DOMINION ENERGY UTAH

INTEGRATED RESOURCE PLAN

Docket No. 21-057-01

(Plan Year: June 1, 2021 to May 31, 2022)

Submitted: June 14, 2021

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EXECUTIVE SUMMARY

This Integrated Resource Plan (IRP) is submitted by Questar Gas Company dba Dominion Energy Utah in Utah, and dba Dominion Energy Wyoming in Wyoming. For purposes of this document, we refer to Dominion Energy Utah and Dominion Energy Wyoming collectively as “DEUWI” or “Company.” The Company is a subsidiary of Dominion Energy, Inc. (Dominion Energy) – one of the nation’s largest producers and transporters of energy, energizing the homes and businesses of more than seven million customers in 20 states with electricity or natural gas.

The Company files this IRP with the Utah Public Service Commission (Utah Commission) and the Public Service Commission of Wyoming (Wyoming Commission), for its natural gas distribution operations that are subject to the respective jurisdiction of each regulatory body. The Company continues to experience strong customer growth in its Utah, Wyoming, and Idaho natural gas service territories of over 2% per year.

Since the early 1990s, the Company has engaged in an annual IRP process as part of its commitment to providing safe, reliable, and affordable natural gas service to its customers. This process results in a planning document that is used as a guide in meeting the natural gas requirements of the Company’s customers for the ensuing year. As a fundamental part of the IRP process, the Company conducts an assessment of available resources through the utilization of a cost-minimizing linear-programming computer model. Open dialogue with regulatory agencies and interested stakeholders is an overarching principle of the IRP process.

The IRP process this year has resulted in the following key findings:

1. The Company forecasts Design Day firm sales demand of approximately 1.229 MMDth at the city gates for the 2021-2022 heating season.

2. The Company forecasts a 2021-2022 IRP-year cost-of-service gas production level of approximately 58.4 MMDth assuming the completion of new development drilling projects (49.6 % of forecast demand).

3. The Company forecasts a 2021-2022 IRP-year balanced portfolio of gas purchases of approximately 60 MMDth.

4. The Company will maintain flexibility in purchase decisions pursuant to the planning guidelines listed herein, because actual weather and load conditions will vary from assumed conditions in the modeling simulation.

5. The Company is reviewing its hedging practices, in light of a February 2021 weather event that impacted natural gas prices. DEUWI will update the Commission and interested stakeholders of the results of this review in the future.

6. The Company will continue to monitor and manage producer imbalances.

7. The Company will continue to promote cost-effective energy-efficiency measures.

8. The Company will enter into contracts to serve peak-hour requirements and to secure needed storage and transportation capacity.

9. The Company has purchased land and is moving forward with constructing an LNG facility for supply reliability purposes. The facility is planned to be functional and have 9 million gallons of LNG available for vaporization for the 2022 – 2023 heating season. In subsequent heating seasons the full 15 million gallons will be available for vaporization.

10. DEUWI is focusing on methane reduction programs and renewable natural gas projects as part of Dominion Energy's commitment to net zero carbon and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050.

As its customer base continues to grow, the Company conducts an annual analysis to ensure that its system can continue to meet customer needs. The DEUWI system will be capable of meeting the demands of the 2021-2022 heating season with adequate supplies and pressures in the system. This system capacity assessment is based on the fact that the gate stations have adequate capacity, the supply contracts are adequate, and system models show that pressures are sufficient to meet demand.

This report is organized into the following sections: 1) Executive Summary; 2) Industry Overview; 3) Customer and Gas Demand Forecast; 4) System Capabilities and Constraints; 5) Distribution System Action Plan (DNG Action Plan); 6) Integrity Management; 7) Environmental Review; 8) Purchased Gas; 9) Cost-of-Service Gas; 10) Gathering, Transportation, and Storage; 11) Supply Reliability; 12) Sustainability; 13) Energy-Efficiency Programs; 14) Final Modeling Results; 15) General IRP Guidelines/Goals, and 16) a Glossary.

The preparation of this planning document is dependent on information from many sources. The Company acknowledges the contributions of all who have participated in the IRP process this year. In the event there are questions, comments, or requests for additional information, please direct them to:

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INDUSTRY OVERVIEW

This planning document pertains to the natural gas distribution operations of Dominion Energy that are subject to the jurisdictions of the Utah and Wyoming Commissions. The Company receives its natural gas supplies from interstate pipelines with the majority of supply coming from basins in Utah, Wyoming, and Colorado. These interstate pipelines and supplies are subject to regulation by the Federal Energy Regulatory Commission (FERC) and are affected by industry changes and events that occur throughout the country including weather.

This section includes discussion regarding major regulatory factors impacting the industry in the last year, including changes at the FERC and clean energy regulation, power generation impacts on the natural gas industry, and trends regarding pricing, production, storage, and natural gas infrastructure. This section also contains a summary of the Wyoming and Utah IRP processes.

FEDERAL ENERGY REGULATORY COMMISSION UPDATE

The FERC regulates, among other things, the interstate natural gas pipeline system used to deliver natural gas to local distribution companies in the U.S., including those upstream pipelines that deliver supplies to the Company. The FERC consists of five members appointed by the President of the United States with the advice and consent of the Senate. By rule, not more than three members of the FERC may come from the President's party. All have an equal vote and the President selects the Chairman. The FERC requires at least three members to operate as a quorum.

On January 21, 2021 Richard Glick became chairman of the FERC[1]. This resulting commission now consists of five members, Chairman Richard Glick, Commissioner Neil Chatterjee, Commissioner Allison Clements, Commissioner Mark Christie, and Commissioner James Danly.

CLEAN ENERGY REGULATION

On June 19, 2019, The U.S. Environmental Protection Agency (EPA) issued the final Affordable Clean Energy (ACE) rule. This rule replaced the previous administration's Clean Power Plan (CPP). The ACE plan empowers states to continue to reduce emissions while providing affordable and reliable energy. This new rule resulted from a review of the CPP, in response to President Trump's Executive Order 13783 - Promoting Energy Independence and Economic Growth. The EPA expects ACE to result in reductions of U. S. power sector carbon dioxide (CO2) emissions by as much as 35% below 2005 levels in 2030. The EPA expects that the rule will reduce CO2 emissions by 11 million short tons, reduce SO2 emissions by 5,700 tons, reduce NOx emissions by 7,100 tons, reduce PM2.5 emissions by 400 tons, and reduce mercury emissions by 59 pounds, all by 2030. The EPA has also indicated that the rule will result in net benefits of $120 million to $730 million, including costs, health-co-benefits, and domestic climate benefits.

[1] "President Biden Names Glick Chairman of FERC," News Release, Federal Energy Regulatory Commission, January 21, 2021.

The rule establishes guidelines for emissions that states can use for developing plans to limit CO2 at coal fired power plants. The plan identifies the best system of reduction for CO2 from coal-fired power plants to be heat rate improvements. These improvements can be made at individual facilities. States will have 3 years to submit plans[2], which is consistent with timelines included in the Clean Air Act.

On January 22, 2020, the EPA requested public comment on a proposal to approve the State of Utah's regional haze plan to reduce emissions from the Hunter and Huntington power plants in Emory County, Utah. The plan includes providing credits for emissions control systems in place at these power plants. It also includes reductions associated with the 2015 closure of the nearby Carbon power plant. The state is required to work with the EPA to develop and implement air quality protection plans as part of the Clean Air Act. The EPA accepted public comments through March 23, 2020[3]. On October 28, 2020 the EPA announce the approval of the plan[4].

On February 12, 2021 the EPA released the 2021 edition of its comprehensive annual report on greenhouse gas emissions. This reported an overall emission decrease of 1.7% from 2018 -2019. This inventory shows that since 2005, national greenhouse gas emissions have reduced by 13%

POWER GENERATION IMPACT ON NATURAL GAS

Wind, Solar, and Natural Gas are expected to make up the majority of power generation capacity additions in 2020. The U.S. Energy Information Administration (EIA) expects 39.7 gigawatts (GW) of new capacity to be added in 2021. Wind is expected to account for 31% of this new generation capacity. Solar is expected to account for the biggest portion at 39%. Natural gas is expected to account for 16.6% or 6.6 GW.

The 6.6 GW is projected to come from 3.9 GW of combined-cycle plants and 2.6 GW of combustion-turbine plants. More than 70% of these additions are planned for Pennsylvania, Texas, and Ohio[5]. The EIA is projecting 36% of total U.S. electricity generation will be fueled by natural gas in 2021. This is a reduction from 39% in 2020. This reduction is expected to result in higher forecasted natural gas prices in 2021.[6]

PRICING TRENDS

In its March 2021 Short-Term Energy Outlook, the EIA forecasted that U.S. natural gas prices would be down from the first quarter of 2021 after the extreme pricing and weather

[2] "EPA Finalizes Affordable Clean Energy Rule, Ensuring Reliable, Diversified Energy Resources while Protecting our Environment," News Release, U.S. Environmental Protection Agency, June 19, 2019.
[3] "EPA proposes to approve Utah's regional haze plan", U.S. Energy Information Administration, January 22, 2020.
[4] "EPA approves Utah's regional haze plan," News Release, U.S. Environmental Protection Agency, October 28, 2020.
[5] "Renewables account for most new U.S. electricity generating capacity in 2021", U.S. Energy Information Administration, January 11, 2021.
[6] "EIA forecasts less power generation from natural gas as a result of rising fuel costs", U.S. Energy Information Administration, January 19, 2021.

event that occurred mid-February 2021. However, the expected price going forward is $1.11 higher than the same time last year[7].

Currently, the EIA forecasts that natural gas spot prices at Henry Hub will average $3.14/MMBtu for the rest of 2021 and then increase to $3.16/MMBtu in 2022. The EIA now expects this price increase to occur primarily due to increased LNG exports coupled with flat production.[8]

An extreme weather event across most of the country in February 2021 led to record prices in many markets. The cold weather coupled with declines in production due to freeze-offs resulted in record-high prices. Henry Hub reached the highest point since Feb 2003 and saw the highest monthly average since Feb 2014. Most freeze offs occurred in Texas' Permian Basin. Oneok Gas Transmission in Oklahoma reached a presumed historical high of any hub in history at $1,192/MMBtu on February 17, 2021.[9] DEUWI saw hub prices over $160/dth over 50-times the average price paid through the heating season.

PRODUCTION TRENDS

According to the EIA, U.S. dry natural gas production will average 91.4 Bcf/d in 2021 which is relatively flat to 2020. This production is down from a record in 2019 that had an average of 92.2 billion cubic feet per day (Bcf/d). Warmer than normal weather along with effects of the COVID-19 pandemic drove demand down. These declines are due to low natural gas prices discouraging drilling in dry gas regions and reduced associated gas production in oil directed wells due to low oil prices. This reduction is expected to continue into 2021. However, the production is expected to increase in late 2021, and as prices begin to rise there is expected to be a small production increase in 2022[10].

The oil field services company, Baker Hughes, monitors and publishes drilling rig data. Since Baker Hughes began tracking rig data in 1987, the highest weekly gas-directed rotary rig count for North America occurred during August and September of 2008 when the peak reached 1,606 rigs on two occasions. On two other separate occasions during August of 2016, the gas-directed rig count dropped to a low of 81 rigs. By January 2019, the gas-direct rig count had recovered to a level of 202 rigs. However, by July 24, 2020, there were only 68 gas-directed rigs. As of April 16, 2021, there were 94 gas-directed rigs. The gas-directed rig count at this point in time is only about 21% of the total rigs in operation[11]

On January 11, 2021, the EIA released its annual report on natural gas proved reserves for the 2019 calendar year. The EIA reported that U.S. proved reserves of natural gas at year-end 2019 decreased to 494.9 Tcf. This level was a 1.9% decrease from the previous level of 504.5 Tcf set in 2018. This was the first decrease in proved reserves since 2015.

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7 "EIA expects higher wholesale U.S. natural gas prices in 2021 and 2022," Today in Energy, Energy Information Administration, January 13, 2021.

8 "Short-Term Energy Outlook", Energy Information Administration, April 6, 2021.

9 "ECold weather brings near record-high natural gas spot prices," Today in Energy, Energy Information Administration, March 5, 2021.

10 "Short-Term Energy Outlook", Energy Information Administration, April 6, 2021.

11 "North America Rig Count Current Week Data," Baker Hughes, http://www.rigcount.bakerhughes.com, April 16, 2021.

Higher prices typically increase reserve estimates because operators consider a larger portion of the natural gas economically producible. In 2019, the annual average spot price for natural gas decreased 21.5% at Henry Hub. Ohio had the largest increase in reserves in 2019. The majority of the increase in 2019 reserves was due to increased reserves in the Utica/Pt. Pleasant shale play in the Appalachian Basin. The largest decreases were in Texas. Total U.S. production of natural gas increased by 9.8% from 2018 to 2019.[12]

On January 27, 2021, President Biden issued an executive order that implemented a moratorium on new oil and gas leases on federal lands and waters. This is expected to have a longer-term impact on production. President Biden said, “We’re going to review and reset the oil and gas leasing program”, but he also clearly stated “we’re not going to ban fracking”.[13]

This is not expected to have a near-term impact on production because existing leases and production are not impacted and because of the existing stockpile of leases by the industry. The industry already owns “millions of acres of leases” and is “sitting on approximately 7,700 unused, approved permits to drill”, according to the Department of Interior. However, this could shift the industry away from federally controlled regions. Sixty percent of shale gas production in Utah comes from federal lands. Id.

STORAGE TRENDS

On January 13, 2020, the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a final rule regarding underground natural gas storage facilities. The rule outlines safety standards for different types of underground facilities and provides minimum federal standard for inspection, enforcement, and training. This new rule will apply to approximately 200 interstate facilities. The rule also clarifies the threshold for reportable changes and events which require PHMSA notification and revises the definition of an Underground Natural Gas Storage facility.[14]

The EIA generally uses two metrics for assessing underground working natural gas storage capacity, design capacity and demonstrated peak capacity. Design capacity is the theoretical limit on the total amount of natural gas that can be stored. This is calculated based on the physical limits of the reservoirs and equipment associated with 387 active storage fields in the lower 48 states. The demonstrated peak capacity is the sum of all of the maximum volumes withdrawn from each of the fields during the most recent five-year period.

Recently, offsetting trends in the industry have impacted the underground storage industry. Increased production, reduced volatility, infrastructure buildout and smaller summer and winter natural gas price spreads have decreased the demand for additional storage. Meanwhile, the growing use of natural gas power generation and exports had increased the demand. As a result, the industry has shown little change.

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[12] “U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2019,” U.S. Energy Information Administration, U.S. Department of Energy, January 11, 2021.
[13] “Biden issues broad moratorium on oil, gas leases on federal lands, waters”, Gas Daily, S&P Global Platts, January 28, 2021.
[14] “PHMSA Issues Final Rule for Underground Natural Gas Storage Facilities,” U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, January 13, 2020

In 2020, a small increase in design capacity of 4 Bcf was reported for the November 2020 report period compared to the November 2019 reporting period. Included in this increase was a 16 Bcf working gas increase at Spire Storage West's Belle Butte facility (formally Ryckman Creek). This increase was a reversal of the reduction reported at this facility in 2019 after the acquisition and returns the working gas capacity to the authorized level of 35 Bcf. The Belle Butte change was the only change in the Mountain Region.

The demonstrated peak capacity decreased by 8Bcf during this period despite growth in a number of areas. This decrease was mostly due to a decrease of 34 Bcf in the Pacific region driven by reductions at the Aliso Canyon facility in California. Since a five-year average is used, this was the first time the peak levels that occurred prior to the 2015 gas leak at that facility were no longer included in the calculation.[15]

The Company discusses its use of natural gas storage facilities in the Gathering, Transportation, and Storage section of this report.

LNG EXPORTS

The U.S. has been a net exporter of natural gas since 2016. The U.S. exports natural gas to Canada and Mexico by pipeline. The U.S. now also exports natural gas to over 30 countries as LNG. In February 2021, the EIA reported that exports of LNG set consecutive monthly records of 9.4 Bcf/d in November 2020 and 9.8 Bcf/d in both December 2020 and January 2021. Forecasts expect LNG exports to average 8.5 Bcf/d in 2021 and 9.2 Bcf/d in 2022. These exports are expected to exceed exports by pipeline in the first and fourth quarters of 2021 and for the year in 2022.

These increases are due to all six U.S. LNG export facilities operating near full design capacity. In December 2020, the Corpus Christi LNG facility in Texas, completed its third and final unit. This brought the total U.S. liquefaction capacity to 9.5 Bcf/d. Higher international LNG prices, particularly in Asia, have been driving these increases.[16]

The proposed Jordan Cove LNG export facility on the Oregon coast is of particular interest to the Company because the addition of this facility could impact prices in the Rockies. Pembina Pipeline Corporation (Pembina), the developer of Jordan Cove, acquired a 50% interest in the Ruby Pipeline in 2014. The Ruby Pipeline extends from the Opal Hub in Wyoming to the Malin Hub in Oregon and crosses the Company's northern service territory. The Company regularly purchases natural gas at the Opal Hub. The Ruby Pipeline provides direct access to the Jordan Cove LNG facility through the proposed Pacific Connector Gas Pipeline.

