reserve, the Company typically secures additional hourly energy, which allows other generating resources to reduce their output, thereby regaining a corresponding amount of reserve capacity to satisfy the BAL requirements. Alternatively, the Company may dispatch additional generation resources, for instance, a combustion turbine generator, to restore Operating Reserve.

Transmission Constraints: The pre-scheduled transactions necessary for load service have been curtailed due to unforeseen transmission conditions either within or external to the Company's transmission system. Re-supply of the curtailed transaction takes the form of a replacement short-term transaction on an alternate transmission path or re-dispatch of generation if available.

Physical Limits of Generating Unit Load Ramp: Hourly net area interchange schedules are planned such that system generating resources can be ramped upward and downward as necessary to maintain continuous balance within the BAA. There are practical limits impacting how quickly generating resources can ramp up and down, and hence, there are limits to the hourly change of the aggregate net system interchange. At times, the ramp capability of the available generating resources is insufficient to maintain the required balance, and short-term purchases must be made to reduce the amount of hourly change in the output of the generation fleet. This is also known as "smoothing the ramp."

13. Q. PLEASE DESCRIBE THE POLICIES AND PROCEDURES THAT GOVERN DECISIONS TO EXECUTE SHORT-TERM TRADES TO SUPPORT SYSTEM RELIABILITY.

A. The Company's Transmission and Balancing Operators adhere to all applicable NERC and WECC standards and operating practices. The Company has established a FERC Compliance Plan, which includes an appendix specific to compliance with the NERC Reliability Standards provided in **Exhibit Whetzel-Direct-2**. Further, the Company is subject to the WECC Compliance Monitoring and Enforcement Program, which includes self-certification, spot-check audits and formal compliance audits to ensure that full compliance is continuously demonstrated, see **Exhibit Whetzel-Direct-3**. In keeping with the Company's obligation to comply with these standards, short-term transactions may be directed by system operators as necessary to maintain compliance.

III. NEVADA POWER BALANCING AUTHORITY JOINING THE CAISO EIM

14. Q. WHAT WAS THE PRIMARY REASON FOR THE BA TO JOIN THE CAISO EIM OPERATIONS?

A. The Commission approved the Companies' participation in the CAISO in Docket No. 14-04024. The decision to participate in the EIM was primarily based on direct financial benefits to the Companies' customers, improved electric system reliability, promotion of renewable energy integration and enhanced system visibility. The Companies began participation in the CAISO EIM in December 2015, and Nevada Power was designated as the BA and TOP for the Companies.

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

15. Q. DID THE EIM OPERATIONS CHANGE THE COMPANY'S RELIABILITY AND COMPLIANCE OBLIGATIONS?

A. No. The Company, as a BA and TOP, maintains its authority and responsibility as a reliability entity. As such, the Company remains responsible for mandatory compliance with NERC and WECC Reliability Standards, and is responsible for its reliability related services and meeting compliance obligations. In addition, the BA may manually dispatch units when necessary for reliability purposes even if contrary to the dispatch signals from CAISO EIM operations.

16. Q. HOW DOES THE CAISO EIM AID IN IMPROVING ELECTRIC SERVICE RELIABILITY FOR THE COMPANY?

A. As a participant in the CAISO, the Company has access to a wider pool of energy resources to manage natural intra-hour load deviations caused by changes in forecast and changes in the output of variable energy resources, such as solar, geothermal and wind based renewable generation. The Company also provides the EIM with a detailed model of its transmission system, allowing for redundant monitoring of potential congestion across its transmission system (through the Company's and CAISO models running congestion analysis, simultaneously).

17. Q. HOW DOES THE EIM OPERATE?

A. The CAISO EIM is a combination of two market models. The 15-Minute Market ("FMM") commits and dispatches the resources available to the market to balance against the BAA load forecast for every 15-minute period. A more granular Real Time Dispatch ("RTD") dispatches the available resources to the EIM to balance against the BAA's load forecast for each five-minute period within the FMM. The EIM-based dispatch of resources takes into account the regional transmission system availability to provide congestion relief, and dynamically transfers energy between participating BAAs based on market economics and transmissions system availability.

18. Q. HOW ARE RENEWABLE ENERGY RESOURCES MANAGED WITHIN THE EIM?

A. The BA provides a five-minute forecast for all variable energy resources, including all solar, geothermal and wind generation within the Company's BAA, to the EIM. The forecast is updated every five minutes, providing an accurate account for any changes in the renewable energy output. This allows the EIM to manage any resulting imbalances through RTD of resources available to the EIM. The Company uses an independent service provider for forecasting of variable energy resources for the EIM, and the variable energy resource forecast is provided directly to the CAISO.

19. Q. WHAT IS AN EIM ENTITY AND WHO PERFORMS THE FUNCTIONS OF EIM ENTITY ON BEHALF OF NV ENERGY?

A. The EIM Entity is the BA responsible for facilitating the EIM operations for participating resources within its BAA. The EIM Entity is also responsible for facilitating the operation of non-participating resources, as well as managing settlements associated with EIM charges and credits. For the Company, the Transmission organization is the EIM Entity.

20. Q. EXPLAIN EIM TIMELINE FOR OPERATIONS.

A. The FMM divides each operating hour into four segments. Each 15-minute segment is treated as an independent resource commitment and balancing opportunity. With the first 15-minute segment starting at the top of the operating hour (T), the EIM optimization run is initiated 37.5 minutes prior to the start of the operating hour (T-37.5 minutes) based on the EIM Entity's submission of balanced schedules for the hour. The EIM tariff requires that the BA, acting as the EIM Entity, submit balanced schedules for the operating hour to the Market Operator (the CAISO) at least 40 minutes prior to the start of the operating hour (T-40 minutes). This ensures that each EIM Entity comes into the market fully balanced, and the EIM Operator is only responsible for natural intra-hour deviations in load and resources. Each FMM is further divided into three five-minute segments for RTD. Market instructions are provided for participating resources for each five-minute period, to ensure optimal balance of resources and load every five minutes.

21. Q. HOW DOES THE COMPANY ENSURE THAT THE RELIABILITY NEEDS OF ITS BAA ARE MET IN THE EIM?

A. Based on the EIM requirement to have the balanced schedules available to the market no later than 40 minutes prior to the start of the operating hour (T-40 minutes), all Participating Resource Scheduling Coordinators ("PRSCs") and Non-Participating Base Scheduling Coordinators ("NP BSCs") are required to have the resource schedules available to the EIM Entity no later than 57 minutes prior to the operating hour (T-57 minutes). For the Nevada Power BA, this means that the Resource Optimization team (the Company's PRSC) must submit a schedule to the Transmission organization by T-57. All Load Serving Entities ("LSE") within the Company's BAA must also provide a balanced schedule of resources against the LSE forecasted load. Based on the available schedules, the EIM Operator conducts balancing tests to verify the Nevada BAA's reliability balance at 55 minutes prior to the operating hour (T-55 minutes). The EIM Operator then provides the results of these reliability tests to the EIM Entity. Only the BA (that is, the Transmission organization) acting as the EIM Entity, has the ability to make any changes to the resource schedules from 55 minutes prior to the start of the operating hour to 40 minutes prior to the start of the operating hour. The EIM Entity (i.e., the Transmission organization) uses the period from T-55 minutes to T-40 minutes to ensure that all reliability standards are met, and the resources are balanced against the most current load forecast.

22. Q. WHAT TYPE OF CHANGES ARE MADE BY THE EIM ENTITY TO THE OPTIMIZED BASE SCHEDULES AFTER T-55?

A. The EIM Entity is ultimately responsible for safety, reliability, and compliance of BA operations. As such, the EIM Entity only makes changes to the economically optimized base schedules to ensure safety, reliability and compliance. Such practices allow for maximizing economic opportunities offered through the EIM while maintaining safe, reliable, and compliant operation of the BAA.

23. Q. HOW ARE THE COMPANY'S RELIABILITY NEEDS MET AFTER THE EIM TIMELINES?

A. The EIM Entity has the ability to make changes that may be required for reliability purposes to its resource portfolio at any time, including after T-40 submission of the balanced schedules for the T-37.5 EIM-area optimization. The EIM Entity retains the ability to make any needed reliability-based changes in real-time to load forecasts, resource schedules and transmission system availability as needed.

24. Q. WHAT IS AN EIM BALANCING TEST AND WHAT WAS THE COMPANY'S PERFORMANCE IN THE BALANCING TESTS?

A. The Market Operator assesses the scheduled resources against the most current load forecast 40 minutes prior to the start of the operating hour for each BAA participating in the EIM. The test is considered successful if the scheduled resources are within 1 percent of the BAA's load forecast. In 2023, the Company successfully passed 99.9 percent of the hourly balancing tests. For comparison, the Market Operator's FERC approved readiness criteria established a performance target of 90 percent.

25. Q. WHAT TYPE OF TESTS ARE CONDUCTED BY THE EIM OPERATOR AND WHAT ARE THE CONSEQUENCES OF NOT PASSING ONE OR MORE TESTS?

A. Each hour, the EIM Operator conducts four tests to ensure that the EIM Entity is properly scheduled and will not be burdensome on other EIM participants during the operating hour. The feasibility test calculates estimated transmission system flows to ensure that the entity's resource schedule will not violate any transmission facility limits. The balancing test measures the resources scheduled by the EIM Entity against the load forecast. A balancing test is considered passed if the sum of scheduled resources is within one percent of the load forecast. If a balancing test is failed, then the EIM Entity may face load forecasting charges if the actual load is not within 5 percent of the sum of scheduled resources. Bid range capacity tests are performed to ensure that each entity has provided bids that will allow its internal resources to move up or down to meet the imbalance between load, interchange, and generation. Additional flexible ramp tests are conducted for each 15-minute period to ensure the EIM Entity's ability to ramp up or down to meet the normal variations in the forecasted load and the renewable energy generation (wind and solar). Failure to pass the bid range capacity or flexible ramp tests may result in restriction on the EIM Entity to import or export incremental energy for the associated 15- minute period that the test(s) failed. Preliminary tests are conducted twice, and the results allow the EIM Operator to adjust resource schedules and bids ahead of the third and final (binding) test.

26. Q. WAS THE COMPANY RESTRICTED FROM PARTICIPATING INTO THE EIM FOR ANY PERIOD WITHIN 2023?

A. No.

27. Q. WHO PROVIDES THE EIM LOAD FORECAST FOR THE COMPANY BALANCING AUTHORITY?

A. The CAISO provides the load forecast for the Nevada BAA. By using the CAISO provided load forecast rather than an alternative forecast, the Company mitigates exposure to additional costs imposed by the CAISO for large discrepancies between the forecast and actual load. CAISO has dedicated resources for load forecasting. CAISO's load forecasting accuracy was tested in several months prior to the start of parallel operations in the EIM, and was found to be accurate for the purposes of load and resource balancing.

28. Q. HOW CAN THE COMPANY MAKE ADJUSTMENTS TO THE CAISO PROVIDED LOAD FORECAST?

A. If the Company BAA has a reasonable confidence in a CAISO forecasting inaccuracy, the EIM Entity can contact the CAISO load forecasting team and provide any additional information needed for an improved and accurate forecast.

The Company may use its own forecast if it ultimately determines, using its own experience and judgement, that the CAISO-provided forecast has an untenable degree of inaccuracy. Any anomalies in the CAISO forecast are identified through trending of several similar days of the Company's historical, actual balancing area load against the real-time forecast provided by the CAISO.

29. Q. HOW DOES THE EIM ENTITY COMMUNICATE WITH THE EIM OPERATOR IN REAL TIME?

A. The EIM Entity uses a number of EIM operational tools to communicate electronically with the EIM Operator. These tools include, but are not limited to, Base Schedule Aggregate Portal, Balancing Authority Area Operations Portal, and Outage Management System. Electronically telemetered information is also provided directly to the EIM Operator. In addition, the EIM Entity is able to verbally communicate with the Real Time Market Operator at CAISO to resolve any issues that may come up during operations.

30. Q. HOW HAS THE COMPANY BALANCING AUTHORITY FUNCTION CHANGED FROM PRE-EIM TO POST-EIM?

A. Prior to joining the EIM, the Transmission organization, as the BA, dispatched its own operationally-controlled resources, based on an internal optimization, to account for natural deviations between scheduled and actual energy and load. In the EIM, the CAISO provides dispatch instructions to all resources available to the EIM (including resources from other EIM participating balancing authorities) to account for the natural deviations between scheduled and actual energy and load in the entire EIM footprint. The Company's Transmission organization retains the ability to change the Market Operator's resource dispatch instructions based on its safety, reliability, and compliance requirements.

Moreover, prior to joining EIM, the Company had a BA obligation to provide this imbalance service to its customers (both retail and FERC jurisdiction). For certain non-native load customers, the Transmission organization issued bills for the provision of imbalance service to account for deviations between scheduled and actual energy (both load demand and generation production). Whereas for native load customers, there was no separate identification and tracking of imbalance service. The Company's participation in the EIM did not alleviate the Company's obligation to continue providing this imbalance service. Instead, the EIM merely added transparency to the provision of this service through market invoices and settlement statements. Both prior to and after joining the EIM, the Transmission organization issues bills to non-native load customers for the provision of imbalance service under its federally approved OATT.

IV. CONCLUSION

31. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT WHETZEL-DIRECT-1

Kim Whetzel
Director, Grid Operations & Reliability
NV Energy, Inc.
6100 Neil Road
Reno, NV 89511
(775) 834-3776

Kim Whetzel has been the Director, Grid Operations and Reliability for NV Energy, Inc. ("NVE"), since July 2022. She has extensive knowledge of the application of North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Federal Energy Regulatory Commission (FERC) reliability and compliance standards. The Grid Operations business group includes balancing, transmission, and distribution system operations for Sierra Pacific Power Company and Nevada Power Company.

Employment History

NV Energy, Inc.
July 1999 to present

July 2022 to present
Director, Grid Operations and Reliability
Responsible for balancing, transmission, and distribution system operations. Serves as the primary compliance contact for all compliance activities related to NERC and WECC Reliability Standards including reliability enforcement activities such as audits and investigations.

May 2016 to July 2022
Manager, Transmission and Distribution Operations

August 2008 to May 2016
Transmission/Distribution System Operator

May 2003 to August 2008
Utility Material Specialist

July 1999 to May 2003
Clerical Specialist

Education

Western Governors University, Salt Lake City, UT
Masters in Business Administration, 2022

Bismarck State College, Bismarck, ND
Bachelor of Applied Science in Energy Management, 2015

Bismarck State College, Bismarck, ND
Associate of Applied Science in Electrical Transmission System Technologies, 2013

University of Nevada, Reno, NV
Bachelor of Science in Biology, 2005

Truckee Meadows Community College, Reno, NV
Associate of Science in Biology, 2003

Certification

NERC RC Certification RC201001006, issued 2010, active status

EXHIBIT WHETZEL-DIRECT-2

NERC Reliability Compliance Plan

Compliance and Standards

The Companies are committed to the safe, efficient, and reliable operation of the electric distribution, transmission and generation facilities that support reliability and security of the Bulk Electric System. To that end, the Company commits to act in compliance with all NERC Reliability Standards applicable to the Company's electric utility operations. EVERY employee is responsible for ensuring that their actions, and the actions of the entire business unit in which they work, comply with all applicable NERC Reliability Standards.

Table of Contents

NERC Reliability Compliance Plan

I. BACKGROUND

The Bulk Electric System ("BES") has operated under the guidance of a set of North American Electric Reliability Corporation ("NERC") Policies – replaced by NERC Standards – since the early 1960s. Adherence to these Policies and Standards, until 2007, was technically a matter of voluntary compliance, with one notable exception in the West. Following the 1996 Disturbance events in the Western United States ("Region"), the Western Electricity Coordinating Council ("WECC") established a program of mandatory compliance with more than a dozen Reliability Standards deemed by the WECC members as being key to the preservation of BES reliability. This program, known as the Reliability Management System ("RMS"), was established through the voluntary participation of the largest electric utilities within the WECC Region. These utilities contracted with WECC to comply with the provisions in the RMS and submitted to sanctions and penalties for non-compliance with those provisions.

Historically, the industry was largely successful in monitoring itself and holding participants accountable for the provisions of the standards. However, in August of 2003 a major disruption of the electric grid in the northeastern United States and Canada caused loss of service to tens of millions of electric customers. Investigation of the root causes of this blackout event found that numerous of the then-established NERC Policies had been violated and that this not only was the cause, but it also contributed to the severity of the event and its duration.

In 2005, Congress acted to pass legislation known as the Energy Policy Act of 2005 ("EPAct 2005") which for the first time made BES reliability a legal requirement and called for a comprehensive set of mandatory Reliability Standards that must be followed by all entities that own, operate or use the BES. The EPAct 2005 designated the Federal Energy Regulatory

Commission ("FERC") as the federal agency responsible for administration and enforcement of the law's provisions. FERC subsequently designated NERC as the Electric Reliability Organization ("ERO") whose responsibilities include development, monitoring and enforcement of the Mandatory Reliability Standards ("Standards") under which the BES is to operate.

NERC, as the ERO, has undertaken an industry-wide effort to register BES owners, operators and users across North America, so that these entities may become fully accountable for the applicable Reliability Standards Requirements ("Requirements"). FERC initially approved 83 of the body of NERC Reliability Standards for implementation and compliance enforcement beginning June 18, 2007. Each Standard contains numerous Requirements and associated measures, which are metrics indicating the degree of compliance ("Measures"). The number of Standards and Requirements continues to fluctuate as a result of new versions of existing Standards, creation of new Standards and retirement of Standards.

NV Energy, Inc., its subsidiaries and affiliates ("NVE") and its operating companies, Nevada Power Company and Sierra Pacific Power Company doing business as NV Energy ("the Companies"), have had a proud history of cooperation and compliance with the NERC Policies, Standards and WECC Regional requirements since their inception and continually improve in the formality for which compliance with the applicable Reliability Standards is achieved.

In 2015, NERC deployed a risk-based approach to compliance monitoring and enforcement through a Reliability Assurance Initiative (RAI). This effort transformed the program into one that is forward-looking, focuses on areas that represent a high risk to BES reliability, and reduces the administrative burden on Registered Entities. NV Energy has utilized these concepts to align with the Risk-based Compliance Oversight Framework (Framework).

Prior to July 2020, the Companies were registered as separate NERC Registered Entities, with the Companies each serving in the "Registered Functions" of Transmission Operator (TOP), Transmission Owner (TO), Transmission Planner (TP), Transmission Service Provider (TSP), Resource Planner (RP), Planning Authority (PA), Generator Operator (GOP), Generator Owner (GO) and Distribution Provider (DP). In addition to these aforementioned functions, Nevada Power Company serves in the "Registered Function" of Balancing Authority (BA).

In June 2020, the Companies were consolidated into a single NERC Registered Entity, under the Nevada Power Company Registered Entity (with company name change to NV Energy), so that all current Registered Functions are held by the same Registered Entity. Sierra Pacific Power Company was deregistered as a NERC Registered Entity.

The applicable Reliability Standards for NV Energy based on these Registered Functions are documented in Appendix B.

II. PROMOTING A CULTURE OF COMPLIANCE

For purposes of this NERC Reliability Compliance Plan, "Senior Management" refers to NV Energy employees that are at the level of Director and above, including "Senior Officers." Senior Officers are identified as NV Energy employees that are at the level of Vice President and above.

Senior Officers are committed to promoting a culture of compliance in all aspects of the Company's electric utility operations. Senior Officers have established a robust compliance atmosphere, through a "tone at the top" approach, and is committed to promoting NVE's continued compliance efforts. To this purpose, NV Energy maintains a Risk Committee composed of senior officers which review and assess risks including NERC related compliance activities and initiatives. The committee meets on a monthly basis.

Senior Management is committed to providing the appropriate level of resources, both financial and personnel, taking into account, reliability and other operating requirements and economic conditions to maintain NVE's compliance program and culture of compliance.

This NERC Reliability Compliance Plan (“Plan”) is to help ensure that all employees of NVE comply with all applicable provisions of the Energy Policy Act of 2005 (“EPAct2005”), with respect to the mandatory Reliability Standards. Our purpose is to promote a culture of compliance and security -- where compliance and ethical behavior are well understood, proactively addressed at all levels, and treated as an essential part of our business.

A. Purpose

1. FERC’s *Policy Statements on Enforcement* and FERC’s *Policy Statements on Penalty Guidelines*[1] provide that among the factors FERC will evaluate when determining remedies for violations – including application of the enhanced civil penalty authority provided by

[1] *Policy Statement on Enforcement*, 113 FERC ¶ 61,068 (2005) and *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 (2008), *Policy Statement on Penalty Guidelines,* 130 FERC ¶ 61,220 (2010) and *Revised Policy Statement on Penalty Guidelines*, 132 FERC ¶ 61,216 (2010).

the EPAct 2005 – is a company's "culture of compliance"[2] and the steps a company has taken "to create a strong atmosphere of compliance in their organizations."[3]

2. FERC's *Policy Statements on Enforcement* and FERC's *Policy Statements on Penalty Guidelines* were explicitly influenced by the U.S. Justice Department's Federal Sentencing Guidelines, specifically the 2004 and 2008 amendments which included a detailed discussion of effective compliance and ethics programs and the impact that such programs can have on the calculation of the culpability score used to determine the sentence to be imposed after conviction of a corporation or other business entity. In particular, the Federal Sentencing Guidelines laid out seven principles for an "Effective Compliance and Ethics Program,"[4] which can be summarized as follows:

    a. establish standards and procedures to prevent and deter unlawful conduct;

    b. ensure knowledge and oversight of the compliance program by Senior Management, with specific individuals delegated day-to-day operational authority;

    c. use reasonable efforts to exclude from "substantial authority personnel" individuals whom the organization knew, or should have known, have engaged in unlawful or non-compliant activities;

    d. provide reasonable steps to periodically communicate compliance standards and procedures to Senior Officers, employees, and agents though training;

    e. perform internal monitoring and periodic evaluation of the compliance program's effectiveness and create a publicized confidential mechanism to allow employees to report or seek guidance about potential unlawful or non-compliant conduct;

---

[2] *Id.* at P 2.

[3] *Id.* at P 22.

[4] *Effective Compliance and Ethics Programs*, Federal Sentencing Guidelines, Chapter 8, Part B, Section 2 (2004).

f. promote the compliance and ethics program through (i) appropriate employee incentives and (ii) appropriate disciplinary measures; and

g. take reasonable steps to respond to conduct and to prevent future occurrences after unlawful conduct is detected.

3. The basic purpose of this NERC Reliability Compliance Plan is to aid in creating the culture of compliance that FERC has outlined, through a robust and effective compliance program that satisfies the principles of the Justice Department Guidelines as well as FERC's *Policy Statements on Enforcement*.

4. This NERC Reliability Compliance Plan represents one component of NV Energy's NERC Compliance Program which is designed to work in concert with other measures, policies, documents and procedures that also are designed to promote and maintain a culture of compliance.

5. To promote a culture of NERC compliance, NVE shall designate a Chief Compliance Officer, who oversees this NERC Reliability Compliance Plan. The NERC Compliance department, specifically the Director of FERC/NERC Compliance, has overall responsibility to implement and maintain this NERC Reliability Compliance Plan.

6. While the Director, FERC/NERC Compliance is charged with these overall responsibilities, all NVE employees remain responsible for ensuring that their actions, and the actions of the entire business unit in which they work, comply with all applicable NERC Requirements. Accordingly, all employees are required to be familiar with the NERC Reliability Standards relevant to their business, know Reliability Standards applicable to his/her specific job and

comply with such requirements in executing their duties. Failure to meet these obligations may result in disciplinary action, up to and including possible termination of employment.

7. To further foster a culture of compliance, the compensation of every employee in all relevant business units responsible for NVE's electric utility operations will include a component for compliance, *e.g.*, Scorecard KPIs, Performance Appraisals, Individual Performance Objectives, or a Short-Term Incentive Plan Corporate goal.

III. POLICY STATEMENT

NV Energy is committed to the secure and reliable operation of the electric distribution, transmission and generation facilities that support reliability of the Bulk Electric System. To that end, NV Energy commits to act in compliance with all NERC Reliability Standards applicable to NV Energy's electric utility operations. EVERY employee is responsible for ensuring that their actions, and the actions of the entire business unit in which they work, comply with all applicable NERC Reliability Standards.

IV. NERC COMPLIANCE ROLES and RESPONSIBILITIES

The Chief Compliance Officer, the Director of FERC/NERC Compliance and members of the Compliance Support Team are designated and identified in Appendix C, attached hereto. No NVE employee shall have the ability to take any adverse or retaliatory action against another NVE employee for actions with respect to their Compliance responsibilities.

A. Chief Compliance Officer

The Chief Compliance Officer, among other responsibilities, shall oversee this NERC Reliability Compliance Plan. The Company will have a Chief Compliance Officer or an Acting

Chief Compliance Officer in place at all times. The Chief Compliance Officer reports to the Chief Executive Officer/President.

B. Director, FERC/NERC Compliance

The Director of FERC/NERC Compliance is responsible for implementing this NERC Reliability Compliance Plan and addressing NERC compliance issues and policies. He/She reports to the Chief Compliance Officer and shall have access to all Senior Officers at his/her independent discretion.

The Director of FERC/NERC Compliance shall have sufficient resources to administer his/her responsibilities and shall submit recommendations as warranted to the Chief Compliance Officer regarding staffing, budgeting, and other resources (*e.g.*, training, travel, etc.).

The Director of FERC/NERC Compliance, along with the Chief Compliance Officer, shall oversee the business units and employee compliance efforts related to NERC requirements. These responsibilities shall include, but are not limited to:

a. overseeing the NV Energy Standards development program;

b. overseeing the NV Energy Standards implementation program;

c. overseeing the NV Energy compliance monitoring and controls program;

d. remaining continuously informed of NERC compliance policies and requirements;

e. communication of compliance/enforcement policies, requirements and other NERC related information to NVE employees as appropriate;

f. overseeing NERC compliance business processes and other BES Reliability related initiatives;

g. reporting compliance performance, issues, or concerns to the Chief Compliance Officer;

h. providing compliance updates to Senior Officers and the Risk Committee;

i. ensuring that compliance-required training takes place for NVE employees engaged in electric utility operations, and responding to their questions on an ongoing basis;

j. with respect to audits and investigations instituted by NERC and WECC, coordination of NVE companies' responses and interactions with NERC and WECC staff;

k. participating, as appropriate, in any technical conferences, rulemakings, or other proceedings involving any of the subject matters for which he/she has responsibility; and

l. working in coordination with the Company's Legal Department ("Legal") to coordinate audits and compliance reviews with NVE's internal or external auditors and may also provide guidance to the internal auditing organization when it conducts formal audits that involve NERC requirements.

The Director of FERC/NERC Compliance will coordinate with NVE Internal Audit to ensure that NERC compliance issues are effectively considered in the Company's overall audit program. He/She will serve as a resource for Internal Audit in terms of providing background information, developing audit protocols, and assisting in the audit process as requested by Internal Audit.

C. Compliance Support Team

The Compliance Support Team is made up of several specialists that, among many responsibilities, play key roles in the implementation and effectiveness of the NERC Reliability Compliance Plan. Note, the legal counsel and other subject matter experts described, may exist outside of the NERC Compliance and Standards department. The Compliance Support Team can be classified into four categories:

- NERC Compliance Engineering
- NERC Compliance Implementation

- NERC Compliance Monitoring
- Legal Counsel

The Compliance Support Team is designated and identified by name, in Appendix C, attached hereto.

1. NERC Compliance Engineering

The roles and responsibilities of NERC Compliance Engineering include, but are not limited to:

a. implementing the NV Energy "*NERC Standards Development Procedure*";

b. implementing the "*Procedure for NERC Compliance Technical Assessments*" to support the effectiveness of the NERC Compliance Monitoring Program;

c. supporting business units on technical aspects of standards by reviewing and providing feedback to internal policy, procedure, studies, assessments, and interpretations;

d. supporting compliance monitoring and conducting technical engineering studies and investigations to increase the effectiveness of the monitoring program;

e. supporting compliance projects to implement changes for new or revised standards or to implement enhanced detection, correction or prevention of compliance risks;

f. supporting the involvement of the department in external and internal industry forums and activities; and

g. supporting all related WECC and NERC audit activities.

NERC Compliance Engineering personnel will report to the Director of FERC/NERC Compliance and shall have access to the Chief Compliance Officer at his/her independent discretion.

2. NERC Compliance Implementation

Compliance Implementation is led by the Project Manager of NERC Compliance and its responsibilities in the Compliance Support Team include, but are not limited to:

a. implementing the NV Energy "*NERC Standards Implementation Procedure*".

b. supporting business units in management of new requirements and obligations, especially those that span multiple departments;

c. supporting compliance projects to implement changes for new or revised standards or to implement enhanced detection, correction or prevention of compliance risks;

d. supporting Compliance and Standards on reliability related initiatives and major projects; and

e. supporting all related WECC and NERC audit activities.

The Project Manager of NERC Compliance reports to the Director of FERC/NERC Compliance and shall have access to the Chief Compliance Officer at his/her independent discretion.

3. NERC Compliance Monitoring

NERC Compliance Monitoring is led by the Manager of NERC Compliance and its responsibilities in the Compliance Support Team include, but are not limited to:

a. instituting and maintaining an effective compliance monitoring and enforcement program for the NERC Reliability Standards and their related policies and procedures, from an independent perspective;

b. conducting periodic independent assessments of NERC Reliability Standards compliance and disseminating results of such assessments to the Director of FERC/NERC Compliance;

c. overseeing the administration and tracking of periodic certifications related to NERC Compliance through the Compliance Data Management System (webCDMS) and

d. ensuring that annual self-reviews/self-certifications are conducted by Compliance Leads;

e. assisting the business functions in designing and executing compliance controls that will facilitate compliance with NERC Reliability Standards;

f. maintaining and administering the SharePoint database and tracking tools for the NERC Reliability Standards; and

g. supporting all related WECC and NERC audit activities.

The implementation of the NERC Compliance Monitoring Program ensures independence from the operating areas of NV Energy to which the Requirements apply. The Manager of NERC Compliance has direct and independent access to Senior Officers, including the Chief Compliance Officer and CEO/President.

4. Legal Counsel

The roles and responsibilities of NERC Legal Counsel include, but are not limited to:

a. supporting Compliance and Standards as necessary.

D. Compliance Lead

Due to the technical nature and wide variety of applicability of the NERC Reliability Standards to electric utilities, it is necessary to distribute the responsibility for compliance with the Requirements to key individuals imbedded in the various operating units of NV Energy. These individuals are referred to as Compliance Leads. One or more subject matter expert(s) within the relevant business units will be identified as Compliance Leads. Compliance Leads are responsible for knowing and understanding Reliability Standards applicable to their specific job and ensuring their business unit implements and maintains processes and procedures that demonstrate compliance with the Requirements identified in the NERC Reliability Standards. In the event that there are multiple Compliance Leads assigned to a single Requirement, collaboration on all aspects of compliance is necessary. The criterion for the Compliance Lead is that he/she has a strong working technical knowledge of the assigned NERC Reliability Standard(s), be at a level to make decisions and enforce change, and be able to collaboratively work across business units. The monitoring and control process allows NERC Compliance to evaluate the effectiveness of the Compliance Leads in ensuring compliance. The Compliance Leads are designated and identified in Appendix B, attached hereto. The process for selecting Compliance Leads is further defined in the *"Procedure for Designating a Compliance Lead"*.