On March 19, 2020, the FERC voted to approve the Jordan Cove Energy Project[17]. This approval does not mean the project can move forward at this point. Since the approval, opponents quickly began asking for rehearings. Jordan Cove developers also requested

[15] "Underground Natural Gas Working Storage Capacity," Energy Information Administration, U.S. Department of Energy, with Data for November 2020, Released May 30, 2021.
[16] "Annual U.S. liquified natural gas exports forecast to exceed pipeline exports in 2020," Today in Energy, Energy Information Administration, U.S. Department of Energy, February 18, 2021.
[17] "Statement of Chairman Neil Chatterjee", Federal Energy Regulatory Commission, March 19, 2020

corrections to the order. Jordan Cove developers appealed to the U.S. Commerce secretary regarding a February 19, 2020, ruling by the Oregon Department of Land Conservation and Development. The developers requested clarification regarding whether a U.S. Commerce secretary determination overriding a Coastal Zone Management Plan in Oregon would suffice to meet the conditions of the order[18]. Meanwhile, numerous state agencies in Oregon, including the Oregon Department of Energy, the Department of Environmental Quality, the Department of Fish and Wildlife, and the Department of Land Conservation and Development have all joined the challenge against the ruling by the FERC.[19]

At its January 19, 2021, open meeting, FERC released an order that denied the petition by Jordan Cove Energy Project requesting that the FERC find that Oregon Department of Environmental Quality had waived its authority to issue certification for the project. Opponents of the project are hopeful this will mean the end of this project.[20]

SUSTAINABILITY TRENDS

Throughout the country, companies across the natural gas value chain are taking actions to reduce methane emissions. Many of these companies have joined a coalition, One Future, committed to this goal. The coalition includes production, gathering, processing, transmission and storage, and distribution companies. Distribution companies encompassing 30 states and over 36 million customers are part of this coalition. Participating companies include Antero Resources, Apache, Ascent Resources, Atmos Energy, Berkshire Hathaway Pipeline Group, BKV Corporation, Blue Racer Midstream, Boardwalk Pipeline Partners, LP, Caerus Oil and Gas, ConEdison, Crestone Peak Resources, Crestwood, Dominion Energy, DTE Energy, Duke Energy, EagleClaw Midstream, Enbridge Inc., Encino Acquisition Partners, Equitrans Midstream Corporation, EQT, Hess, Jonah Energy, Kinder Morgan, National Grid, New Jersey Natural Gas, Northeast Natural Energy, NW Natural, ONE Gas, Inc., ONEOK, Sempra Energy, Southern Company Gas, Southern Star, Southwestern Energy, Spire, Summit Utilities, TC Energy, Tug Hill Operating, UGI Utilities, Inc., Western Midstream, Williams, Woodland Midstream, and Xcel Energy.

The goal of One Future is to "ensure the future of natural gas as a clean energy source by reducing member company methane emissions to 1% (or less) by 2025". This will preserve "the future of natural gas as a long-term sustainable fuel. This goal will help to preserve the industry's leadership in energy production and reduction of emissions."[21]

WYOMING IRP PROCESS

The Company has been involved in Integrated Resource Planning in the state of Wyoming since the early 1990s. In 1992, the Wyoming Commission ordered the Company to prepare

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[18] "Jordan Cove LNG developers seek several fixes to FERC authorizations," Platts Gas Daily, April 21, 2020.
[19] "Oregon steps up legal battle over FERC orders authorizing Jordan Cove LNG," Platts Gas Daily, April 22, 2020.
[20] "FERC dashes hopes of Jordan Cove LNG developer by denying water permit petition", Platts Gas Daily, January 20,2021.
[21] https://onefuture.us/who-is-one-future/

and file Integrated Resource Plans.[22] On February 3, 2009, the Wyoming Commission issued an order initiating a rulemaking pertaining to Integrated Resource Planning. The Wyoming Commission proposed the rule to "...give the Wyoming Commission a more formalized process for requiring the filing of integrated resource plans, in some cases, and reviewing such plans."[23] On May 12, 2009, the Wyoming Commission approved Chapter 3, Section 33 of the Wyoming Commission rules and on January 24, 2011 the Wyoming Commission approved the natural gas IRP guidelines.[24]

The Company filed its 2020-2021 IRP on June 12, 2020, with the Wyoming Commission. Commission Staff solicited written public comments on the IRP filing by noticing the matter on the Wyoming Commission's open meeting agendas indicating that comments on the IRP were due on September 4, 2020 and that a hearing would occur after October 30, 2020. No public comments were received.

UTAH IRP PROCESS

Over the previous decade, the Utah Commission has promulgated new IRP standards and guidelines. This implementation process has included numerous discussions between IRP stakeholders in public meetings and the submission of extensive comments.

On March 31, 2009, the Utah Commission issued its Report and Order on Standards and Guidelines for Questar Gas Company (2009 IRP Guidelines) to be effective starting with the Company's 2010 IRP.[25] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[26]

On June 12, 2020, the Company filed its IRP for the plan year, June 1, 2020, to May 31, 2021 (2020-2021 IRP). A technical conference was held on June 30, 2020, to discuss the 2020-2021 IRP with regulatory agencies and interested stakeholders. On September 3, 2020, the Utah Office of Consumer Services (Office) filed its IRP comments.[27] The Utah Division of Public Utilities (Division) submitted its report and recommendation on September

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[22] "In the Matter of the Application of Mountain Fuel Supply Company to File its Integrated Resource Plan as Directed by the Commission in Docket No. 30010-GI-90-8," Findings, Conclusions and Order, Docket No. 30010-GI-91-14, May 21, 1992.

[23] Before the Public Service Commission of Wyoming, "In the Matter of the Proposed Adoption of Chapter 2, Section 253 of the Commission Procedural Rules and Special Regulations Regarding Integrated Resource Planning," Order Initiating Rulemaking, Docket No. 90000-107-XO-09 (Record No. 12032, February 3, 2009).

[24] Correspondence from the Public Service Commission of Wyoming; Alan B. Minier, Chairman, Steve Oxley, Deputy Chairman, and Kathleen "Cindy" Lewis, Commissioner, To All Wyoming Natural Gas Utilities, dated January 24, 2011.

[25] "In the Matter of the Revision of Questar Gas Company's Integrated Resource Planning Standards and Guidelines," Report and Order on Standards and Guidelines for Questar Gas Company, Docket No. 08-057-02, Issued: March 31, 2009.

[26] "In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: May 1, 2009 to April 30, 2010," Report and Order, Docket No. 09-057-07, Issued: March 22, 2010.

[27] Memorandum titled, "In the Matter of: Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2020 to May 31, 2021," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Alex Ware, Utility Analyst, Bela Vastag, Utility Analyst, September 03, 2020.

1, 2020.[28] On October 7, 2020, the Company filed its Reply Comments.[29] On October 13, 2020 the Office filed its Reply Comments.[30]

On January 5, 2021, the Utah Commission issued its Report and Order on the 2020-2021 IRP. The Utah Commission found that "the 2020 IRP as filed generally complies with the requirements of the Standards and Guidelines." The Commission adopted the Company's commitment to include an additional Supply Reliability subsection that will include updates on the LNG facility and address any supply reliability concerns. The Commission also adopted the Company's commitments to provide pandemic-related updates and additional details when management overrides the SENDOUT model recommendations in the quarterly variance reports. The Commission adopted the Company's commitments to provide additional details in the Long-Term Planning and Sustainability sections of this report. The Commission also adopted the Company's commitment to report on IRP-related stakeholder meetings and technical conferences.[31]

On March 10, 2020, the Company met with Division and Office Staff to discuss IRP related issues. This meeting was attended by representatives from Dominion Energy, Division and the Office. The topics discussed in this meeting were:

- Topics to be presented in IRP Technical Conferences
- Inclusion of a Long-Term Planning section in the annual IRP and examples of what should be included in this section.
- The details and history that should be included in the Distribution Action Plan section of the IRP.
- Inclusion of a comparison between Highest Sendout Day and Peak Day as part of the "Heating Season Review"
- An explanation of the Joint Operating Agreement (JOA)
- Integrity Management variance explanations
- Wexpro well shut-in management

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[28] Action Request Response, To: Utah Public Service Commission, From: Division of Public Utilities; Artie Powell, Director, Doug Wheelwright, Utility Technical Consultant Supervisor, Eric Orton, Utility Technical Consultant, , Subject: Action Request Docket No. 20-057-02, Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2020 to May 31, 2021 , Recommendation (Acknowledge), Date: September 1, 2020.

[29] "In the Matter of Dominion Energy Utah's Integrated Resource Plan for Plan Year: June 1, 2020 to May 31, 2021," Before the Public Service Commission of Utah, Dominion Energy Utah's Reply Comments, Docket No. 20-057-02, October 7, 2020.

[30] Memorandum titled, "Docket 20-057-02 Reply Comments, In the Matter of: Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2020 to May 31, 2021," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Alex Ware, Utility Analyst, Bela Vastag, Utility Analyst, October 13, 2020.

[31] "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2020 to May 31, 2021," The Public Service Commission of Utah, Order, Docket No. 20-057-02, Issued: January 5, 2021.

- Lost and unaccounted for gas explanation
- Hedging program explanation
- Inclusion of a Glossary section in the IRP
- Emergency Planning
- Inclusion in the IRP of all relevant details discussed in technical conferences

One outcome of this meeting was the Company agreed to look further into additional hedging options. Meetings were held on this topic with stakeholders during the IRP technical conference on February 9, 2021, and in a separate meeting on February 22, 2021. This is an ongoing evaluation and the Company will continue meet with stakeholders to discuss this issue.

Periodically, technical conferences are held in the IRP process to respond to specific issues, as ordered by the Utah Commission, to receive input for the IRP process or report on the progress of the Company's planning effort.

On February 9, 2021, the Utah Commission held an IRP technical conference in conjunction with the development of the 2020-2021 IRP. The attendees discussed the following topics:

- Review of the Utah IRP Standards and Guidelines
- Review of the Utah Commission's 2020 IRP Order
- Review of the March 2020 Stakeholder Meeting
- Rural Expansion Update
- LNG Project Update
- Hedging Program Discussion

The Utah Commission held another technical conference on April 28, 2021. The attendees discussed the following topics:

- Heating Season Review
- System Integrity Update

Part of the April 28, 2021, technical conference was confidential. During the confidential part of the meeting, the following topics were discussed:

- Wexpro Matters
- RFP Recommendations

The heating season review presented in this meeting included a review of weather, demand, pricing, supply, and storage usage from the 2020-2021 heating season. The primary focus of this presentation was on the high-price event that occurred in February 2021. This event was caused by extreme cold weather in the middle of the country and Texas which resulted in high demand and supply reductions. This event impacted gas prices in DEUWI's service area as a result of increased shift in gas flow from the primary producing areas that typically supply DEUWI to the impacted areas in southern states, primarily Texas.

The Utah Commission held another technical conference on May 18, 2021, where the following topics were discussed:

- IRP Project Detail
- Long-Term Planning Update
- Hydrogen Pilot Update
- Future STEP Project Update

The Company welcomes discussion and open dialogue and will schedule additional technical conferences to answer questions and resolve any remaining issues. The Utah Commission has scheduled a technical conference for June 22, 2021, to discuss the 2020-2021 IRP with Utah regulatory agencies and interested stakeholders.

During the course of the IRP process, the Company has maintained the following goals and objectives:

1. To project future customer requirements and analyze alternatives for meeting those requirements from a distribution system standpoint, an integrity management standpoint, an environmental standpoint, a gas-supply source standpoint, an upstream capacity standpoint (including taking into consideration the inter-day load profile of each source), a reliability standpoint, and a sustainability standpoint;

2. To provide present and future customers with the lowest-reasonable cost alternatives for the provision of natural gas energy services, over the long term, that are consistent with safe and reliable service, stable prices, and are within the constraints of the physical system and available gas supply resources;

3. To use the guidelines derived from the IRP process as a basis for creating a flexible framework for guiding day-to-day, as well as longer-term gas supply decisions, including decisions associated with cost-of-service gas, purchased gas, gathering, processing, upstream transportation, and storage; and

4. To provide the framework by which the Company will become the most sustainable natural gas company in the country.

The Company utilizes a number of models as part of its IRP processes. The complexity of the systems being analyzed necessitates the use of computer-based tools. Modeling tools are an integral part of the forecasting, gas network analysis, energy-efficiency analysis, and resource selection processes. In each section of this report where the Company has referred to modeling tools, the IRP contains a description of the functions of each model and the version utilized. The IRP also contains discussion of any material changes (logic and data) from the previous year's IRP including the reasons for those changes.

An annual IRP process coincides well with the natural cycles of the gas industry. Some of the end-of-calendar-year data is not available and fully analyzed for IRP purposes until mid-April. The utilization of this information ensures the Company is including the most current and relevant information in its IRP. The required data input assumptions utilized in IRP models are voluminous. Nevertheless, the intent of this IRP is to summarize, in a readable fashion, the Company's planning processes.

CUSTOMER AND GAS DEMAND FORECAST

EFFECTS OF COVID-19

When last year's gas demand and customer growth forecasts were completed, stay-at-home orders resulting from the onset of the COVID-19 pandemic had just been put in place. With no similar event to base predictions on, trying to forecast the longevity of the crisis and its effects on customer growth and gas demand was extraordinarily challenging. However, the Company anticipated a decline in usage within the commercial and industrial sectors and a temporary slowdown in customer growth as results of the new restrictions and the economic recession that was just beginning to take shape.

The expected usage decline did indeed occur. Through the 11 months ending February 2021, total demand was down 2% from the year prior. The commercial sector declined 5%, and the industrial sector declined 3%. Average usage among the GS commercial customers dropped by over 20 Dth, offsetting demand gains from the addition of over 600 new customers in that class.

Although average usage among the residential class declined by about 1 Dth, total usage was stable throughout the 11 months ending February 2021 and increased 1% over the same period ending in February 2020 – the result of substantial customer growth. Average usage during the early Spring months was slightly higher, likely resulting from office workers staying home and increasing space heating consumption.

The pandemic's effect on customer growth, however, was surprising. The Company expected residential construction and customer growth to temporarily subside on the assumption that the economic downturn would dampen demand and pandemic-related restrictions would restrain construction progress. But neither outcome materialized. Restrictions did not affect construction. The pandemic stimulated an increase in demand for new housing as interest rates dropped and home prices continued to rise. In 2020 the Company saw its largest number of new customer additions since before the 2008 recession. At this time, 2021 is showing signs of similarly high activity.

In this year's forecast the momentum of the surge in housing permits is expected to carry through 2021 and maintain the high customer growth rate over the next couple of years. The Company expects commercial and industrial usage to return to pre-pandemic levels as vaccinations continue to proliferate and restrictions on in-person activity in offices, schools, and retail establishments continue to ease. Forecasted growth in demand reflects these expectations. It is premature to anticipate an evolution in the use of office space and how any such shift might affect gas consumption in the commercial sector. If such an evolution is occurring, it will become clearer as communities settle into a new normal in the coming months and years.

SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2020-2021 IRP AND ACTUAL RESULTS

On a temperature-adjusted basis, the Company's estimated natural gas sales through the IRP year ending May 2021 is 115.5 MMDth. The Company forecasted a total of 115.9 MMDth for the period in last year's IRP. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2020-2021 IRP year at 213.1 MMDth. Last year's IRP projected 212.5 MMDth for the same period.

TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2021-2022 IRP YEAR

The forecasted level of sales demand for the 2021-2022 IRP year is 117.8 MMDth. The growth is driven by the current surge in residential construction that is expected to continue through the coming IRP year as housing supply continues to lag behind demand. If the positive economics fueling the growth persist, sales demand is projected to reach 131.5 MMDth in the 2030-2031 IRP year (see Exhibit 3.10).

When this forecast was completed, about 50 sales customers had notified the Company of intent to shift to transportation service this year. On a weather-normalized basis, those customers collectively burn approximately 500,000 Dth annually. The forecast assumes the same number of customers and annual Dth moving to transportation service from sales classes in the following two IRP years, but no further shifting is assumed beyond that point.

The 2021-2022 IRP sales forecast of 117.8 MMDth will be the denominator used in the calculation of the percentage of sales supplied by cost-of-service production per the Trail Unit Settlement Stipulation. The numerator will be the actual cost-of-service quantity as reported at the wellhead.

This year's forecast of GS customer growth projects 1.15 million customers at the end of the 2021-2022 IRP year and 1.40 million GS customers by the end of the 2030-2031 IRP year (see Exhibit 3.1). The Company forecasts annual Utah GS usage per customer at 99.7 Dth in the 2021-2022 IRP year and 91.9 Dth by end of the 2030-2031 IRP year (see Exhibit 3.2). Annual Wyoming GS usage per customer is projected to be 123.5 Dth in the 2021-2022 IRP year and 119.0 Dth at in the 2030-2031 IRP year (see Exhibit 3.5).

The Company forecasts system total throughput in this year's forecast to increase from 215.5 MMDth during the 2021-2021 IRP year to 229.8 MMDth by end of the 2030-2031 IRP year (see Exhibit 3.10).

RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

Utah

Utah residential GS customer additions through the twelve months ending December 2020 totaled 28,351. About 40% of those additions were multi-dwelling units. As the inventory of existing homes for sale remains below average and interest rates remain low, high demand for new single-dwelling, condominium, and townhome units will continue. Apartment construction is expected to persist as well, especially along Utah's Wasatch Front, although the pace should slow as a rising inventory of new units softens demand some. But high house prices we keep demand for more affordable multi-dwelling options alive. The Company is forecasting about 28,000 residential additions through the 2021-2022 IRP year and just over 27,000 the following year. This high growth follows from the momentum of the current surge in demand for new housing. After that, the Company expects high growth to continue but at a decelerating pace as the economic recovery becomes firm and interest rates begin to rise.

Actual temperature-adjusted residential usage per customer for the twelve months ending December 2020 was 79.2 Dth. The Company projects an average of 78.0 Dth for the 2021-2022 IRP year. The overall downward trend in average consumption is expected to continue through the 2030-2031 IRP year as the appliance and shell efficiencies improve and smaller residential dwellings begin to occupy a greater share of the overall dwelling mix. (see Exhibit 3.3).

The Company employs several statistical methods to analyze and forecast residential gas demand. These methods include univariate and multivariate time series modeling of demand and such explanatory variables as demand history, customer growth and commodity price. SAS Enterprise Time Series 14.1 is the software tool used for the statistical time series modeling.

The Company also studies residential consumption by end use such as space heating, water heating and cooking with respect to dwelling type, appliance type, appliance efficiencies, and other such variables. Applying estimates of usage segregated by end use to expectations in the evolution of the appliance makeup among customers aids in long-term forecasting. This end use analysis makes extensive use of data collected by the Company's Energy Efficiency Experts as they conduct in-home energy audits through the Energy Efficiency Program.

Wyoming

Through 2020, the Wyoming residential customer base added 139 service agreements. The Company projects about 140 new additions through the 2021-2022 IRP year and about 150 the following year. This relatively moderate growth is expected to continue as the five counties in the Company's Wyoming service territory grapple with a struggling natural resources sector of the State's economy.

The average annual usage per residential customer in Wyoming was 85.1 Dth in calendar year 2020. The Company forecasts an average of 84.5 Dth during the 2021-2022 IRP year and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. The 2030-2031 IRP year ends at 80.5 Dth (see Exhibit 3.6).

SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

Utah

Temperature-adjusted Utah GS commercial usage per customer in 2020 was 413.7 Dth, a decline of 11 Dth per customer. As anticipated in last year's IRP forecast, commercial GS demand declined as the pandemic closed offices, retail establishments, and schools and restricted commercial activity. This year's forecast assumes a return to a pre-pandemic usage level as vaccination proliferates and restrictions continue to soften. It is unclear at this point if an evolution in the use of commercial office space is underway and how such an evolution might alter space heating by that sector. The Company will continue to analyze commercial usage and identify evidence of any long-term effects of the pandemic.

This year's forecast also incorporates the expectation of about 40 GS customers shifting to transportation service in July with a Dth transition of approximately 350,000 Dth annually. The same level of transition from GS to transportation service is assumed for the following two IRP years as well.

About 650 new Utah GS commercial customers were added in 2020. The Company forecasts a gradual increase in the number of additions over the next two IRP years with about 650 and 750 additions respectively. Beyond that, the Company expects annual addition levels around 900.

Wyoming

Usage among commercial GS customers in Wyoming for the twelve months ended December 2020 averaged 431.6 Dth, a decline of 14 Dth from 2019. With such a small base of customers and varying usage patterns, total and average usage in this sector can be volatile. But it is likely that some of that decline is attributable to usage reduction caused by the pandemic. As with the Utah service territory, the Company expects decline in usage brought about by pandemic restrictions to be reversed in the coming IRP year, at least to some extent. Average annual usage of 448.0 Dth is forecasted for the 2021-2022 IRP year. and 446.9 Dth through the following IRP year.

There was a net loss of 14 commercial GS service agreements through 2020. Some growth in this sector is expected, though it will likely be moderate. About 15 new agreements per year have been forecasted for the next three IRP years with a slightly higher level per year through the remaining years of the 10-year forecast horizon.

NON-GS COMMERCIAL, INDUSTRIAL, AND ELECTRIC GENERATION GAS DEMAND

The Company forecasts demand in this sector to grow modestly from 57.8 MMDth in the 2021-2022 IRP year to 58.1 MMDth in the 2030-2031 IRP year. A modest degree of shifting from the GS class to transportation service is assumed through the next three IRP years. But no such assumptions are made beyond that point. At this time, major additions or departures within this class are not anticipated. Beyond moderate growth from customer shifts, usage is held steady through the remainder of the IRP forecast horizon (see Exhibit 3.8).

This year's forecast of electric generation demand holds a steady level of about 43.3 MMDth per year. It is a midpoint of the range that seems reasonable given usage levels over the past two years. Demand at some plants comes from generation used to meet peaking load and can vary considerably over time. In addition, baseload generation has been frequently supplemented with open-market procurement in recent years, making a forecast of ongoing demand levels difficult. The forecasted level combines the most recent usage levels of some customers whose usage is trending up with a two-year average of others whose usage can vary considerably year to year.

FIRM CUSTOMER DESIGN DAY GAS DEMAND

The Design Day firm customer demand projection is based on a gas day when the mean temperature is –5 degrees Fahrenheit at the Salt Lake Airport weather station.

Heating degree days, wind speed, the day of the week, and prior day demand are significant factors in the prediction of daily gas sales during the winter heating season. Note that the Design Day demand projection distinguishes between firm sales and firm transportation demand for gas supply and system capacity planning purposes.

As shown in Exhibit 3.9, the firm sales and firm transportation demand for the heating seasons of 2016-2017 through 2020-2021 show actual firm sendout for the coldest day in each season. Design Day conditions did not occur during those time periods. However, January 2017 represented the 2nd highest total sendout month for the Company and included the 2nd and 3rd highest total sendout days on record.

The firm sales Design Day gas supply projection for the 2021-2022 heating season is 1.23 MMDth and grows to 1.37 MMDth in the winter of 2030-2031. This estimate is based upon the following Design Day scenario: 70 heating degree days in Salt Lake region; mean daily wind speed of 9.5 mph as measured at the Salt Lake City Airport weather station; the day is not a Friday, Saturday, or Sunday, and it is not a winter holiday. Note that the assumed level of wind speed was observed on the December 22-23 gas day of 1990 when the mean temperature was -4.7 degrees Fahrenheit.

SOURCE DATA

The Company has obtained economic, demographic, and other data from the University of Utah's Kem C. Gardner Policy Institute and IHS Markit.

ALTERNATIVES TO NATURAL GAS

The Company's customers have alternatives to using natural gas for virtually every application. Some customer end-use applications are dominated by other energy sources (cooking and clothes drying) while others are dominated by natural gas (space and water heating). A material shift in available competitive energy options would affect future demand and load profiles.

Full Fuel-Cycle Efficiency

Natural gas remains the most efficient and least expensive form of energy for use in space heating, water heating, cooking, and clothes drying applications. This is particularly evident when compared to electricity through a full fuel-cycle analysis. Full fuel-cycle analysis looks at the journey of different forms of energy, and their associated losses, from the point of production to the point at which the customer receives and uses the energy. Figure 3.1 shows that for each 100 MMBtu of natural gas extracted, 91 MMBtu are delivered to the customer for direct use. Conversely, for each 100 MMBtu of other energy sources extracted for conversion to electricity, 36 MMBtu are ultimately delivered to the customer for direct use. In other words, converting any fossil fuel source into electricity to power comparable electric end-use products only maintains 36% of usable energy.

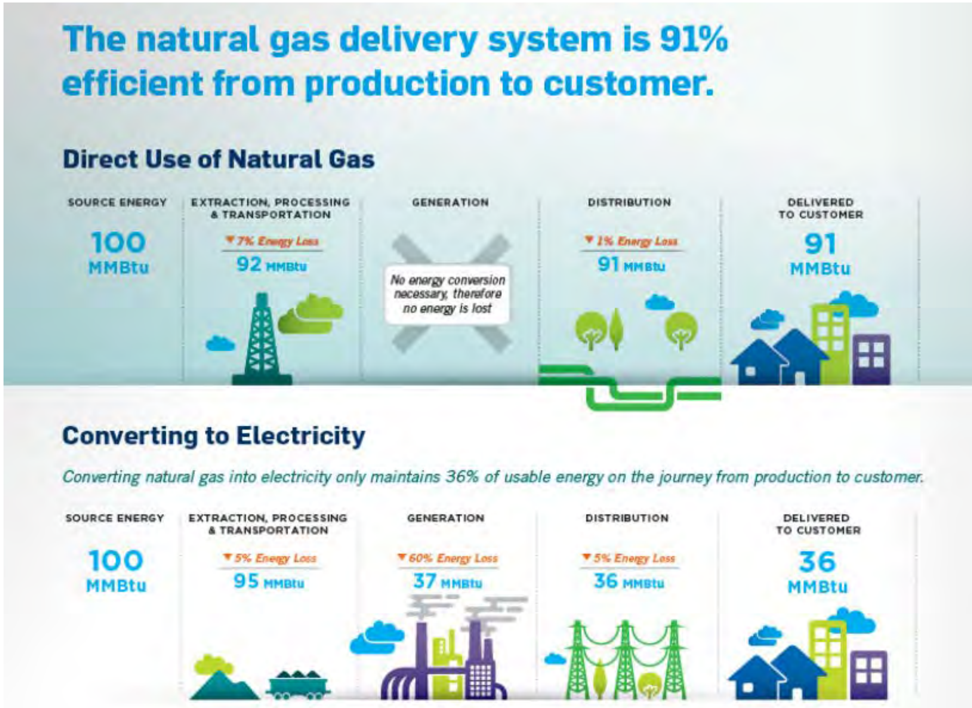


Figure 3.1: Full Fuel-Cycle Analysis
(Source American Gas Association 2021 Playbook)

Solar

Although solar penetration is a significant issue for electric utilities, the Company does not currently anticipate that solar-powered space or water heat will have a significant impact in the Company's natural gas service territory. However, as battery technology improves and solar panels become more affordable with lower material cost and continued federal and state tax credits, their application will become more prevalent in the residential and commercial markets.

The Company will continue to monitor this issue and participate in studies with the Gas Technology Institute (GTI), NYSEARCH, and AGA and will report any impacts on the service territory in future IRPs.

Heat Pumps

In the 2021 energy efficiency budget filing (Docket No. 20-057-20), the Company proposed, and the Commission approved, rebates in the ThermWise® Appliance, Builder, and Business programs for customers who purchase and install dual-fuel heating systems. These systems combine electric heat pumps, which can achieve levels of efficiency as high as 300% at optimal ambient air temperatures, with a high efficiency furnace of ≥ 95% annual fuel utilization efficiency (AFUE). The Company designed this rebate measure with the heat pump performing heating operations at or above 40° outside air temperature and the high efficiency furnace providing heat when outside air temperatures drop below that set point. The Company forecasts that a typical customer (using 80 dekatherms annually for space and water heat) who installs a dual-fuel system would reduce annual natural gas usage by

29 dekatherms or 36%. The Company expects first-year participation in this rebate measure to be 600 or fewer units with participation growing in future years as the heating, ventilation, and cooling trades become more familiar with these technologies.

GAS LOST AND UNACCOUNTED FOR

The Company estimates gas that is lost or unaccounted for (LAUF) by taking the difference between gas volume received into the Company's distribution system and the sum of volumes accounted for through customer billing, Company use, line pack, and loss from tear-outs or flaring. Each year data is collected for the 12-month period ending in June of the current year to calculate the variance. The estimation approach the Company employs has been in place for years and has been refined over time to incorporate additional data and to eliminate unnecessary sources of estimation error.

It is important to understand that a LAUF percentage is not simply an estimate of gas quantity that has escaped the system. It is the calculation of a difference between gas volume received into the system and gas volume accounted for. In addition to gas physically lost from the system through leaks, theft, or damage, variance also arises from other sources. These additional sources are not unique to DEUWI but are common to most LDCs.

One of these contributing factors is measurement variance. This is variation in the measurement of gas volume and heat content on the same quantity of gas as it passes through different elevation and temperature zones and is delivered to customers at various regulating pressures. Compensations at the meter level must be made for temperatures and pressures that deviate from the NAESB standard values used to calculate volume and heat content. Differences in the sophistication of meter-level compensation used at system receipt points and that of customer meters or billing system compensation is also a source of variance.

Timing is an additional source of variance. Gas volume and heat content is measured throughout the day at the system receipt points using highly sophisticated equipment. But end-use consumption of that volume is calculated for customer billing through monthly meter reads. Because most billing is done on a cycle basis that includes portions of two consecutive months, some estimation is required to convert portions of billing cycle data to the calendar-month format in which receipt point data are collected. This can also introduce error.

In recent years, the Company has reduced measurement variance by implementing more granular temperature and elevation correction of customer meter reads when the meter does not have built-in compensation. This has reduced the average estimate from around 1.5% to about 0.4% to 0.5%. This billing-system compensation was introduced in the Company's Utah/Idaho service regions in 2009 and in its Wyoming regions in 2010. Further, when older meters need to be replaced, a meter with built-in temperature compensation is installed in its place. The Company has also modified the calculation process to minimize the estimation that must be done to render billing cycle data into a calendar-month form for comparison with system receipt data.

Gas that is lost and unaccounted for is chiefly a measurement and gas accounting issue. Nevertheless, some gas is physically lost through leaks, theft, and damage to the Company's pipe by third parties. The Company is taking numerous steps to minimize the volume of gas lost from the distribution system as part of its methane emissions program. This is discussed in detail in the Sustainability section of this report.

The important metric in tracking LAUF year to year is the percentage, not the estimated quantity. Estimated quantity can vary considerably from year to year, and there is no sure way to isolate all sources and assign a share of the LAUF portion to them. However, the Company's estimated percentage has remained stable and well below 1% since the implementation of temperature and elevation compensation by the billing system. Estimates by other LDCs provided to the U.S. Energy Information Administration vary considerably across the industry and range from negative percentages to some at 30% or higher[32].

Negative estimates do not suggest that an LDC is making gas inside of its distribution system. Unusually high percentages do not necessarily indicate that an LDC is losing a high portion of the gas it takes in. Instead, such a range of estimates underscores the imprecise nature of comparing measurements of gas volumes taken at different times from a multitude of locations, equipment, and estimated data sources.

The Company calculates the portion of gas that is lost or unaccounted for using a moving three-year average of annual proportions. These proportions are derived by dividing the total of system receipts for the twelve-month period ending June 30 into the sum of Company use gas (accounts 810 and 812), loss from tear-outs, and volumes that are unaccounted for during the same period. The updated average is 0.582% and reflects meter-level compensation for temperature and elevation in the Utah service territory that began in August of 2010 and in the Wyoming service territory in October of 2012.

The current calculation for the most recent three years is included in Table 3.1.