The roles and responsibilities of each Compliance Lead include, but is not limited to, the following:

a. thoroughly research and understand the specific Reliability Standards, Requirements and Measures that have been assigned to their responsibility area;

b. evaluate performance within their responsibility area and compare this to the assigned Requirements;

c. prepare action plans as necessary to maintain full, auditable compliance with assigned Requirements;

d. document internal controls to support the reliability and security of the bulk power system for assigned Requirements

e. identify weaknesses or gaps in compliance with assigned Requirements and orchestrate necessary corrective action;

f. through the performance of self-reviews and self-certifications, attest on an annual basis to the status of compliance with assigned Requirements. These self-reviews include written attestations. The self-certifications are done via WECC's webCDMS online submission portal;

g. immediately disclose any incidents or occurrences of non-compliance with assigned Requirements to NERC Compliance and ensure that appropriate facts and data are made available for reporting to WECC or NERC;

h. implement changes to procedures and policies or create new procedures and documentation to ensure compliance with evolving Requirements or new Requirements that emerge from NERC;

i. to the extent that additional statutes, orders, rules, or regulations change the application of NERC requirements or create new NERC requirements, the Compliance Leads and Business Unit Leaders shall be primarily responsible for ensuring compliance with these changes; and

j. complete and provide documents (e.g. RSAW and evidence) as requested for internal monitoring and auditing.

E. Meetings

It is essential that Business Unit Leaders keep abreast of NERC Reliability Standards and Requirements and ensure their compliance efforts track such developments. Compliance Leads, or their designee(s), in all relevant business units, shall meet semi-annually, or more frequently as necessary, at "Compliance Lead Roundtable" meetings with NERC Compliance to discuss NERC compliance developments, efforts, issues, and questions.

V. STANDARDS DEVELOPMENT

As NERC Standards or Regional Standards and Criterion are revised or added, it is important that these Standards effectively support the reliability of the North American BES, and that NV Energy is well positioned to meet or exceed expectations of the Standard. NERC Compliance Engineering will participate in all stages of the development process to ensure that the new or changing Standards are meeting these expectations. During the commenting and balloting period for new or revised Standards, NERC Compliance Engineering will take steps to ensure the appropriate Compliance Leads and Subject Matter Experts are advised of new or proposed changes to the Standards, as well as, incorporate their input into the comments and balloting position for NV Energy. It is critical that Compliance Leads and Subject Matter Experts are engaged during these early stages of Standards development, in order to aid the Standard Development process.

At the completion of the Standards Development phase, the NERC Compliance Engineer will transition all information from the Standard drafting project to the Project Manager of NERC Compliance to begin the Standards Implementation phase. NV Energy's NERC Standards Development process is identified in detail in the "NERC Standards Development Procedure".

VI. STANDARDS IMPLEMENTATION

The Standards Implementation phase includes aspects of change management. With the focus on results, NV Energy implements the plan-execute-measure-correct method to guide execution of new and revised controls and documentation to ensure compliance requirements will be met and exceeded by the Effective Date of the Reliability Standard.

It is the responsibility of the Project Manager of NERC Compliance to help manage the implementation of new Reliability Standards, as well as versioning changes to existing Reliability Standards, and direct other compliance significant initiatives. This includes working with the necessary business units to meet or exceed implementation schedules of required controls and documentation to ensure compliance with the new or revised Reliability Standard. Additionally, providing oversight to Compliance Leads in achieving appropriate controls, necessary training and/or education, and providing the tools required to demonstrate compliance. Tools such as the "*Interpretation and Implementation Assessment*" or other documentation will be utilized to educate and promote successful execution of changes. This document includes, but is not limited to;

- Reliability Standards summary,
- revisions and additions to NERC Glossary Terms,
- mapping,
- application examples, and
- analysis of requirements through the use of the Standard's RSAW

To provide additional support through the implementation phase, meetings will be regularly scheduled with Compliance Leads to disseminate the aforementioned information on the modified Reliability Standards. Through this collaborative implementation phase, it is still the responsibility of each Compliance Lead to take the necessary actions within their responsibility areas to ensure continued compliance.

At the completion of the Standards Implementation phase, conceptually, the Project Manager of NERC Compliance will then transition all relevant implementation information to the Manager of NERC Compliance to begin the Monitoring phase. NV Energy's NERC Standards implementation process is identified in detail in the "*NERC Standards Implementation Plan*".

VII. RISK ASSESSMENT

The Compliance and Standards department builds its procedures to develop a robust culture of compliance and ethical behavior (e.g., compliance plans, training schedules, monitoring schedules, documentation reviews, procedures and protocol development, risk assessments, etc.) that focuses on ensuring the reliability of the Bulk Electric System. NV Energy leverages

NERC Reliability Compliance Plan

Risk Assessments performed by both NERC and WECC as noted in NERC's Annual Compliance Monitoring and Enforcement Program Implementation Plan.

NERC and WECC use a risk-based approach to identify, assess and prioritize risks to the Bulk Electric System and to determine an appropriate compliance monitoring approach, which enables the Compliance Enforcement Authority (CEA) to assign resources where they are most needed and likely to be the most effective.

NERC's Risk Assessment involves a review of system-wide risks and considerations that include Reliability Standard and Requirement Violation Risk Factors, events and disturbances, system trends, grid operating data, input from FERC and NERC standing committees, and input from NERC program areas and departments. Western Electricity Coordinating Council's Risk Assessment identified specific risks unique to its Regional footprint and assessed Registered Entities to identify the reliability risk that a specific entity may pose to the Bulk Electric System.

NV Energy implements a Risk Assessment and Control Evaluation similar to those that are a part of the Reliability Assurance Initiative (RAI) that the CEAs apply to the Registered Entities. Additional criteria considered by NV Energy's Compliance and Standards department, identified in the "*Procedure for NERC Compliance Risk Assessment*", includes but is not limited to: violation risk factors, NERC's most violated, review frequency, number of parties involved, history, amount of human involvement, and the potential impact to the BES.

VIII. COMPLIANCE MONITORING AND CONTROLS

The NERC Compliance Monitoring Assessment Process aligns with NERC's risk-based approach and strategic direction. The NERC Compliance Monitoring Schedule is created based upon the annual NERC Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan, which is designed to monitor, assess, and enforce compliance with all "enforceable" Reliability Standards, focusing first on those standards and their associated controls that pose a greater risk to the Bulk Electric System.

Enforceable Reliability Standards include all requirements of the Reliability Standards that have been approved by the Federal Energy Regulatory Commission and are "effective." NERC Compliance Monitoring methodology ensures that all enforceable standards will be reviewed within WECC's 3-year audit cycle with requirements identified as presenting a higher risk having an annual monitoring period. Those requirements that are more technical in nature will also receive a technical assessment with the NERC Compliance Monitoring review to help ensure that the requirements are being applied correctly. Furthermore, a control monitoring process is in place in which requirements identified in the "*Procedure for NERC Compliance Risk Assessment*" to have weak controls are assigned to the appropriate Compliance Leads to be amended. The updated controls are then tested and reviewed by the NERC Compliance Monitoring team.

The following items may require modifications to the schedule:

- new requirements,
- modifications to existing requirements become effective,

- shifts in regulatory direction,
- changes to NERC's Annual Implementation Plan,
- changes in WECC's compliance monitoring and enforcement approach

The monitoring assessment process is implemented by the NERC Compliance Monitoring team which reviews the completed Reliability Standards Audit Worksheet (RSAW) packages and compliance supporting evidence submitted by the Compliance Leads for the related NERC Reliability Standards and Requirements (based on a specified schedule taking into account a number of factors).

The technical assessment process is implemented by NERC Compliance Engineering, and includes reviewing Requirements that require technical studies, analyses, or calculations. Upon completion of the technical assessment, NERC Compliance Engineering will provide both suggestions and help to identify possible gaps that could reduce the reliability to the Bulk Electric System.

NV Energy's NERC Compliance monitoring review methodology and compliance monitoring process are identified in detail in the documents "*NERC Reliability Monitoring Schedule Implementation Plan*", "*Procedure for NERC Compliance Monitoring Assessments*", "*Procedure for NERC Compliance Risk Assessment" and the "Procedure for NERC Compliance Technical Monitoring Assessments"*.

The primary compliance monitoring tool for the NERC Reliability Standards is Microsoft Office SharePoint. SharePoint serves as the central repository for NERC Compliance evidence. Within this application, each and every applicable Requirement is individually listed and, via a workflow task, assigned to a Compliance Lead within NV Energy for demonstration of compliance for his/her specific Requirement. Additionally, there are means to attach pertinent supporting documentation or attach hyperlinks to such documentation.

Compliance Leads must periodically review and attest to the status of compliance with each assigned Requirement as a part of the self-certification process, periodic data submittal process and/or certain NERC Requirements. The period of this review is dependent upon the nature and identified risk of each assigned Requirement.

IX. DISCLOSURE OF VIOLATIONS / SELF-REPORTING

Instances of actual or suspected violations of the NERC Reliability Standards are to be immediately reported by the employee who recognizes the issue. Such reporting should begin with the employee's immediate leader, or to the Compliance Lead who has the responsibility for the particular area in which the violation occurred. Immediate communication is necessary due to certain Requirements carrying time sensitive reporting criterion, which is noted in a separate field in the SharePoint tool, for each Requirement. The actual disclosure communication of the non-compliance to WECC and NERC will be coordinated between the business unit in which the non-compliance was found, NERC Compliance and the appropriate Senior Officers. The *"Procedure for Self-Reporting"* outlines the specific actions to be taken in instances where self-reporting is necessary.

The Director of FERC/NERC Compliance will inform the appropriate Senior Officers of actual and potential compliance violations and address potential compliance self-reports with the appropriate members of Senior Management.

It is the intent of this NERC Reliability Compliance Plan to encourage an environment where employees are expected to disclose actual or suspected violations of the NERC Reliability

Standards without concern for personal consequence. We reserve the right to investigate all violations, willful or not, and to determine disciplinary action in accordance with NV Energy established disciplinary practices up to and including termination.

During the mitigation plan or corrective action process, NERC Compliance will assess if there are necessary changes to the NERC Reliability Compliance Plan or other processes or procedural documents to prevent the likelihood of recurrence of the identified violation. NV Energy's Root Cause Analysis (RCA) tools and Human Performance Improvement (HPI) tools are available to help identify and correct weaknesses. For possible violations, self-reports, near misses and other exposures to non-compliance the Compliance and Standards department will utilize these tools to identify and correct potential gaps.

X. TRAINING

Training is an integral part of the process when it comes to maintaining a reliable system. Business units such as, but not limited to, Transmission, Electric Delivery, and Energy Supply employ trainers and compliance personnel to ensure that training is effectively and consistently delivered.

In addition to business unit specific programs, Compliance and Standards implements compliance training practices. These practices include, but are not limited to, the following;

- new Compliance Lead and Subject Matter Expert training,
- face-to-face biannual training and awareness for Compliance Leads and Subject Matter Experts,
- centrally stored compliance training material available to all employees,

- standards implementation and interpretation guidance,
- internal and third-party department training for the Compliance Support Team and leadership, and
- additional training and guidance as needed
- monthly delivery of the NV Energy NERC Compliance Newsletter includes information about upcoming events.

Senior Officers, Senior Management, the Compliance Support Team, Compliance Leads and Subject Matter Experts are encouraged to participate in and attend electric reliability and compliance related webinars, conferences, and trainings.

XI. COMPLIANCE COMMUNICATIONS

NERC Compliance utilizes various methods to communicate compliance related matters including but not limited to the following:

1. The NV Energy NERC Compliance Newsletter. A monthly electric reliability compliance newsletter is distributed to Senior Management, the Compliance Support Team, Compliance Leads, Subject Matter Experts and other interested parties. The purpose of the newsletter is to deliver relevant information in a summarized fashion to key individuals at NV Energy.
2. During meetings with the Compliance Leads, like the Compliance Lead Roundtables, Compliance and Standards will communicate material changes in the NERC and WECC Reliability Standards/Requirements and the NERC Reliability Compliance Plan to the Compliance Leads. While this is a way to make sure that Compliance Leads receive updates

regarding major changes in compliance requirements, Compliance Leads are still charged with remaining informed of changes in NERC Requirements that impact their business.

3. The most up-to-date version of the NERC Reliability Compliance Plan shall be made available to all employees via NVE's intranet.
4. Other compliance communications (e.g., Compliance Awareness, Security Awareness, Hotline Reporting, etc.), as deemed necessary, shall be communicated periodically throughout the year utilizing an appropriate methodology (e.g., Intranet, email, physical postings, etc.).

XII. MEASUREABLE COMPLIANCE PERFORMANCE TARGETS

NVE utilizes a number of different compliance performance targets and goals to stress the importance of and achieve compliance with the NERC Reliability Standards. These goals vary from corporate level performance to specific individual performance. NV Energy operates by six core principles, two of which are regulatory integrity and operational excellence. Business units and individual performance goals are established to align with the corporate goals and core principles as appropriate.

XIII. ANNUAL REVIEW

The NERC Reliability Compliance Plan shall be reviewed at least once per year and modified as necessary to update changes to the NERC Reliability Standards and ensure that the overall compliance program remains effective and addresses the evolving requirements of the operation of the Bulk Electric System. The appropriate Senior Officers shall approve material changes to this NERC Reliability Compliance Plan before they become effective. Revisions to the NERC

Reliability Compliance Plan shall be timely conveyed to employees with compliance responsibilities.

A. Revision History

The following table represents a summary of the NERC Reliability Compliance Plan revisions:

Revision Date	Custodian	Modification Description
May 29, 2007	Ruth Urbantke	Initial Release
October 17, 2007	Ruth Urbantke	Various
April 14, 2008	Brian Pauling	Revised Compliance Leads on Compliance Lead Table
April 29, 2008	Brian Pauling	BOD Approved April 14 modifications*
May 8, 2008	Brian Pauling	Revised Compliance Leads on Compliance Lead Table
August 14, 2009	Brian Pauling	Revised to reflect NV Energy name change, Back ground, Policy Statement, Compliance Leads on Compliance Table, Paul Kaleta's title change, Annual Review reference
November 18, 2009	Brian Pauling	Add compensation clause from overall FERC Compliance Plan to the NERC Compliance Plan (Appendix A)
March 12, 2010	Brian Pauling	Revised Background to include SPPC's Audit/Spot Check and Compliance Leads on Compliance Lead Table
February 7, 2011	Brian Pauling	Revised Background to include Standard count fluctuation language and include NPC's Spot Check. Updated Compliance Leads on Compliance Lead Table
March 1, 2012	Brian Pauling	Significant updates including, but not limited to; remove NERC Compliance Plan as an Appendix to the FERC Compliance Plan and add information to become a standalone document, update roles and responsibilities section, meetings, measureable performance targets, and compliance communication section
September 26, 2012	Brain Pauling	Non-substantial changes; update titles and appendices.

NERC Reliability Compliance Plan

June 13, 2013	Brian Pauling	Review. Updated appendices.
December 19, 2013	Brian Pauling	Update responsibility section for FERC Compliance, and the evolving standards/evolving standards section to ensure coordination. Updated appendices.
November 25, 2014	Brian Pauling	Review, non-substantial changes. Updated appendices.
January 12, 2015	Tammie Henderson	Updated appendices.
July 31, 2015	Eric Schwarzrock	Significant updates including, but not limited to; cover page, table of contents, roles and responsibilities and the compliance support team, compliance engineering, compliance implementation, reference to RAI, Risk Committee, risk assessment, mention to company's RCA and HPI tools, the NVE NERC Newsletter, update associated policy/procedures, and added this revision history to the annual review section.
August 23, 2016	Eric Schwarzrock	Split New/Evolving Standards section to Development and Implementation sections. Rearranged Development, Implementation, Risk and Monitoring section to align with NVE compliance framework. Updated titles. Updated training section. Added clarification for the Manager of Compliance Implementation and NERC Compliance Engineer.
April 26, 2017	Tammie Henderson	Formatting changes in Section IV and updated Appendices B and C.
July 24, 2017	Leilani Hinyard	Added clarity to Compliance Lead, Section IV-D. Revised Compliance Leads – Roles and Responsibilities, Section IV-E.
January 31, 2018	Kevin Salsbury	Grammatical revisions; Document structure; Corrected position titles to match company designations and other Plan documentation references
December 20, 2018	Kevin Salsbury	Annual Review; Grammatical revisions and position title revisions
December 19, 2019	Kevin Salsbury	Annual Review
February 10, 2020	Kevin Salsbury	Updated titles in Plan and Appendices; Added FERC attorney
February 12, 2021	Kevin Salsbury	Revised title of Director of FERC/NERC Compliance; Included language on consolidation of Registered Entities; Removed reference "the Companies"; Updated Appendix C

APPENDIX A

NV Energy employees participate in a significant number of Regional and Sub-Regional forums to help shape the regulations and to stay abreast of the changes. Some of these include:

WECC Region	
Member Representatives	Market Interface Committee
Operating Committee	Planning/Coordination Committee
NAESB Work Group	Operating Practices and Event Analysis Subcommittee
EMSDM Work Group	Relay Work Group
Critical Infrastructure and Information Management	Chief Dispatcher Forum
Interchange Scheduling & Accounting Subcommittee (past Chair)	Remedial Action Scheme Reliability Subcommittee (Chair)
Unscheduled Flow Admin Subcommittee	Joint Synchrophasor Information Subcommittee
Compliance User Group	CIP User Group
Northwest Power Pool Sharing Group	
Operating Committee	Frequency Reserve Sharing Group
Reserve Sharing Subcommittee	
Other	
Standards Drafting Teams	Joint Engineering/Operating Committees (Eldorado, Navajo, McCullough)
NERC Registered Ballot Body - Segment 5	North American Transmission Forum (NATF)
National Energy Compliance Forum	Western Interconnection Compliance Forum (WICF)
Electricity Information Sharing and Analysis Center	EnergySec

APPENDIX B

Appendix B can be found by clicking on the following link.

APPENDIX C

The following employees are designated as the Compliance Support Team:

Role	Name	Title
NV Energy, Chief Compliance Officer	Brandon Barkhuff	Vice President, General Counsel, Corporate Secretary
NV Energy FERC and NERC Compliance Leader	Kevin Salsbury	Director, FERC/NERC Compliance
NV Energy Compliance Implementation	Dwanique Spiller	Project Manager, NERC Compliance
NV Energy NERC Compliance Monitoring	Tammie Henderson	Manager, NERC Compliance
NV Energy NERC Compliance Monitoring	Leilani Hinyard	Senior NERC Compliance Analyst
NV Energy NERC Compliance Monitoring	Ramiro Garza	Associate NERC Compliance Analyst
NV Energy CIP Compliance Support	Casey Jones	Senior NERC CIP Specialist
NV Energy FERC Compliance	Bridget Metzger	Manager, FERC Compliance
NV Energy FERC Compliance	Jason Barney	Senior FERC Compliance Analyst
NV Energy Legal Counsel	Michael Knox	Senior Attorney
NV Energy Legal Counsel	David Rubin	Federal Energy Policy Director

EXHIBIT WHETZEL-DIRECT-3

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

2023 ERO Enterprise Compliance Monitoring and Enforcement Program Implementation Plan

Version 1.0

October 2022

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

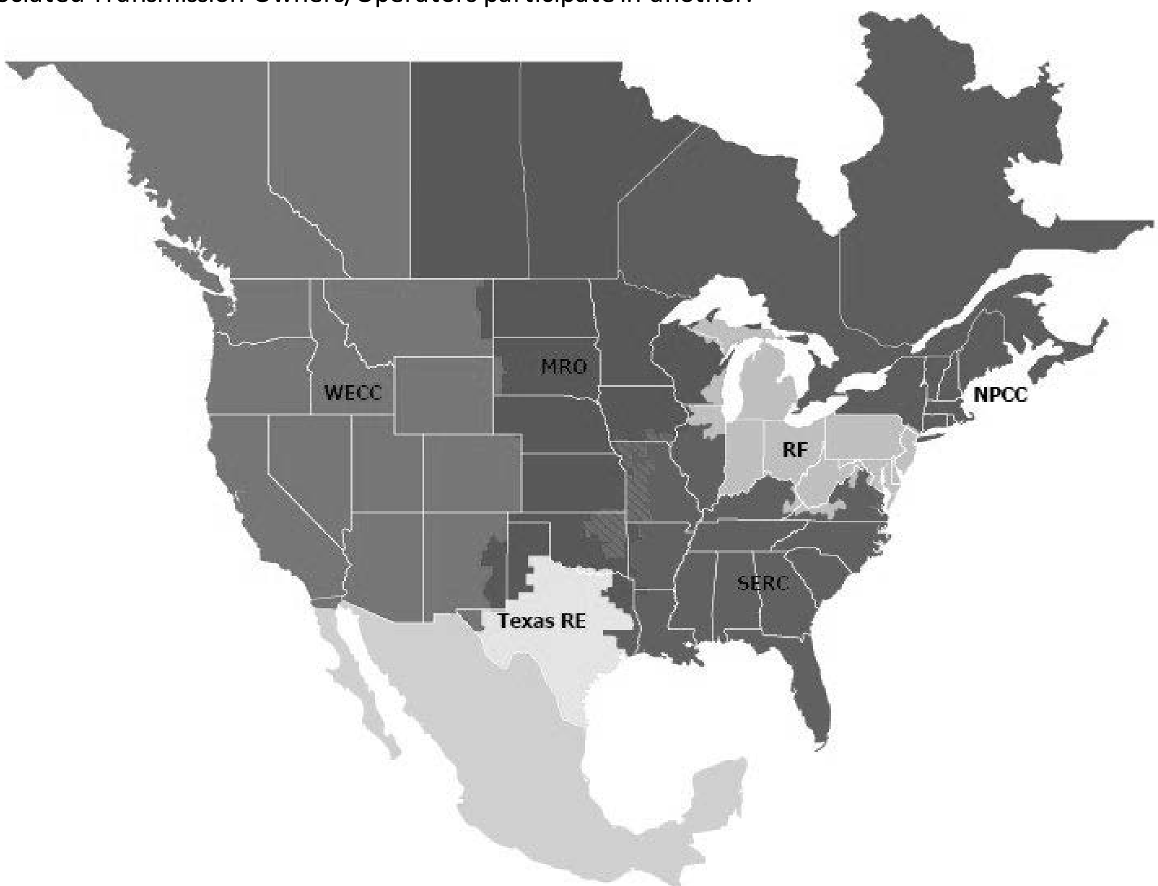
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Revision History

Version	Date	Revision Detail
Version 1.0	October 2022	• Release of the 2023 ERO CMEP Implementation Plan.

Introduction

Purpose

The Electric Reliability Organization (ERO) Enterprise[1] Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan (IP) is the annual operating plan used by the ERO Enterprise in performing CMEP responsibilities and duties. The ERO Enterprise executes CMEP activities in accordance with the NERC Rules of Procedure (ROP) (including Appendix 4C), their respective Regional Delegation Agreements, and other agreements with regulatory authorities in Canada and Mexico. The ROP requires development of an annual CMEP IP.[2]

The ERO Enterprise is pleased to release the 2023 CMEP IP describing the risks that will be priorities for the ERO Enterprise's CMEP activities in 2023. Collectively, NERC and each Regional Entity have worked collaboratively throughout this CMEP IP's development to evaluate reports of NERC committees (especially the Reliability Issues Steering Committee [RISC]), ERO Enterprise analysis of events, and NERC reliability assessments to identify the existing and emerging risks to reliable and secure operations.

This strategic CMEP IP highlights the focus of our monitoring and enforcement efforts in 2023 on the risk elements identified within. The CMEP IP gives guidance to the employees of the ERO Enterprise involved with monitoring and enforcement, and through public posting informs the ongoing conversations with industry about the risks we all seek to mitigate. The risk elements described herein are all developed with the four risks designated "manage" and the four risk profiles, all identified in the 2021 RISC ERO Reliability Risk Priorities Report.[3] The risks designated "manage" are: 1) Changing Resource Mix, 2) Cybersecurity Vulnerabilities, 3) Resource Adequacy and Performance, and 4) Critical Infrastructure Interdependencies. In addition, the report focuses on four risk profiles: 1) Grid Transformation, 2) Security Risks, 3) Extreme Events, and 4) Critical Infrastructure Interdependencies. While compliance with Reliability Standards is evaluated as part of continuous monitoring, the main focus of a mature CMEP is on how the ERO Enterprise and industry proactively identify and mitigate risks to the BPS.

The CMEP IP represents the ERO Enterprise's high-level priorities for its CMEP activities. While the ERO Enterprise will decide how to monitor each registered entity based on its unique characteristics, registered entities should consider the risk elements and their associated areas of focus as they evaluate opportunities and priorities to enhance their internal controls and compliance operations to mitigate risks to reliability and security. There is not an expectation that every Risk Element or every Requirement mapped to a Risk Element should be contained within every possible engagement. Risk Elements serve as an input in determining the appropriate monitoring of risks and related Reliability Standards and requirements in the Compliance Oversight Plan (COP) for each registered entity.

[1] The ERO Enterprise is comprised of NERC and the six Regional Entities, which collectively bring together their leadership, experience, judgment, skills, and supporting technologies to fulfill the ERO's statutory obligations to assure the reliability of the North American BPS.

[2] NERC ROP, Appendix 4C Section 3.0 (Annual Implementation Plans).

[3] RISC ERO Priorities Report; August 2021

Periodic Data Submittals

The Compliance Enforcement Authorities (CEAs) require Periodic Data Submittals (PDS) in accordance with the schedule stated in the applicable Reliability Standards, as established by the CEA, or as needed, in accordance with the NERC ROP, Appendix 4C Section 4.6. The ERO Enterprise's data format requirements and specifications, data review processes, potential noncompliance determination processes, as well as Preliminary Screening and Enforcement actions, are managed by the ERO Enterprise. Submittal forms within Align for applicable Standard requirements are maintained by ERO Collaboration groups or are provided with the Standard.

NERC posts an annual and ERO-wide PDS schedule for awareness across Regional boundaries. The CEAs use the PDS schedule posted by NERC on the NERC Compliance One-Stop Shop, located under "Compliance" at this link: NERC Compliance One-Stop Shop.

One-Stop-Shop (CMEP, Compliance, and Enforcement) - Active

Documents	Year	Category	Date
⊟ **Compliance** (36)			
⊞ CIP ERT & User Guide (3)			
⊞ CIP FAQs (1)			
⊟ Compliance (10)			
2022 ERO Enterprise Periodic Data Submittal Schedule	2022	Compliance	12/16/2021
2023 ERO Enterprise Periodic Data Submittal Schedule	2023	Compliance	10/14/2022

2023 ERO Enterprise Risk Elements

Process for Risk Elements and Associated Areas of Focus

The ERO Enterprise uses the ERO Enterprise Risk-based Compliance Monitoring Framework (Framework) to identify both ERO Enterprise-wide risks to the reliability of the BPS and mitigating factors that may reduce or eliminate the impacts from a given reliability risk. The ERO Enterprise accomplishes this by using the risk element development process.[4] As such, the ERO Enterprise identifies risk elements using data including, but not limited to: compliance findings; event analysis experience; data analysis; and the expert judgment of ERO Enterprise staff, committees, and subcommittees (e.g., the RISC). Reviewed publications include the RISC's biennial report,[5] the State of Reliability Report,[6] the Long-Term Reliability Assessment, publications from the RISC, special assessments, the ERO Enterprise Strategic Plan, ERO Event Analysis Process insights, and applicable Regional Risk Assessments. The ERO Enterprise uses these risk elements to identify and prioritize Interconnection- and continent-wide risks to the reliability of the BPS. The ERO Enterprise uses these identified risks to focus compliance monitoring and enforcement activities.

The ERO Enterprise reviewed and reassessed the 2022 risk elements to determine applicability for 2023. The CMEP IP identifies NERC Reliability Standards and Requirements to be considered for focused CMEP activities. The ERO Enterprise recognizes, however, that by using the Framework and other risk-based processes, the CEAs will develop an informed list of NERC Reliability Standards and Requirements for any monitoring activities specific to a registered entity's risks. Notably, the CMEP IP is not intended to be a representation of just "important" Reliability Standard requirements; rather, it is intended to reflect the ERO Enterprise's prioritization within its CMEP based on its inputs and to communicate to registered entities to bring collective focus within their operations to address each prioritized risk.

Impact of Risk Elements

The CEAs evaluate the relevance of the risk elements to the registered entity's facts and circumstances as they plan CMEP activities throughout the year. For a given registered entity, requirements other than those in the CMEP IP may be more relevant to mitigate the risk, or the risk may not apply to the entity at all. Thus, depending on regional distinctions or registered entity differences, focus will be tailored as needed.

The 2023 risk elements included in Table 2 reflect the continued maturation of the risk-based approach to compliance monitoring. The names of the Risk Elements have been changed from previous years, and the content of them made more direct, more specifically reflecting the discrete risks that may receive increased focus from CMEP staff. Even though there are more risk elements, they are targeted. The discrete risks identified within the risk elements provide focus for measuring current state and validating registered entity progress. By tracking improvements, industry and the ERO Enterprise can justify focusing on different risks in the future.

The resulting risk elements are shown in Table 1. The 2022 risk element "models impacting long-term and operational planning" was refocused on specific concerns, namely into the new risk elements named "stability studies" and "inverter-based resources". The 2022 risk element "gaps in program execution" was retired as being too broad of a topic, and "protection system coordination" was merged into "inverter-based resources". Meanwhile, the 2022 risk element "extreme events" has been focused into "cold weather response" and "incident response". The risk elements "remote connectivity" and "supply chain" remain largely the same as they were already focused on particular risks.

---

[4] Appendix C, ERO Enterprise Guide for Compliance Monitoring; October 2016

[5] RISC ERO Priorities Report; August 2021

[6] NERC State of Reliability 2022

Compliance monitoring is not the only tool available to address the risks identified. CMEP staff may assist in various forms of outreach with industry to understand how effectively certain obligations are being implemented and to encourage best practices to achieve the common goal of mitigating risk to the BPS. Enforcement may consider these risks when assessing risk from possible noncompliance, assisting with mitigation plans, or assessing penalties. In Q4 2022, the ERO Enterprise released the ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings report [7] intended to aid stakeholders in strengthening the accuracy and sustainability of their facility ratings programs, resulting in the lessening of facility ratings challenges and ensuring a more reliable and secure bulk power system. To support our stakeholders, the ERO Enterprise actively engaged in mitigating activities associated with facility ratings and identified four common themes that pose challenges to the sustainability of accurate facility ratings:

- Lack of awareness
- Inadequate asset and data management
- Inadequate change management
- Inconsistent development and application of facility ratings methodologies

Table 1: 2022 Risk Elements
Remote Connectivity
Supply Chain
Models Impacting Long-term and Operational Planning
Gaps in Program Execution
Protection System Coordination
Extreme Events

Table 2: 2023 Risk Elements
Remote Connectivity
Supply Chain
Incident Response
Stability Studies
Inverter-Based Resources
Facility Ratings
Cold Weather Response

[7] ERO Enterprise Themes and Best Practices for Sustaining Accurate FR - Final - Oct-20-22.pdf (nerc.com)

Remote Connectivity

The protection of critical infrastructure remains an area of elevated significance. This risk element focuses on the human element of security, one of the descriptors of cybersecurity vulnerabilities identified in the 2018 RISC report.[8] The 2021 RISC report[9] continues to emphasize the need to control poor cyber hygiene. The 2022 State of Reliability report[10] highlights supply chain compromise, geopolitical events, ransomware, and physical security threats as the primary cybersecurity threats to the BPS. A lesson learned from the coronavirus pandemic across all industries has been changes to the designed interaction between employees, vendors, and their workspaces which could have unintended effects on controls and protections of a remote workforce.