Table 3.1: Three-Year Rolling Average of Estimated DEUWI Use and Calculation of Gas Lost and Unaccounted for (Dth)

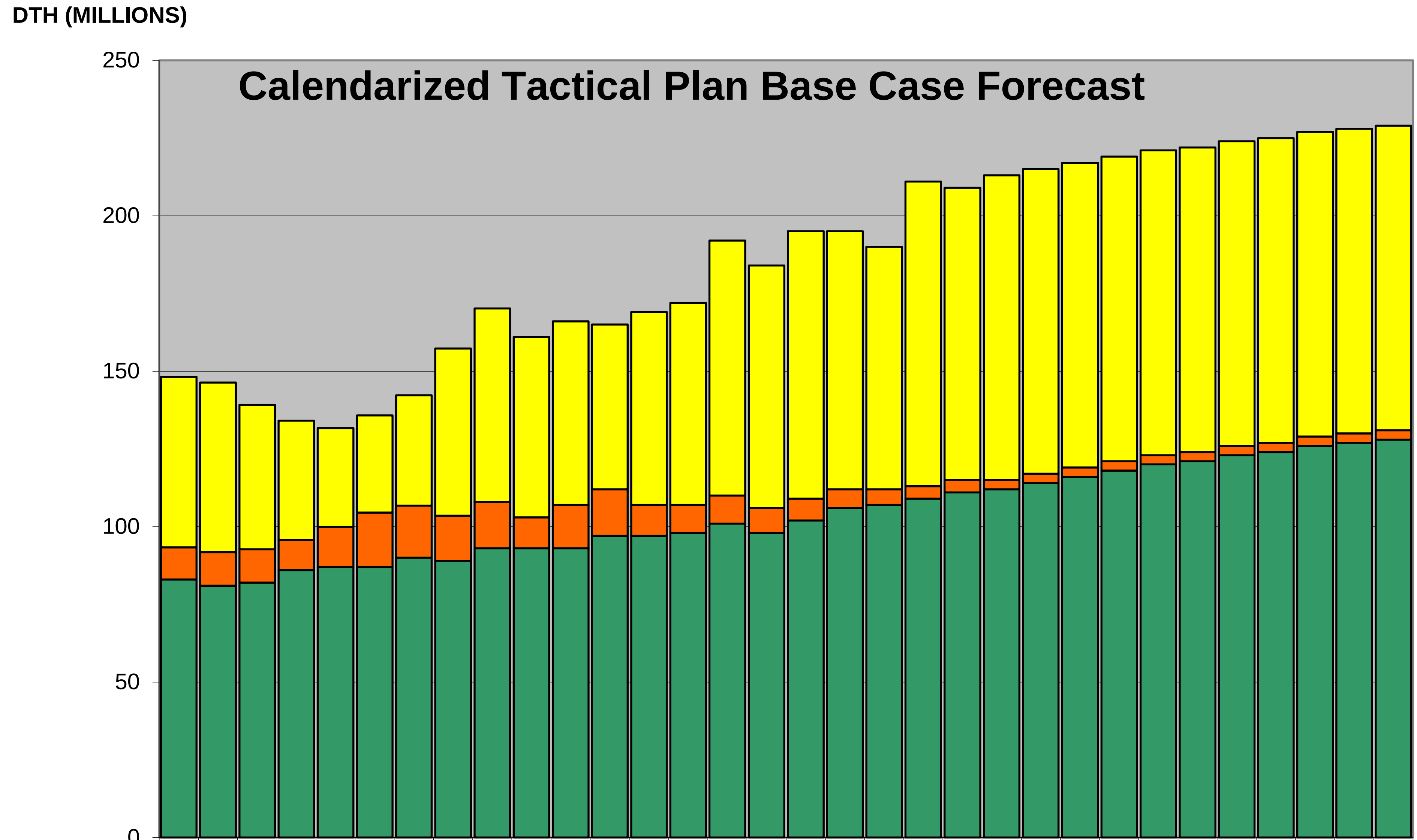
Year	DEUWI Customer Sales	DEUWI Customer Transport.	Total Receipts	DEUWI Sales & Transportation	DEUWI Use Acct. 810&812	DEUWI Loss Due to Tearouts	DEUWI Lost & Unaccounted for Gas	Total Sales, Transport, Company Usage and L&U
2017-2018	105,266,225	78,050,010	183,316,235	181,824,568	170,188	30,771	1,290,708	183,316,235
2018-2019	115,015,137	99,051,746	214,066,883	213,164,268	169,345	31,627	701,643	214,066,883
2019-2020	113,189,937	93,799,591	206,989,528	205,868,216	90,617	44,984	985,712	206,989,528
Total	**333,471,299**	**270,901,347**	**604,372,646**	**600,857,051**	**430,150**	**107,382**	**2,978,063**	**604,372,646**
	Lost-&-Unaccounted-For-Gas %		0.493%	Company Use and Lost-&-Unaccounted-For-Gas %				0.582%

FORECAST EXHIBITS

The following charts summarize the 10-year customer and gas demand forecast. All charts contain temperature-adjusted data with forecast horizons summarized on an IRP-year basis (June 1 – May 31).

[32] American Gas Association (2014, February), *Lost and Unaccounted for* Gas

TEMP ADJUSTED THROUGHPUT

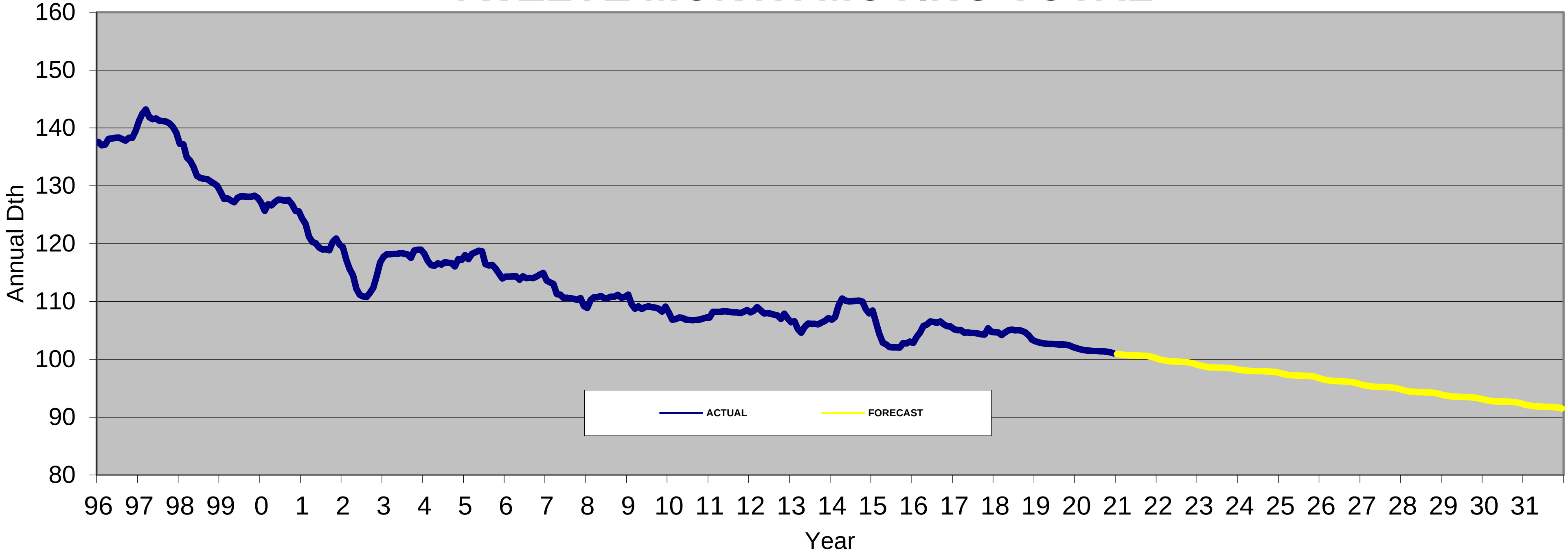


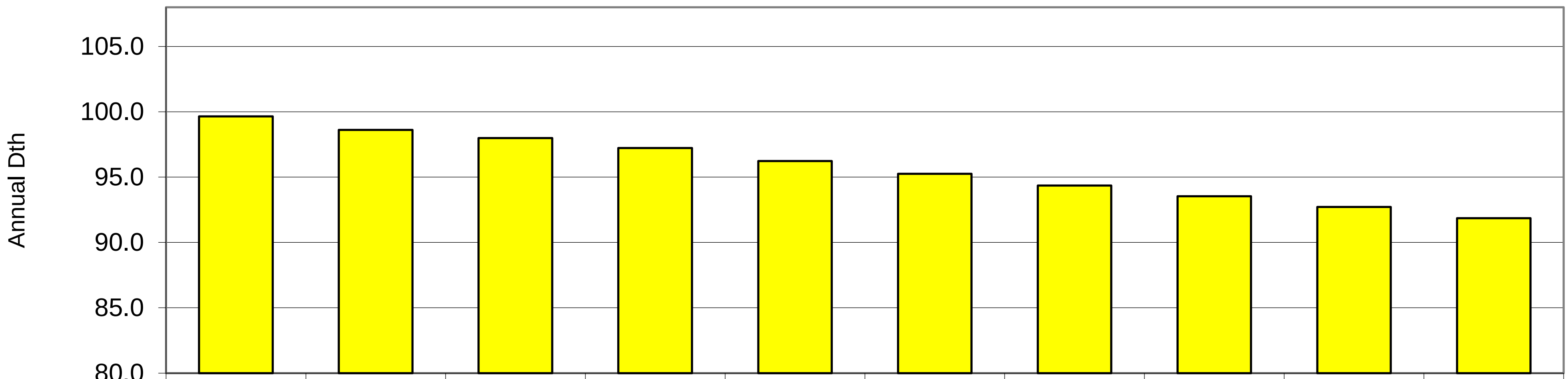
	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21	21/ 22	22/ 23	23/ 24	24/ 25	25/ 26	26/ 27	27/ 28	28/ 29	29/ 30	30/ 31
TRANS	55	55	46	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	94	98	98	98	98	98	98	98	98	98	98	98
NON-GS SALES	10	11	11	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	3	3	3	3	3	3	3	3	3	3	3
SYSTEM GS	83	81	82	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	111	112	114	116	118	120	121	123	124	126	127	128

Exhibit 3.11

UTAH GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





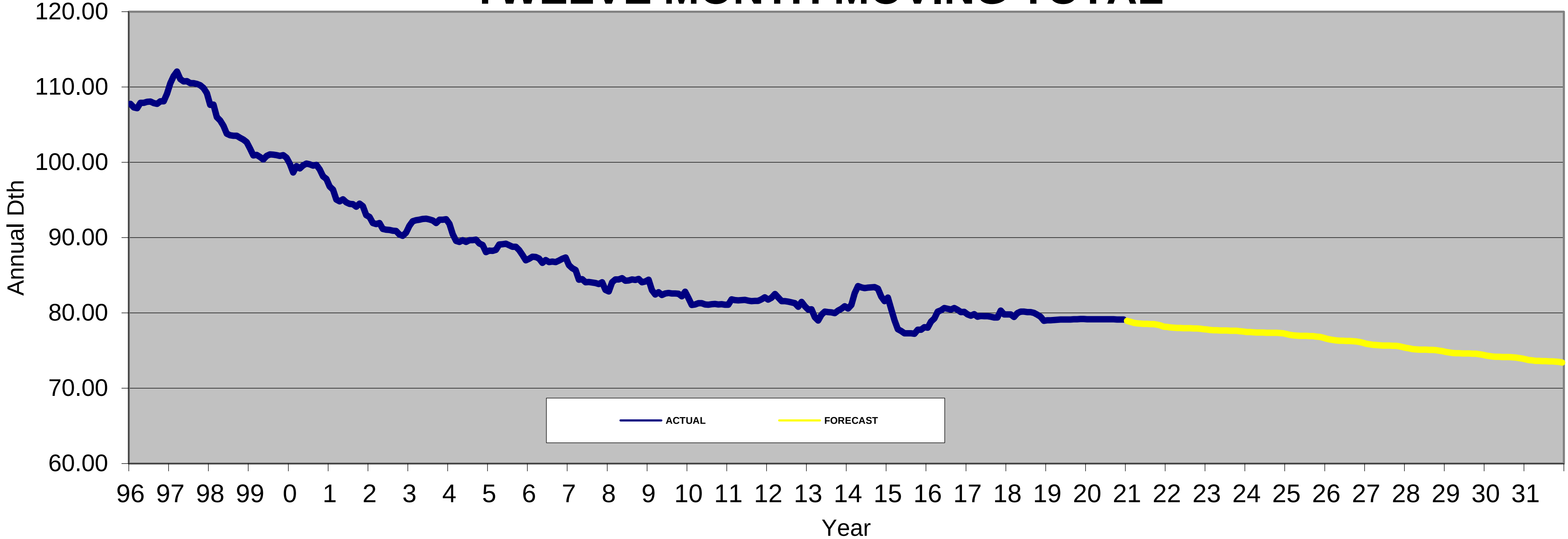
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
FORECAST	99.7	98.6	98.0	97.2	96.2	95.3	94.4	93.5	92.7	91.9

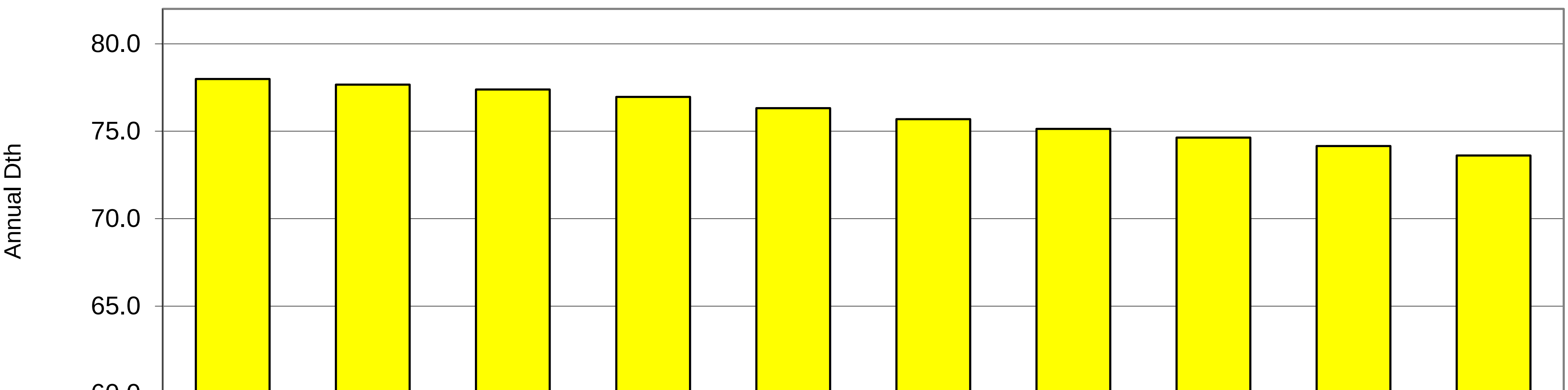
IRP Year

Exhibit 3.2

UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





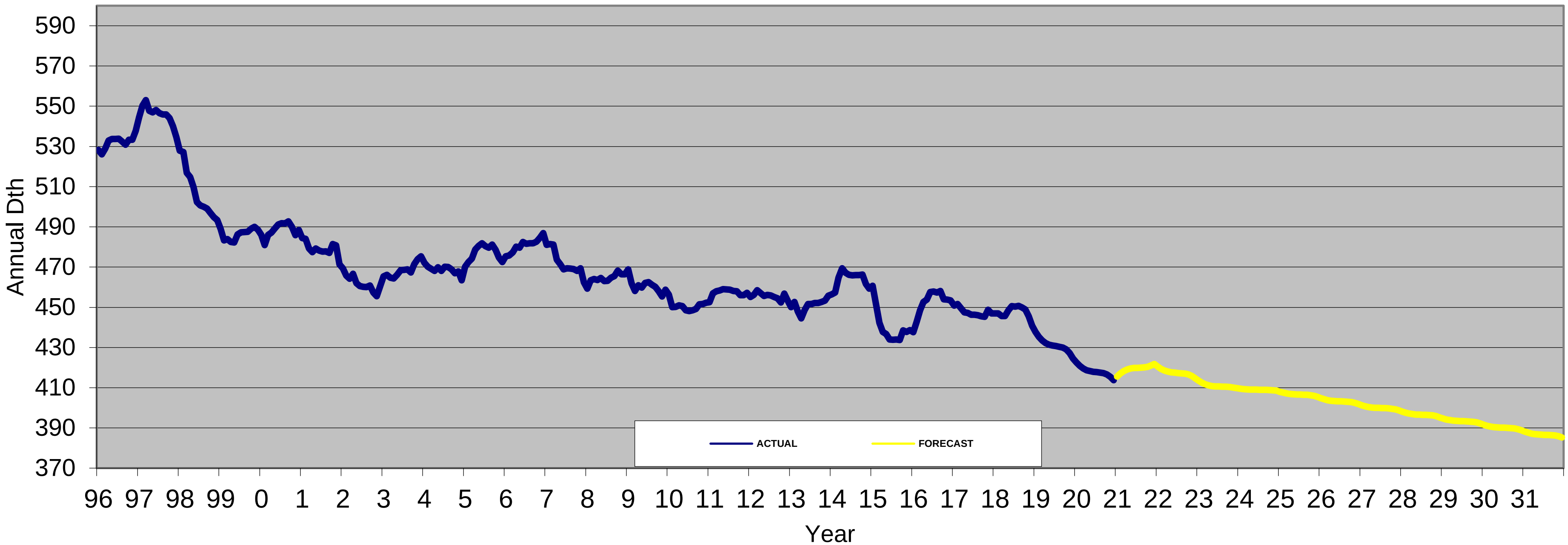
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
FORECAST	78.0	77.7	77.4	77.0	76.3	75.7	75.1	74.6	74.2	73.6

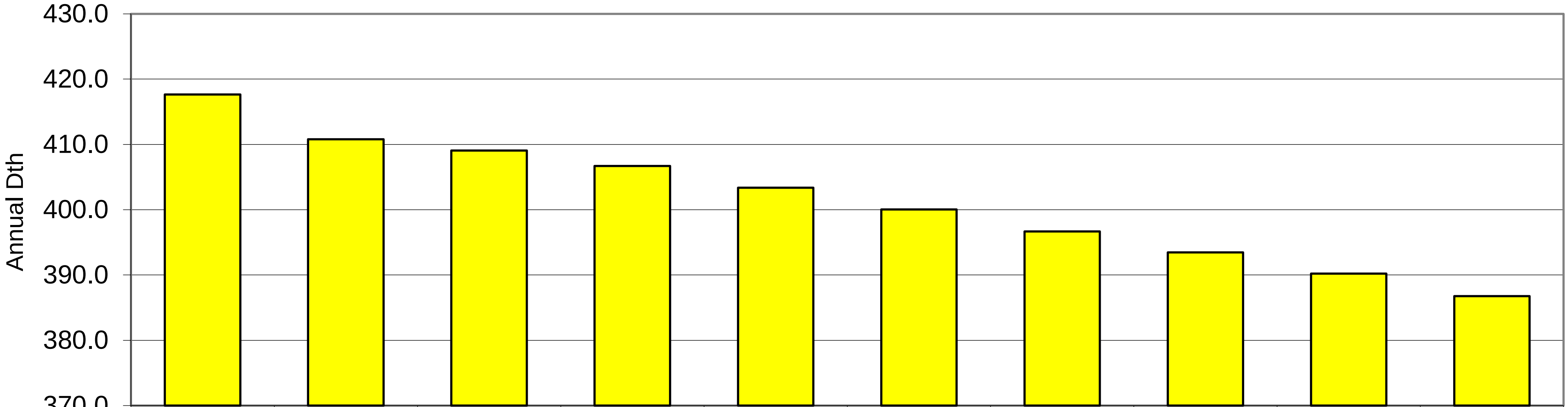
IRP Year

Exhibit 3.3

UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL





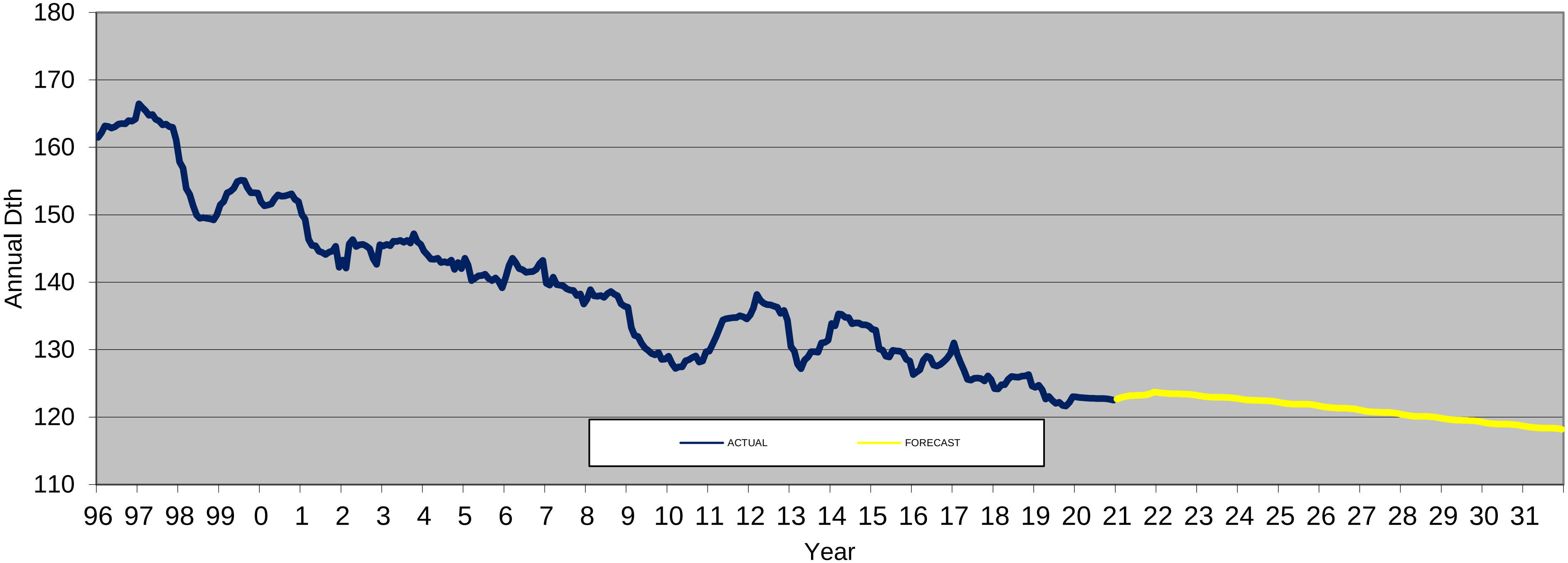
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
FORECAST	417.6	410.8	409.1	406.7	403.4	400.0	396.7	393.5	390.2	386.8

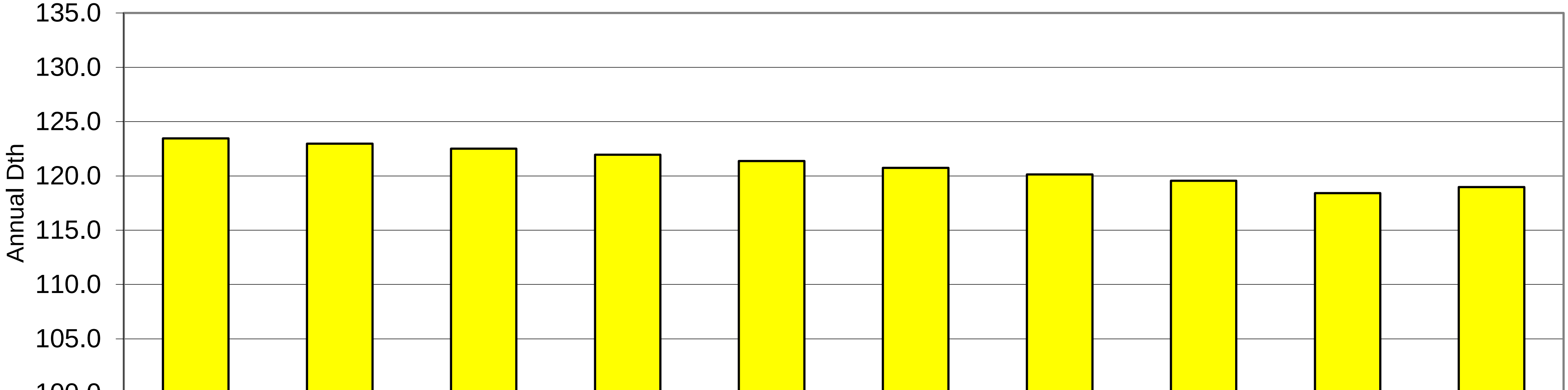
IRP Year

Exhibit 3.4

WYOMING GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



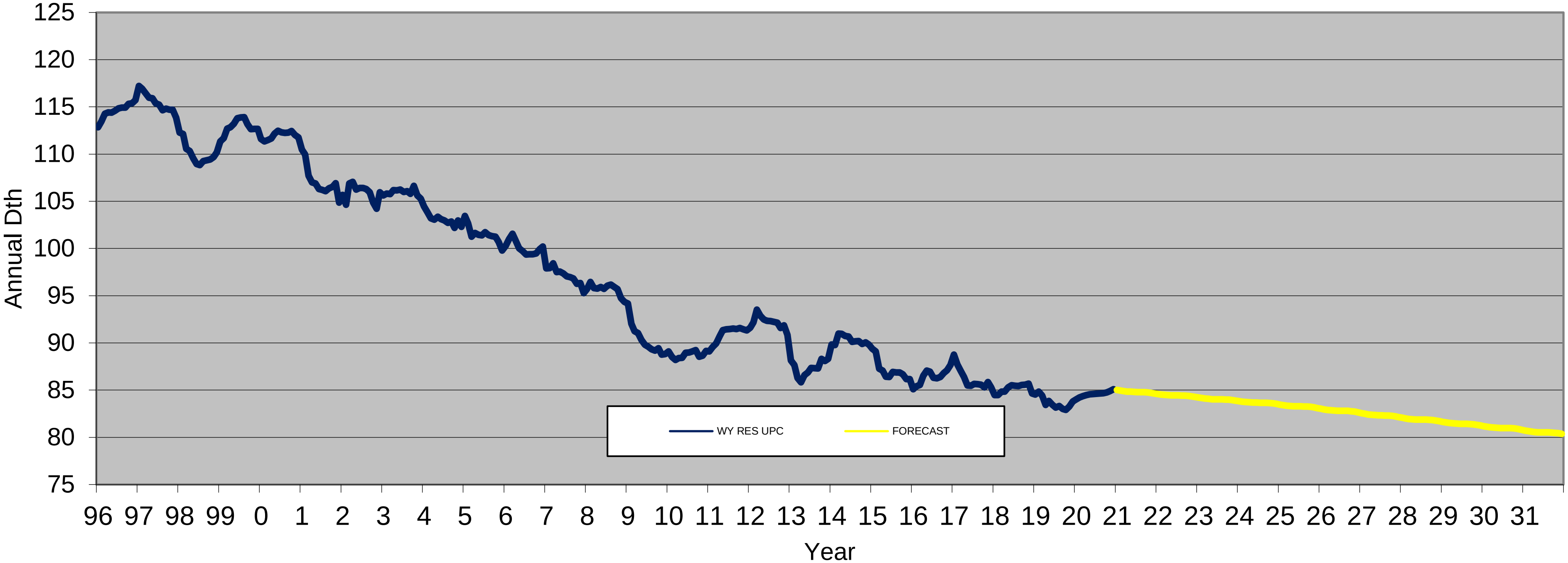


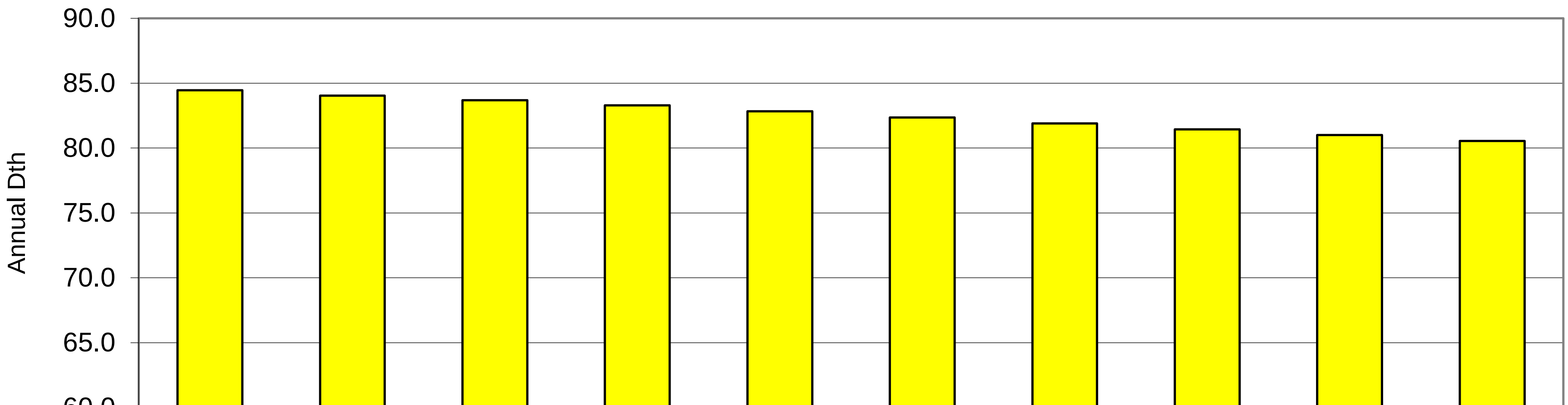
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
WY GS	123.5	123.0	122.5	121.9	121.4	120.8	120.1	119.6	118.4	119.0

IRP Year

Exhibit 3.5

WYOMING GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



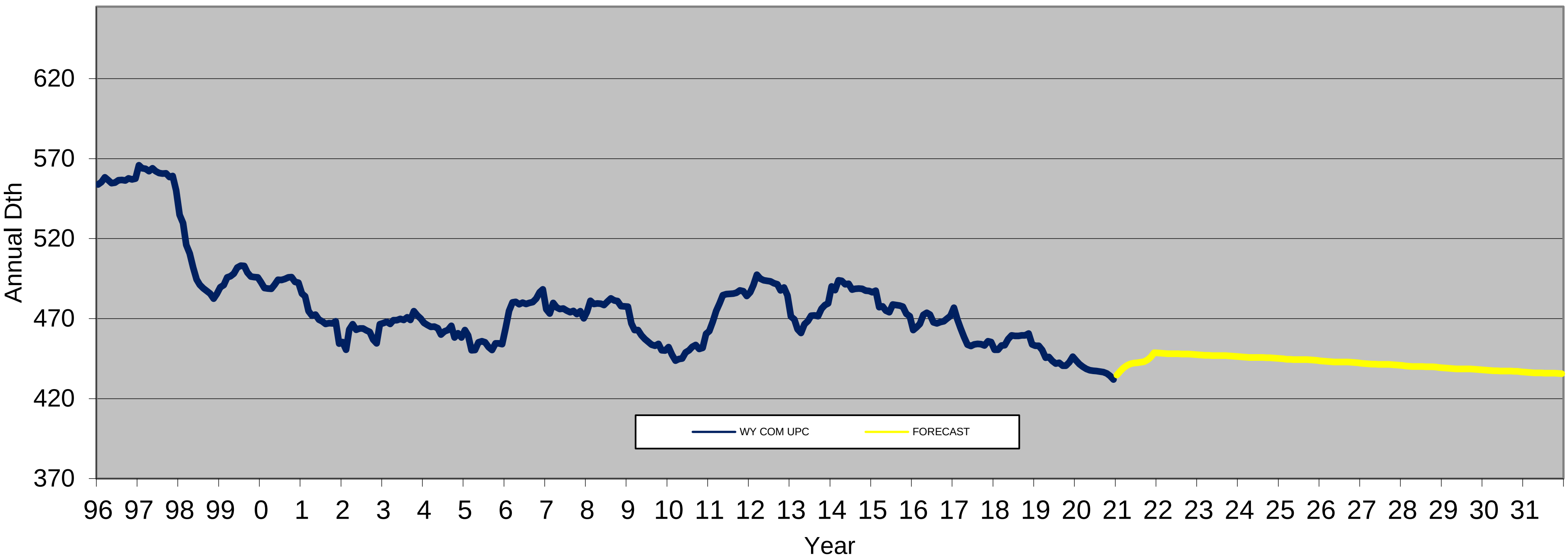


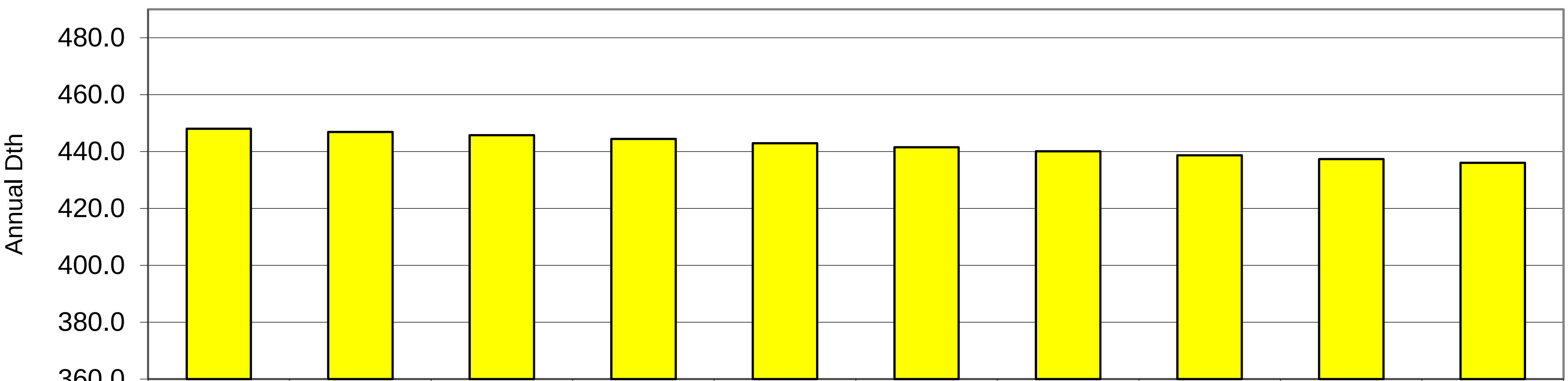
	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
WY GS RES UPC	84.5	84.0	83.7	83.3	82.8	82.4	81.9	81.5	81.0	80.5