Regardless of the sophistication of a security system, there is potential for human error. Compliance monitoring should seek to understand how entities manage the risk of remote connectivity and the complexity of the tasks the individuals perform. If security has increased the difficulty in performing personnel's normal tasks, personnel may look for ways to circumvent the security to make it easier to perform their job. On the other hand, when an entity replaces complex tasks with automation, focus should be on: 1) whether the automation was correctly configured; 2) controls to ensure the automation is operating as intended; and 3) access controls to manage the granting and use of access.

Harvesting credentials and exploiting physical and logical access of authorized users of BES facilities and Cyber Systems (BCSs) pose a major risk to systems that monitor and control the BES. With the target being users, privileged or non-privileged, who have authorized unescorted physical access and/or various levels of access to critical elements of the BES, the risk becomes elevated. By actively and covertly employing social engineering techniques and phishing emails, attackers may deceive authorized users to harvest credentials and gain unauthorized access.[11]

Areas of Focus

Table 3: Remote Connectivity

Rationale	Standard	Req	Entities for	Asset Types
Remote access to Critical Infrastructure Cyber Assets introducing increased attack surface, as well as possible increased exposure.	CIP-005-7	R2	Balancing Authority Distribution Provider Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner	Backup Control Centers Control Centers Data Centers Generation Facilities Transmission Facilities Substations
Malware detection and prevention tools deployed at multiple layers (e.g., Cyber Asset, intra-Electronic Security Perimeter, and at the Electronic Access Point) are critical in maintaining a secure infrastructure.	CIP-007-6	R3	Balancing Authority Distribution Provider Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner	Backup Control Centers Control Centers Data Centers Generation Facilities Transmission Facilities Substations

[8] ERO Reliability Risk Priorities; February 2018
[9] RISC ERO Priorities Report; November 2021
[10] 2022 State of Reliability report
[11] US-CERT TA18-074A

Supply Chain

Supply Chain risks are growing and continue to be a focal point. FERC and NERC released a Joint Staff white paper on Supply Chain vendor identification that provided non-invasive techniques that registered entities may use to identify a vendor of network interfaces deployed on their network.[12] Further, the Presidential Executive Order[13] banning specific foreign manufacturers' equipment addresses supply chain risk from international espionage that is only increasing. In addition, NERC has published several NERC Alerts on Supply Chain risks.[14] Various publications have highlighted several vendors, services, and products widely used by industry, underscoring the importance of awareness as it relates to the supply chain risks.[15] Additionally, it has been reported that security components of BES Cyber Systems may have been compromised within their respective supply chains.[16]

FERC and NERC E-ISAC published a NERC Alert[17] regarding the SolarWinds Orion platform and Microsoft Azure/365 Cloud compromises, highlighting large and recent supply chain attacks that had widespread implications. The SolarWinds Orion attack mainly affected key suppliers, resulting in industry being impacted downstream even though the registered entity may not have purchased and/or installed the infected software. Underscoring the severity of these supply chain attacks, the U.S. Department of Homeland Security (DHS) Cybersecurity and Infrastructure Security Agency (CISA) required federal agencies to take action in an Emergency Directive 21-01.[18] Due to both supply chain attacks, DHS CISA developed various tools[19] to help identify compromises. Additionally, the supply chain attacks on meat processing giant JBS and Colonial Pipeline have lessons learned that can be applied to the electric sector. While these risks may create registered entity reliability issues, collectively the risks could cause BPS cascading disruptions. Additionally, President Biden's National Security Memorandum of July 28, 2021[20] mandated CISA to publish cross-sector cybersecurity goals and objectives for critical infrastructure control systems. The initial draft[21] covers nine common baseline controls, including supply chain.

[12] Joint Staff Whitepaper on Supply Chain

[13] Executive Order on Securing the Information and Communications Technology and Services Supply Chain

[14] NERC Alerts

[15] EPRI, Supply Chain Risk Assessment Report, July 2018; Office of the Director of National Intelligence, Supply Chain Risk Management: Reducing Threats to Key U.S. Supply Chains, September 2020; Microsoft, Defending the power grid against supply chain attacks, February 2020; Department of Energy, America's Strategy to Secure the Supply Chain for a Robust Clean Energy Transition, February 2022

[16] NATF, Cyber Security Supply Chain Risk Management Guidance, June 2018; Department of Homeland Security and Department of Commerce, Assessment of the Critical Supply Chains Supporting the U.S. Information and Communications Technology Industry, February 2022; American Public Power Association, Shortage Changed: How Utilities Are Adapting to Supply Chain Issues, February 2022

[17] NERC, SolarWinds and Related Supply Chain Alert

[18] CISA ED 21-01

[19] CISA Sparrow and Aviary

[20] National Security Memorandum on Improving Cybersecurity for Critical Infrastructure Control Systems

[21] Cross-Sector Cybersecurity Performance Goals (CPGs) Common Baseline: Controls List

Area of Focus

Table 4: Supply Chain				
Rationale	**Standard**	**Req**	**Entities for**	**Asset Types**
Unverified software sources and the integrity of their software may introduce malware or counterfeit software.	CIP-010-4	R1	Balancing Authority Distribution Provider Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner	Backup Control Centers Control Centers Data Centers Generation Facilities Transmission Facilities Substations
Mitigate risks to the reliable operation of the BES by implementing sound Supply Chain policies and procedures.	CIP-013-2	R1 R2	Balancing Authority Distribution Provider Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner	Backup Control Centers Control Centers Data Centers Generation Facilities Transmission Facilities Substations

Incident Response

Incident response has increasingly emerged as a risk to the BPS. Dragos has published a white paper[22] on the malware developed by threat group Chernovite named Pipedream. This particular piece of malware is targeting industrial control systems, including the electric sector. One of the long-term readiness best practices within this white paper is to have an updated industrial control system-focused incident response plan with accompanying Standard Operating Procedures and Emergency Operating Procedures for operating with a hampered or degraded control system. Additionally, the CISA Cross-Sector CPGs Common Baseline includes the need to develop, maintain, and practice incident response plans to ensure effective response to threat actions against all assets, along with reporting cybersecurity incidents across IT and OT assets to CISA and any other mandatory reporting stakeholders.

Area of Focus

Table 5: Incident Response				
Focused Risk	**Standard**	**Req**	**Entities for**	**Asset Types**
Mitigate risks to the reliable operation of the BES as the result of a Cyber Security Incident.	CIP-008-6	R1 R2	Balancing Authority Distribution Provider Generator Operator Generator Owner Reliability Coordinator Transmission Operator Transmission Owner	Backup Control Centers Control Centers Data Centers Generation Facilities Transmission Facilities Substations

22 Pipedream: Chernovite's Emerging Malware Targeting Industrial Control Systems

Stability Studies

The ERO Enterprise continues to make steady progress in evaluating operational and transmission planning impacts resulting from the changing resource mix. The NERC 2021 Long-term Reliability Assessment highlights BPS risks associated with inverter-based resources (IBRs).[23] In particular, events with tripping of IBRs during disturbances are increasing in both frequency and severity. Unexpected tripping of IBRs indicates issues with dynamic model accuracy as well as issues with the robustness and thoroughness of stability studies. The ERO Enterprise has released new guidance documents pertaining to modeling verification practices that should be incorporated to, sufficiently address grid transformation impacts.[24] Industry adaptation to recent guidance will also require incremental improvements in stability studies performed for both long-term and operational planning to provide assurance adverse system conditions are being effectively identified and corrected.

CMEP reviews of transmission planning studies have traditionally focused more heavily on the development of Contingency lists as well as steady-state studies. Building off that knowledge, CMEP staff may further seek to understand how entities are effectively studying within the time-domain in order to preemptively identify system performance issues following simulated system disturbances. The selection of cases, Contingencies, and monitored elements should be evaluated for robustness. The selection of criteria and thresholds should be evaluated for appropriateness, thoroughness, and alignment between neighboring entities. This risk may be also be associated with incorrect protection system settings and modeling inaccuracies. These other areas should be considered, as additional areas to investigate to gain assurance stability studies are effective.

Areas of Focus

Table 6: Stability Studies			
Rationale	**Standard**	**Requirements**	**Entities for Attention**
Planning studies are effective in identifying system performanc e issues following both minor and major system disturbances	TPL-001-4, TPL-001-5.1	R4, R6	Transmission Planner Planning Coordinator
	CIP-014-3	R1	Transmission Owner

[23] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

[24] https://www.nerc.com/comm/RSTC/Pages/default.aspx

Inverter-Based Resources

Studies have shown a need to understand and more accurately model IBR characteristics. NERC has identified adverse characteristics of IBRs in two separate Alerts.[25,26] NERC has also released detailed reports about disturbances in Texas[27] and California[28] which strongly recommend that industry take timely action to implement all of the recommendations set forth within the disturbance reports and related NERC reliability guidelines. With the recent and expected increases of both utility-scale solar resources and distributed generation, the causes of a sudden reduction in power output from utility-scale power inverters need to be widely communicated and addressed by the industry. Entities with increasing IBRs should be aware and address this within their models.[29]

The Texas[30] and California[31] reports identify that solar PV plants lack sufficient ride-through capability to support the BPS for normal BPS fault events. This reliability concern is persistent, growing in the number of resources prone to this issue, not being mitigated appropriately, and warrants mitigating actions.

CMEP staff are expected to review and consider the guidance for auditing relevant requirements using the ERO Enterprise CMEP Practice Guide: Information to be Considered by CMEP Staff Regarding Inverter-Based Resources.[32]

For transparency, NERC's Inverter-Based Resource Strategy was released in September 2022[33].

Area of Focus

Table 7: Inverter Based Resources			
Rationale	**Standard**	**Requirements**	**Entities for Attention**
Clear and consistent interconnection requirements for IBRs	FAC-001-3	R1, R2	Generator Owner Transmission Owner
IBRs being adequately studied	FAC-002-3	R1, R2	Generator Owner Transmission Planner Planning Coordinator
IBRs staying online when needed	PRC-024-3	R1, R2	Generator Owner

25 Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings - II; May 2018
26 NERC Modeling Notification: Recommended Practices for Modeling Momentary Cessation Distribution; February 2018
27 Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report; September 2021
28 Multiple Solar PV Disturbances in CAISO Disturbances between June and August 2021; April 2022
29 Considerations for Power Plant and Transmission System Protection Coordination, July 2015
30 Odessa Disturbance Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report; September 2021
31 Multiple Solar PV Disturbances in CAISO Disturbances between June and August 2021; April 2022
32 https://www.nerc.com/pa/comp/guidance/CMEPPracticeGuidesDL/ERO%20Enterprise%20CMEP%20Practice%20Guide%20Regarding%20Inverter-Based%20Resources.pdf
33 https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

Facility Ratings

The accuracy of Facility Ratings is a cornerstone of being able to use and protect the BES. Inaccurate Facility Ratings undermine the usefulness of Stability Studies, which is another risk element identified earlier in this CMEP IP. Operators depend on Facility Ratings to provide reliable System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) that inform operating decisions. Protection engineers rely on Facility Ratings to protect equipment from damage while also allowing equipment to stay online when it is both safe and most needed. Some registered entities have Facility Ratings based on inaccurate equipment inventories, or ratings are not being updated during projects or following severe weather.

Given its importance, CMEP staff is urged to understand an entity's controls that it has put in place to track Facility Ratings, which can be a large amount of data. Knowing how an entity has established an accurate baseline for its data, and how it handles any changes going forward from that baseline, can give a good indication of if an entity is struggling.

Table 8: Facility Ratings

Rationale	Standard	Requirements	Entities for Attention
Ensuring entities maintain accurate Facility Ratings	FAC-008-5	R6	Generator Owner Transmission Owner

Cold Weather Response

Cold weather events encompass a wide range of situations that can cause major BPS impacts. As identified in the 2021 RISC report,[34] recent cold weather events (e.g., in ERCOT, MISO, and SPP) show that not only do cold weather events pose challenges due to the nature and frequency of the events themselves, but also that grid transformation heightens the effects and complicates mitigation of the event. Cold weather events can stress the BPS and expose weaknesses such as poor coordination between neighboring entities in planning or operations.

This risk element needs to be understood in light of: the recently expedited FERC approval[35] of the Cold Weather Reliability Standards,[36] the November 2021 release of the FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States,[37] and the *Cold Weather Preparations for Extreme Weather*[38] *Events* Alert.[39] The updated Reliability Standards changed to focus on cold weather preparedness are not enforceable until April 1, 2023. Therefore, ERO Enterprise CMEP staff may find that an entity has yet to develop and implement the relevant processes and procedures. However, it is important to understand entity plans for, and progress toward, mitigating risk for the upcoming winter and going forward. The ERO Enterprise has developed a Practice Guide[40] to support understanding of this risk.

Areas of Focus

Table 9: Cold Weather Response

Rationale	Standard	Requirements	Entities for Attention
Ensure plans are developed and implemented to mitigate operating Emergencies	EOP-011-2	R1, R2, R3, R6, R7	Balancing Authority Generator Owner Reliability Coordinator Transmission Operator

34 RISC ERO Priorities Report; August 2021

35 eLibrary | File List (ferc.gov)

36 Project 2019-06 Cold Weather (nerc.com)

37 FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States

38 Extreme Cold Weather as defined in the *Polar Vortex Review* dated September 2014; Extreme Cold Weather conditions occurred in lower latitudes than normal, resulting in temperatures 20 to 30° F below average.

39 https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2021-08-18-01%20Extreme%20Cold%20Weather%20Events.pdf

40 ERO Enterprise CMEP Practice Guide - Cold Weather Preparedness

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

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, KIM WHETZEL, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: March 1, 2024

KIM WHETZEL

APPENDIX 1A

Q1 2023 Natural Gas Hedging Update

March 29, 2023

Market Fundamentals Overview

- ✓ In January and February, below-average U.S. natural gas consumption in the residential and commercial sectors was driven by mild winter weather across large parts of the country, particularly in the Northeast and the Midwest. Based on preliminary data from the National Oceanic and Atmospheric Administration (NOAA) for January and February, the first two months of 2023 combined were among the three warmest on record for that period going back to 1895. In March, Energy Information Administration (EIA) expects natural gas consumption in the residential and commercial sectors to average almost 32 billion cubic feet per day (Bcf/d), which is close to the five-year average, because EIA expects more normal temperatures in March with a close to average number of heating degree days. [EIA, Short-Term Energy Outlook, March 7, 2023].

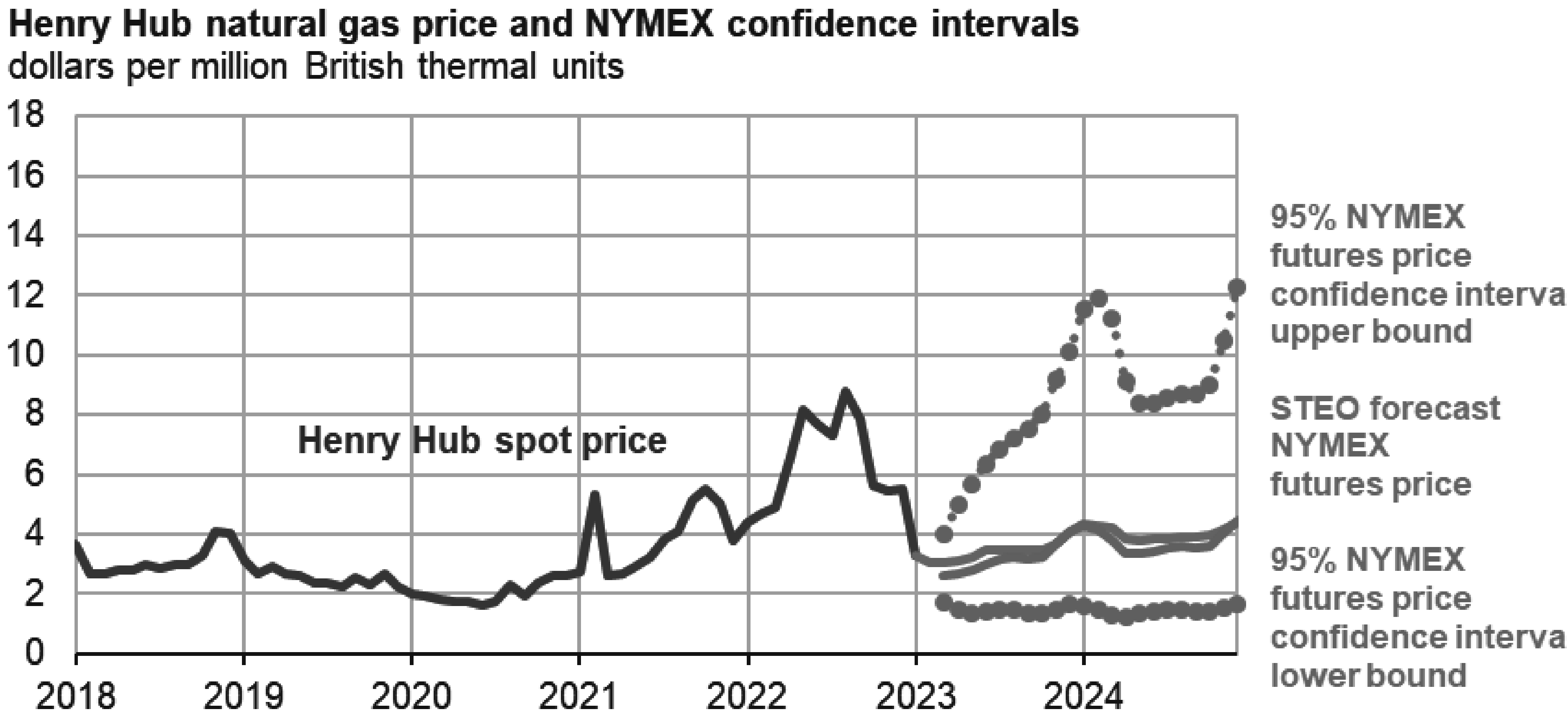
Market Fundamentals Overview

- ✓ As a result of the mild winter and low natural gas consumption in the residential and commercial sectors, EIA in its most recent report for the March forecasts 2.4% or 2 Bcf/d less U.S. natural gas consumption in 2023 than in 2022. Reduced natural gas consumption in January and February slowed withdrawals from natural gas inventories to less than the five-year average and reduced natural gas prices. The spot price of natural gas at the U.S. benchmark Henry Hub averaged $2.38 per million British thermal units (MMBtu) in February (see chart on pg.5), the lowest monthly average since September 2020 [EIA, Short-Term Energy Outlook, March 7, 2023].

Market Fundamentals Overview

- ✓ EIA anticipates that the U.S. will close the withdrawal season at the end of March with more than 1.9 trillion cubic feet of natural gas in storage or 23% more than the five-year average (see chart on pg.6). [EIA, Short-Term Energy Outlook, March 7, 2023].
- ✓ EIA expects natural gas production will be relatively flat for the rest of 2023 as producers reduce drilling in response to lower prices (see chart on pg.7) [EIA, Short-Term Energy Outlook, March 7, 2023].
- ✓ The Henry Hub natural gas spot price in the EIA forecast averages about $3 per MMBtu in 2023, down by more than 50% from last year. Price increases in the second half of 2023 and in 2024 forecast, result from rising demand from Freeport liquefied natural gas (LNG) reopening (see chart on pg.8), which shut down last June due to a fire, and seasonal increases in natural gas demand in the electric power sector. [EIA, Short-Term Energy Outlook, March 7, 2023].

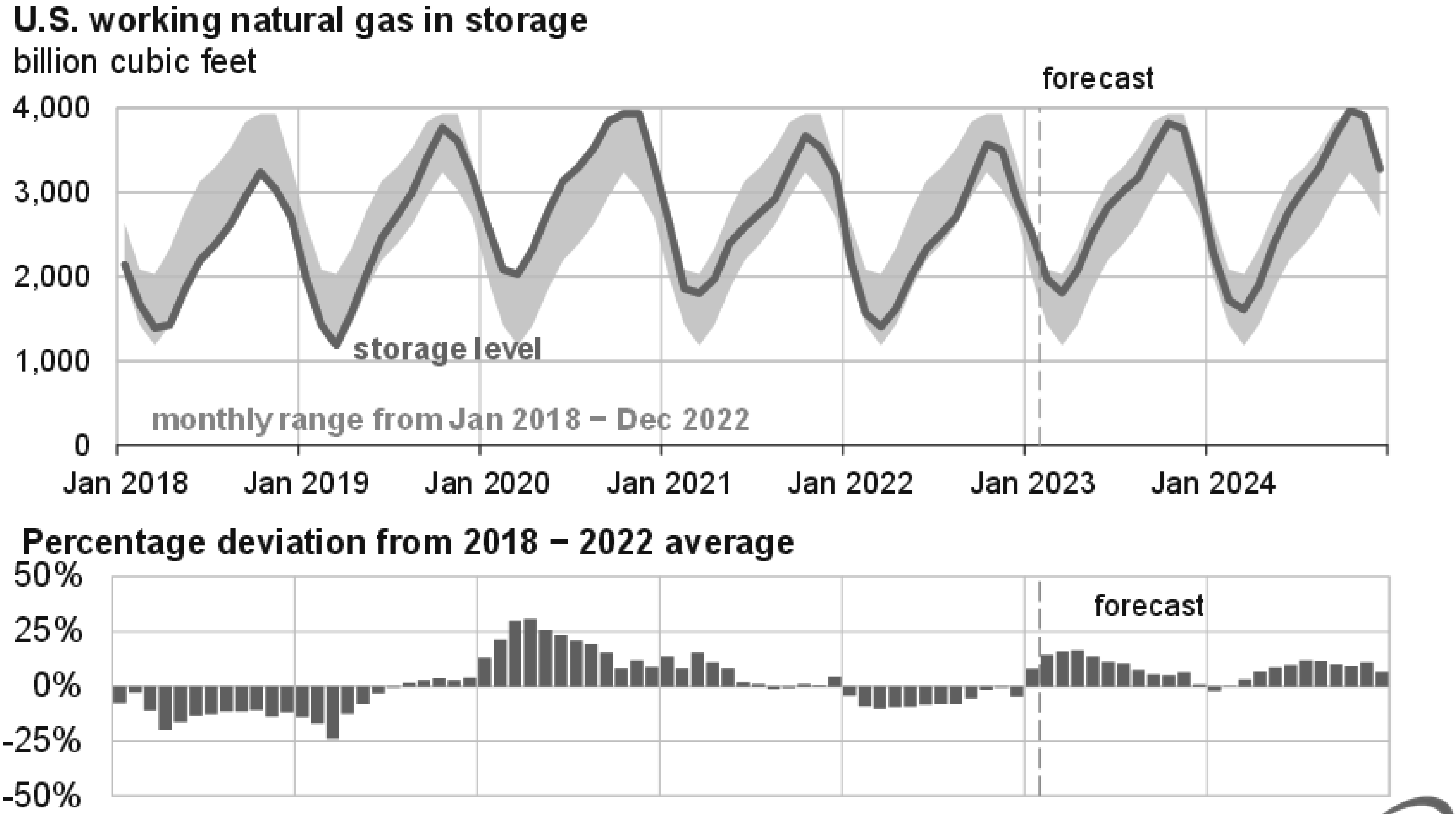
U.S. Natural Gas Prices



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, February 2023, CME Group, and Refinitiv an LSEG Business

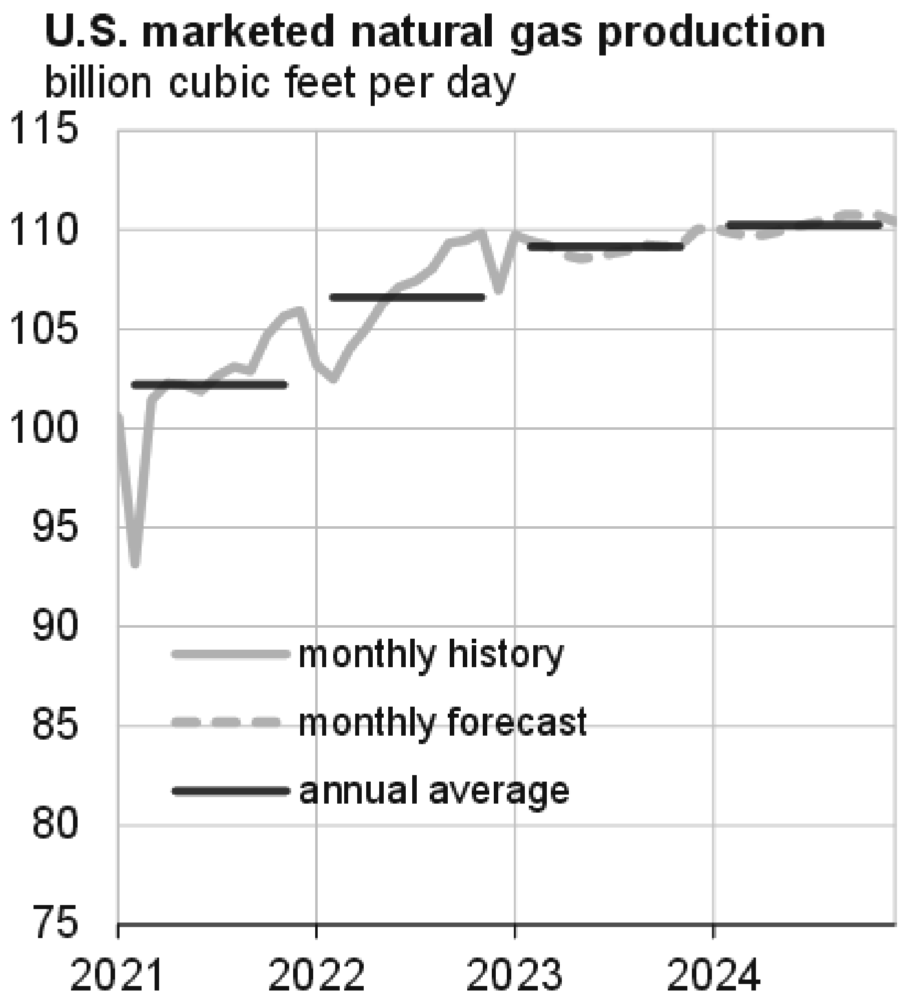
Note: Confidence interval derived from options market information for the five trading days ending February 2, 2023. Intervals not calculated for months with sparse trading in near-the-money options contracts.

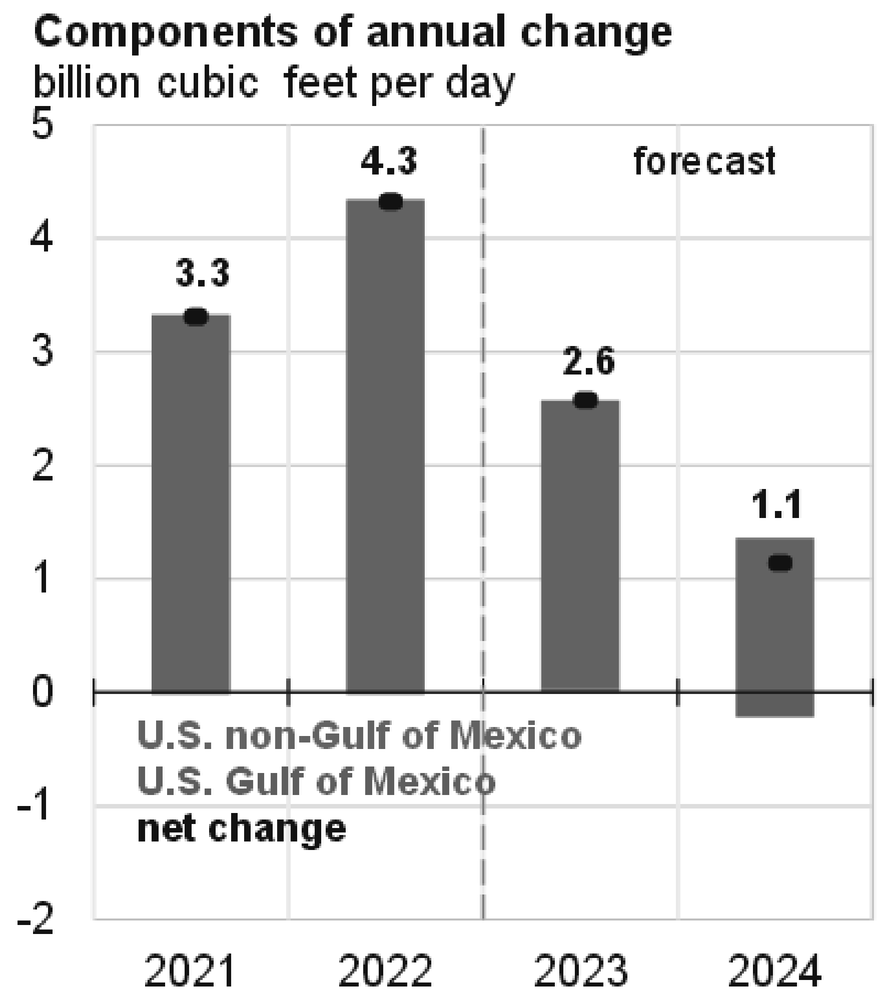
U.S. Gas Storage (Lower 48)



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, February 2023

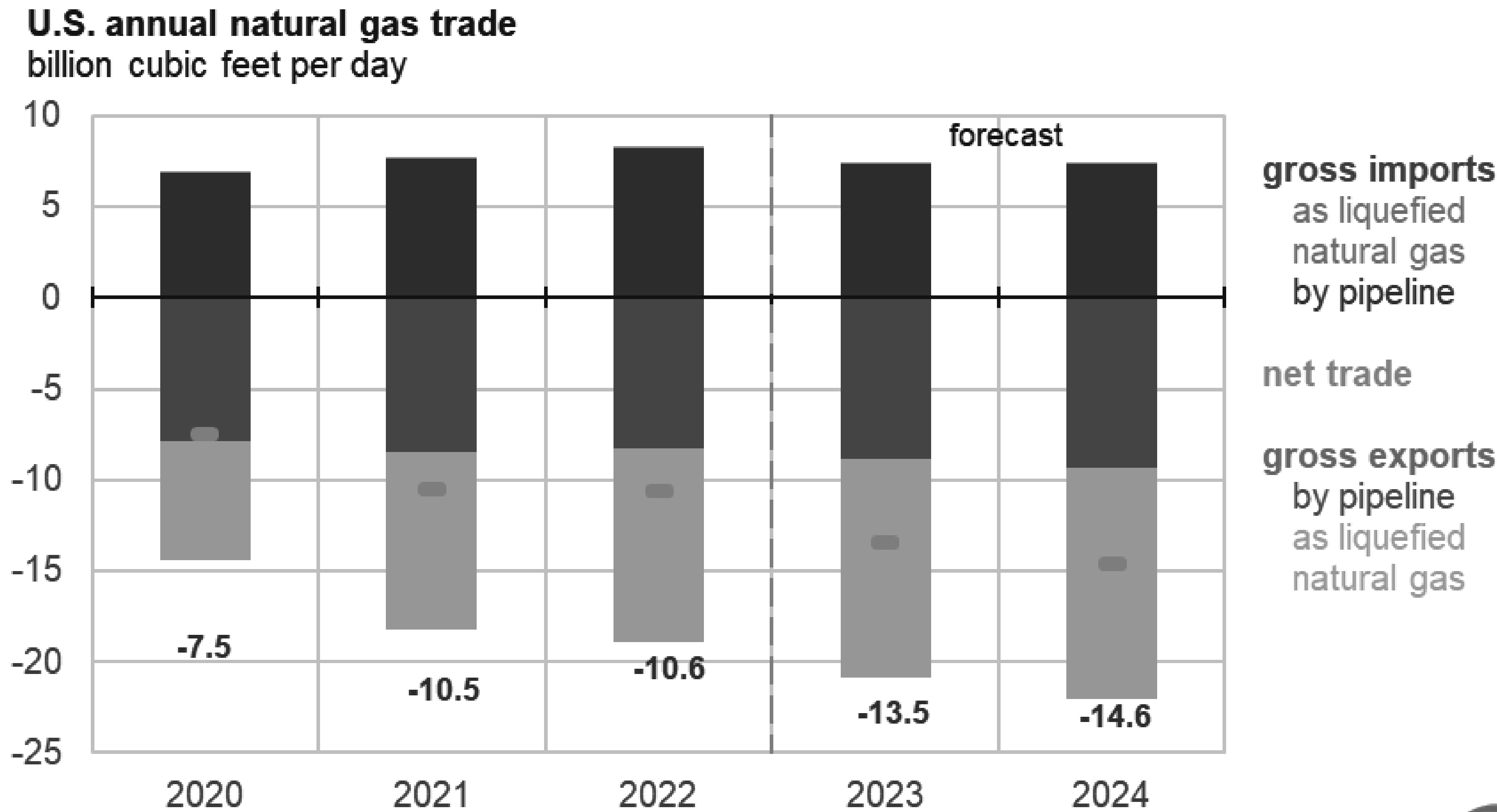
U.S. Dry Natural Gas Production





Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2023

U.S. Natural Gas Trade



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, March 2023

Natural Gas Pipeline Activities

✓ Tuscarora Pipeline

- ❑ Tuscarora Gas Transmission Company was required by the FERC to file a Section 4 rate case by July 31, 2022. The rate case was filed.
- ❑ The Company began participating in pre-settlement discussions with Tuscarora this summer regarding the rate case.
- ❑ On March 1, 2023, the Company and other parties reached a settlement agreement with Tuscarora. On March 9, a Stipulation and Agreement of Settlement was filed with the FERC.

✓ Kern River Pipeline

- ❑ The Company is collaborating with Kern River to increase the delivery capacity at the Silverhawk plant.
- ❑ The capacity is being increased to accommodate the addition of 440 MW of peaking turbines. This request was approved in NPC/SPPC 4th IRP Amendment, Docket 22-11032.

Gas Risk Evaluation Matrix (NVE South)

	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	1,453,378	1,881,653	2,475,587	2,945,005	2,775,203	2,225,662	1,622,092	1,342,037	1,494,753	1,490,234	1,326,047	1,415,456	22,447,107
Previous Quarter [2]	1,466,521	1,895,872	2,488,382	2,957,290	2,788,429	2,239,448	1,636,122	1,354,170	1,506,807	1,502,541	1,337,156	1,427,986	22,600,727
Current Outlook [3]	1,451,254	1,878,791	2,469,857	2,936,754	2,767,446	2,219,272	1,615,821	1,334,460	1,485,533	1,511,673	1,345,793	1,436,374	22,453,027
Change from Filed ESP	(2,124)	(2,861)	(5,731)	(8,251)	(7,757)	(6,390)	(6,271)	(7,578)	(9,219)	21,439	19,746	20,918	5,921
Change from Previous Quarter	(15,267)	(17,081)	(18,525)	(20,537)	(20,983)	(20,176)	(20,302)	(19,710)	(21,274)	9,132	8,636	8,387	(147,699)
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Previous Quarter [2]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Current Outlook [3]	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	6,233,338	9,367,651	9,171,468	13,037,674	11,271,353	9,678,416	8,558,132	7,567,968	9,059,909	8,511,965	6,446,678	6,140,310	105,044,863
Previous Quarter [2]	6,834,333	10,163,500	8,757,934	12,194,075	10,975,424	9,264,882	8,841,219	7,869,679	9,298,796	8,720,567	6,510,176	6,555,720	105,986,307
Current Outlook [3]	8,185,472	10,798,351	9,596,040	11,975,624	11,371,434	10,802,122	10,501,185	9,170,426	10,992,507	10,732,109	8,795,844	8,865,293	121,786,406
Change from Filed ESP	1,952,133	1,430,700	424,571	(1,062,050)	100,080	1,123,706	1,943,053	1,602,458	1,932,597	2,220,144	2,349,167	2,724,983	16,741,544
Change from Previous Quarter	1,351,139	634,851	838,105	(218,451)	396,010	1,537,240	1,659,966	1,300,747	1,693,711	2,011,542	2,285,668	2,309,573	15,800,099

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] December 2022 Risk Run
[3] March 2023 Risk Run
[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)
[5] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[6] December 2022 forecasts
[7] March 2023 forecasts

Gas Risk Evaluation Matrix (NVE North)

Page 1 of 2

	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	751,904	810,267	841,051	999,264	967,091	798,668	783,565	808,835	883,167	880,289	784,201	839,934	10,148,235
Previous Quarter [2]	758,806	817,925	848,304	1,006,352	974,981	806,518	790,645	815,621	890,046	887,310	790,604	847,167	10,234,280
Current Outlook [3]	828,039	887,714	920,862	1,081,954	1,053,772	880,640	861,267	883,235	956,827	957,929	858,057	919,952	11,090,247
Change from Filed ESP	76,135	77,447	79,811	82,690	86,681	81,971	77,701	74,400	73,660	77,640	73,857	80,017	942,011
Change from Previous Quarter	69,233	69,789	72,558	75,603	78,790	74,121	70,622	67,614	66,781	70,618	67,454	72,785	855,967
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	247,399
Previous Quarter [2]	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	247,399
Current Outlook [3]	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	247,399
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Consumption Forecast (MMBtu):													
ESP [1]	1,305,621	844,967	554,990	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	18,625,182
Previous Quarter [2]	1,305,621	844,967	554,990	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	18,625,182
Current Outlook [3]	1,305,621	844,967	554,990	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	18,625,182
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	2,262,930	2,832,591	2,692,101	3,489,435	3,183,919	2,709,118	2,672,923	2,273,644	2,227,816	2,213,214	2,255,947	2,270,741	31,084,377
Previous Quarter [2]	2,326,091	2,728,809	2,865,380	3,871,202	3,251,516	2,974,086	2,779,534	2,543,514	2,425,319	2,278,631	2,237,722	1,758,223	32,040,028
Current Outlook [3]	1,938,412	2,698,812	2,989,285	3,947,878	3,553,698	3,118,700	2,793,526	2,574,864	2,534,475	2,365,291	2,052,167	2,232,085	32,799,193
Change from Filed ESP	(324,517)	(133,779)	297,184	458,444	369,779	409,582	120,603	301,220	306,659	152,077	(203,780)	(38,656)	1,714,816
Change from Previous Quarter	(387,679)	(29,997)	123,905	76,677	302,181	144,614	13,993	31,350	109,156	86,660	(185,556)	473,862	759,165

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] December 2022 Risk Run
[3] March 2023 Risk Run
[4] Combined Paiute and Tuscarora transportation contracts

REDACTED PUBLIC VERSION

Gas Risk Evaluation Matrix (NVE North)
Page 2 of 2

	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	12 Mos.
[redacted]													

[5] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[6] December 2022 forecasts
[7] March 2023 forecasts

NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.
- ✓ NV Energy is currently investigating the potential for natural gas pricing hedging and will modify its' plan if necessary.

Forward Sales Transactions

- ✓ The Company will continue to market prompt month heat rate call option sales when the material length is available.
- ✓ There were no forward sales executed in Q1.

APPENDIX 1B

Q2 2023 Natural Gas Hedging Workshop

June 28, 2023

Market Fundamentals Overview

- ✓ EIA in its June outlook forecasts the U.S. benchmark Henry Hub natural gas spot price to rise in the summer months, averaging just over $2.60/MMBtu in 3Q23, up from an average of $2.15/MMBtu in May. Rising natural gas use in the electric power sector and flattening production growth are the primary drivers. The Henry Hub spot price averages around $3.40/MMBtu in 2024 in the June forecast, nearly 30% higher than in 2023 (see slide on pg.5). Although EIA forecasts an increase in natural gas prices for the summer months, it is expected high inventory levels will keep prices well below last year's prices, which averaged almost $8.00/MMBtu in 3Q22 [EIA, Short-Term Energy Outlook, June 2023].

Market Fundamentals Overview

- ✓ As EIA estimates U.S. dry natural gas production set a monthly record in April of 104 billion cubic feet per day (Bcf/d), up from 102 Bcf/d in March (see slide on pg.6). The production record occurred despite natural gas prices that averaged below $2.50 per million British thermal units (MMBtu) at the U.S. benchmark Henry Hub in March and April, about $4.00/MMBtu less than the 2022 annual average [EIA, Short-Term Energy Outlook, June 2023].
- ✓ Production growth has been concentrated in two regions: the Haynesville region in northeastern Texas and northwestern Louisiana, and the Permian Basin in western Texas and southeastern New Mexico. Growth in the Haynesville region reflects the lagged effects of high natural gas prices in 2022 that increased drilling activity in the region. Growth in natural gas production in the Permian, because of which is mostly associated natural gas, has been driven by relatively high oil prices and increased oil production [EIA, Short-Term Energy Outlook, June 2023].

NVEnergy

Market Fundamentals Overview

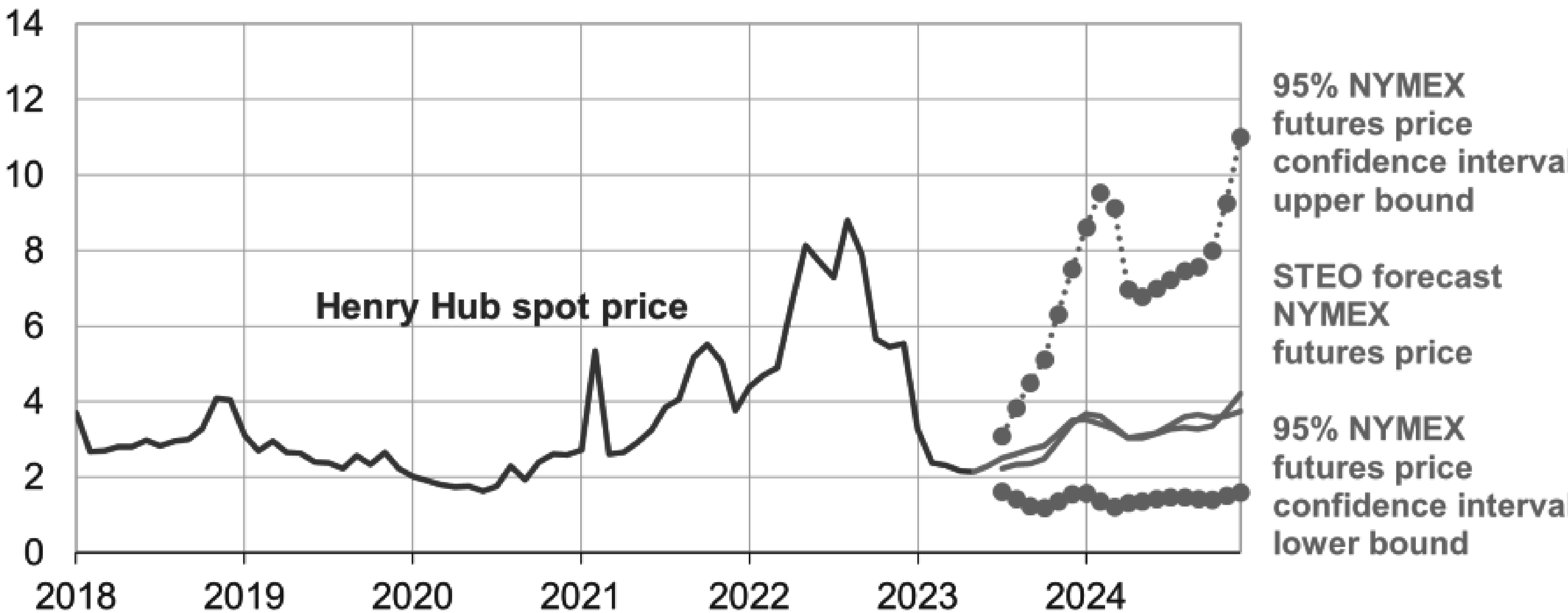
- ✓ EIA forecast dry natural gas production will remain close to record levels through much of the rest of the forecast period, averaging around 103 Bcf/d during the second half of 2023 and 2024. The flat production reflects reduced natural gas-directed drilling in response to the drop in natural gas prices this year being offset by increasing associated natural gas production in the Permian Basin [EIA, Short-Term Energy Outlook, June 2023].

- ✓ EIA Natural gas storage inventories were 15% above the five-year average at the end of May compared with a deficit of 14% below the 2017–2021 average at the end of May 2022 (see slide on pg.7). The average rate of injections into storage is 8% higher than the five-year average so far in the refill season (April through October). If the rate of injections into storage matched the five-year average of 9.0 Bcf/d for the remainder of the refill season, the total inventory would be 3,957 Bcf on October 31, which is 362 Bcf higher than the five-year average of 3,595 Bcf for that time of year. [EIA, Natural Gas Weekly Update for week ending June 21, 2023.]

NVEnergy

U.S. Natural Gas Prices

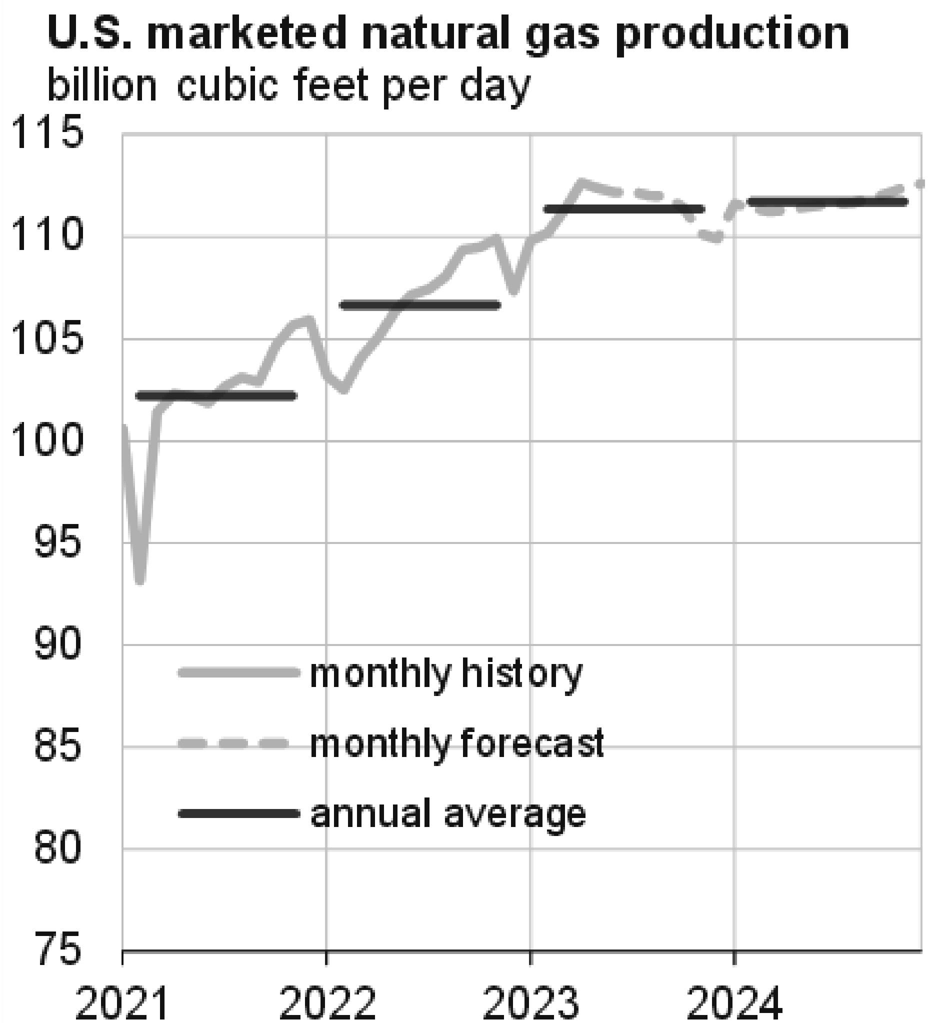
Henry Hub natural gas price and NYMEX confidence intervals
dollars per million British thermal units

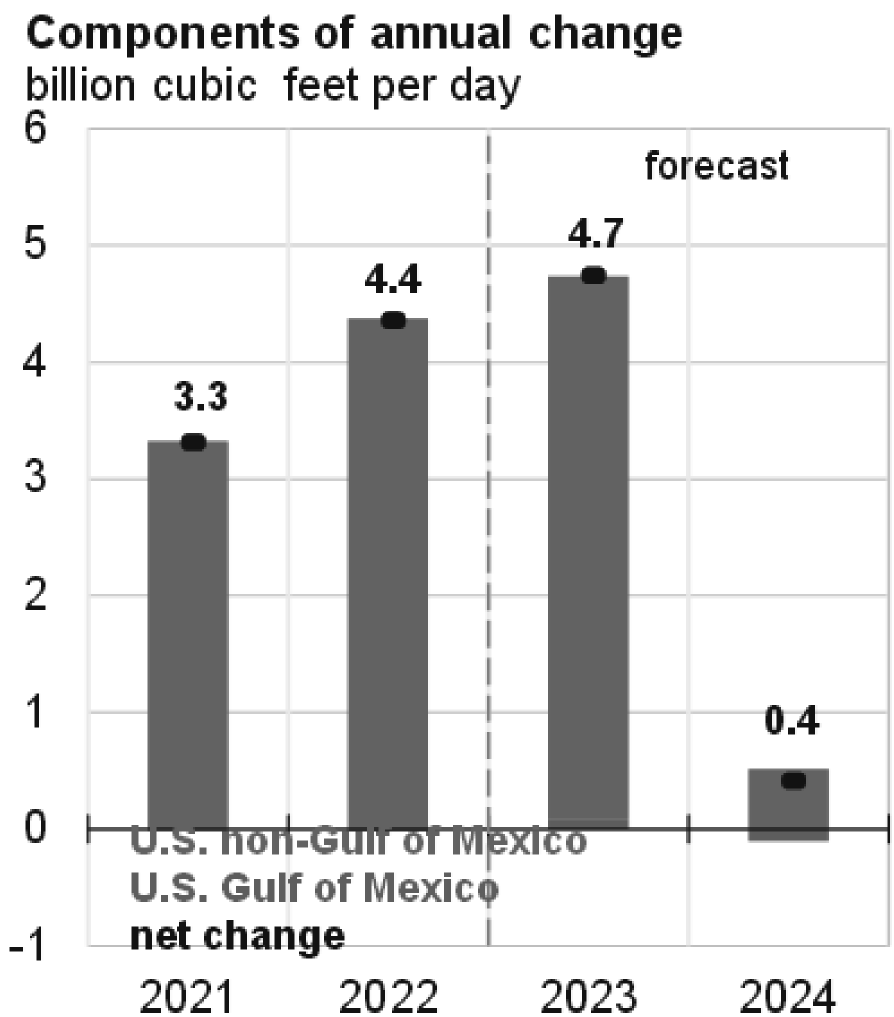


Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, June 2023, CME Group, and Refinitiv an LSEG Business

Note: Confidence interval derived from options market information for the five trading days ending June 5, 2023. Intervals not calculated for months with sparse trading in near-the-money options contracts.

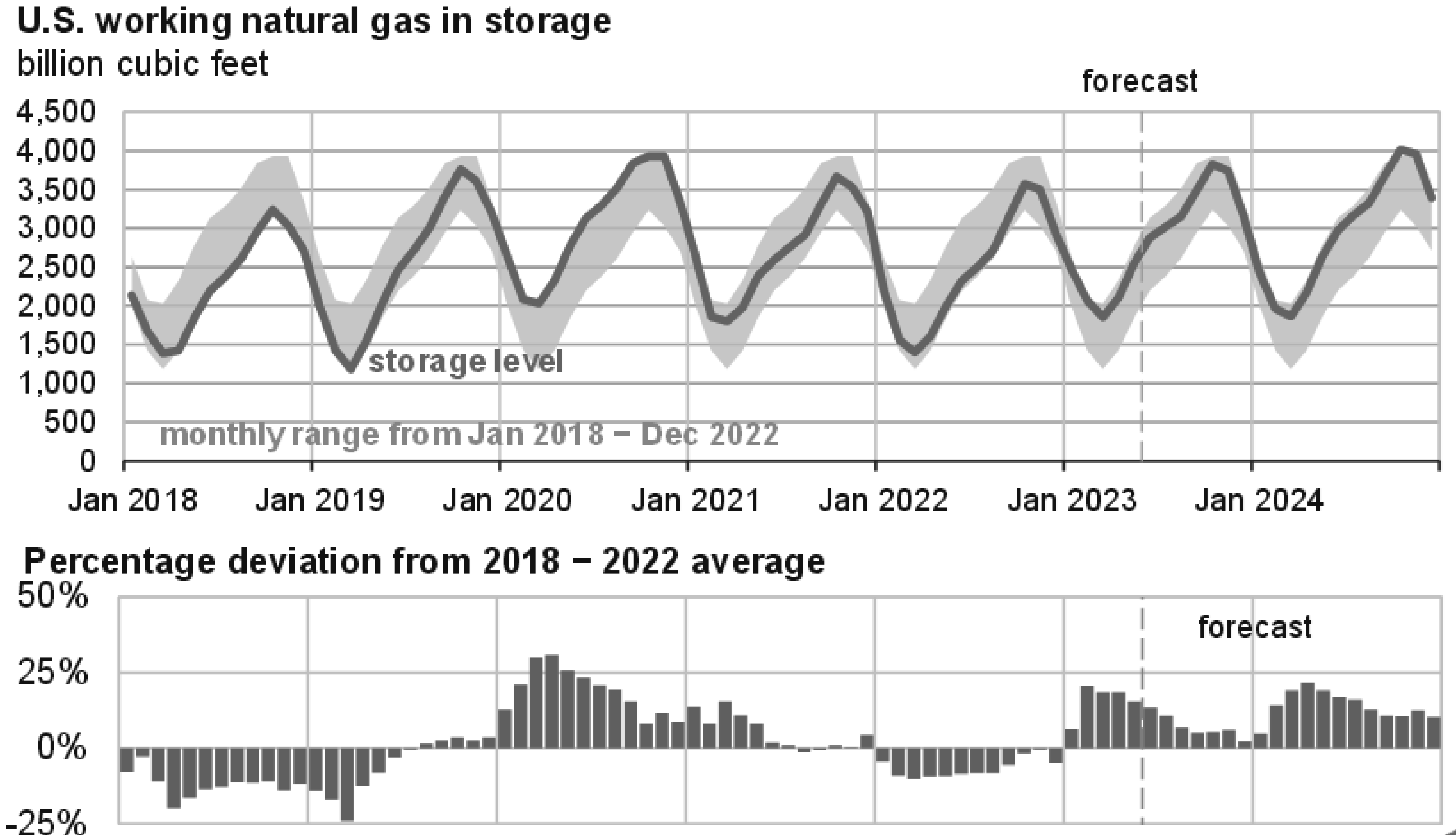
U.S. Dry Natural Gas Production





Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, June 2023

U.S. Gas Storage (Lower 48)



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, June 2023

Natural Gas Pipeline Activities

✓ Gas Transmission Northwest (GTN) Pipeline

- ❑ GTN is required by the FERC to file a Section 4 rate case by September 30, 2023.
- ❑ The Company along with other utilities and natural gas marketers began participating in pre-settlement discussions with GTN on May 12.
- ❑ Data requests were submitted to GTN for clarification.
- ❑ Negotiations are ongoing.

NVEnergy

Gas Risk Evaluation Matrix (NVE South)

	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	2,945,005	2,775,203	2,225,662	1,622,092	1,342,037	1,494,753	1,490,234	1,326,047	1,415,456	1,484,453	1,925,750	2,524,081	22,570,772
Previous Quarter [2]	2,936,754	2,767,446	2,219,272	1,615,821	1,334,460	1,485,533	1,511,673	1,345,793	1,436,374	1,505,133	1,946,910	2,542,637	22,647,804
Current Outlook [3]	2,957,290	2,788,429	2,239,448	1,636,122	1,354,170	1,506,807	1,502,541	1,337,156	1,427,986	1,497,459	1,939,815	2,536,562	22,723,786
Change from Filed ESP	12,285	13,226	13,787	14,031	12,133	12,055	12,307	11,109	12,530	13,006	14,065	12,481	153,015
Change from Previous Quarter	20,537	20,983	20,176	20,302	19,710	21,274	(9,132)	(8,636)	(8,387)	(7,674)	(7,095)	(6,075)	75,982
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Previous Quarter [2]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Current Outlook [3]	424,935	424,935	424,935	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	13,037,674	11,271,353	9,678,416	8,558,132	7,567,968	9,059,909	8,511,965	6,446,678	6,140,310	6,397,172	7,161,199	8,856,205	102,686,981
Previous Quarter [2]	11,975,254	11,371,249	10,802,122	10,501,185	9,170,426	10,992,507	10,732,109	8,795,844	8,865,293	8,529,953	9,955,882	10,786,651	122,478,475
Current Outlook [3]	12,714,050	10,570,355	10,085,562	9,217,453	8,105,319	9,652,614	9,511,319	7,833,742	7,540,664	7,821,404	8,781,768	10,013,338	111,847,588
Change from Filed ESP	(323,624)	(700,998)	407,146	659,322	537,351	592,705	999,354	1,387,065	1,400,354	1,424,232	1,620,569	1,157,133	9,160,607
Change from Previous Quarter	738,796	(800,893)	(716,560)	(1,283,732)	(1,065,107)	(1,339,893)	(1,220,790)	(962,102)	(1,324,629)	(708,549)	(1,174,114)	(773,313)	(10,630,886)

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] March 2023 Risk Run
[3] June 2023 Risk Run
[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)
[5] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[6] March 2023 forecasts
[7] June 2023 forecasts

Gas Risk Evaluation Matrix (NVE North)

Page 1 of 2

	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	999,264	967,091	798,668	783,565	808,835	883,167	880,289	784,201	839,934	781,237	841,917	872,935	10,241,104
Previous Quarter [2]	1,081,954	1,053,772	880,640	861,267	883,235	956,827	957,929	858,057	919,952	857,141	918,926	952,177	11,181,876
Current Outlook [3]	1,006,352	974,981	806,518	790,645	815,621	890,046	887,310	790,604	847,167	788,233	849,622	880,257	10,327,356
Change from Filed ESP	7,087	7,891	7,850	7,080	6,785	6,879	7,022	6,403	7,233	6,996	7,704	7,322	86,252
Change from Previous Quarter	(75,603)	(78,790)	(74,121)	(70,622)	(67,614)	(66,781)	(70,618)	(67,454)	(72,785)	(68,908)	(69,304)	(71,919)	(854,519)
[redacted]													
[redacted]													
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	247,399
Previous Quarter [2]	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	247,399
Current Outlook [3]	234,627	234,627	234,627	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	247,399
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Consumption Forecast (MMBtu):													
ESP [1]	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	18,679,141
Previous Quarter [2]	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	18,679,141
Current Outlook [3]	478,355	481,515	596,929	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	18,679,141
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	3,489,435	3,183,919	2,709,118	2,672,923	2,273,644	2,227,816	2,213,214	2,255,947	2,270,741	1,691,426	2,021,001	2,591,055	29,600,238
Previous Quarter [2]	3,947,878	3,553,698	3,118,700	2,793,526	2,574,864	2,534,475	2,365,291	2,052,167	2,232,085	2,368,871	2,529,146	2,937,334	33,008,035
Current Outlook [3]	3,947,679	3,863,940	3,242,845	3,202,352	2,720,302	2,614,534	2,654,073	2,357,049	2,732,521	1,879,232	2,552,632	2,992,523	34,759,682
Change from Filed ESP	458,244	680,021	533,727	529,429	446,658	386,718	440,859	101,103	461,780	187,806	531,631	401,468	5,159,444
Change from Previous Quarter	(199)	310,242	124,145	408,825	145,438	80,059	288,782	304,883	500,436	(489,639)	23,487	55,189	1,751,646

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] March 2023 Risk Run
[3] June 2023 Risk Run
[4] Combined Paiute and Tuscarora transportation contracts

Gas Risk Evaluation Matrix (NVE North)
Page 2 of 2

	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	12 Mos.
[redacted]													

[5] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[6] March 2023 forecasts
[7] June 2023 forecasts

NV Energy Course of Action

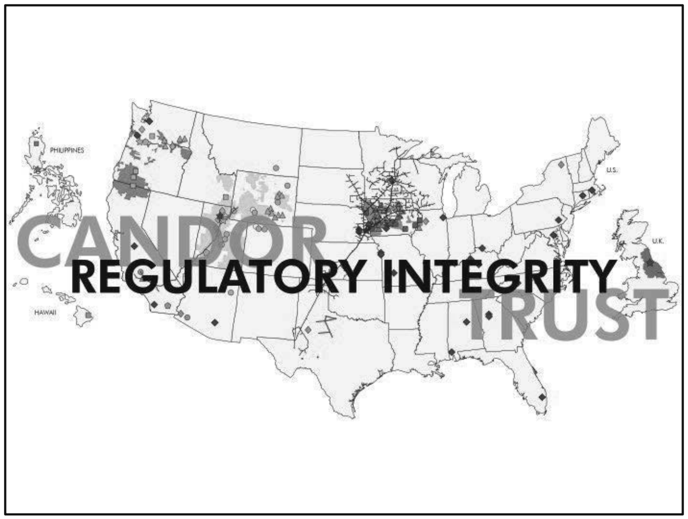
- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

Forward Sales Transactions

- ✓ The Company will continue to market prompt month heat rate call option sales when the material length is available.
- ✓ There were no forward sales executed in Q2.

NVEnergy

APPENDIX 1C



Q3 2023 Natural Gas Hedging Workshop

October 4, 2023

Market Fundamentals Overview

- ✓ EIA forecasts U.S. dry natural gas production to remain relatively flat for the rest of 2023 and 2024. Dry natural gas production averaged more than 102 billion cubic feet per day (Bcf/d) in the first half of 2023 (1H23), which is a 6 Bcf/d increase compared with the same period in 2022. According to EIA forecast dry natural gas production will rise to about 104 Bcf/d through the end of the forecast in 2024 as new pipeline capacity comes online and demand for liquefied natural gas feed gas increases as developers expect two new facilities to come online (see slide on pg.5). Production has remained at relatively high levels throughout 2023 despite a decline in U.S. natural gas prices. [EIA, Short-Term Energy Outlook, September 2023].
- ✓ The U.S. benchmark Henry Hub spot price averaged $2.41 per million British thermal units (MMBtu) in 1H23, compared with an annual average of $6.42/MMBtu in 2022 (see slide on pg. 6). [EIA, Short-Term Energy Outlook, September 2023].