IRP Year

Exhibit 3.6

WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL



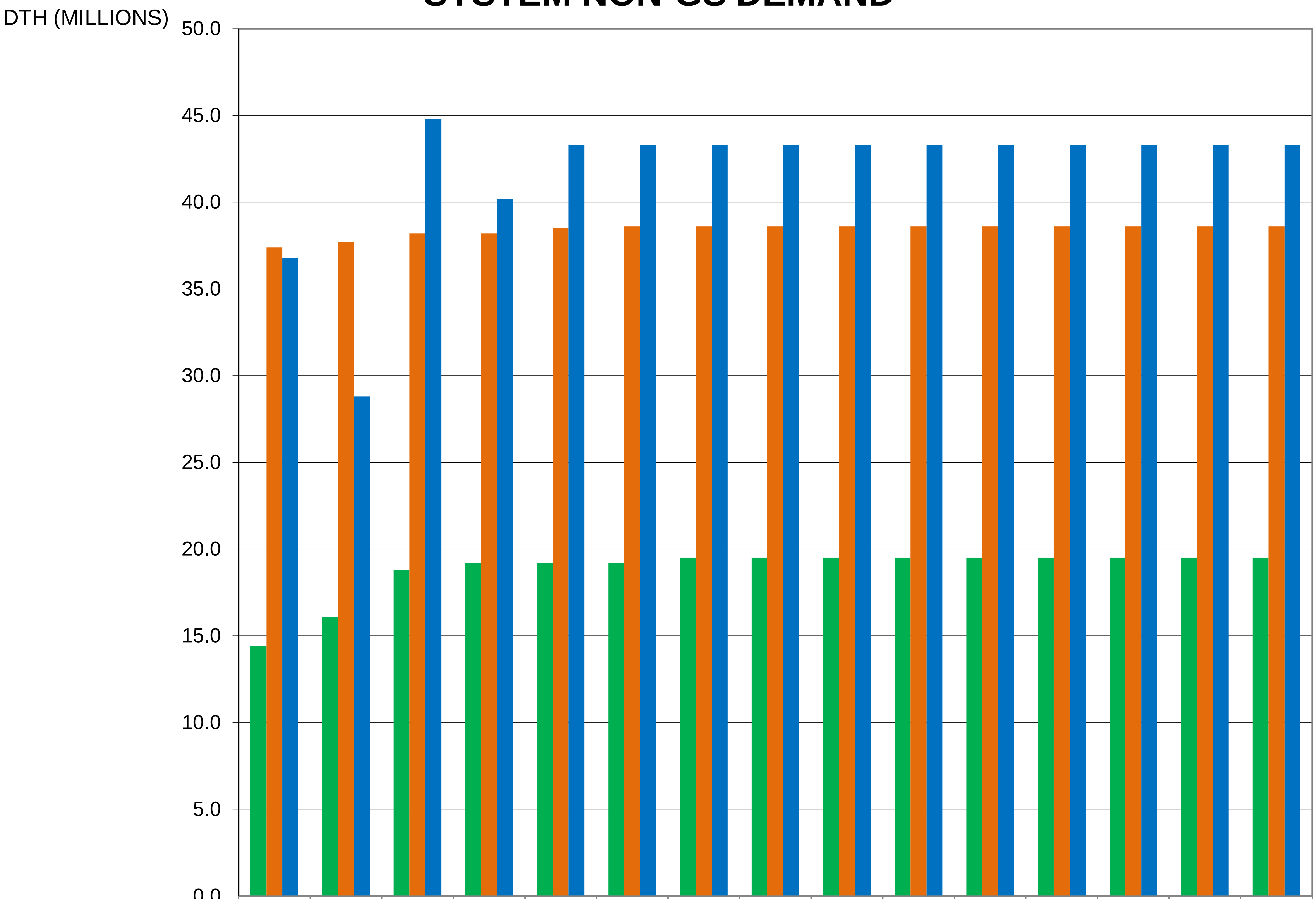


	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
WY GS COM UPC	448.0	446.9	445.7	444.4	443.0	441.5	440.1	438.6	437.3	436.0

IRP Year

Exhibit 3.7

SYSTEM NON-GS DEMAND

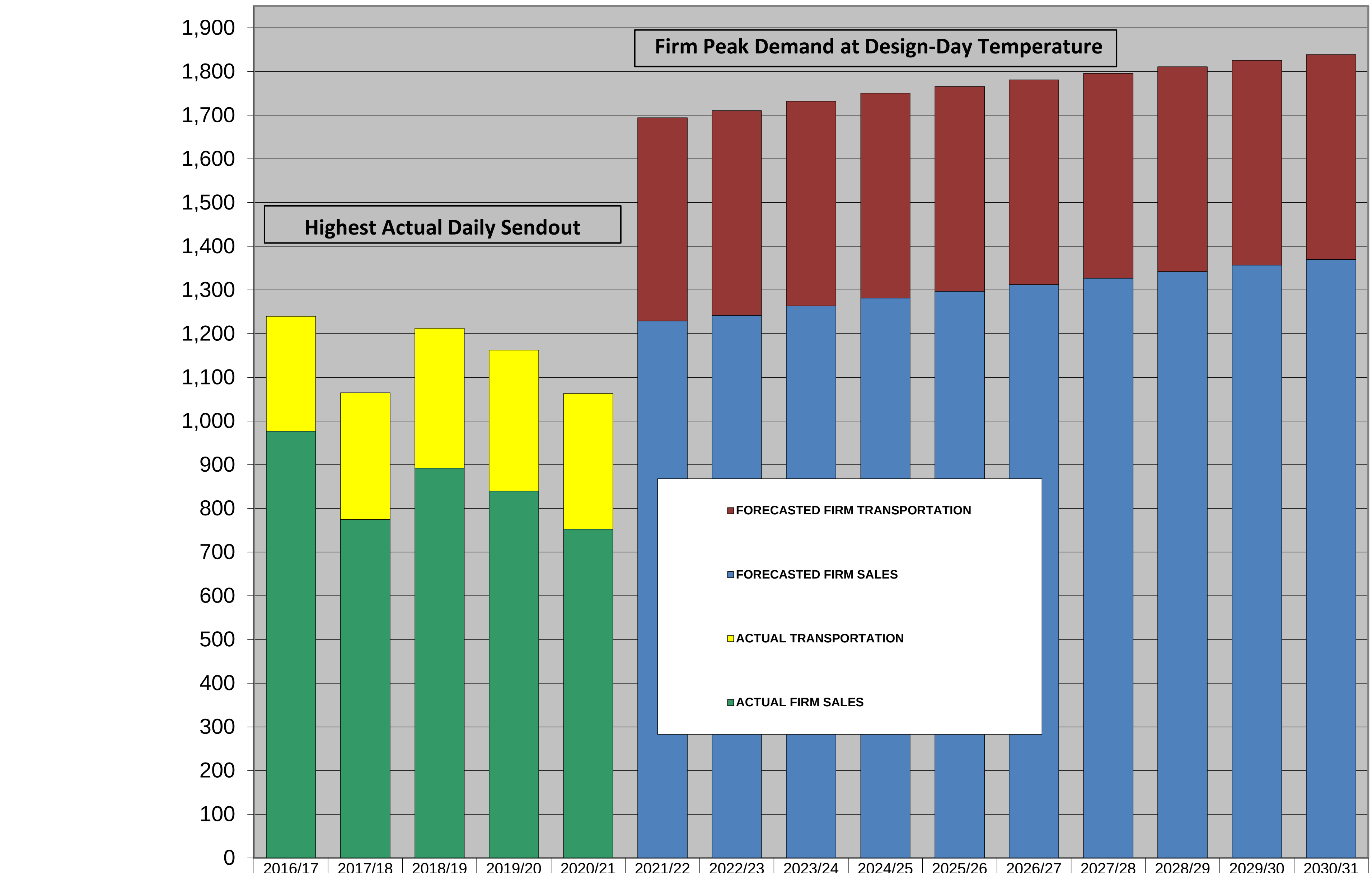


	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
LARGE COMMERCIAL DEMAND	14.4	16.1	18.8	19.2	19.2	19.2	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
INDUSTRIAL DEMAND	37.4	37.7	38.2	38.2	38.5	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
ELECTRIC GENERATION	36.8	28.8	44.8	40.2	43.3	43.3	43.3	43.3	43.3	43.3	43.3	43.3	43.3	43.3	43.3

Exhibit 3.8

DESIGN PEAK-DAY DEMAND FORECAST

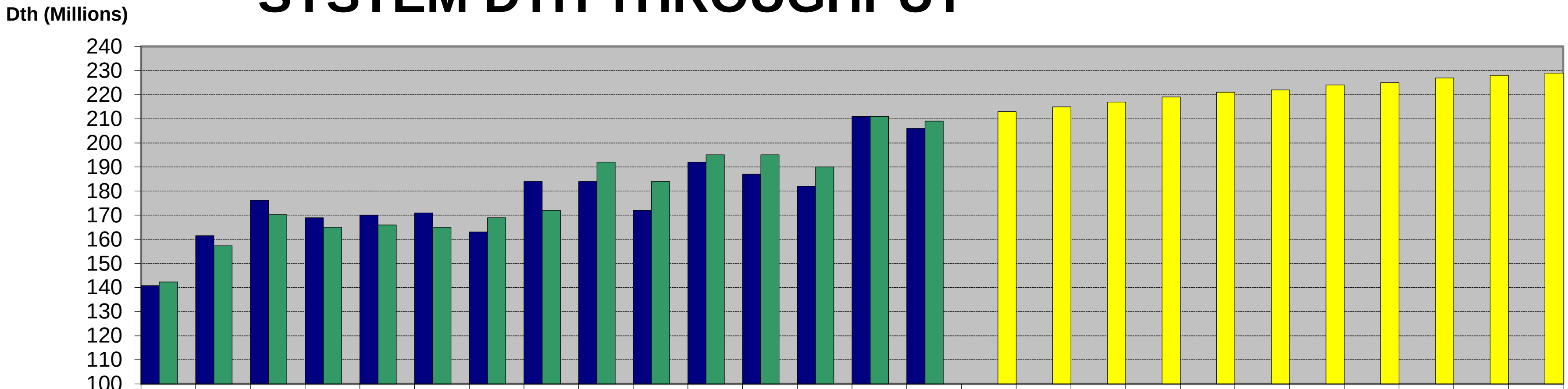
By Heating Season



	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
FORECASTED FIRM TRANSPORTATION						465	469	469	469	469	469	469	469	469	469
FORECASTED FIRM SALES						1229	1242	1263	1282	1297	1312	1327	1342	1357	1370
ACTUAL TRANSPORTATION	262	290	320	323	311										
ACTUAL FIRM SALES	977	775	892	840	752										

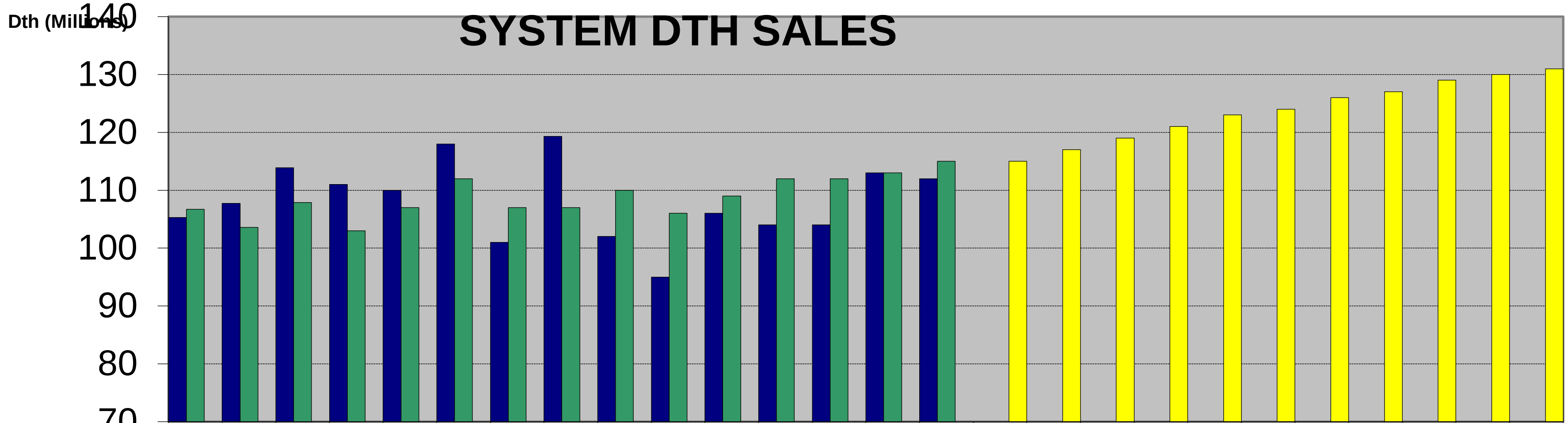
Exhibit 3.9

SYSTEM DTH THROUGHPUT



	06	07	08	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
ACTUAL	141	162	176	169	170	171	163	184	184	172	192	187	182	211	206											
TEMP ADJUSTED	142	157	170	165	166	165	169	172	192	184	195	195	190	211	209											
FORECAST																213	215	217	219	221	222	224	225	227	228	229

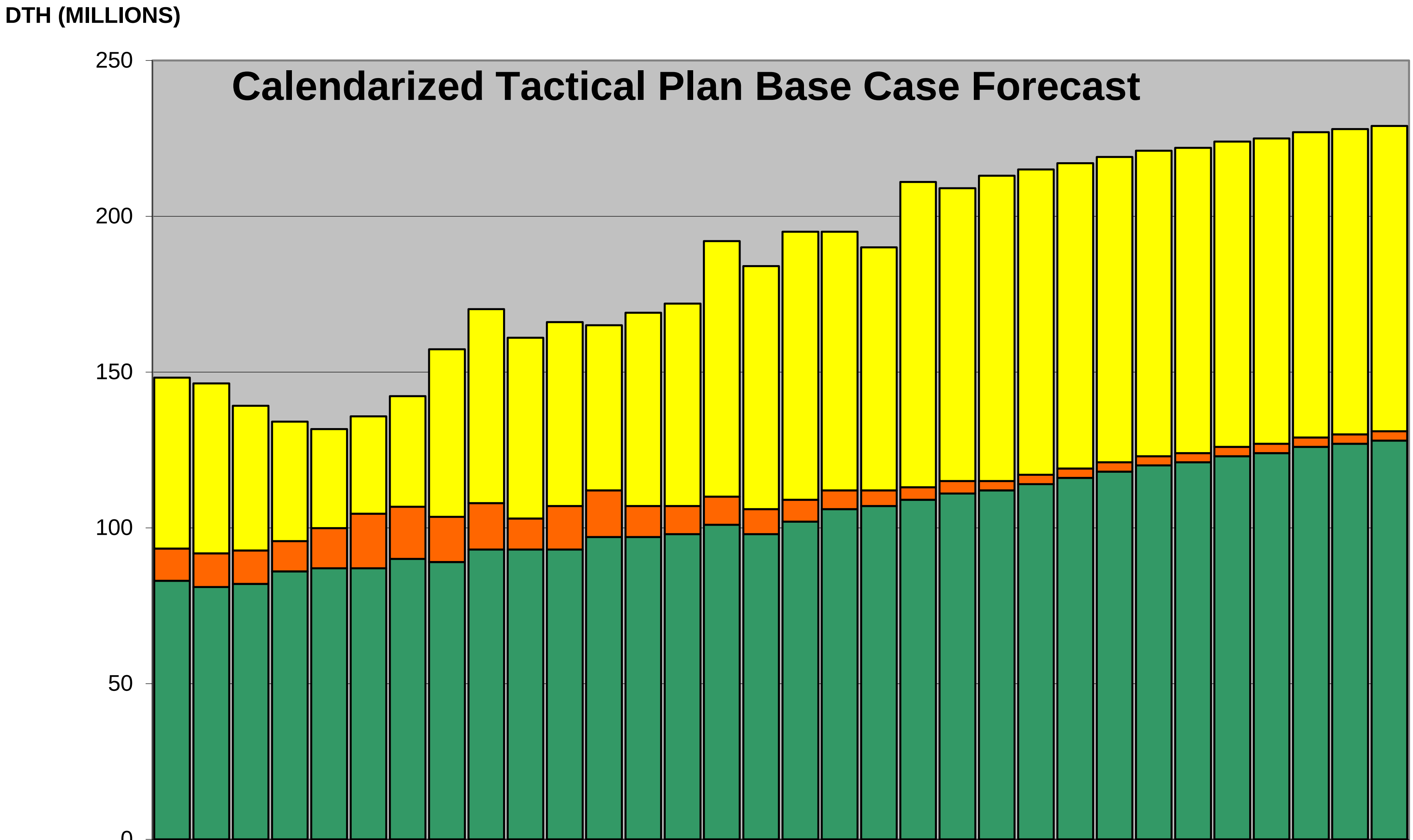
SYSTEM DTH SALES



	06	07	08	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
ACTUAL	105	108	114	111	110	118	101	119	102	95	106	104	104	113	112											
TEMP ADJUSTED	107	104	108	103	107	112	107	107	110	106	109	112	112	113	115											
FORECAST																115	117	119	121	123	124	126	127	129	130	131

Exhibit 3.10

TEMP ADJUSTED THROUGHPUT



	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31
TRANS	55	55	46	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	94	98	98	98	98	98	98	98	98	98	98	98
NON-GS SALES	10	11	11	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	3	3	3	3	3	3	3	3	3	3	3
SYSTEM GS	83	81	82	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	111	112	114	116	118	120	121	123	124	126	127	128

Exhibit 3.11

SYSTEM CAPABILITIES AND CONSTRAINTS

DEUWI SYSTEM OVERVIEW

The Company's system currently consists of approximately 20,653 miles of distribution and transmission mains serving more than 1,120,000 customers. The system operates at pressures that range up to 1,000 psig and is separated into many subsystems in order to deliver the pressures and volumes that customers require. The Company builds system models annually to determine when and to what extent system improvements will be required. Figure 4.1 shows the Company's high-pressure (HP) system, its service area, connecting interstate pipelines, and adjacent producing basins.