Market Fundamentals Overview

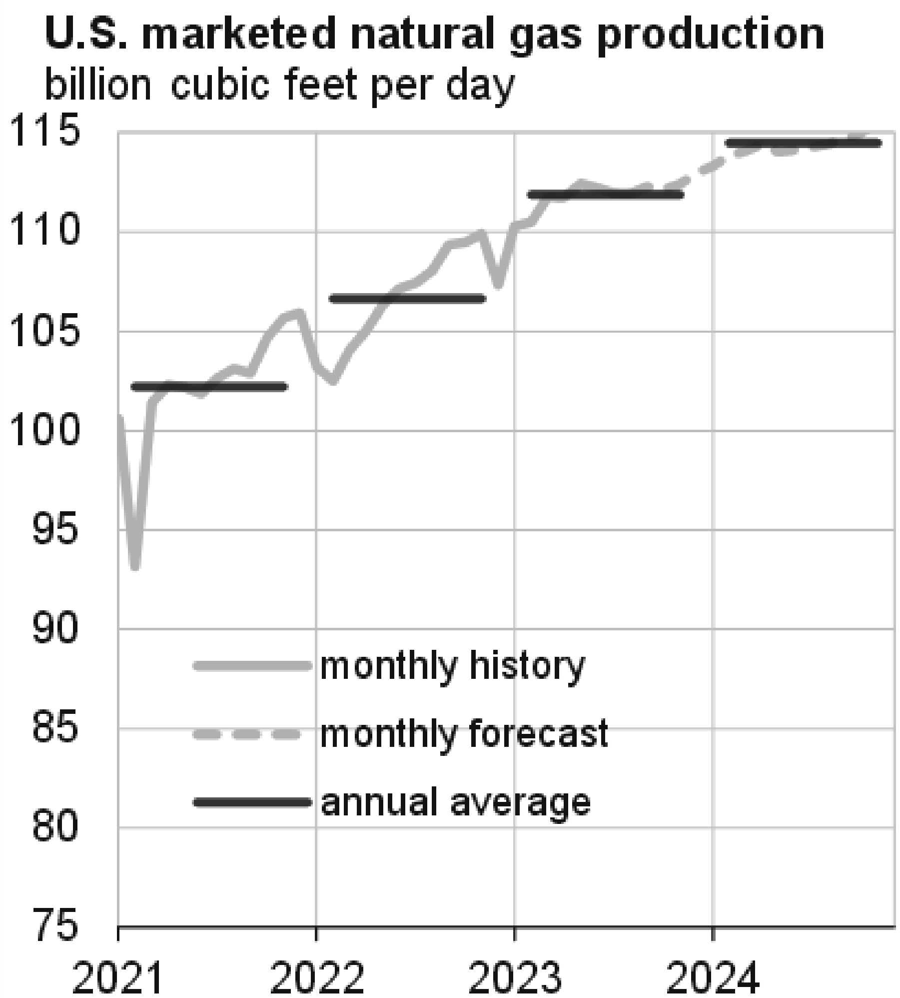
- ✓ U.S. working natural gas inventories totaled 3,051 Bcf at the end of July, 12% above the five-year (2018–2022) average and 22% above the same period last year (see slide on pg.7). Net injections of natural gas into storage have exceeded the five-year average by 3% so far this refill season (April 1–October 31), in part due to high natural gas production. The increased surplus of natural gas storage inventories reduced natural gas prices throughout 1H23 compared with 2022. [EIA, Short-Term Energy Outlook, September 2023].
- ✓ EIA forecasts working natural gas inventories to end the refill season at nearly 3.9 trillion cubic feet (Tcf) which is 7%, or 250 Bcf, higher than the five-year average. Natural gas storage inventories are expected to remain above the five-year average throughout 2024 as natural gas production remains high and natural gas consumption declines by 2% in 2024 compared with 2023. [EIA, Short-Term Energy Outlook, September 2023].

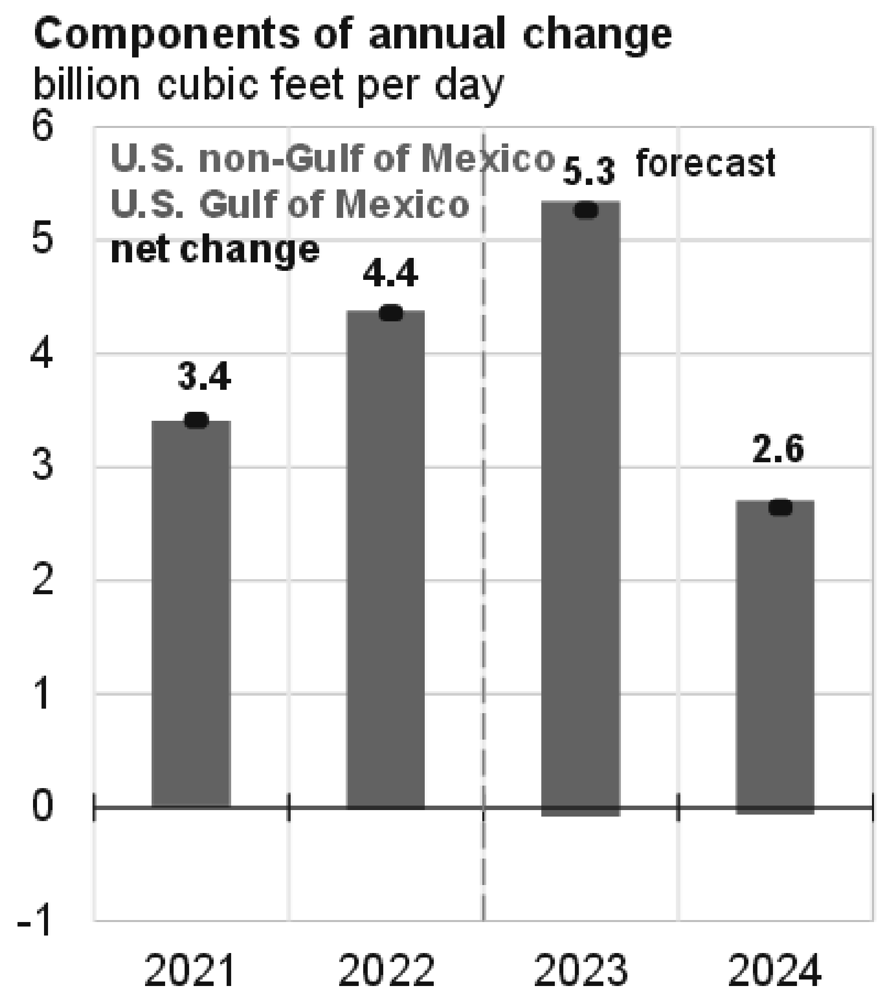
NVEnergy

Regional Market Fundamentals

- ✓ California's spot natural gas prices were the highest in the country lasts few weeks. Total consumption of natural gas in California increased 13% (0.6 Bcf/d) week over week, driven by a 35% (0.6 Bcf/d) increase in consumption in the electric power sector according to data from S&P Global Commodity Insights (SPGCI). The higher-than-average temperatures in the Riverside Area had increased demand for air conditioning [EIA, Natural Gas weekly Update, September 14].
- ✓ Natural gas storage inventories at Aliso Canyon, California's largest natural gas storage facility, reached 44.5 Bcf on September 13, up 2.2 Bcf from September 6. Southern California Gas Company, operator of Aliso Canyon, has been filling the facility ever since the California Public Utility Commission (CPUC) decided to increase the working natural gas storage level, increasing total demand for natural gas in the region [EIA, Natural Gas weekly Update, September 14].
- ✓ On August 31, the CPUC voted to increase the working natural gas storage level to 68.6 Bcf at Aliso Canyon, California's largest underground natural gas storage facility located northwest of Los Angeles. The CPUC stated the increase of 27.4 Bcf from about 41.2 Bcf was necessary to moderate potential energy price increases and enhance reliability for the upcoming 2023–2024 winter.

U.S. Dry Natural Gas Production

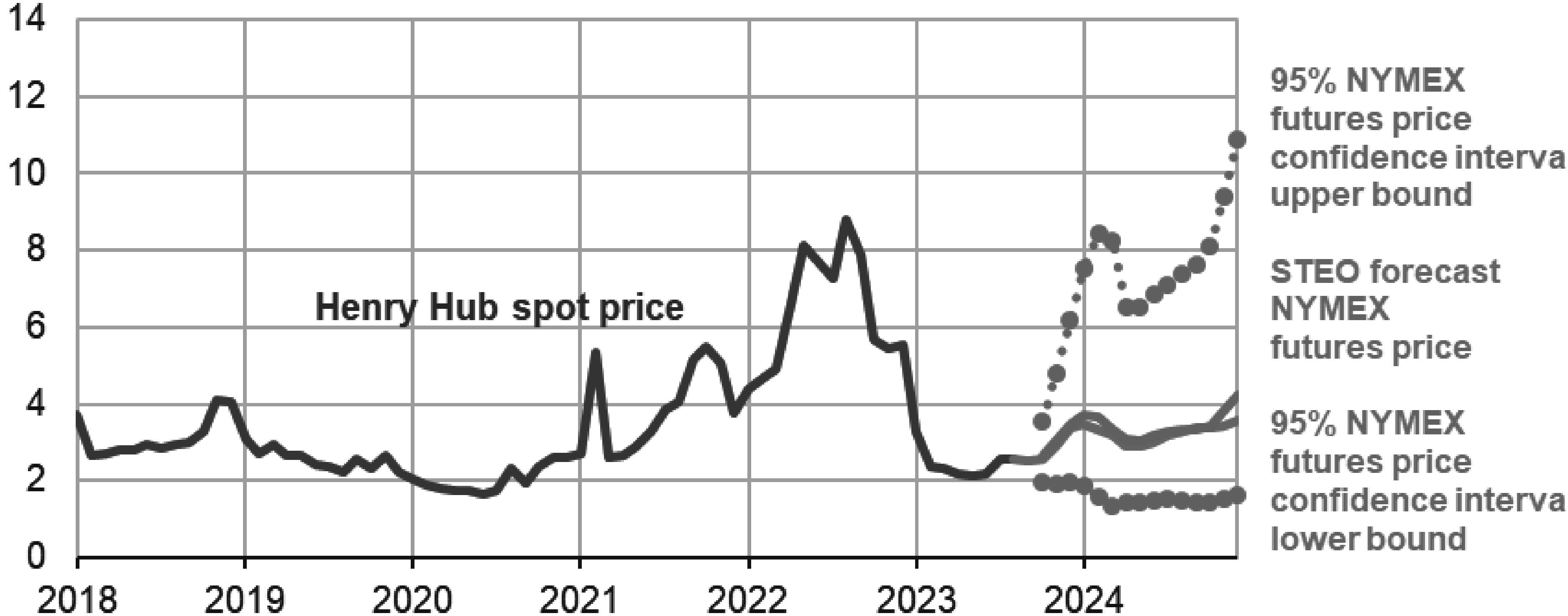




Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2023

U.S. Natural Gas Prices

Henry Hub natural gas price and NYMEX confidence intervals
dollars per million British thermal units



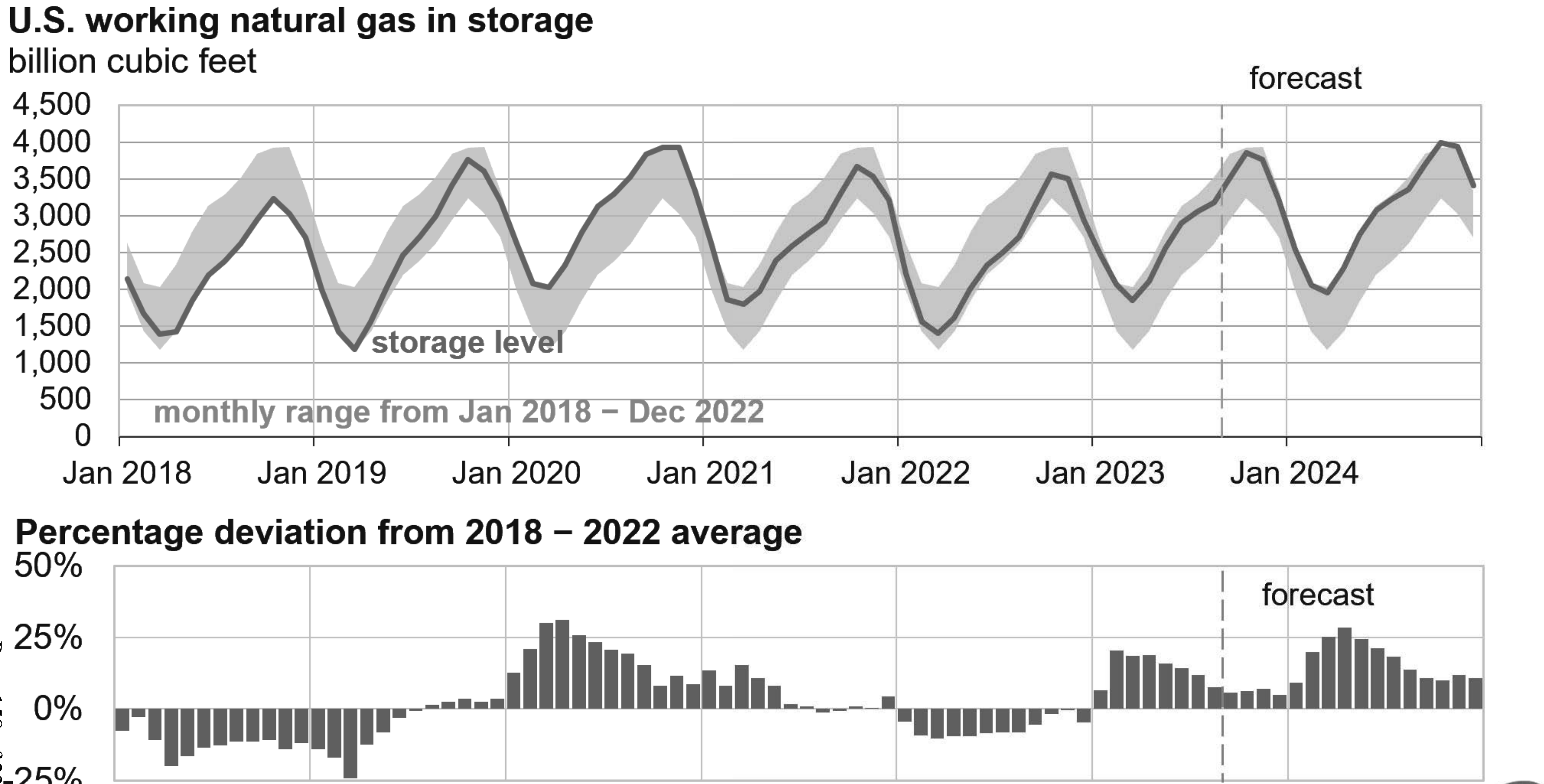
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2023, CME Group, and Refinitiv an LSEG Business

Note: Confidence interval derived from options market information for the five trading days ending September 7, 2023. Intervals not calculated for months with sparse trading in near-the-money options contracts.

eia

NVEnergy

U.S. Gas Storage (Lower 48)



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, September 2023

NVEnergy

Natural Gas Pipeline Activities

✓ Gas Transmission Northwest (GTN) Pipeline

- ❑ GTN is required by the FERC to file a Section 4 rate case by September 30, 2023.
- ❑ The Company along with other utilities and natural gas marketers began participating in pre-settlement discussions with GTN on May 12.
- ❑ Data requests were submitted to GTN for clarification.
- ❑ Negotiations have not led to a settlement, and it appears that GTN will be filing this rate case.
- ❑ The Company will be monitoring this filing closely.

Gas Risk Evaluation Matrix (NVE South)

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	1,622,092	1,342,037	1,494,753	1,490,234	1,326,047	1,415,456	1,484,453	1,925,750	2,524,081	3,003,696	2,830,888	2,272,037	22,731,522
Previous Quarter [2]	1,636,122	1,354,170	1,506,807	1,502,541	1,337,156	1,427,986	1,497,459	1,939,815	2,536,562	3,015,726	2,843,973	2,285,735	22,884,052
Current Outlook [3]	1,636,122	1,354,170	1,506,807	1,502,541	1,337,156	1,427,986	1,497,459	1,939,815	2,536,562	3,015,726	2,843,973	2,285,735	22,884,052
Change from Filed ESP	14,031	12,133	12,055	12,307	11,109	12,530	13,006	14,065	12,481	12,030	13,085	13,699	152,530
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
[redacted]													
[redacted]													
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	404,098
Previous Quarter [2]	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	404,098
Current Outlook [3]	424,935	374,925	374,925	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	8,558,132	7,567,968	9,059,909	8,511,965	6,446,678	6,140,310	6,397,172	7,161,199	8,856,205	13,145,170	11,632,659	9,674,460	103,151,826
Previous Quarter [2]	9,217,453	8,105,319	9,652,614	9,511,319	7,833,742	7,540,664	7,821,404	8,781,768	10,013,338	14,795,913	13,561,221	11,150,765	117,985,521
Current Outlook [3]	10,248,303	9,175,048	11,231,479	11,129,154	8,832,751	8,450,036	9,928,067	9,720,102	10,282,853	15,549,637	14,126,410	11,938,435	130,612,275
Change from Filed ESP	1,690,171	1,607,081	2,171,569	2,617,189	2,386,073	2,309,726	3,530,895	2,558,903	1,426,648	2,404,467	2,493,751	2,263,976	27,460,449
Change from Previous Quarter	1,030,850	1,069,730	1,578,864	1,617,835	999,008	909,372	2,106,663	938,334	269,515	753,724	565,189	787,670	12,626,754

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] June 2023 Risk Run
[3] September 2023 Risk Run
[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)

Gas Risk Evaluation Matrix (NVE North)

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	783,565	808,835	883,167	880,289	784,201	839,934	781,237	841,917	872,935	1,032,007	998,764	826,595	10,333,447
Previous Quarter [2]	790,645	815,621	890,046	887,310	790,604	847,167	788,233	849,622	880,257	1,039,335	1,006,797	834,480	10,420,117
Current Outlook [3]	790,645	815,621	890,046	887,310	790,604	847,167	788,233	849,622	880,257	1,039,335	1,006,797	834,480	10,420,117
Change from Filed ESP	7,080	6,785	6,879	7,022	6,403	7,233	6,996	7,704	7,322	7,328	8,032	7,885	86,669
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
[redacted]													
[redacted]													
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	247,399
Previous Quarter [2]	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	247,399
Current Outlook [3]	234,627	265,279	265,279	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	247,399
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Consumption Forecast (MMBtu):													
ESP [1]	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	18,710,189
Previous Quarter [2]	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	18,710,189
Current Outlook [3]	1,246,793	2,025,827	3,096,956	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	18,710,189
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	2,672,923	2,273,644	2,227,816	2,213,214	2,255,947	2,270,741	1,691,426	2,021,001	2,591,055	3,564,591	3,239,695	2,772,422	29,794,475
Previous Quarter [2]	3,202,352	2,720,302	2,614,534	2,654,073	2,357,049	2,732,521	1,879,232	2,552,632	2,992,523	4,303,251	4,147,446	3,513,110	35,669,024
Current Outlook [3]	3,181,632	2,628,334	2,365,045	2,544,903	2,500,281	2,948,409	810,749	2,462,014	2,900,012	4,154,069	3,987,445	3,417,430	33,900,325
Change from Filed ESP	508,709	354,690	137,229	331,690	244,335	677,668	(880,676)	441,013	308,957	589,479	747,750	645,008	4,105,850
Change from Previous Quarter	(20,720)	(91,968)	(249,489)	(109,169)	143,232	215,888	(1,068,483)	(90,618)	(92,511)	(149,181)	(160,001)	(95,680)	(1,768,700)

[1] Joint ESP filed 9/2/2022 (Docket No. 22-09002)
[2] June 2023 Risk Run
[3] September 2023 Risk Run
[4] Combined Paiute and Tuscarora transportation contracts

NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

Electric Power Activities

- ✓ No forward sales were executed in Q3.
- ✓ The Company will continue to evaluate forward transaction opportunities as appropriate.
- ✓ The Western Energy Imbalance Market (“EIM”) continued to be utilized to optimize system resources. Q2 benefits have exceeded $46m.
- ✓ The Company continues to fill its 2024 open capacity position through its approved laddering strategy.
- ✓ Coal – the Company is completing bid analysis of a 2023 August coal supply RFP for 2024 and is expected to soon award the bids.

NVEnergy

APPENDIX 1D

Q3 2023 Natural Gas Hedging Update

December 18, 2023

Market Fundamentals Overview

- ✓ EIA forecasts, in its December Short term Outlook (STEO), the U.S. benchmark Henry Hub spot price to average about $2.80 per million British thermal units (MMBtu) for the rest of the winter heating season which ends in March (see slide on pg. 5). EIA lowered the forecast for natural gas prices this winter by compared with previous STEO forecasts. The lower price forecast is due to recent increases in natural gas production, which reduced natural gas prices in November, and high natural gas storage inventory levels. [EIA, Short-Term Energy Outlook, December 2023].

- ✓ The Henry Hub spot price averaged $2.71/MMBtu in November, down 27 cents from October. Increased U.S. natural gas production in October and November 2023 contributed to the natural gas price decline in November. U.S. dry natural gas production averaged about 105 billion cubic feet per day (Bcf/d) in November, the most for any month on record (see slide on pg. 6). U.S. dry natural gas production averaged almost 103 Bcf/d in 1H23 and has increased in most months during 2H23. EIA forecasts dry natural gas production to remain close to 105 Bcf/d for the rest of winter. [EIA, Short-Term Energy Outlook, December 2023].

NVEnergy

Market Fundamentals Overview

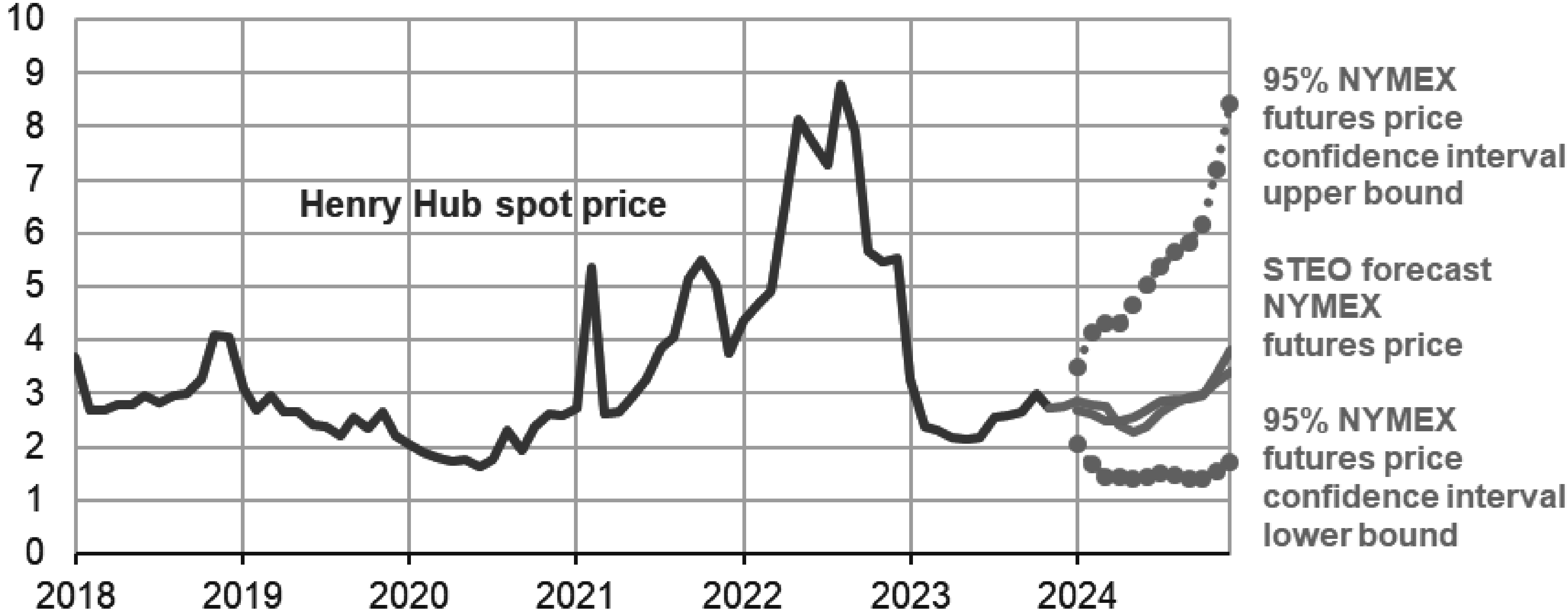
- ✓ Increased natural gas production throughout all of 2023 contributed to more natural gas in U.S. storage to start the winter heating season. High inventories at the end of November reduced forecast natural gas prices for this winter heating season. Storage inventories started the winter heating season at more than 3,800 billion cubic feet (Bcf), 5% more than the five-year (2018–2022) average. Mild winter weather in the United States in November reduced natural gas consumption. Less natural gas consumption along with increased natural gas production help increase storage inventories to 3,771 Bcf at the end of November, 7% more than the five-year average. EIA forecasts natural gas storage inventories to remain above the five-year average throughout winter and for all of 2024 (see slide on pg.7). [EIA, Short-Term Energy Outlook, December 2023].

NVEnergy

Regional Market Fundamentals

- Across the West Coast, prices continue to decrease week after week. The price at PG&E Citygate in Northern California fell 65 cents, down from $4.86/MMBtu last week to $4.21/MMBtu on December 13. The price at SoCal Citygate in Southern California have decreased to $4.31/MMBtu on December 13. Temperatures in the Riverside Area, east of Los Angeles, averaged 58°F in the last week, resulting in 47 heating degree days (HDDs), 25 HDDs fewer than normal. The price at Northwest Sumas on the Canada-Washington border, the main natural gas pricing point in the Pacific Northwest, fell $2.46 from $3.58/MMBtu the week before to $1.12/MMBtu on December 13. Temperatures in the Seattle City Area averaged 43°F, resulting in 149 HDDs, 12 HDDs fewer than normal. In addition, natural gas storage inventories in the Pacific region totaled 289 Bcf for the week ending December 8, which is 41% more than year-ago levels. [EIA, Natural Gas weekly Update, December 14].

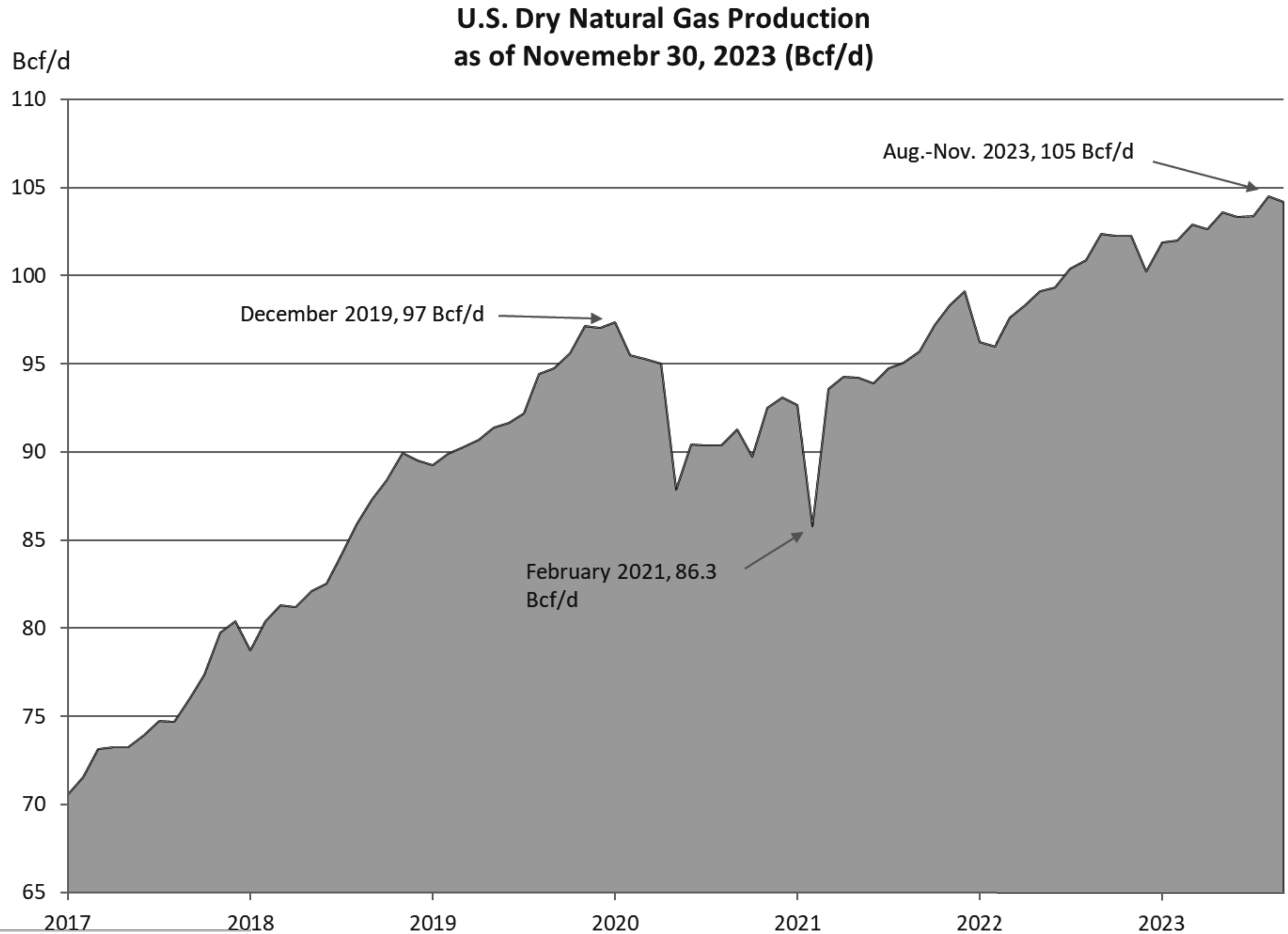
U.S. Natural Gas Prices



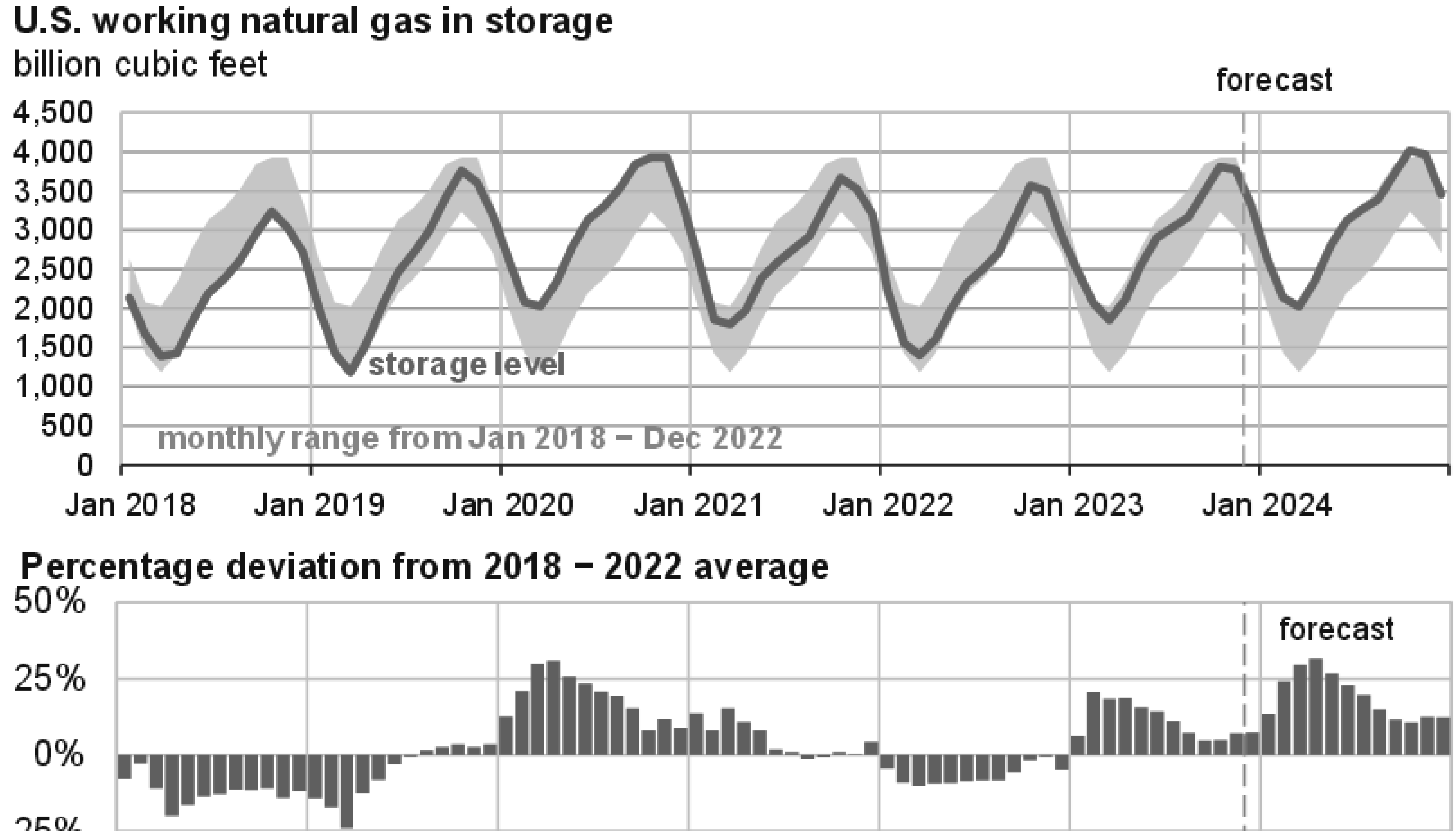
Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2023, CME Group, and Refinitiv an LSEG Business

Note: Confidence interval derived from options market information for the five trading days ending December 7, 2023. Intervals not calculated for months with sparse trading in near-the-money options contracts.