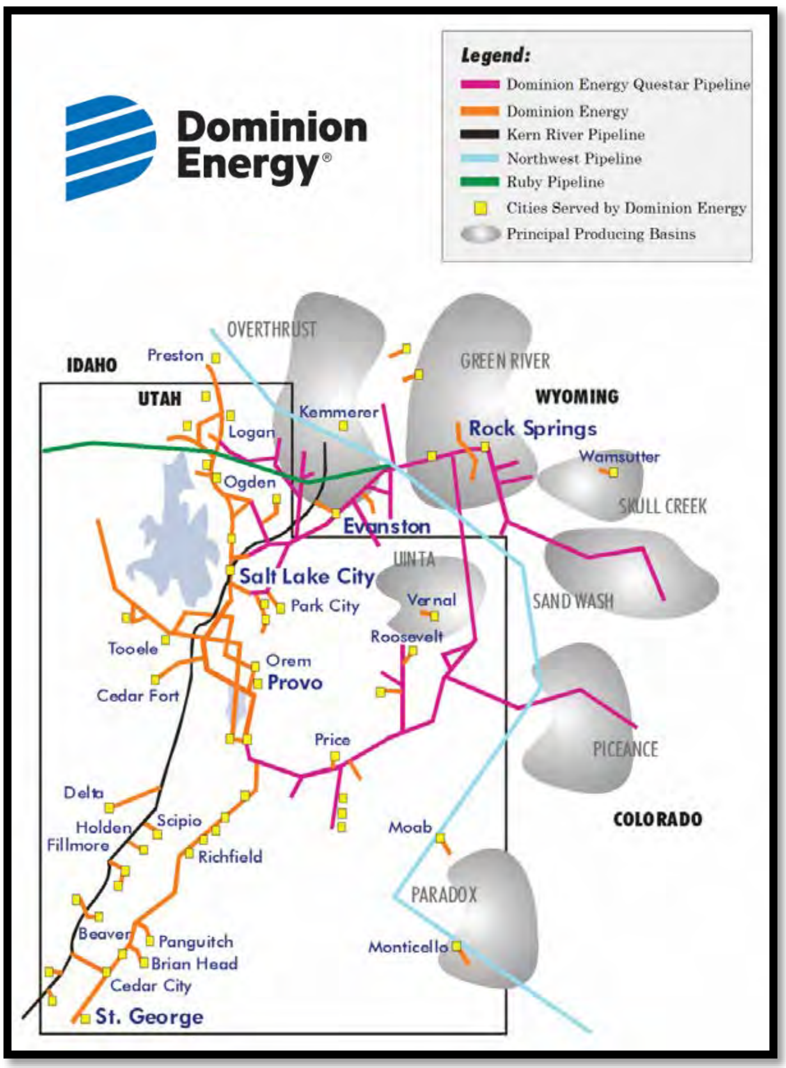


Figure 4.1: DEUWI High Pressure System

ONGOING AND FUTURE SYSTEM ANALYSIS PROJECTS

Master Planning Models

The Company creates gas network analysis (GNA) master planning models to more accurately predict impacts of system growth. The models are created using global growth projections as well as anticipated growth from specific planned developments in each area. The benefit of using this data is that the resulting system pressures will reflect the impact of the specific growth centers and provide improved projections of system impacts during a peak event.

System Supply Analysis and Joint Operating Agreement

The Company analyzes its gas supply contracts each year to determine if they will meet the coming year's demands. The Company carefully considers the upstream (interstate transmission pipelines) constraints and capabilities as well as the ability to acquire gas to deliver to its system on a Design Day. The purpose of this analysis is to determine the amount of gas required on a Design Day, and if the current contracts (sales and transportation) facilitate this required delivery.

The Company and Dominion Energy Questar Pipeline (DEQP) work together each year to update a Joint Operating Agreement (JOA) as part of this analysis. The JOA includes details regarding the pressures and flows available at the jointly operated gate stations, as well as operational and facilities responsibilities. One objective of this agreement is to ensure that the Company receives adequate inlet pressures to these stations in order to maintain system reliability. This is a complicated process that requires detailed collaboration because the flows at these stations fluctuate through the day to match the changing demands on the Company's system.

Updating the JOA is a necessary practice for ensuring customers receive safe and reliable service. DEUWI's transportation contracts with DEQP permit delivery to multiple gate stations. As a result, DEUWI enjoys a great deal of flexibility. However, because each gate station delivers supply to DEUWI's system at different pressures, engineering analysis is required to ensure that pressures and flows across DEUWI's system are balanced, that the operation of that system does not cause deliveries to exceed contractual maximums, and that gas is flowing at adequate operational system pressures on a Design Day. DEUWI need not engage in such analysis with other pipelines because those entities do not have such a complex network of interconnects with DEUWI's system, and contracts for each interconnect are more limited and rigid.

Interruption Analysis

A number of customers on the Company's system have chosen to purchase interruptible service and to thereby utilize any available system capacity. Because DEUWI's system is not designed to provide continuous service for these customers, and because these customers use system capacity on an "as available" basis, it is important to understand the temperatures at which an interruption would be expected. The Company performs an interruption analysis on an annual basis. The interruption analysis divides the system into interruption zones and determines the temperature at which interruption of interruptible customers within a specific zone is appropriate in order to ensure reliable service to the surrounding firm service customers.

Operational Models

The Company prepares for planned maintenance and construction work as well as unforeseen events that impact system capabilities by developing and maintaining operational models of the system. The Company maintains these models to represent current conditions that exist in the system. The Company's engineers review these models on an ongoing basis with the Company's Gas Control, Gas Supply, Marketing, Operations, and Measurement and Control departments in order to inform them of expected system conditions.

SYSTEM MODELING AND REINFORCEMENT

The Company utilizes steady-state Intermediate High Pressure (IHP) gas network computer models to determine the required system improvements needed to maintain required operational pressures throughout the distribution system. The Company uses these models to identify the required locations and sizing of new mains and/or regulator stations. The Company also uses the models to compare the required flow from the regulator stations to the maximum delivery capacity of the existing regulator stations. This analysis provides the Company with the information necessary to determine which reinforcements the Company should construct each year. Based on the modeling results, the Company constructs a number of IHP mains, new regulator stations and upgrades to existing regulator stations.

The HP system models have more variables than the IHP system models and are also used to design for customer demand and growth. Engineers consider gate station capacities, existing supply contracts, supply availability, line pack and the piping system in conducting HP analysis. Because HP projects typically take longer to complete than IHP projects, the Company must identify the need for HP improvements earlier than would be required for IHP projects. The Company and the interstate pipeline companies that supply its system collaborate to identify potential constraints to ensure that the Company's supply needs can be met.

MODEL VERIFICATION

The Company verifies the accuracy of the steady-state (24-hour period) GNA models using recorded pressure data and calculated demands. The Company's engineers built steady-state models to represent the system conditions that were present on Wednesday, December 30, 2020, using actual data from that day. Model settings were adjusted to match the actual temperatures and other conditions for this day. The model pressures were compared to actual pressures at 342 verification points. Three hundred and forty-one of these points were found to be within 7% of the actual pressures on that day. Three hundred and thirty-nine of the pressures in the verification model were within 5% of the actual pressure. Based on this analysis, the Company has determined that the loads and infrastructure utilized in the GNA models are accurate, and that the Company can rely upon the models for their intended purpose.

The Company verifies the unsteady-state (hourly results for a 24-hour period) models in the same manner as the steady-state models. The temperatures and the gate station flows and pressures are matched as closely as possible. The Central and Northern Regions are the largest of the Company's connected HP systems with nine gate stations and two primary maximum allowable operating pressure (MAOP) zones. There are other smaller isolated systems which also require unsteady-state model analysis included in the results (Figures 4.3 – 4.8). The unsteady-state model minimum pressures were found to be within 7% of the actual minimum pressures at 341 verification points on that day. Three hundred and thirty-seven of the pressures in the verification model were within 5% of the actual pressure. The results of these comparisons confirm the accuracy of the unsteady-state models.

GATE STATION FLOWS VS. CAPACITY

The Company's system models must accurately emulate the physical pressure and flow limitations of each specific station. To ensure this, The Company completes a capacity study each year for each of the gate stations on the system. The Company calculates hourly and daily flow capacities for each station based on facility limitations, set pressures, and inlet pressures provided by the upstream pipelines. Some stations have specific minimum pressures based on contractual volumes. Other stations have fluctuating inlet pressures based on the changing flow on the Company's system. For the stations with changing inlet pressures, this analysis was based on the inlet pressures included in the update to the JOA.

There are a number of other gate stations that are at or near 100% utilization shown in Table 4.1. These stations will be upgraded as necessary in the coming years in order to accommodate their respective required flows. Each of these stations are either flowing at capacity, as reflected in last year's JOA update, or are nearing the physical capacity of the station. Stations at or near capacity that do not have urgent associated projects may not be a concern due to the fact that multiple gate stations feed the same HP subsystem.

Table 4.1: Gate Stations Nearing Capacity in the JOA

Station	2021-2022 (MMcfd)	Station Capacity (MMcfd)	% Utilization	Upgrade Year
Central Tap	50.1	50.1	100%	2024
Riverton	192.6	200.0	96%	-
Como Springs	1.2	1.3	92%	2021
Rockport	14.4	15.7	92%	2022
Morgan	1.8	1.9	91%	2022

The Central Tap is currently listed at full utilization, but its capacity can increase dynamically depending on its compressor's available suction and desired discharge pressures. Due to the smaller diameter size of FL81, which is downstream of the compressor, a higher discharge pressure of up to 1000 psig is required to deliver required volumes against pressure losses along FL81. As the Southern Expansion project adds larger diameter pipe parallel to FL81, this problem will be resolved, and lower discharge pressures will be needed. This will effectively raise the capacity of the Central Tap. Further details regarding the Southern Expansion project are provided in the Distribution Action Plan.

The Riverton gate station has been operating at or near capacity for almost a decade. It currently does not require a capacity upgrade due to other nearby gate stations with adequate capacity which also supply gas into the same HP system.

The Como Springs, Rockport, and Morgan gate stations are DEQP stations and require an upgrade to continue to supply gas reliably to their given areas. Each of these DEQP station upgrades in capacity will be performed by DEQP with coordination from the Company.

The Northern HP system continues to approach its maximum gate station capacity. The addition of the Kern River Gas Transmission (KRGT) Rose Park gate station this year provides the ability to bring additional firm gas to the Wasatch Front. In addition, when the FL23 replacement project is complete, there will be additional capacity available to the Wasatch Front through the Hyrum gate station.

The Saratoga Tap requires a remodel to meet growing demand. Saratoga Springs, Lehi, and Eagle Mountain are some of the fastest growing communities in DEU's service territory. The Saratoga gate station is designed to serve these communities. The Saratoga gate station, while not at capacity on a Design Day, requires a remodel due to operational concerns. Therefore, the Company will upgrade this station by 2022-2023. This project is discussed in greater detail in the Distribution Action Plan section of this report.

SYSTEM PRESSURES

Once the Company verifies the GNA models and properly sets contractual obligations and station capacities, it uses the models to analyze the gas distribution system to verify that it has adequate pressures in order to supply customers. The Company uses Design Day models for this analysis. Design Day models include firm loads for sales and transport customers. The Company uses the daily contract limits for applicable customers and assumes that interruptible demands are curtailed during the Design Day.

Northern

The Northern Region includes the distribution system throughout Salt Lake City and northern Utah, including Box Elder, Cache, Davis, Morgan, Salt Lake, Summit, Tooele, Utah, Wasatch, and Weber counties. The Company serves this region through interconnects with DEQP at Meter Allocation Point (MAP) 164 using the Hyrum, Little Mountain, Payson, Porter's Lane, and Sunset stations. The Company also serves the region through Payson gate station from DEQP's Main Line 104 (MAP 332), multiple smaller taps from DEQP (MAP 162) and KRGT at Eagle Mountain, Lake Side, Hunter Park, Riverton, Westport, and Rose Park gate stations.

In the steady-state model, the calculated low point in the main portion of the northern system is 209 psig, in Santaquin. The lowest steady-state pressure in the Summit/Wasatch system is in Woodland, which is 301 psig. These pressures remain higher than the Company's minimum allowable design pressure of 125 psig.

The steady-state pressures at some of the key locations in the Company's system are shown in Table 4.2. The locations on the system are shown in Figure 4.2. The Company models these pressures on a Design Day at system endpoints and low points in the area and important intersections. The Company builds steady-state models using average daily flows that most closely represent average pressures for the Design Day. The unsteady-state GNA models profile demands throughout the day and represent the pressure fluctuations throughout the Design Day.

Table 4.2: DEUWI High Pressure System Steady-State Design Day Pressures

Location	Pressure (psig)
Endpoint of FL 29 – Plymouth	299
Endpoint of FL 36 – West Jordan	245
Endpoint of FL 48 – Stockton	274
Endpoint of FL 51 – Plain City	247
Endpoint of FL 54 – Park City	356
Endpoint of FL 62 – Alta	236
Endpoint of FL 63 – West Desert	241
Endpoint of FL 70 – Promontory	300
Endpoint of FL 74 – Preston	292
Endpoint of FL 106 – Bear River City	319
Intersection of FL 29 & FL 127 – Brigham City	375

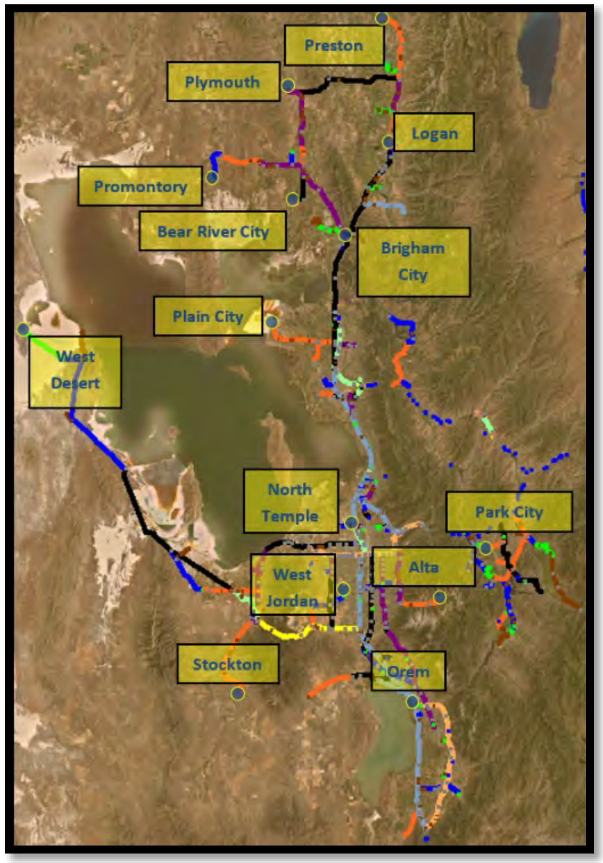


Figure 4.2: Northern Region Key Pressure Locations

The curves shown in, Figure 4.4, and Figure 4.5 are the expected Design Day pressures for the Northern Region HP system. In the projected unsteady-state models, the low point in the Northern Region is West Jordan at 157 psig. The lowest predicted pressure in the Summit Wasatch subsystem is at the Woodland regulator station with 228 psig during the peak hour of Design Day. In the HP system north of the Flyer Way station, the minimum pressure occurs at Plain City with a minimum pressure of 214 psig.