U.S. Dry Natural Gas Production



U.S. Gas Storage (Lower 48)



Data source: U.S. Energy Information Administration, Short-Term Energy Outlook, December 2023

Natural Gas Pipeline Activities

✓ Gas Transmission Northwest (GTN) Pipeline

- GTN was required by the FERC to file a Section 4 rate case by September 30.
- The Company has been monitoring this filing closely.
- A prehearing conference will be held on December 18.

REDACTED PUBLIC VERSION

Gas Risk Evaluation Matrix (NVE South)

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	1,502,541	1,337,156	1,427,986	1,497,459	1,939,815	2,536,562	3,015,726	2,843,973	2,285,735	1,674,273	1,379,548	1,529,766	22,970,538
Previous Quarter [2]	1,502,541	1,337,156	1,427,986	1,497,459	1,939,815	2,536,562	3,015,726	2,843,973	2,285,735	1,674,273	1,379,548	1,529,766	22,970,538
Current Outlook [3]	1,581,976	1,380,047	1,346,990	1,383,182	1,814,756	2,439,699	2,877,148	2,709,915	2,162,880	1,525,584	1,402,591	1,625,075	22,249,843
Change from Filed ESP	79,435	42,891	(80,996)	(114,277)	(125,059)	(96,863)	(138,578)	(134,058)	(122,855)	(148,689)	23,043	95,309	(720,695)
Change from Previous Quarter	79,435	42,891	(80,996)	(114,277)	(125,059)	(96,863)	(138,578)	(134,058)	(122,855)	(148,689)	23,043	95,309	(720,695)
[redacted]													
[redacted]													
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Previous Quarter [2]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Current Outlook [3]	374,925	374,925	374,925	424,935	424,935	424,935	424,935	424,935	424,935	424,935	374,925	374,925	404,098
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	10,271,421	7,825,588	7,232,197	8,649,658	8,463,714	9,342,389	14,221,335	12,974,392	10,543,475	9,235,711	8,035,580	10,245,416	117,040,877
Previous Quarter [2]	11,129,154	8,832,751	8,450,036	9,928,067	9,720,102	10,282,853	15,549,637	14,126,410	11,938,435	9,963,151	8,527,970	10,606,252	129,054,818
Current Outlook [3]	11,818,087	9,320,805	7,967,565	8,640,233	8,351,812	8,846,606	12,564,779	11,051,539	9,246,001	8,533,813	8,798,498	11,341,404	116,481,141
Change from Filed ESP	1,546,665	1,495,217	735,368	(9,426)	(111,902)	(495,783)	(1,656,557)	(1,922,853)	(1,297,474)	(701,898)	762,918	1,095,988	(559,736)
Change from Previous Quarter	688,933	488,054	(482,470)	(1,287,834)	(1,368,290)	(1,436,248)	(2,984,858)	(3,074,871)	(2,692,434)	(1,429,338)	270,527	735,152	(12,573,677)
[redacted]													

[1] Joint ESP filed 9/3/2023 (Docket No. 23-09003)
[2] September 2023 Risk Run
[3] December 2023 Risk Run
[4] Kern River transportation contracts (excluding 134,000 Dth/Day backhaul capacity)
[5] Joint ESP filed 9/3/2023 (Docket No. 23-09003)
[6] September 2023 forecasts
[7] December 2023 forecasts

REDACTED PUBLIC VERSION

Gas Risk Evaluation Matrix (NVE North)

Page 1 of 2

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Mos.
Load Forecast (MWh):													
ESP [1]	887,310	790,604	847,167	788,233	849,622	880,257	1,039,335	1,006,797	834,480	816,141	838,643	913,093	10,491,681
Previous Quarter [2]	887,310	790,604	847,167	788,233	849,622	880,257	1,039,335	1,006,797	834,480	816,141	838,643	913,093	10,491,681
Current Outlook [3]	976,187	894,015	917,630	861,936	893,397	922,110	1,100,300	1,066,550	937,553	879,301	905,318	979,956	11,334,253
Change from Filed ESP	88,877	103,411	70,463	73,703	43,775	41,853	60,965	59,753	103,073	63,160	66,675	66,863	842,572
Change from Previous Quarter	88,877	103,411	70,463	73,703	43,775	41,853	60,965	59,753	103,073	63,160	66,675	66,863	842,572
[redacted]													
[redacted]													
Gas Pipeline Capacity (Dth/Day):[4]													
ESP [1]	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	247,399
Previous Quarter [2]	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	247,399
Current Outlook [3]	265,279	265,279	265,279	234,627	234,627	234,627	234,627	234,627	234,627	234,627	265,279	265,279	247,399
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Consumption Forecast (MMBtu):													
ESP [1]	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	1,271,658	2,066,229	3,158,721	18,837,222
Previous Quarter [2]	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	1,271,658	2,066,229	3,158,721	18,837,222
Current Outlook [3]	2,999,367	2,717,339	2,276,523	1,331,660	861,819	566,058	487,895	491,118	608,834	1,271,658	2,066,229	3,158,721	18,837,222
Change from Filed ESP	0	0	0	0	0	0	0	0	0	0	0	0	0
Change from Previous Quarter	0	0	0	0	0	0	0	0	0	0	0	0	0
Power Plant Gas Burn (MMBtu):													
ESP [1]	2,992,060	3,078,419	3,237,657	1,389,235	2,719,000	3,055,924	4,503,379	4,504,184	4,059,512	2,477,912	2,714,117	2,666,712	37,398,111
Previous Quarter [2]	2,544,903	2,500,281	2,948,409	810,749	2,462,014	2,900,012	4,154,069	3,987,445	3,417,430	2,401,346	2,548,440	2,624,676	33,299,775
Current Outlook [3]	2,892,657	2,998,711	2,880,032	1,496,826	2,730,370	3,117,767	4,232,684	4,102,808	3,622,193	2,584,740	2,664,848	2,825,133	36,148,769
Change from Filed ESP	(99,403)	(79,707)	(357,625)	107,591	11,370	61,843	(270,695)	(401,376)	(437,319)	106,828	(49,269)	158,420	(1,249,342)
Change from Previous Quarter	347,754	498,430	(68,377)	686,077	268,356	217,754	78,615	115,363	204,763	183,394	116,408	200,456	2,848,993

[1] Joint ESP filed 9/3/2023 (Docket No. 23-09003)
[2] September 2023 Risk Run
[3] December 2023 Risk Run
[4] Combined Paiute and Tuscarora transportation contracts

Gas Risk Evaluation Matrix (NVE North)

Page 2 of 2

KEY FORECAST METRICS
NVE NORTH (SIERRA PACIFIC POWER COMPANY)

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	12 Mos.

[5] Joint ESP filed 9/3/2023 (Docket No. 23-09003)
[6] September 2023 forecasts
[7] December 2023 forecasts

NV Energy Course of Action

- ✓ At this time, based on assessment of market fundamentals presented in previous slides, NV Energy will continue the current hedging strategy and will not physically or financially hedge the natural gas portfolio for the northern or southern Nevada service territories.

Electric Power Activities

- ✓ No forward sales were executed in Q4.
- ✓ The Company will continue to evaluate forward transaction opportunities as appropriate.
- ✓ The Western Energy Imbalance Market (“EIM”) continued to be utilized to optimize system resources. The Company Q3 benefits have exceeded $60m.
- ✓ The Company continues to fill its 2024 open capacity position through its approved laddering strategy.
- ✓ Coal – the 2024 coal supply procurement has been completed and contracts fully executed.

APPENDIX 2A

NV Energy, Inc.

Risk Management and Control Policy

Risk Committee Approval

November 15, 2023

This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided to anyone outside the Company without the prior approval of the Risk Control Department.

TABLE OF CONTENTS

I. Background

NV Energy, Inc. (the Company) has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the 'Companies') who are engaged in the generation, transmission and distribution of electric energy and in the distribution of natural gas in Nevada. The Companies are exposed to a variety of risks inherent in their commercial operations. Those risks include accidental loss risk, credit risk, energy supply risk, environmental risk, facilities risk, financial risk, information and control systems risk, and other operating risk. In aggregate, these risks constitute the Companies' enterprise risk.

The Companies manage risk in a variety of ways. For example, commitments to generation and transmission and to longer-term energy supply contracts are managed through the resource planning process (including distributed energy resource plans) and culminating with Public Utilities Commission of Nevada (PUCN) approval of the resource plans. Other multiyear risks are managed, in part, through the Companies' strategic planning exercises. Shorter-term risks are managed through annual Energy Supply Plans, budgets, key performance indicators and prioritized objectives by departments or functional area[1].

II. Objectives

This policy establishes standards for monitoring and managing enterprise risk.

The primary objectives of the Companies' risk management and control efforts will be:

- The identification of risks;
- The qualitative or quantitative assessment of risks;
- The evaluation of the costs and merits of risk mitigation options;
- The identification of risks to be retained by the Companies; and,
- The identification of risks to be shifted to other entities and the means to do so.

Continuous oversight of the Companies' risk management programs is essential for effective risk control. The Risk Committee will be responsible for the overall policy direction and administration of the Companies' risk control efforts.

[1] Because organizations change names, responsibilities, and reporting relationships, references in this policy to 'department' or 'departments' is effectively referencing the executive or senior vice president responsible for that department or functional area,

The Treasurer will assist the Risk Committee in monitoring the operations of the Companies to ensure compliance with risk related policies and procedures. All material omissions and exceptions will be promptly reported to the Risk Committee. The Treasurer will also be responsible for assisting with modifications to those policies and procedures dictated by changing conditions, new technologies and other factors affecting the risks faced by the Companies. The executive leader of each functional area will be responsible for maintaining an inventory of the three biggest risks faced by their organization. Appraisals of those risks will be reported to the Risk Committee on a semi-annual basis along with mitigation plans/tracking/variances.

III. Enterprise Risk Types

The Companies encounter several types of risk in their day-to-day operations. For the purposes of this policy, such risks have been categorized as:

A. Accidental loss risk
B. Credit risk
C. Energy supply risk
D. Environmental risk
E. Facilities risk
F. Financial risk
G. Information and control systems risk
H. Other risk (e.g., regulatory, reputational, legal, etc.)

A. Accidental Loss Risk

Accidental loss risk is defined as the possibility that the Companies will experience financial losses or detrimental operating effects because of accidents and other unanticipated occurrences for which insurance may be acquired. Financial losses can result from damage to the Companies' property, increased operating costs, liability for injury to employees and others, and liability for damage to the property of others.

B. Credit Risk

The Companies contract with numerous entities in the normal course of business. Credit risk is defined as the possibility that a counterparty to one or more contracts will be unwilling or unable to fulfill its financial or physical obligations to the Companies because of the counterparty's financial condition.

C. Energy Supply Risk

The Companies buy and sell coal, natural gas, oil, wholesale power, carbon allowances, and other products (e.g. Renewable Energy Credit's or Portfolio Energy Credit's) to meet the energy requirements of their customers. They also operate generating plants that produce electric energy for their customers. Those activities expose the Companies to energy risk which causes uncertainty as to the Companies' cash flow requirements for fuel and wholesale power, the expense the Companies incur as a result of their energy procurement efforts, and the Companies' recovery of these costs in customer rates. Energy risk also encompasses reliability risk which is the prospect that energy supplies will not be sufficient to fulfill customer requirements.

D. Facilities Risk

The Companies lease or own numerous facilities that are used to provide services to their customers. Facilities risk is defined as the uncertainty introduced by the threat of vandalism, sabotage and other willful acts that could result in injury or death to the Companies' personnel and the general public while they are at the Companies facilities and damage to those facilities. Facilities risk will also include the prospective loss of revenue through theft of service and misappropriation of the Companies' assets through burglaries and other wrongful acts.

E. Environmental Risk

The Companies operate generating facilities, electric transmission and distribution lines and substations, gas pipelines and other facilities with the potential to adversely affect the environment. Environmental risk is defined as the possibility that the Companies will experience financial losses or adverse operating conditions because of an emission or release to the environment in excess of that which is currently allowed by law.

F. Financial Risk

The primary constituents of financial risk are earnings and liquidity risk. Earnings risk constitutes the uncertainty inherent in the Companies' efforts to earn acceptable levels of revenue. Liquidity risk addresses the uncertainty inherent in the Companies' efforts to have sufficient cash and credit facilities to cover their needs.

G. Information and Control Systems Risk

The Companies operate and maintain electronic systems for the accumulation and dissemination of data, the preparation of documents, the distribution of information and the monitoring and control of facilities used in the provision of service to their customers. Information and control systems risk is defined as the uncertainty introduced by the threat of disruption to business activities and to the services provided that could be caused by the wrongful infiltration or manipulation of those information and control systems.

H. Other Operating Risk

The preceding description of certain types of operating risk is not intended to be exhaustive. The Companies are currently exposed to other risks and will continue to be exposed to new risks because of the changing business environments in which they operate. This policy will be modified to address any areas of significant risk that have not been specifically cited.

IV. Risk Management and Control Framework

The Companies will systematically manage and control each of the types of risk identified above through three primary vehicles.

A. Organization and Governance

This policy defines certain risk parameters and exposure management techniques that the departments and employees are expected to use in managing the risk faced by the Companies. The Risk Committee will be responsible for the risk policies of the Company. Each department will be responsible for administration of the Companies' risk management and risk mitigation programs and will be accountable to the Risk Committee.

B. Risk Management Programs

The Companies' personnel, who are responsible for managing each type of risk, will maintain risk management programs that provide for the assessment and quantification of the magnitude of each type of risk on an ongoing basis by the development of risk policies; the creation and maintenance of risk mitigation plans; and the implementation of these plans and policies in a manner consistent with this policy.

C. Risk Control Practices

The Companies personnel, who are responsible for risk control, will monitor compliance with approved risk management policies and procedures through the use of specific notification thresholds and processes.

V. Organization and Governance

A. Chief Executive Officer

The Chief Executive Officer will be responsible for assuring that the Risk Committee follows its charter.

To preclude interruptions in the performance of the Risk Committee's assigned duties, the Chief Executive Officer may replace members of the committee who leave the organization or are otherwise assigned within the organization with other members.

The Chief Executive Officer will also have the authority to designate authorized representatives for the members of the Risk Committee and its committees. Authorized representatives will have the same rights and obligations as the members.

B. Risk Committee

The Risk Committee will be responsible for the overall policy direction and administration of the Companies' risk control activities.

The Risk Committee will be responsible for ensuring that the Chief Executive Officer is kept apprised of Risk Committee activities and required notifications and approvals as stated in the Company's Energy Risk Management and Control Policy.

The Risk Committee will provide a forum for the discussion and evaluation of all of the risks faced by the Companies to achieve an integrated view of overall risk.

The Risk Committee will be responsible for ensuring that adequate risk assessment and control policies and procedures are in place and followed. The Risk Committee will have full authority to approve risk policies and risk mitigation programs of the Company.

The Risk Committee will pursue its objective through and as a complement to the Companies' existing organizational structures.

The Risk Committee is comprised of the following individuals:

- Senior Vice President, General Counsel, Corporate Secretary, Chief Compliance Officer (Chairperson)
- Vice President, Chief Financial Officer
- Vice President, Electric Delivery & Natural Disaster Protection
- Vice President, Regulatory
- Vice President, Transmission
- Vice President, Customer Operations
- Vice President, Environmental Services & Land Management
- Vice President, Gas Delivery
- Treasurer
- Vice President, Integrated Energy Services
- Director, Resource Planning & Analysis
- Vice President, Renewables
- Vice President, Generation
- Vice President, Resource Optimization

A quorum of the committee will consist of seven of the members. Any action taken by the Risk Committee will require a majority of affirmative votes. The Risk Committee will meet at least once each quarter, or more frequently if requested by the Chairman of the committee. Meetings may be conducted in person, via telephone, video conference, or email. The purpose of the meetings will be to perform the duties set forth in this policy and any additional duties assigned to the committee by the Chief Executive Officer.

Minutes of the Risk Committee meetings will be kept in accordance with Company's Records Retention Policy. Those minutes will include, as attachments, all of the documents presented to the committee during the associated meetings.

The Risk Committee will be responsible for:

- Monitoring the current and expected future economic conditions, assessing their effect on the general business environment and on the Companies, and disseminating the information obtained through such monitoring to the management of the Companies;
- Initiating the preparation of new risk control policies when or where appropriate and the modification of risk control polices already in place;
- Ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Resolving any disputes regarding the appropriate application of those policies and procedures;
- Ensuring the availability of the systems required to monitor, record and report on the risks inherent in the Companies' operations;
- Reviewing and approving the Companies' resource plans, energy supply plans prior to Chief Executive Officer approval;
- Assuring integration of energy procurement or sale risk, credit risk, cash flow risk and ratepayer risk;
- Reviewing and approving all transactions requiring exceptions to the approved plans for acquiring or selling fuel and wholesale power prior to implementation;
- Reviewing all energy procurement or sale transactions requiring the approval of the Chief Executive Officer[2] prior to the presentation of such transactions to the Chief Executive Officer; and
- Assessing the appropriateness of the Companies' risk control activities and modifying this policy, whenever modifications are required to ensure the ongoing viability of the Companies' risk management and control programs and the continued fulfillment of the Companies' obligations.

The Risk Committee will have the right to delegate portions of its assigned duties to one or more committees. The Risk Committee will establish the charter of each Committee when it is established and modify the charter if necessary. Committees will keep minutes in the same manner as the Risk Committee. Committees will also make periodic reports of their activities to the Risk Committee in the manner designated by the Risk Committee.

[2] The review by the Risk Committee prior to the presentation to the Chief Executive Officer is not required if such transactions are being done in accordance with an Energy Supply Plan already approved by the Chief Executive Officer.

VII. *General Counsel*

The officers and managers of the Companies will be responsible for enforcing the Companies' risk control policies and procedures applicable to the areas for which they are responsible. The General Counsel will serve as the independent compliance officer responsible for monitoring the operations of the Companies to ensure compliance with policies and procedures as identified in Section VI and VII. All material omissions and exceptions identified by any department will be promptly reported to the General Counsel.

VII. *Risk Control*

Each department will be responsible for developing policies, procedures and risk mitigation plans dictated by changing conditions, new technologies, and other factors affecting the risk faced by the department.

Each department will be responsible for maintaining an inventory of the risks faced by that department and providing integrated appraisals of those risks to the Risk Committee at least once each year. Each department will take steps to ensure that the Risk Committee has adequate descriptions of possible future conditions as a setting for risk analysis, evaluation and policy direction. Each department subject to general oversight will monitor compliance with this policy and any additional policies approved by the Risk Committee.

VI. Risk Management Programs

Each of the previously identified types of enterprise risk will be managed through the Companies' risk management programs. Primary responsibility for risk management execution will be through these programs and company management as distinct from the risk integration and control function of the Risk Committee.

VII. *Accidental Loss Risk*

The Companies will attempt to avoid financial losses through the identification, assessment, prevention, monitoring, and financing of insurable risks. The program will have provisions for the timely evaluation of alternatives for minimizing the frequency and severity of losses and for the mitigation of losses. Financing alternatives such as self-insurance and various forms of commercially available insurance will be routinely evaluated. The program will also have provisions for the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements.

VII. *Credit Risk Management*

See the Credit Risk Management and Control Policy

VII. *Energy Supply Risk Management Program*

See the Energy Risk Management and Control Policy

VII. *Environmental Risk*

The Companies will attempt to avoid financial losses through the identification, evaluation, prevention, and monitoring of environmental risks. The program will rely heavily upon the training of personnel to help to ensure compliance with environmental laws and regulations. The program will also have provisions for ongoing communication and cooperation with environmental agencies and other groups.

E. Facilities Risk

The Companies, through a program of identification and evaluation of threats, monitoring of facilities, and training of personnel, will attempt to preclude injury, damage, and losses to its facilities. The program will also have provisions for the ongoing communication and cooperation with law enforcement agencies and for the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements. Additionally, the program will have provisions to ensure adequate preparation for prompt recovery if any of the Companies' facilities are damaged by willful acts or natural disasters.

F. Financial Risk

The Companies have numerous processes like their budgetary processes for the control of expenditures and the management of cash flow as well as the annual financing plan. Financial risk will be addressed through the management processes in place for that purpose.

G. Information and Control Systems Risk

The Companies, through a program of identification and evaluation of threats, monitoring of systems, installation of safeguards, and training of personnel, will attempt to preclude infiltration or manipulation of their electronic information and electronic control systems. The program will also have provisions for the preparation of periodic reports to document the Companies' efforts and to comply with legal and regulatory requirements. Additionally, the program will have provisions to ensure adequate preparation for prompt recovery if any of the Companies' information and control systems are adversely affected by such wrongful acts or natural disasters.

VII. *Other Operating Risk*

The Companies will address other operating risk through management processes in place for that purpose.

VII. Risk Reporting

The Companies' risk control policies will contain practices, which will incorporate risk identification, reporting and risk management.

Reporting Process

As directed by the Risk Committee, departments will report on identified risks and the plan to mitigate such risks on a semi-annual basis.

Appendix A: Policy Revision Log

Date	Revision(s)
August 28, 2014	Modified Existing Policy: 1. Replaced the title of "President" with the title of "Chief Executive Officer". • Although Paul Caudill is the President and Chief Executive Officer, we are using his highest title in the Policy • Change is applied throughout the document 2. Added carbon allowances as instruments that the Companies buy and sell. • This recommended change is a result of the change made to Appendix D (Approved financial instruments and physical products) of the Energy Risk Management and Control Policy 3. Replaced "Senior Officer in Charge of General Counsel" with "General Counsel" 4. Changed the quorum of the Committee <u>from six to seven</u> members of the twelve member committee. Thus any action to be taken by the committee requires a majority vote of the committee. 5. Modified language regarding the Risk Committee's reviewing and approving Energy Supply Plans and any exceptions to the Energy Supply Plans. 6. Added a policy revision log.
December 16, 2014	Modified Existing Policy: 1. Replaced the acronyms RECs and PECs with their full wording. 2. Corrected the appendix reference in the policy revision log.
May 20, 2015	Modified Existing Policy: 1. Updated the members of the Risk Committee by replacing the Executive, Ethics and Corporate Compliance and the Director, Corporate Insurance with the Senior Officer in Charge of Compliance and Standards and the Manager, Corporate Insurance.
July 27, 2016	Modified Existing Policy: 1. Removed the Chief Executive Officer, the senior officer in charge of Compliance and Standards and the Manager of Corporate Insurance from the Risk Committee. 2. Added the senior officer in charge of Customer Operations and the senior officer in charge of Resource Planning & Analysis to the Risk Committee. 3. Updated Risk Committee members' titles where appropriate. 4. A quorum of the Committee will now consist of 6 of the 10 members. 5. Added that the Risk Committee will be responsible for ensuring that the Chief Executive Officer is kept apprised of Risk Committee

	activities and required approvals and notifications as stated in the Company's Energy Risk Management and Control Policy. Added how meetings can be conducted; in person, via telephone, videoconference, or via email.
July 26, 2017	Modified Existing Policy: 1. Organizational changes necessitated a title change from Senior Vice-President Renewable Energy, Origination and Strategy, to Senior Vice-President Renewable Energy and Smart Infrastructure. 2. Organizational changes necessitated updating Jim Doubek's title to Vice President, Energy Delivery. 3. Added the Director, Resource Planning and Analysis as a member of the Risk Committee.
January 24, 2018	Modified Existing Policy: 1. Removed the Vice President Energy Delivery and Senior Vice President, Renewable Energy and Smart Infrastructure from the Risk Committee 2. Replaced the title of "Senior Vice President, Energy Supply" with the title of "Executive Vice President, Chief Operations Officer" and replaced the title of "Senior Vice President, Regulation & Strategic Planning" with "Senior Vice President, Business Planning, Regulation & Legal Strategy".
May 7, 2018	Modified Existing Policy: 1. Replaced Chief Executive Officer with President 2. Replaced Director, Risk Control with Treasurer 3. Updated titles
December 19, 2018	Modified Existing Policy: 1. Replaced "President" with "Chief Executive Officer" 2. Replaced the title of "Senior Vice President, Chief Financial Officer" with the title of "Vice President, Chief Financial Officer 3. Replaced the title of "Senior Vice President, Customer Operations" with the title of Vice President, Customer Operations" 4. Added footnote on page 3 referencing the "executive or senior vice president"
December 4, 2019	Modified Existing Policy 1. Added Senior Vice President Renewable & Origination as voting member to Risk Committee 2. Changed member title from Senior Vice President, Business Planning, Regulation & Legal Strategy to Vice President, Regulatory
September 17, 2020	Modified Existing Policy 1. Added Assistant along side Treasurer 2. Added Vice President, Electric Delivery to Risk Committee 3. Added Vice President, Transmission to Risk Committee 4. Added Vice President, Generation to Risk Committee 5. Added Assistant Treasurer to Risk Committee 6. Deleted Senior Vice President, Operations from Risk Committee 7. Added & Treasurer to Vice President, Chief Financial Officer title
November 16, 2021	Modified Existing Policy 1. Deleted Vice President, Resource Optimization
December 14, 2022	1. Deleted Senior Vice President, Energy Supply 2. Added Vice President, Renewables 3. Added Vice President, Generation 4. Added Vice President, Resource Optimization

April 19, 2023	Modify Existing Policy 1. Change Senior Vice President, Chief Financial Officer & Treasurer to Vice President, Chief Financial Officer 2. Change Assistant Treasurer to Treasurer
November 15, 2023	Modify Existing Policy 1. Replaced Assistant Treasurer with Treasurer 2. Removed Appendix B (Employee acknowledgement)

APPENDIX 2B

NV Energy, Inc.

Energy Risk Management and Control Policy

Risk Committee Approval

November 15, 2023

This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided outside the Company without the prior approval of the Risk Committee Chairperson.

TABLE OF CONTENTS

I. Background

NV Energy, Inc. (the Company) has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the 'Companies') who are engaged in the generation, transmission and distribution of electric energy and in the distribution of natural gas in Nevada.

This policy addresses energy risks of the Companies. The officers and management of the Companies are responsible for enforcing this policy and the associated procedures in the areas for which they are responsible. The Companies are exposed to a variety of risks inherent in their commercial operations. Those risks include accidental loss risk, credit risk, energy supply risk, environmental risk, facilities risk, financial risk, information and control systems risk, and other operating risk. In aggregate, these risks constitute the Companies' enterprise risk.

The Companies manage risk in a variety of ways. For example, commitments to generation and transmission and to longer-term energy supply contracts are managed through the resource planning process (including distributed energy resource plans) and culminating with Public Utilities Commission of Nevada (PUCN) approval of the resource plans. Other multiyear risks are managed, in part, through the Companies' strategic planning exercises. Shorter-term risks are managed through annual Energy Supply Plans, budgets, key performance indicators and prioritized objectives by departments or functional area[1].

II. Application and Purpose

This policy will be applied to all physical and financial transactions related to energy procurement, energy sales, and energy hedging in accordance with Energy Supply Plans or Integrated Resource Plans approved by the PUCN as applicable. Any variances from the approved Energy Supply Plans or Integrated Resource Plans must be approved in accordance with Section V.D.2.

III. Policy Objectives

1. Provide preset notification thresholds for transactions entered into pursuant to this policy;

2. Establish sound principles for entering into and managing such transactions; and,

[1] Because organizations change names, responsibilities, and reporting relationships, references in this policy to 'department' or 'departments' is effectively referencing the executive or vice president responsible for that department or functional area.

3. Define the responsibilities for managing and monitoring those risks.

IV. Energy Risk Definition

The Companies are engaged in the generation, transmission and distribution of electricity, and in the distribution of natural gas in Nevada. The Companies deal in the coal, natural gas, oil and wholesale power markets (including renewable) to meet the energy requirements of their customers. They also acquire, develop and operate generating plants that produce electric energy for their customers. In so doing, the Companies are exposed to a variety of risks inherent in their energy supply efforts, including among others: price, volumetric, credit, and operational risk.

V. Energy Risk Management and Control Framework

The Companies will systematically manage price, volumetric and credit risks through three primary vehicles: (i) organization and governance; (ii) energy risk management programs; and (iii) energy risk control practices. Credit risk is addressed by a separate Credit Risk Management and Control Policy.

A. Organization and Governance

1. **Risk Committee:** The Risk Committee will be responsible for overall policy direction of the Companies' energy risk management and control efforts. Specific activities for which the Risk Committee will be responsible are set forth in Appendix B, Section A. The Risk Committee has the right to delegate portions of its assigned duties to one or more committees.

2. **Risk Control:** Risk Control, under the direction of the Vice President, Chief Financial Officer and Treasurer, will monitor the operations of the Companies to ensure compliance with this policy and the associated procedures. All omissions and exceptions will be reported promptly to the Risk Committee by Risk Control. Risk Control will be responsible for the activities set forth in Appendix C, Section A.

3. **Credit Risk Management:** Credit Risk Management, under the direction of the Vice President, Chief Financial Officer and Treasurer, will be responsible for managing and mitigating the Companies' credit risk exposures associated with energy and service delivery transactions. Credit Risk Management will be responsible for the activities set forth in Appendix C, Section B.

4. **Resource Optimization:** Resource Optimization, under direction from the Vice President of Resource Optimization, will be responsible for the resource optimization, balancing, forward trading, and contract negotiation related to fuel

and short-term wholesale power. Specific activities for which Resource Optimization will be responsible are set forth in Appendix C, Section C.

5. **Renewables and Origination:** Renewables and Origination, under the direction of the Vice President of Renewables will be responsible for the origination functions related to renewable energy and long-term (i.e., three year or greater term) wholesale power. Specific activities for which Renewables and Origination will be responsible are set forth in Appendix C, Section D.

6. **Resource Planning and Analysis:** Resource Planning and Analysis, under direction from the Vice President, Resource Optimization will be responsible for preparation of forecasts of: customer energy requirements; energy and fuel prices; production costs; and fuel requirements. Additionally, Resource Planning and Analysis will develop Integrated Resource Plans and Energy Supply Plans in accordance with the Public Utilities Commission of Nevada resource planning regulations. Specific activities for which Resource Planning and Analysis will be responsible are set forth in Appendix C, Section E.

7. **Fuel and Purchased Power Accounting:** Fuel and Purchased Power Accounting, under direction from the, Chief Financial Officer and Treasurer, will be responsible for ensuring transactions are accurately recorded in the financial system of record. Specific activities for which Fuel and Purchased Power Accounting will be responsible are set forth in Appendix C, Section F.

B. Energy Risk Management Program

1. **Portfolio Optimization:** The Companies, through the purchase and sale of the financial instruments and physical products set forth in Appendix D, Section A, will manage the energy risks inherent in the Companies' operations and prepare periodic reports to document the Companies' efforts and comply with legal and regulatory requirements. The Companies' will enter into transactions to balance and optimize their portfolios. However, speculative transactions are not permitted. Bookouts In Lieu of Liquidated Damages are permitted. Bookout transactions for the sole purpose of financial gain or of transactions that were not originally intended for physical delivery are not permitted.

2. **Energy Supply Plans.** The Companies will seek the PUCN approval of Energy Supply Plans to govern the purchase and sale of fuel and wholesale power and the associated transmission and transportation services. The process will include assessments of projected loads and resources, assessments of expected market prices, evaluations of relevant options available to the Companies for the purchase, sale, or optimization of resources, and evaluations of the risk attributable to those portfolio options. The Energy Supply Plans will include recommended courses of action to be followed during the three-year period covered by each plan.

   Any energy transactions that deviate from the PUCN approved Energy Supply Plans may only be entered into in accordance with Section V.D.2. The Energy

Supply Plans will be reviewed on an ongoing basis and updated at least once a year. Changes in the data and assumptions underlying the approved Energy Supply Plans will be promptly reported to the Risk Committee.

3. **Authorized Products and Authority of Personnel.** The personnel listed in Appendix D, Section B are authorized to originate transactions for the commodities and services indicated.

C. Documenting Transactions and Authorized Signatories

The Companies will not enter into any transaction for the purchase or sale of fuel and wholesale power without a written contract delineating the associated terms and conditions. The contract may be an agreement for a specific transaction, a standard agreement, or a master agreement. Transactions entered into for Energy Supply typically fall into two types: (i) transactions entered into for specific transactions under standard contract practices ("Non-Standard Transactions"), and (ii) transactions entered into orally pursuant to master agreements ("Standard Transactions"). These two types of transactions require different execution and risk control practices.

1. **Non-Standard Transactions.** Non-Standard Transactions are all contracts executed pursuant to this policy that are not Standard Transactions or Online Exchange Transactions. Non-Standard Transactions may be executed by the individuals identified in Appendix D, Section B and Section C in accordance with the Signature Authority Levels in Appendix D, Section F.

2. **Standard Transactions.** Standard Transactions are transactions that are entered into orally pursuant to a master trading agreement (as further discussed below) and subsequently confirmed, in the case of term transactions (one month or more), in writing. Gas transactions of less than one month are not required to be confirmed in writing. Power transactions of less than seven days are not required to be confirmed in writing. Standard transactions will be entered into or confirmed (for transactions entered into via brokers, ICE Chat or other industry acceptable methods) on recorded phone lines. The Companies will maintain telephone systems capable of recording trader transactions. Notices are provided pursuant to the Commitment Notification Thresholds for Oral Transactions as indicated in Appendix E Section A. The individuals indicated in Appendix D, Section D are authorized to enter into oral transactions.

3. **Online Exchange Transactions.** Online Exchange Transactions are transactions that are entered into via an online commodities exchange platform, such as the Intercontinental Exchange ("ICE"). These transactions do not require oral confirmation over a recorded phone line. Online Exchange Transactions are subject to the same notification limits as Oral Transactions. The individuals identified in Appendix D; Section D are authorized to enter into oral transactions.

4. **Master Agreements**. Master agreements include, but are not limited to, the International Swap and Derivatives Association ("ISDA") Agreement for financial

and physical gas transactions (where a physical annex exists), WSPP Inc. Agreement for physical power, and the North America Energy Standard Board ("NAESB") Agreement for physical gas. Master agreements will be executed by the Vice President of Renewables. When a master agreement is in place, a transaction may be entered into orally in accordance with the terms of the relevant master agreement and subsequently confirmed, in the case of gas transactions (one month or more) and power transactions (seven days or more), in writing. Risk Control shall notify the appropriate personnel if the Dollar Threshold is exceeded in the Table in Appendix E, Section A. Confirmations will be executed by the Manager, Power and Gas Trading or Power Trader.

5. **Authorized Signatories**. The individuals listed in Appendix D, Section E are authorized to execute transactions and confirmations for approved financial and physical instruments on behalf of the Companies provided that such transactions conform to the Energy Supply Plan approved by the Public Utilities Commission of Nevada or as otherwise approved by Risk Committee. Invoices shall be approved in accordance with the signature authority limits of the Corporate Governance and Approvals Policy.

D. Risk Control Practices

Risk Control Practices are established to monitor and manage the risks inherent in the efforts to secure reliable supplies of fuel and wholesale power, and to optimize the portfolio through sales. Risk Control Notification Thresholds have been established to monitor and report risk metrics for transactions entered into by the Companies.

1. **Notification Thresholds:** The Companies will adhere to the notification thresholds set forth in this policy. The notification thresholds fall into three categories: Transaction Approval Notification thresholds, Portfolio Risk Notification thresholds, and Credit Risk Notification thresholds.
2. **Transaction Notification Thresholds.** The transaction notification thresholds relate to the values of contracts to which authorized personnel of the Companies obligate the Companies. Risk Control will report any transactions that exceed the transaction notification thresholds (Appendix E, Section A) monthly to the voting members of the Risk Committee.
3. **Portfolio Risk Control Notification Thresholds:** Value-at-Risk notification thresholds and Mark-to-Base change notification thresholds will be applied to the Companies' energy procurement and sales activities. Risk Control will report any instances where the Value-at-Risk and Mark-to-Base metrics exceed the portfolio risk control notification thresholds (Appendix E, Sections B and C) monthly to the members of the Risk Committee as they occur.

   i. **Value-at-Risk Notification Thresholds:** The Value-at-Risk (also referred to as Cash-Flow-at-Risk when used in analyzing liquidity requirements) notification thresholds set forth in Appendix E, Section B will be the notification threshold for the expected maximum increase in fuel and wholesale power costs. The Companies will use methodologies, consistent with industry standards, for calculating the Value-at-Risk for their energy portfolios. Those calculations will incorporate the level of confidence, length of term and holding period set forth in Appendix E, Section B.

ii. **Mark-to-Base Notification Thresholds:** Base Tariff Energy Rates (BTER) are set at levels that anticipate the Companies' expenditures for fuel and wholesale power. During any period, recovery of expenditures in excess of the revenue produced by those base rates is first offset against sales for the same period. To the extent that expenditures for fuel and wholesale power exceed BTER revenues and offsets for sales, the excess will be deferred. Mark-to-Base will provide an estimate of such deferrals for the current deferral period. It will reflect actual expenditures to date, committed expenditures for the balance of the deferral period, and expected expenditures for uncommitted purchases. The Mark-to-Base Notification thresholds set forth in Appendix E, Section C will trigger notifications if changes in Mark-to-Base Thresholds occur on both a cumulative basis and a month-to-month basis. Mark-to-Base for each deferral period will begin to be assessed three months before the beginning of each deferral period and continue to be assessed until the end of each deferral period.

4. **Energy Credit Risk Notification Thresholds:** All Energy Credit Risk Notifications shall be made in accordance with the Credit Risk Management and Control Policy.
5. **Exception Management Process**: The Risk Committee may approve exceptions to this policy and to the plans and procedures developed in accordance with this policy. Transactions which are not contemplated by an Integrated Resource Plan or Energy Supply Plan may only be entered into if approved by the Risk Committee and the President.

6. **Procedures:** The Companies will maintain procedures for reporting exceptions and notifications pursuant to this policy and the plans and procedures developed in accordance with this policy. The procedures will have provisions for the prompt notification of the Treasurer or Assistant Treasurer, who will, in turn, be responsible for notifying the Companies' personnel responsible for resolution of the exception, and the Risk Committee. Presentations to the Risk Committee will include descriptions of the exceptions, proposed courses of action to resolve the exceptions, and schedules for resolving the exceptions.

VI. Compliance

All personnel who are or may become involved in any energy procurement or sale activities or otherwise influence the energy procurement or sale decisions covered by this policy will be provided a copy of this policy and any associated procedures. Company personnel are prohibited from buying and selling any approved commodity for their own account or for the benefit of any entity other than the Companies. Additionally, Company personnel are required to disclose any significant direct interest[2] in any of the Companies' counterparties for transactions covered by this policy. To facilitate that disclosure, a listing of the Companies' counterparties and their parent organizations will be made available upon request.

Personnel who are or may become involved in any energy procurement or sale activities covered by this policy will be familiar with this policy and any associated procedures and solicit clarification of any areas that they do not understand. Each such employee will be advised of their responsibilities as set forth in the Employment Acknowledgement, Appendix G, confirming his or her understanding of the policy requirements, and confirming his or her agreement to fully comply with those requirements. Each such employee also will be required to complete an Employee Acknowledgment form whenever substantive updates are made, or at one-year intervals, whichever comes first. Consistent with the Employee Acknowledgement form:

1. Each employee will have an affirmative duty to alert management immediately upon learning of any potential violations of this policy.

2. Each employee also will have an affirmative duty to alert management immediately upon learning of any risks not adequately covered by this policy and the associated procedures, methodologies, and systems.

[2] For the purposes of this policy, a direct interest will be defined as the direct ownership of shares in a publicly traded entity or an ownership interest in a privately held entity. A significant direct interest will be one with a current value greater than one thousand dollars. The ownership of shares via a mutual fund will not be deemed a direct interest.

Appendix A: Definitions

Aggregate Exposure	An estimate of the current cost of replacing all of the contracts with a counterparty.
Approved Commodity	Electricity, natural gas, propane, coal, oil, and portfolio energy credits together with derivatives that are linked to those commodities and transmission or transportation services for those commodities. Renewable energy credits that fall outside the definition of portfolio energy credits.
Bookouts	An agreement entered into subsequent to an agreement for the physical delivery of a commodity to cancel an outstanding agreement by the parties involved, through cash settlement of the difference between the price specified in the agreement and an acceptable reference price. A Bookout must be memorialized in a subsequent agreement in writing between the parties involved to comply with Dodd-Frank regulations.
Bookouts In Lieu of Liquidated Damages	An agreement entered into to cancel an outstanding delivery obligation or portion thereof in lieu of the payment of liquidated damages by the parties involved, through cash settlement of the difference between the price specified in the agreement and an acceptable reference price.
Counterparty	An entity that has entered into a contract with one of the Companies.
Energy Supply Plans	Plans that the Companies will develop to govern the purchase and sale of fuel and wholesale power and the associated transmission and transportation services. Energy Supply Plans will cover three-year periods.
Financial Instruments	Swaps, options, futures, and options on futures entered into to hedge risks.
Fixed Price Agreement	A contract in which the price of the commodity or service is set at a particular level when the contract is executed.
Forwards	Agreements to buy or sell a quantity of a product, at an agreed price, for delivery at a specific location and for a future period and traded over the counter directly with counterparties.
Indexed Agreement	A contract in which the price of the commodity or service is tied to one or more published indices.

Liquid Market	A market characterized by narrow bid/offer spreads, easy access to reliable price data, and small movements in prices as a result of sizable transactions.
Mark-to-Base	An estimate of costs that may be deferred through deferred energy or purchased gas adjustment accounting.
Mark-to-Market	The value of a financial or physical instrument, or an aggregation of such instruments, at the Companies' best estimate of current market prices.
Options	Instruments which give the holder the right, but not the obligation, to sell or buy the underlying commodity at specified prices, times, and locations.
Physical Instrument	A contract for a commodity under which the Companies expect to take delivery of the specified commodity.
Portfolio Energy Credit	A credit that is earned through energy produced or saved from a renewable energy system or energy efficiency measure. These credits are issued to any eligible renewable energy producer as defined in Nevada Revised Statute 704.7811. These credits may be purchased and sold to meet the Renewable Portfolio Standard.
Products	Commodities with specific characteristics like electricity delivered during predefined periods.
Renewable Energy Benefits	Represents the property rights to the environmental, societal, and other nonpower qualities of renewable electricity generation. A Portfolio Energy Credit and its associated attributes and benefits can be sold separately from the underlying physical electricity associated with a renewable-based generation source.
Swaps	Agreements to exchange net future cash flows or physical positions.
Transaction	A contract obligating the Companies to buy or sell physical commodities and services. Transactions will also include monetary obligations incurred through financial instruments.
Transmission Agreement	A contract to move electricity from one point to another. Such contracts are frequently referred to as "wheeling" agreements.
Transportation Agreement	A contract to move coal, natural gas, or oil from one point to another.

Value-at-Risk (also referred to as Cash-Flow-at-Risk when used in analyzing liquidity requirements)	The expected maximum increase in fuel and wholesale power costs over a target horizon within a given confidence interval and holding period. Value-at-Risk serves as a gauge of market exposure, summarizing the total market risk in a portfolio of assets.
Western North America Coal Sources	Coal mines in the States of Arizona, Colorado, New Mexico, Utah, and Wyoming that produce coal that can be burned efficiently and effectively in the Companies' generating units.
Western North America Natural Gas Hubs	Locations in the western half of the United States and Canada at which natural gas is traded in quantities sufficiently large to ensure liquid markets.
WSPP Regional Power Markets	Locations in the western half of the United States and Canada at which electricity is traded in quantities sufficiently large to ensure liquid markets. Such electricity is often traded under the provisions of the WSPP agreement.

Appendix B: Areas of Responsibility - Committee

Risk Committee: The Risk Committee will be responsible for:

- Assessing the appropriateness of the Companies' energy supply risk management and control activities and making recommendations for modifications to existing policies;
- Approving changes and exceptions as designated in specific sections of this Policy and ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Assessing the systems required to monitor, record, and report on the risks inherent in the Companies' energy supply related activities and making recommendations for improvements to existing risk policies;
- Approving Energy Supply Plans;
- Reviewing all transactions requiring exceptions to the applicable policies and procedures;
- Reviewing and approving all energy procurement and sale transactions that are Transactions not transacted in accordance with the Energy Supply Plan, requiring the approval of the President;
- Reviewing all violations of notification thresholds and processes established under this policy, approving, or recommending for approval remedies of the violations, and monitoring progress of such remedies; and
- Assigning the completion of any other activities to guide the overall policy direction of the Companies' energy risk management and control efforts; and,
- Approving any exceptions to the Energy Supply Plan.

Appendix C: Areas of Responsibility – Departments

A. **Risk Control:** Risk Control is responsible for:

- Monitoring compliance with the Energy Risk Management and Control Policy and reporting exceptions;
- Disseminating this policy to the Companies' personnel who will be affected by this policy;
- Measuring the Companies' energy portfolio exposures and comparing the measurements against approved exposure notification thresholds;
- Accumulating risk control information for the Companies;
- Creating monthly risk control reports;
- Assessing proposed modifications to risk control policies and notification thresholds based on changing business or market conditions;
- Recommending the appropriate level of risk - within approved notification thresholds - to be accepted on behalf of the Companies;
- Each business day, review sample of 1 - 5 trades by listening to phone recordings or ICE Chat (gas/power) and verifying that transactions are in the trader log and TRM for natural gas or Allegro and OATI for power; and,
- Notifying Executive Management per the Energy Supply Commitment Threshold Notification levels set forth in Appendix E, Section A.

B. **Credit Risk Management:** Credit Risk Management is responsible for:

- Assessing the creditworthiness of counterparties;

- Approving counterparties and establishing credit ratings for them before the Companies enter into energy-related transactions with them;
- Maintaining the Companies' lists of approved bidders;
- Monitoring and reporting on the creditworthiness of wholesale fuel and power counterparties;
- Reviewing and reporting on all contractual credit terms;
- Reviewing and reporting on information requested by counterparties for collateral or other credit support;
- Notifying Resource Optimization leadership when credit exposure limits have been exceeded and assisting Risk Control in developing the strategy to mitigate risk;
- Resolving credit issues with counterparties;
- Calculating collateral requirements to be posted by counterparties and overseeing the receipt of that collateral;
- Maintaining records of the collateral posted by counterparties;
- Calculating collateral requirements and managing collateral posted by the Companies; and,
- Managing margining requirements.

C. Resource Optimization: Resource Optimization is responsible for:

- Negotiating, developing, and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds;
- Identifying prospective counterparties and presenting viable entities to Credit Risk Management for approval;
- Facilitating Requests For Proposals ("RFPs") for standard power, natural gas, coal, propane, and oil;
- Verifying the accuracy of financial/physical gas, carbon allowances, and spot power invoices received by the Companies related to short-term power, transmission, and California Independent System Operator market transactions;
- Leading the negotiation process for certain natural gas transportation contracts and gas storage;
- Recording transactions for accounting and contract management purposes, distributing the records, and adjusting the records as a result of actualization activities;
- Reviewing confirmations for accuracy prior to approval; and,
- Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure.

D. Renewables and Origination: Renewables and Origination is responsible for:

- Negotiating, developing, and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds;
- Leading the negotiation process of Master Agreements for power and carbon;
- Facilitating Requests For Proposals ("RFPs") for non-standard transactions, portfolio energy credits, other renewable energy credits, and qualifying facilities;
- Managing customer programs and executing associated commercial transactions;

- Performing due diligence and all associated tasks for asset acquisitions and specific asset developments to meet customer or resource planning needs;
- Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure;
-
- Leading the negotiation process for non-standard power contract amendments;
- Providing contract support to Resource Optimization, Credit Risk Management, Contract Management, Legal, Resource Planning and Analysis, Fuel & Purchased Power Accounting, etc.

E. Resource Planning and Analysis: Resource Planning and Analysis is responsible for:
- Developing forecasts of energy and fuel prices;
- Estimating the Companies fuel and the associated costs;
- Developing Integrated Resource Plans;
- Developing Energy Supply Plans and associated risk management strategies;
- Analyzing energy resources available to the Companies to help to ensure the optimal use of those resources; and,
- Preparing or assisting with the preparation of periodic reports.

F. Fuel and Purchased Power Accounting: Fuel and Purchased Power Accounting is responsible for:
- Verifying the accuracy of financial/physical gas, carbon allowances, and spot power invoices received by the Companies;
- Resolving issues regarding financial/physical gas, carbon allowances, and spot power invoices received by the Companies;
- Submitting final invoices to authorized personnel for approval;
- Preparing and issuing invoices for sales to counterparties;
- Verifying the settlement amounts from financial transactions;
- Accounting for all transactions;
- Reconciling the accounts to confirm the accuracy of the energy accounting;
- Ensuring the timely collection of receivables attributable to sales of energy and fuel;
- Supervising the payment and receipt of all settlements from financial transactions; and,
- Preparing designated reports.

G. Energy Supply Contract Management: Energy Supply Contract Management is responsible for:
- Managing pre-commercial and commercial energy supply contracts per their terms and conditions, including but not limited to; certifying completion of contractually required milestones, acceptance of commercial operation, and the invoice settlement function for long-term power and certain natural gas contracts;
- Maintaining counterparty contract and trading status information in the systems of record;
- Managing the confirmation process for term physical/financial gas and power transactions;

- Maintaining energy supply contracts in accordance with the Corporate Records Retention Schedule; and,
- Providing contract support to Resource Optimization, Credit Risk Management, Contract Management, Legal, Resource Planning and Analysis, Fuel & Purchased Power Accounting, etc.

Appendix D : Resource Procurement and Sale Constraints

A. Approved Financial Instruments and Physical Products

Instrument	Commodity											
	Power		Natural Gas		Coal		Oil, Diesel, Propane		SO2 Allowances		Carbon Allowances	
	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell	Buy	Sell
Financial Instruments												
Forwards	X	X	X	X			X				X	X
Options	X	X	X	X			X					
Swaps	X	X	X	X			X					
Physical Products and Instruments												
Spot Agreements	X	X	X	X	X	X	X	X			X	X
Fixed Price Agreements	X	X	X	X	X	X	X	X	X	X	X	X
Indexed Agreements	X	X	X	X	X	X	X	X			X	X
Ancillary Services	X	X										
Options (includes capacity contracts)	X	X	X									
Transmission Agreements	X	X										
Transportation Agreements			X	X	X	X	X					
Storage Agreements			X	X								

Underlying Markets: All Western North America Natural Gas Hubs
The Henry Natural Gas Hub in Louisiana
All WSPP Regional Power Markets
All Western North America Coal Sources

The Risk Committee may approve changes to the Approved Financial Instruments and Physical Products or Underlying Markets as deemed necessary.

B. Authorization to Originate Standard and Non-Standard Transactions Under Approved Energy Supply Plans

	Power		Natural Gas			Oil, Diesel, Propane		Coal		Financial[3]		SO2	Carbon
	Commodity	**Transmission**	**Commodity**	**Transportation**	**Storage**	**Commodity**	**Freight**	**Commodity**	**Freight**	**Swaps**	**Options**	**Allowances**	**Allowances**
Director, Gas Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
Director, Power Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
Manager, Gas Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
Manager, Power Trading	X	X	X	X	X	X	X	X	X	X	X	X	X
Power Traders	X	X	X	X				X	X	X			X
Gas Traders	X	X	X	X		X	X	X	X	X	X		X
Power Trader - Gendesk	X	X	X	X				X	X				X
Resource Optimization Manager								X	X				

The Risk Committee may approve additions and changes to the Authorization to Originate Transactions prior to the origination of the transaction.

C. Authorization to Originate or Amend Renewables and Non-Standard Transactions Under Approved Energy Supply Plans

	Renewable Power and QFs		Portfolio Energy Credits/Renewable Energy Credits		Power	
	Buy	**Sell**	**Buy**	**Sell**	**Buy**	**Sell**
Vice President, Renewables	X		X	X	X	
Director, Renewable Energy & Origination	X	X	X	X	X	X

[3] Financial transactions related to energy commodities only.

Director, Contract Management and Special Programs (Amendments/Settling disputes only)	X		X		X	

The Risk Committee may approve additions and changes to the Authorization to Originate Transactions prior to the origination of the transaction.

D. Individuals Authorized to Enter Into Oral Transactions

- Director, Gas Trading
- Director, Power Trading
- Manager, Gas Trading
- Manager, Power Trading
- Gas Traders
- Power Traders

E. Authorized Signatories – Power and Fuel Contracts and Confirmations

- Chief Executive Officer
- Vice President, Chief Financial Officer
- Vice President, Renewables
- Vice President, Resource Optimization
- Director, Gas Trading
- Director, Power Trading
- Manager, Gas Trading
- Manager, Power Trading
- Resource Optimization Manager

Personnel may not execute contracts or confirmations for transactions they originated.

Signature authority may not be delegated.

F. Authorization Approval Levels for the Execution of Fuel and Purchased Power Transactions and Daily Trades ($ up to and including)

Title	***Limit – RFPs and Daily Trades****	
Chief Executive Officer, Berkshire Hathaway Energy Company	*Unlimited*	
Chief Executive Officer	*$100,000,000*	
Vice President, Chief Financial Officer	*$25,000,000*	
Vice President, Resource Optimization[1],[2]	*$12,500,000*	

Director, Trading Analytics & Operations[3]	*$7,500,000*	
Director, Contract Management and Special Programs (Amendments/Settling disputes only)	*$7,500,000*	
Director, Gas Trading	*$7,500,000*	
Director, Power Trading	*$7,500,000*	
Manager, Gas Trading	*$5,000,000*	
Manager, Power Trading	*$5,000,000*	
Resource Optimization Manager	*$5,000,000*	
Traders	*$1,000,000*	

Approval of invoices are subject to dollar thresholds in the Corporate Governance and Approvals Policy.

**** To ensure reliability, approvals of daily trades may happen after trade execution.***

[1] Applies to transactions longer than one month

[2] Applies to transactions pertaining to the table in Appendix D, Section C

[3] Applies to transactions pertaining to the table in Appendix D, Section B

Appendix E: Risk Control Notification Thresholds

A. Commitment Threshold Notification for fuel and purchase power – Per Transaction[4]

Title	*Dollar Threshold*
Chief Executive Officer	*$100,000,000*
Vice President, Chief Financial Officer	*$25,000,000*
Vice President,Resoucre Optimization l	*$12,500,000*

The maximum total commitment attributable to a transaction at index will be based on the Companies' best estimate of the index at the time of the transaction.

B. Value-at-Risk Commitment:

[4] Applies to transactions longer than one month

Company	Level of Confidence	Length of Term	Holding Period	Amount
Nevada Power	95% or higher	Rolling twelve Months	1 year	$100 million
Sierra Pacific Power	95% or higher	Rolling twelve Months	1 year	$60 million
Local Distribution Company	95% or higher	Rolling twelve Months	1 year	$20 million

C. Mark-to-Base Commitment Threshold Notification – Cumulative/Monthly:

Company	Base	Cumulative Change	Notify
Nevada Power	BTER	$80 million	President
Sierra Pacific Power	BTER	$50 million	President
Local Distribution Company	BTER	$10 million	President

Appendix F: Policy Revision Log

Date	**Revision(s)**
August 28, 2014	Modified Existing Policy. 1. Updated titles of personnel. Replaced "Mid-American Energy Holdings Company" with "Berkshire Hathaway Energy Company". 2. Modified language regarding the Risk Committee's reviewing and approving Energy Supply Plans and any exceptions to the Energy Supply Plans. 3. Added the definition of "Bookout" and language clarifying which types of "Bookout" transactions are permitted. Made a distinction between standard and non-standard transactions. 4. Clarified when power transactions must be confirmed in writing. 5. Added clarifying language that the Risk Committee is responsible for approving any exceptions to the Energy Supply Plan. 6. Added the management of margining requirements as a Credit Risk Management responsibility. 7. Moved the responsibility for leading the negotiation process of Master Agreements for physical/financial gas, power and carbon from Resource Optimization to Renewable Energy & Origination.

	8. Added the responsibility for leading the negotiation process for gas storage to Resource Optimization. 9. Added the responsibility for facilitating Requests for Proposals for propane and oil to Resource Optimization. 10. Modified the responsibilities of Renewable Energy & Origination as follows: • Negotiating, developing and executing transaction plans consistent with the approved Energy Supply Plans and the associated notification thresholds • Leading the negotiation process of Master Agreements for physical/financial gas, power and carbon • Facilitating Requests For Proposals ("RFPs") for non-standard power, and portfolio credits • Coordinating with Risk Control and Credit Risk Management to manage or mitigate any risk exposure. 11. Added oil, diesel, and propane freight and commodity as transactions that gas traders are authorized to originate. 12. Added carbon allowances invoices to Fuel and Purchase Power Accounting's responsibilities, added gas storage and gas transportation as origination transactions the Manager, Market Operations and Trading is authorized to originate (Buying and Selling). 13. Added gas storage and gas transportation as origination transactions the Manager, Commercial and Trading Strategy is authorized to originate (Buying only). 14. Added the Chief Executive Officer, Director of Renewable Energy and Origination (marketing function employee designated position), Project Manager, Power Origination (Confirms only) as authorized signatories to Power and Fuel Contracts and confirmations. 15. Added a policy revision log.
December 16, 2014	Modified Existing Policy: 1. Changes were made throughout the document to fix references to the appendices. 2. Replaced the acronyms, RECs, PECs, PUCN, WSPP, and CAISO with their full wording. 3. Added Renewable Energy Credit and Portfolio Energy Credit to the terms defined in Appendix A (Definitions). 4. Removed the Company's Procurement function from the table indicating who is authorized to originate transactions under the Public Utilities Commission of Nevada approved Energy Supply Plans. 5. Removed the Chief Executive Officer of Berkshire Hathaway Energy Company as the top level commitment threshold notification for fuel and purchase power transactions. 6. Changed the Employee Acknowledgement section to read "A list of the Companies counterparties for transactions covered by the policy and their parent organizations will be provided upon request."
June 3, 2015	Modified Existing Policy: 1. Added the position of Power Marketer, Origination to Appendix D, Section C, (Authorization to Originate or Amend Renewables and Origination Transactions Under Approved Energy Supply Plans).
June 17, 2015	Modified Existing Policy: 1. Updated titles of personnel.

	2. Modified the existing table in Appendix D, section B to pertain to Standard and Non-standard transactions under approved Energy Supply Plans. 3. Modified the existing table in Appendix D, section C to pertain to Non-standard transactions under approved Energy Supply Plans. 4. Transferred the responsibility for notifying Executive Management per the Energy Supply Commitment Threshold notification levels (Appendix E, section A) from Energy Supply Contract Management to Risk Control. Notification will be made to Executive Management via Risk Committee Meetings instead of via email as was previously done.
July 26, 2017	Modified Existing Policy: 1. Updated the Energy Risk Management and Control Policy to include organizational changes made since the policy was last approved on June 17, 2015. 2. Added propane and portfolio energy credits to the definition of approved commodity. 3. Modified the definition of Portfolio Energy Credit. 4. Changed Renewable Energy Credit to Renewable Energy Benefit. 5. Moved the footnotes reference (3, 4, and 5) to the appropriate page.
May 7,2018	Modified Existing Policy: 1. Updated titles of personnel 2. Replaced CEO with President
December 19, 2018	Modified Existing Policy: 1. Added footnote on page 3 defining functional area 2. Replace "Chief Accounting Officer" with "Chief Financial Officer" 3. Removed President line item from Authorization Approval Level and Risk Control Notification Threshold charts 4. Removed "Senior" from Senior Vice President, Chief Financial Officer title
December 4, 2019	1. Modified Appendix A – Approved Commodity; added; Renewable energy credits that fall outside the definition of portfolio energy credits. 2. Modified Renewable and Origination responsibilities • 3rd bullet to read: Facilitating Request for Proposal (RFPs) for non-standard transactions, portfolio energy credits, other renewable energy credits and qualifying facilities • 7th bullet to read; Managing pre-commercial and commercial energy supply contracts per their terms and conditions, including but not limited to; certifying completion of contractually required milestones, acceptance of commercial operation, and the invoice settlement function for long-term power and certain natural gas contracts
Dec 17, 2020	Modified Existing Policy: 1. Deleted Senior Vice President, Operations throughout policy 2. Change page 24 to 25 on table on content 3. Added "in accordance with section V.D.2" and deleted by the Risk Committee and President (page 3) 4. Added "PUCN and may only be entered into in accordance with Section V.D.2"v deleted without the prior approval of Risk Committee and The Companies will not execute) (page 6) 5. Added Transactions which are not contemplated by an Integrated Resource Plan or Energy Supply Plan may only be entered into if approved by the Risk and the President and added Assistant Treasurer (pg+ 8)

	6. Removed "A" in front of Risk Committee (pg 13)
July 21, 2021	Modified Existing Policy: 1. Replaced Manager, Market Operations and Trading with Manager, Power & Gas Trading 2. Replaced Project Manager, Forward Trading with Power Trader 3. Replaced Manager, Coal Operations and Procurement with Resource Optimization Manager 4. Replaced Vice President, Resource Optimization with Director, Trading Analytics & Operations 5. Added a dollar limit in Section F for Director, Trading Analytics & Operations to $7, 500.000 6. Added Section D Power and Natural Gas Trading Limits to Appendix E 7. Updated the CEO and CFO dollar thresholds 8. Added Resource Optimization Manager and Traders to Section F with $5M and $1M dollar limits respectfully
November17, 2021	Modified Existing Policy: 1. Updated title of Manager, Contract Management with Director, Contract Management and updated dollar limits for RFP and daily trades 2. Revised a Risk Control responsibility to be consistent with the corresponding SOX control
December 14, 2022	1. Updated titles 2. Moved several responsibilities from the Renewables section to Contract Management's section
August 1, 2023	1. Changed titles to allow for either Director or Manager of Power and/or Gas Trading consistent with the reorganization and leadership title changes in Resource Optimization.
November 15, 2023	1. Replaced Senior Vice President, Chief Financial Officer and Treasurer with Vice President, Chief Financial Officer 2. Removed Appendix G – Employee acknowledgement statement

APPENDIX 2C

NV Energy, Inc.

Credit Risk Management and Control Policy

Risk Committee Approval

November 15, 2023

This policy should only be distributed to the employees of NV Energy (and its subsidiaries) who need access to the document during the performance of their assigned duties. This policy should not be provided to anyone outside the Company without the prior approval of the Risk Control Department.

TABLE OF CONTENTS

I. Background

NV Energy, Inc. (the "Company") has two wholly owned utility subsidiaries, Nevada Power Company (d/b/a NV Energy) and Sierra Pacific Power Company (d/b/a NV Energy) (and together with NV Energy, the "Companies") who are engaged in the generation, transmission, and distribution of electric energy and in the distribution of natural gas in Nevada.

NV Energy's Risk Committee approved the Risk Management and Control Policy dated January 5, 2021. That policy outlines NV Energy's philosophy toward the management and control of the risk inherent in the Companies' business operations. That policy also created the Risk Committee and made that committee responsible for overall policy direction of the Companies' risk management and control efforts. That policy further instructed the Risk Committee to oversee the development of appropriate risk management and control policies including this Credit Risk Management and Control Policy.

II. Application and Purpose

The Credit Risk Management and Control Policy outlines NV Energy's philosophy toward the management and control of the credit risk inherent in the Companies' normal business operations.

The primary purpose of the policy is to:

- Provide guidelines for employees that are authorized to legally bind the Companies for procurement, sales, and service delivery transactions;
- Establish sound guidelines for the management and control of risks attributable to those transactions; and,
- Define the responsibilities for managing and monitoring those risks.

This policy will be applied to all physical and financial transactions related to the Companies' procurement, sales, and service delivery activities. Five principal areas of credit risk are addressed in this policy:

- Energy supply
- Large customer accounts[1]
- Procurement (non-fuel)
- Transmission
- Rule 9

[1] Credit risk of Mid-to-Small customers is managed by Credit and Billing Department

III. Credit Risk Definition

Credit risk is the possibility that because of a counterparty's financial condition the counterparty's financial or physical obligations may not be timely performed. Credit exposure is the dollar amount that would be at risk in the event that the counterparty fails to perform. Credit loss is the actual dollar amount loss incurred due to the default. An evaluation of credit risk should measure exposure, and the possibility of failure to perform and recovery on defaults.

IV. Credit Risk Management and Control Framework

The Companies will systematically manage and control credit risk through three primary vehicles - organization and governance, credit risk management program, and credit risk control practices.

A. Organization and Governance

1. **Risk Committee:** The Risk Committee is responsible for overall policy direction of the Companies' risk management and control efforts, including credit risk management and risk control efforts. Specific activities for which the Risk Committee is responsible are set forth in Section A of Appendix B. The Risk Committee has the right to delegate portions of its assigned duties to one or more committees.

2. **Vice President, Chief Financial Officer and Treasurer:** The Companies' management is responsible for enforcing this policy and the associated procedures in the areas for which they are responsible. The Vice President, Chief Financial Officer and Treasurer and are responsible for monitoring compliance with this policy and those procedures. All material omissions and exceptions will be promptly reported to the Risk Committee.

3. **Risk Control:** The Risk Control organization monitors compliance with this credit policy and the associated procedures. Risk Control, under direction from the Vice President, Chief Financial Officer and Treasurer are responsible for the activities set forth in Section A of Appendix C.

   a) **Energy Credit Risk Management:** The Companies enter into contracts with numerous counterparties while buying and selling energy including fuel, purchased power, and coal. Credit Risk Management, under direction from the Treasurer, is responsible for the Companies' credit risk management activities as they apply to energy supply. Specific activities for which Energy Credit Risk Management will be responsible are set forth in Section A of Appendix D.

b) Large Customer Credit Risk Management: The Companies provide power services to large customers. The credit risk associated with these customers' results from the possibility that they will be unable or unwilling to remit payment to the Companies after services have been received. Large Customer Credit Risk Management under the direction of the Companies' Risk Control and Credit & Billing organizations will be responsible for the Companies' credit risk management activities as they relate to large customers. Specific activities for which Large Customer Credit Risk Management will be responsible are set forth in Section B of Appendix D.

c) Procurement Credit Risk Management: The Companies enter into non-fuel contracts with numerous suppliers of materials used in the development and maintenance of the electric and gas infrastructure. These contracts are approved per the Corporate Governance and Approvals Policy. Contracts more than $100,000 require performance bonds. Contracts more than $1,000,000 require a risk assessment to be performed by Risk Control. Credit risk associated with these suppliers is the possibility that they will be unable or unwilling to provide materials in time or fail to provide materials altogether. Specific activities for which Procurement Credit Risk Management will be responsible are set forth in Section C of Appendix D.

d) Transmission Credit Risk Management: The Companies enter into contracts with numerous counterparties and customers for long term point-to-point transmission, large and small generator interconnection, and short-term point-to-point transmission. Specific activities for which Energy Credit Risk Management will be responsible are set forth in Section D of Appendix D.

e) Rule 9 Credit Risk Management: The Companies enter into contracts with numerous customers for a large project that the Company has a reasonable basis for believing that circumstances particular to an applicant's project would subject the Company to a substantial risk of not recovering its investment in the applicant's project. Abnormal Risk projects are defined as: project costs will not be fully collected from project developers and new loads enabled by line extensions will be reduced or terminated. Consequently, these will not generate the required rate revenue to pay for the allowance or refund cost of the project over its life. Specific activities for which Energy Credit Risk Management will be responsible are set forth in Section E of Appendix D.

B. Credit Risk Management Program

1. Energy Credit Risk: The Companies will maintain an ongoing energy credit risk program with the objective of avoiding material increase in operating and capital costs attributable to failures to perform by counterparties. The program will address these three key components: i) counterparty credit risk mitigation through arrangements such as credit support, netting, mark-to-market margin collateral, termination clauses, etc.; ii) evaluation and potential use of credit risk transfer instruments such as credit insurance, credit derivatives and clearinghouse transactions; and iii) the implementation of appropriate procedures such as transaction credit approval, exception management, etc. The program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies' operations and for the preparation of periodic reports to document the Companies' efforts. All counterparties will be pre-approved by the Credit Risk Management group of the Risk Control department.

2. Large Customer Credit Risk: The Companies will maintain an ongoing large customer credit risk management program that focuses both on preventing the occurrence of adverse credit outcomes at an account level, and on recovering any material increase in operating and capital costs attributable to failures to pay by customers. As part of the prevention mechanisms, the credit risk management program will implement measures such as but not limited to an assessment of customer credit based on payment history with the Companies, third party credit analysis, tighter billing cycles, late fee assessment, and deposit requirements. All risk management and risk mitigation measures used will be in compliance with the governing legal and regulatory statutes (e.g., the Consumer Bill of Rights, tariff filings, and other applicable regulations). As part of the regulatory recovery mechanisms, the credit risk management program will thoroughly document working capital charges resulting from delayed payments and capture any write offs. The credit risk management program will ensure appropriate regulatory recovery of all such additional costs incurred by the Companies and will have provisions for the preparation of periodic reports to document the Companies' efforts.

3. Procurement Credit Risk: The Companies will maintain an ongoing procurement credit risk program focused on avoiding material interruption and costs attributable to failures by counterparties to perform or pay. The program will include four key components: (i) periodic vendor credit evaluation, (ii) critical vendor status determination, (iii) on-going critical vendor credit status assessment, and (iv) risk mitigation activities. Critical material vendors will be identified by Procurement based on, but not limited to, total contract value outstanding, estimated annual spend, product replacement options, services provided, frequency of transactions, and alliance partners. After a critical vendor has been identified, a credit rating will be given based on external credit ratings services, independent debt rating by major investment banks, or internal evaluation of vendor's financial condition. The credit status and credit exposure of critical material vendors will be monitored and assessed no less than annually and prior to the awarding of major new contracts. Risk mitigation techniques will be utilized for all vendors when available. Such activities will include, but are not limited to, requiring credit support, including provisions for liquidated damages, diversifying vendor portfolio, actively seeking creditworthy vendors, and identifying replacement vendors.

4. Transmission Credit Risk: The Companies will maintain an ongoing transmission credit risk program with the objective of avoiding a material increase in operating and capital costs attributable to failures to perform by counterparties and customers. The program will address these key components: i) counterparty and customer credit risk mitigation through arrangements such as credit support, netting, termination clauses, etc.; ii) The program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies' operations and for the preparation of periodic reports to document the Companies' efforts. All counterparties and customers will be pre-approved by the Credit Risk Management group of the Risk Control department.

5. Rule 9 Credit Risk: The Companies will maintain an ongoing Rule 9 customer credit risk management program that focuses both on preventing the occurrence of project costs not fully being collected from project developers, new load enabled by line extensions will be reduced or terminated, will not generate the required rate revenue to pay the allowance or refund cost of the project over its life or project between 1MW or 10MW or total project cost of $400,000 or more. The program will have provisions for the systematic identification, quantification, evaluation, and management of the credit risk inherent in the Companies' operations and for the preparation of periodic reports to document the Companies' efforts. All counterparties and customers will be pre-approved by the Credit Risk Management group of the Risk Control department. The credit risk management program will ensure appropriate regulatory recovery of all such additional costs incurred by the Companies and will have provisions for the preparation of periodic reports to document the Companies' efforts.

C. Credit Risk Control Practices

The Companies' risk control practices will incorporate limits, metrics, and exception management.

1. **Limits:** The Companies will adhere to the energy credit risk limits set forth in this policy. The purpose of these limits is to balance the need to secure reliable supplies of fuel and wholesale power with the need to control the risks inherent in the process. Energy Credit Risk Limits are set forth in Appendix F.

2. **Standards for Credit and Financial Assessment of Counterparties:**

Creditworthiness assessment for rated counterparties with publicly filed financials is to be updated every quarter with availability of new financials.

Creditworthiness assessment for unrated or privately held counterparties without publicly filed financials is to be performed after receipt of audited financials. The highest exposure power/gas and supply chain private counterparties will be evaluated on an annual basis.

If a counterparty is a subsidiary of a parent company, a guarantee may be required from the parent to support the transactions that are entered into with the subsidiary. The credit limit assigned to this counterparty will be limited to lesser of the amount of the parent guarantee, the unsecured limit the parent qualifies for or the netted credit limit (buys and sells).

The scoring module uses a multi variable scorecard to establish credit limits for counterparties. The scorecard methodology factors in agency ratings, performance, liquidity, leverage ratios, and assigns credit limits based on a percentage of tangible net worth. The assigned credit limits are further adjusted downward to NV Energy defined ratings matrix set forth in Section A of Appendix F. The components of the credit exposure calculation include cash flow, mark-to-market nominal value and the assigned credit limit or collateral.

Counterparties with higher exposures will be evaluated on an annual basis and monitored daily. Qualitative risk acceptance criteria will be incorporated into the evaluation of the highest exposure counterparties.

Under rule 9, large customers (projects >1MW or project costs > $400,000) including mining, data centers, master plan development, renewables and new industry type businesses that are sent to Risk Control for determination of 'Abnormal Risk' will be underwritten using the same scoring methodology and tools that are used to evaluate counterparties.

3. **Metrics:** In addition to the above formal limits, Risk Control will monitor a set of metrics on a periodic basis. The purpose of these metrics is to provide transparency of the corporate credit portfolio to the Risk Committee.

- **Large Customer Credit Metrics:** The Companies have established the Arrears Balance Metric and the Uncollected Deposits Metric to monitor the credit exposure attributable to large customers. Large customers are defined by the Companies based on rate class, total yearly summary bill, or total yearly revenue.
  i. **Arrears Balance Metric:** The Companies will monitor the balance of large customers' accounts receivable in arrears as a percentage of total quarterly revenue due from large customers.
  ii. **Uncollected Deposit Metric:** The Companies will monitor the allowable deposits uncollected as a percentage of total allowable deposits. Total allowable deposits based on prevailing regulations pertaining to maximum allowable deposit assessment.

- **Procurement Metrics:** The Companies have established the Supplier Credit Metric to control the credit exposure attributable to procurement.
  i. **Supplier Credit Metric:** The Companies will not enter into transactions with a material supplier for the purchase of goods or services over the amount of $1,000,000, until Credit Risk Management has analyzed the supplier's financial stability. Contracts in excess of $100,000 require performance bonds.

Exception Management Process:

i. **Limits:** The Risk Committee may approve waivers to this policy and to the plans and procedures developed in accordance with this policy. The Companies will develop and maintain procedures for reporting material exceptions to the limits established under this policy if those exceptions were not approved by the Risk Committee. The procedures will have provisions for prompt notification to the Treasurer who will, in turn, be responsible for notifying the personnel responsible for resolution of the exception and, if necessary, the Risk Committee. Presentations to the Risk

Committee will include descriptions of the exceptions, proposed courses of action to resolve the exceptions, and schedules for resolving the exceptions.

ii. **Metrics:** The relevant business unit may approve exceptions to the stated practices associated with the Large Customer Credit Metrics and Procurement Metrics. The business function will develop procedures and necessary documentation for deviation. Since a formal limit is not associated with the metrics, notification of non-compliance with standard procedures is not required beyond the relevant business unit.

iii. **Reporting Process:** The Companies will monitor credit limits and metrics through a formal reporting process driven by the Treasurer and Assistant Treasurer. On a monthly basis, Risk Control, with the assistance of Energy Credit Risk Management, Large Customer Credit Risk Management, and Procurement Credit Risk Management, will calculate and compile the limits and metrics outlined in this policy into a report. The report will be disseminated monthly to each member of the Risk Committee. Material adverse findings will be discussed at the meetings, and exceptions will be raised to the appropriate business function.

V. Compliance

Each employee will have an affirmative duty to alert management immediately upon learning of any apparent violations of this policy.

Each employee will also have an affirmative duty to alert management immediately upon learning of any risks not adequately covered by this policy and the associated procedures, methodologies, and systems.

Appendix A: Definitions

Aggregate Exposure	An estimate of the current cost of replacing all of the contracts with a counterparty.
Clearinghouse	An entity that clears the total transactions (buys with sales) for the period.
Consumer Bill of Rights	Provisions under Nevada Revised Statutes 704.210 governing billing procedures and processes for residential and small commercial gas and electric customers.
Counterparty	The entity that has entered a contract with one of the Companies.
Credit Derivatives	A financial instrument whose characteristics and value depend upon the characteristics and value of an underlying instrument or asset, typically a commodity, bond, equity, or currency.
Credit Insurance	Insurance on the counterparty portfolio is used to mitigate the risk of one or more of the counterparties in the portfolio defaulting on its obligations.
Critical material suppliers	As defined by the Business Unit(s)
Fixed Price Agreement	A contract in which the price of the commodity or service is set at a particular level when the contract is executed.
Futures	Agreements to buy or sell a quantity of a product, at an agreed price, on a given date, traded on an exchange, and cleared by a clearinghouse.
Indexed Agreement	A contract in which the price of the commodity or service is tied to one or more published indices.
Large Customer	At Nevada Power, an LGS-2 (or larger) customer, along with any additional meters associated with that customer. At Sierra Pacific Power, a GS3 (or larger) customer, along with any additional meters associated with that customer.
Mark-to-Market	The value of a financial or physical instrument, or an aggregation of such instruments, at the Companies' best estimate of current market prices.
Mark-to-Market Margin Collateral	Collateral posted based on the current market value of a financial or physical instrument.

Netting	The act of offsetting purchases with sales.
Options	Instruments which give the holder the right, but not the obligation, to sell or buy the underlying commodity at specified prices, times, and locations.
Physical Instrument	A contract for a commodity under which the Companies expect to take delivery of the specified commodity.
Products	Commodities with specific characteristics like electricity delivered during predefined periods.
Swaps	Agreements to exchange net future cash flows or physical positions.
Transaction	A contract obligating the Companies to buy or sell physical commodities and services. Transactions will also include monetary obligations incurred through financial instruments.

Appendix B: Areas of Responsibility – Committees

Risk Committee: The Risk Committee will be responsible for:

- Monitoring the current and expected future economic conditions, assessing their effect on the general business environment and on the Companies, and disseminating the information obtained through such monitoring to the management of the Companies;
- Initiating the preparation of new risk control policies when or where appropriate and the modification of risk control policies already in place;
- Ensuring the ongoing availability of procedures required to implement those policies or any changes to them;
- Resolving any disputes regarding the appropriate application of those policies and procedures;
- Ensuring the availability of the systems required to monitor, record and report on the risks inherent in the Companies' operations;
- Reviewing and approving the Companies' resource plans, energy supply plans, and the financing of the plans prior to Chief Executive Officer approval;
- Assuring integration of energy procurement or sale risk, credit risk, cash flow risk and customers' risk;
- Reviewing and approving all transactions requiring exceptions to the approved plans for acquiring or selling fuel and wholesale power prior to implementation;
- Reviewing all energy procurement or sale transactions requiring the approval of the Chief Executive Officer[2] prior to the presentation of such transactions to the Chief Executive Officer; and,
- Assessing the appropriateness of the Companies' risk control activities and modifying this policy, whenever modifications are required to ensure the ongoing viability of the Companies' risk management and control programs and the continued fulfillment of the Companies' obligations.

The Risk Committee will have the right to delegate portions of its assigned duties to one or more committees. The Risk Committee will establish the charter of each Committee when it is established and modify the charter if necessary. Committees will keep minutes in the same manner as the Risk Committee. Committees will also make periodic reports of their activities to the Risk Committee in the manner designated by the Risk Committee.

[2] The review by the Risk Committee prior to the presentation to the Chief Executive Officer is not required if such transactions are being done in accordance with an Energy Supply Plan already approved by the Chief Executive Officer.

Appendix C: Areas of Responsibility – Risk Control

Risk Control: Risk Control will be responsible for:

- Disseminating this policy to the Companies' personnel who will be affected by this policy;
- Measuring the Companies' energy portfolio exposures and comparing the measurements against approved exposure limits;
- Accumulating risk control information for the Companies;
- Creating monthly risk control reports;
- Assessing proposed modifications to risk control policies and limits based on changing business or market conditions; and,
- Training employees on this policy.

Appendix D: Areas of Responsibility – Credit Risk Management

A. Energy Credit Risk Management: Credit Risk Management will be responsible for:

- Assessing the financial and credit worthiness of current and potential counterparties;
- Assessing the current market and industry conditions affecting the credit of counterparties through updates and research;
- Providing a forward-looking perspective on counterparty credit, input qualitative remarks for our major counterparties in our scoring tool;
- Approving counterparties and establishing credit ratings for them before the Companies enter into energy-related transactions with them;
- Assigning internal credit rating for counterparties based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities' financial condition;
- Accumulating credit risk management and control information from our system of record;
- Managing and mitigating credit risks associated with energy supply optimization;
- Monitoring current credit of major counterparties on an on-going basis;
- Following processes and procedures outlined by the Credit Policy;
- Providing Risk Control with necessary counterparty credit information on a periodic basis through our system of records and the monthly Credit Report;
- Monitoring and reporting on the creditworthiness of current counterparties;
- Monitoring credit exposures at the counterparty and portfolio level on an on-going basis;
- Evaluating credit impact on counterparty and portfolio credit of large transactions;
- Reviewing and reporting on all contractual credit terms;
- Ensuring credit terms in contracts are in accordance with standard business practices;
- Reviewing and reporting on information requested by counterparties for collateral or other credit support;
- Evaluating costs and benefits associated with risk transfer and reduction methods;

- Resolving credit issues with counterparties;
- Calculating collateral requirements to be posted by counterparties and overseeing the receipt of that collateral; all letters of credit submitted to credit are kept in the Legal Department and tracked;
- Notifying the Manager of Market Operations and Trading when credit exposure limits have been exceeded and assist Risk Control in developing the strategy to mitigate risk; and,
- Maintaining records and tracking collateral posted by counterparties. Calculating collateral requirements and managing collateral posted by the Companies.

B. Large and Mid-to-Small Customer Credit Risk Management: Risk Control along with Credit & Billing will be responsible for managing the credit risk associated with large and mid-to-small customers, and frequently reporting on the status of such risks.
Responsibilities of Risk Control include:

- Managing and mitigating credit risks associated with the customer payment of large non-residential customers;
- Monitoring on-going credit of large non-residential customers and disseminating relevant credit information to Credit & Billing and Major Accounts;

Responsibilities of Credit & Billing include:

- Periodically provide Risk Control with a list of large customers;
- Managing and mitigating credit risks associated with the customer payment of large and mid-to-small non-residential customers;
- Reviewing and tracking occasions of deposits and late fees waivers;
- Monitoring changes in regulations regarding large customer credit;
- Monitoring current credit and payment history of the Companies of customers;
- Collecting and disseminating relevant credit information to managing account executive;
- Following processes and procedures outlined by the Credit Policy and/or applicable regulations;
- Provide information for metrics referenced in Appendix E - Large Customer Credit Metrics;
- Providing Risk Control with necessary customer credit information on a periodic basis; Ensure timely posting of write-offs to accounts for regulatory recovery.

In case of disagreements on the risk assessment of and credit mitigates for customers, Risk Control and Credit & Billing are encouraged to present their recommendations to members of the Risk Committee for further determination.

C. Procurement Credit Risk Management: Risk Control along with Procurement will be responsible for managing the credit risk associated with material vendors and procurement customers.
Responsibilities of Risk Control include:

- Managing and mitigating credit risks associated with material procurement;
- Monitoring current credit of critical material procurement vendors, based on but

not limited to, third party credit rating, and company financials;
- Following processes and procedures outlined by the Credit Policy; and,
- Ensuring credit terms in material contracts are in accordance with standard business arrangements.

Responsibilities of Procurement include:
- Identify critical material procurement vendors;
- Identify contracts in excess of $100,000 requiring performance bonds and contracts in excess of $1,000,000 requiring risk assessment by Risk Control; and,
- Provide information for metrics referenced in Appendix E - Procurement Credit Metrics.

D. Transmission Credit Risk Management: Credit Risk Management will be responsible for:

- Assessing the financial and credit worthiness of current and potential counterparties and customers;
- Assessing the current market and industry conditions affecting the credit of counterparties and customers through updates and research;
- Providing a forward-looking perspective on counterparty and customer credit;
- Approving counterparties and customers and establishing credit ratings for them before the Companies enter into transmission related transactions with them;
- Assigning internal credit rating for counterparties and customers based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities' financial condition;
- Accumulating credit risk management and control information from our system of record;
- Monitoring current credit of counterparties and customers on an on-going basis;
- Monitoring and reporting on the creditworthiness of current counterparties and customers;
- Reviewing and reporting on information requested by counterparties and customers for collateral or other credit support;
- Resolving credit issues with counterparties and customers;
- Reporting on accounts receivable aging information on counterparties and customers;
- Calculating collateral requirements to be posted by counterparties and customers and overseeing the receipt of that collateral; all letters of credit submitted to credit are kept in the Legal Department and tracked;
- Maintaining records and tracking collateral posted by counterparties and customers.

E. Rule 9 Credit Risk Management: Credit Risk Management will be responsible for:

- Assessing the financial and credit worthiness of current and potential and customers;
- Assessing the current market and industry conditions affecting the credit of customers through updates and research;
- Providing a forward-looking perspective on customer credit;
- Approving customers and establishing credit ratings for them before the Companies enter into transmission related transactions with them;
- Assigning internal credit rating for customers based on rating of parent company when parental guarantees are utilized or the lower of credit rating services, independent debt ratings by major investment banks, and internal evaluations of the entities' financial condition;
- Accumulating credit risk management and control information from our system of record;
- Monitoring current credit of customers on an on-going basis;
- Monitoring and reporting on the creditworthiness of current customers;
- Reviewing and reporting on information requested by customers for collateral or other credit support;
- Resolving credit issues with customers;
- Reporting on accounts receivable aging information on customers
- Calculating collateral requirements to be posted by customers and overseeing the receipt of that collateral; all letters of credit submitted to credit are kept in the Legal Department and tracked;
  Maintaining records and tracking collateral posted by customers.

Appendix E: Risk Control Metrics

A. Large Customer Credit Metrics

i. Arrears Balance Metric – Monthly

Total dollar value of current accounts receivable in arrears divided by total dollar value of accounts receivable due or received in a given month

- Arrears balances will be determined as balances outstanding for 30 days or more past the due date
- Individual account balances under summary accounts will not be considered in arrears until 30 days after the summary account billing date

ii Uncollected Deposit Metric – Quarterly

Sum of total allowable deposits uncollected divided by total allowable deposits for unsatisfactory customers in a given quarter

- Allowable deposits uncollected determined as the maximum allowable deposit uncollected or the difference between maximum allowable deposit and the deposit collected by the Companies
- Non-Residential
  - Maximum allowable deposit based 200% of average monthly bill
  - Unsatisfactory customers are defined as customers who pay after their due date even once in a 24-month period, or are subject to disconnect/termination of services
- Residential:
  - Maximum allowable deposit based 150% of average monthly bill
  - Unsatisfactory customers are defined as customers who pay after their due date more than three times in a twelve-month period, or are subject to disconnect/termination of services
- New customers are unsatisfactory at time of initial service agreement if adequate credit is not available in the form of satisfactory past payment history with a utility/municipal agency or guarantor with satisfactory credit

B. Procurement Credit Metric

i. ***Counterparty Credit Metric – Annual***

Total contract value outstanding with a critical material supplier determined on a semi-annual basis

- Total contract value is determined as the greater of maximum possible payment for goods and services or market replace costs associated with goods and services provided to the Companies by critical material suppliers.

Critical material supplier's status based on but not limited to alliance membership, aggregate contract value with NVE and its Subsidiaries, and availability of substitute goods or product

Appendix F: Credit Limits

A. Counterparty and Customer Credit Limits

Counter-party Credit Notification Thresholds-All Transactions		Counter-party Credit Notification Thresholds-Large Transactions	
Credit Rating	Maximum Aggregate Exposure per Counter-party	Credit Rating	Maximum Aggregate Exposure per Counter-party
AAA+ to AA- or equivalent	$20,000,000	AAA+ to AA- or equivalent	$20,000,000
A+ to A- or equivalent	$15,000,000	A+ to A- or equivalent	$15,000,000
BBB+ to BBB- or equivalent	$10,000,000	BBB+ to BBB- or equivalent	$10,000,000
BB+ to BB- or equivalent	$6,000,000	BB+ to BB- or equivalent	$6,000,000
B+ to B- or equivalent	$0	B+ to B- or equivalent	$0
Less than B-	$0	Less than B-	$0

B. Sub-investment Grade Notification Thresholds

Maximum portion of the portfolio below investment grade based on actual Mark-to-Market exposure may not exceed 40% without prior approval from the Risk Committee.

C. Weighted Average Portfolio Credit Notification Thresholds

Weighted average credit rating of portfolio based on actual Mark-to-Market exposure must be 'BBB-' or better.

Appendix G: Collateral Release Procedure:

The Department contacts Credit Risk to have the collateral released that is being held for a specific contract or project. This includes but is not limited to energy credit risk, large customer credit risk, procurement credit risk, transmission credit risk, Rule 9 credit risk, developer credit risk.

- The email that is sent to Credit Risk will include the approval by the Director of the Department. In the absence of a Director, the next level of management over the Department.

- A release of collateral letter, located on MyNVE, is created by Credit Risk, attached to the original letter of credit or bond and sent via Fed Ex to the issuing bank or Surety for cancellation.

- Signature of Authority for the collateral release letter:
  - Business Risk Control Specialist – up to $5M
  - Treasurer – up to $30M
  - Vice President, CFO – over $30M

Appendix H: Policy Revision Log

Date	Revision(s)
December 17, 2014	Modified Existing Policy. 1. Updated risk committee name. Replaced “Enterprise Risk Oversight Committee” with “The Risk Committee”. 2. Reassigned responsibility by replacing “Board of Directors” by “Risk Committee” and “Chief Risk Officer” by “Chief Financial Officer”. 3. Added language related to Rule 9 and the methodology of customer scoring and evaluation. 4. Replaced the Credit Notification Thresholds table with the new approved version. 5. Replaced Risk Committee’s area-of-responsibility description by language in Risk Management and Control Policy for consistency. 6. Removed language related to Energy Risk Committee since it was dissolved. 7. Added a policy revision log.
December 28, 2016	Modified Existing Policy: 1. Updated sub-section A.ii regarding maximum allowable deposit amounts to be consistent with Electric Rules 1 and 13 for both North and South.
July 26, 2017	Modified Existing Policy: 1. Updated the approval date of the Risk Management and Control Policy in the Background section. 2. Updated the approval date of the Credit Risk Management and Control Policy in Appendix H, the Employee Acknowledgement section. 3. Made formatting changes to make the document consistent with the Risk Management and Control Policy and the Energy Risk Management and Control Policy.
May 7, 2018	Modified Existing Policy: 1. Replaced Chief Executive Officer with President 2. Replaced Director, Risk Control with Treasurer 3. Updated titles
December 19, 2018	Modified Existing Policy: 1. Removed “Senior” from “Vice President, Chief Financial Officer” 2. Replaced “President” with Chief Executive Officer

December 4, 2019	Modified Existing Policy **1.** Replaced ratepayer with customers
November 17, 2021	Modified Existing Policy **1.** Add Assistant Treasurer to specified locations throughout document **2.** Removed "A" from Risk Committee on page 12 **3.** Added existing procedures for Transmission and Rule 9
November 15, 2023	Modified Existing Policy **1.** Replaced Assistant Treasurer with Treasurer **2.** Replaced Senior Vice President, CFO & Treasurer with Vice President, CFO **3.** Removed Appendix I: Employee Acknowledgement