One of the HP regulator stations that supplies gas from the 720 psig MAOP of FL26 into the 354 psig MAOP northward is the Lindon station (RE0027). This station requires capacity upgrades to continue to improve supply reliability during potential outages northward. This project will be discussed in greater detail in the Distribution Action Plan section of this report.

Feeder Line 13 currently supplies gas between Magna and Salt Lake City and is currently being replaced as part of the Feeder Line replacement program. FL13 is planned to have an MAOP of 720 psig and be a part of the Company's 720 psig corridor when completed. HP stations will need to be installed on the east and west ends of FL13 to continue to properly regulate pressures between MAOP zones. These projects will be discussed in greater detail in the Distribution Action Plan section of this report.

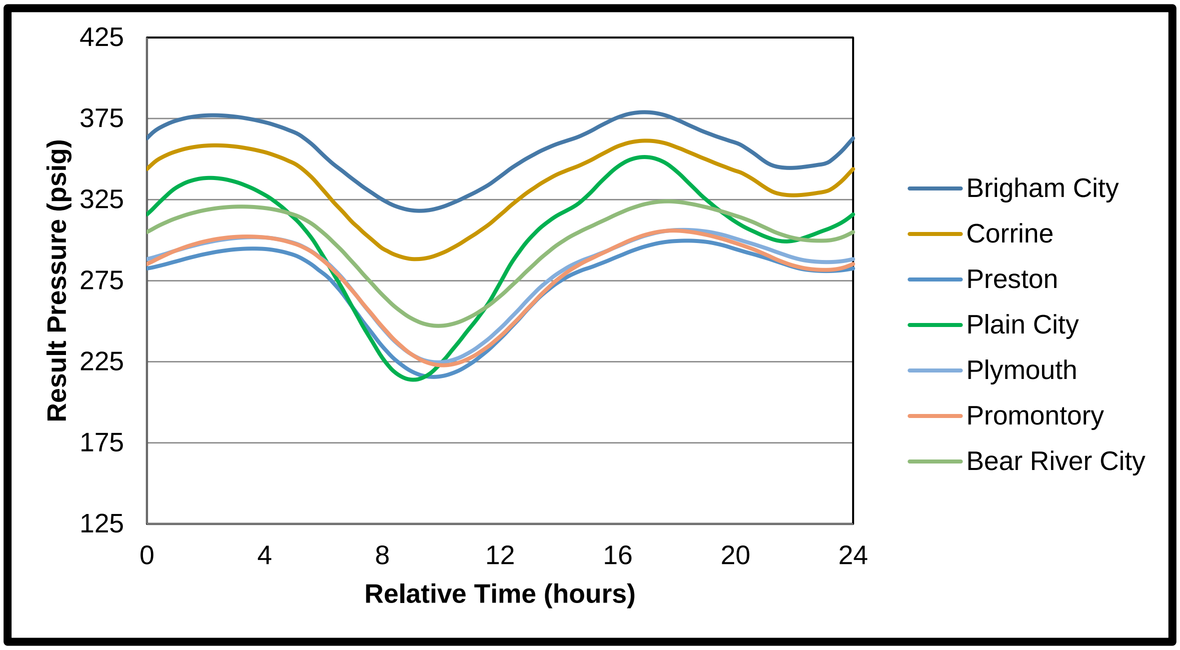


Figure 4.3: 2021-2022 Northern Unsteady-State Design Day Pressures (North of Flyer Way)

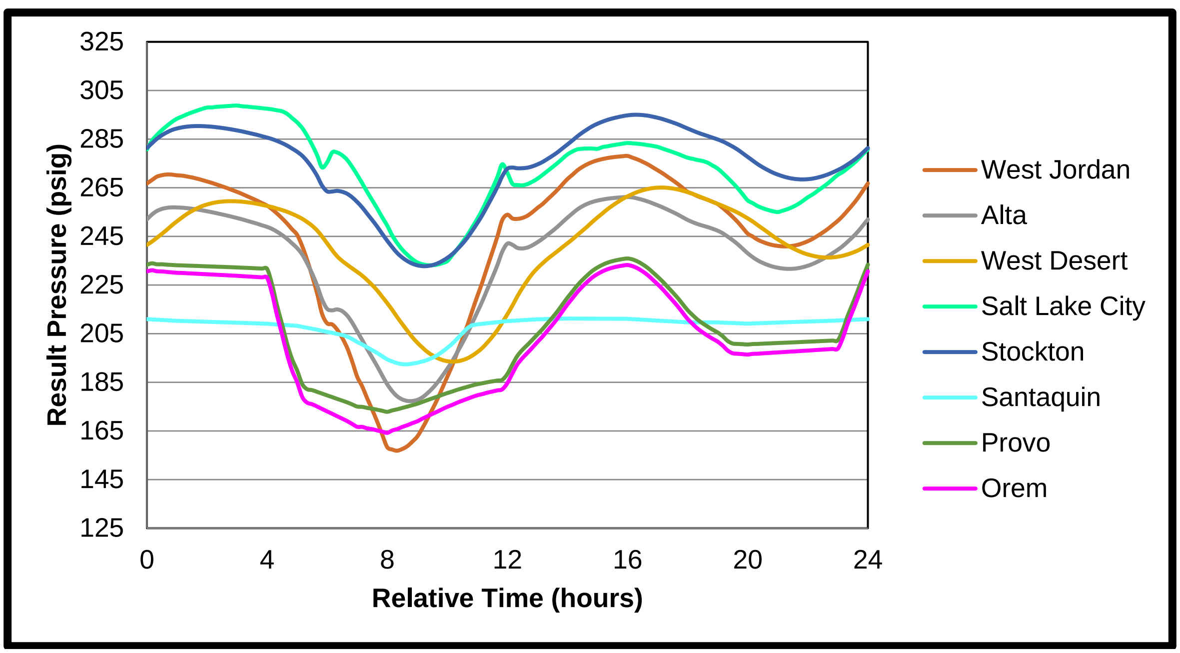


Figure 4.4: 2021-2022 Northern Unsteady-State Design Day Pressures (South of Flyer Way)

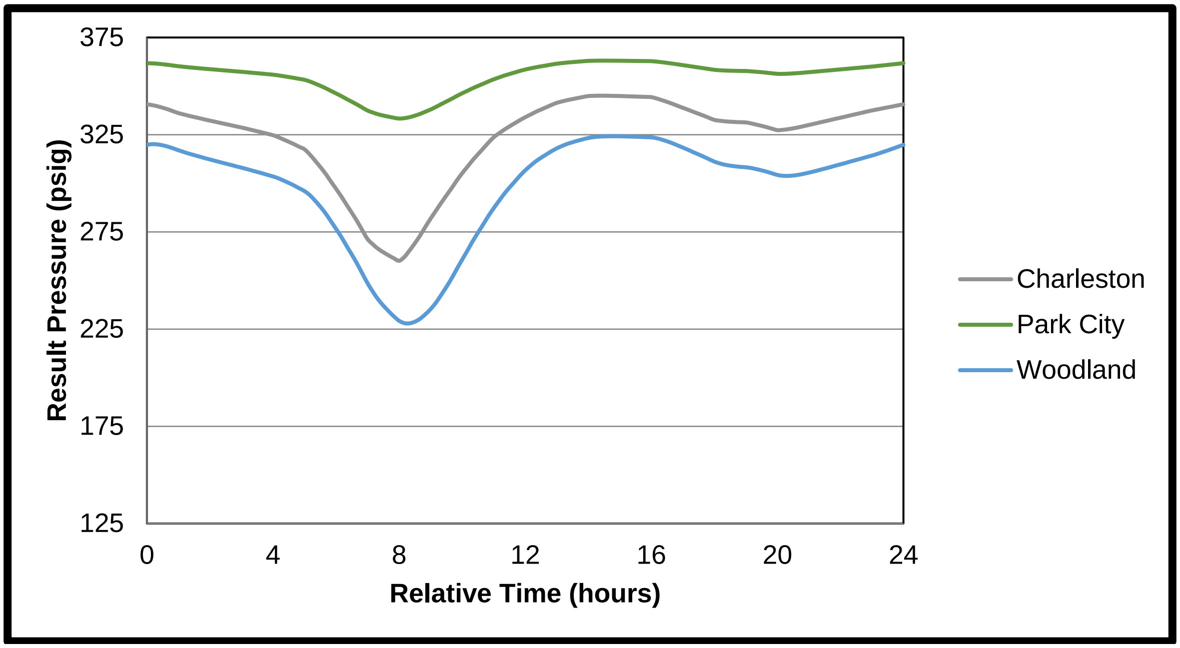


Figure 4.5: 2021-2022 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)

Eastern (North)

The Eastern (North) Region includes Duchesne, Uintah, Carbon, and Emery counties, including the cities of Price and Vernal. The Vernal area is served from DEQP by two gate stations through MAP 163 and MAP 334. Minimum pressures in the Vernal system reach a minimum of 208 psig.

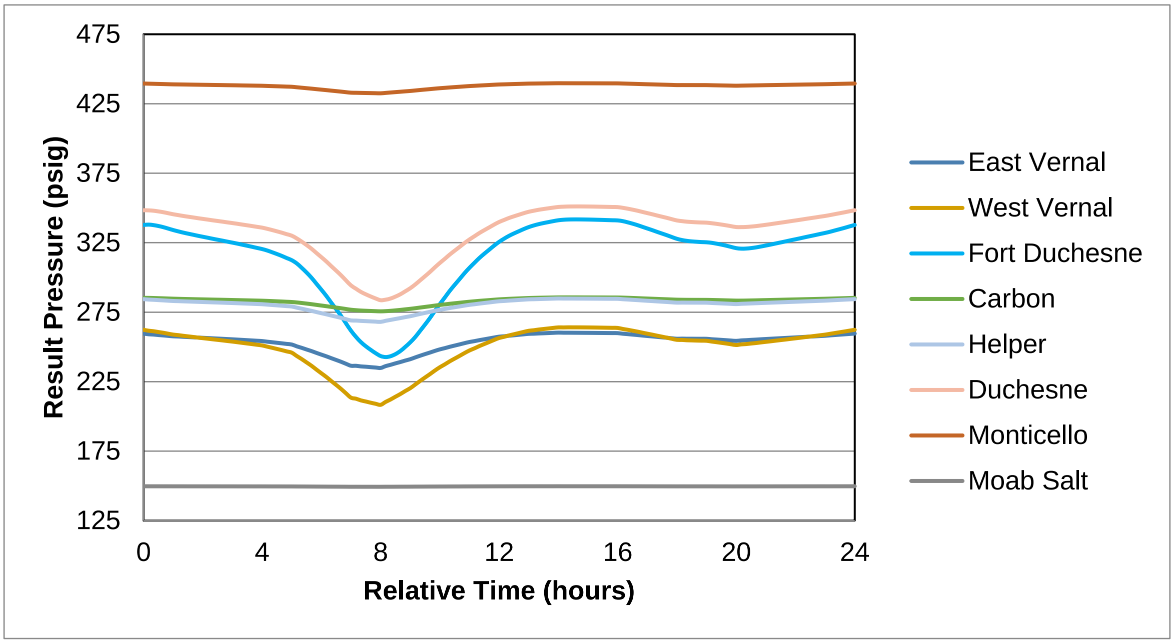


Figure 4.6: 2021-2022 Eastern (North) Unsteady-State Design-Day Pressures

Eastern (Northwest Pipeline)

The Eastern (Northwest Pipeline) Region includes the cities of Moab, Monticello and Dutch John. The Company serves these areas from Northwest Pipeline with two stations in Moab, one station in Monticello, and one station in Dutch John.

The system in this area is comprised of separate subsystems with individual gate stations connected to Northwest Pipeline. All of the segments in this area have adequate pressures, and do not require any improvements to meet the demand for the 2021-2022 heating season.

Southern (Main System)

The Southern (Main System) Region encompasses the areas served by the Indianola, Wecco and Central gate stations including Richfield, Cedar City, and St. George. The Company serves these areas from DEQP at Indianola station through MAP 166 and from KRGT at Central and Wecco stations.

Using the unsteady-state model, the lowest modeled pressure on a Design Day is 386 psig at the Brian Head regulator station. All segments in this area have adequate pressures, and do not require any improvement to meet the existing demand.

The Southern System will require substantial upgrades within the next five years. The Company has been closely monitoring the Southern System growth since the Central Compressor station was installed. In order to maintain system growth, FL81 will need to be looped with 20-inch pipe (FL135) to increase gas flow from the Central tap to St. George as part of the Southern System Expansion. This project is described in greater detail in the Distribution Action Plan section of this report.

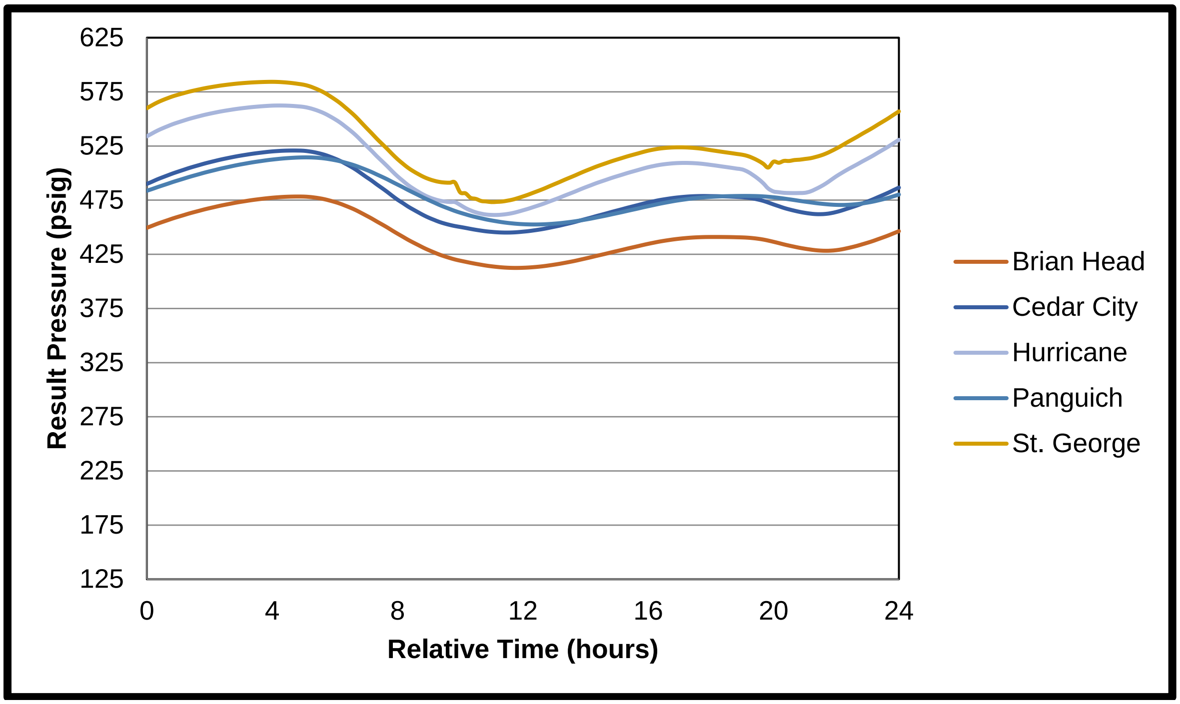


Figure 4.7: 2021-2022 Southern Unsteady-State Design Day Pressures

Southern (KRGT Taps)

The Southern Region includes towns in Juab, Millard, Beaver, Iron, and Washington counties. This includes all towns south of the Payson Gate Station that are not part of the Indianola/Wecco/Central system). These areas are all single feed systems served by KRGT.

The system in this area is comprised of separate subsystems with individual taps off KRGT. All segments in this area have adequate pressures and do not require any improvement to meet the existing demand.

Wyoming

The Wyoming Region includes Rock Springs, Evanston, Lyman, Kemmerer, Baggs, and Granger. The Company serves these areas from DEQP through MAP 168, MAP 169, MAP 177, from CIG at Wamsutter and Rock Springs, and from Williams Field Services (WFS) at La Barge and Big Piney.

The Rock Springs HP system has two gate stations; the Kanda gate station (fed from DEQP), and the Foothill CIG gate station. While neither station is near its capacity on a Design Day, these stations are meant to be redundant for reliability purposes. Kanda will be incapable of meeting the entire Design Day demand of this subsystem and must be upgraded in 2024.

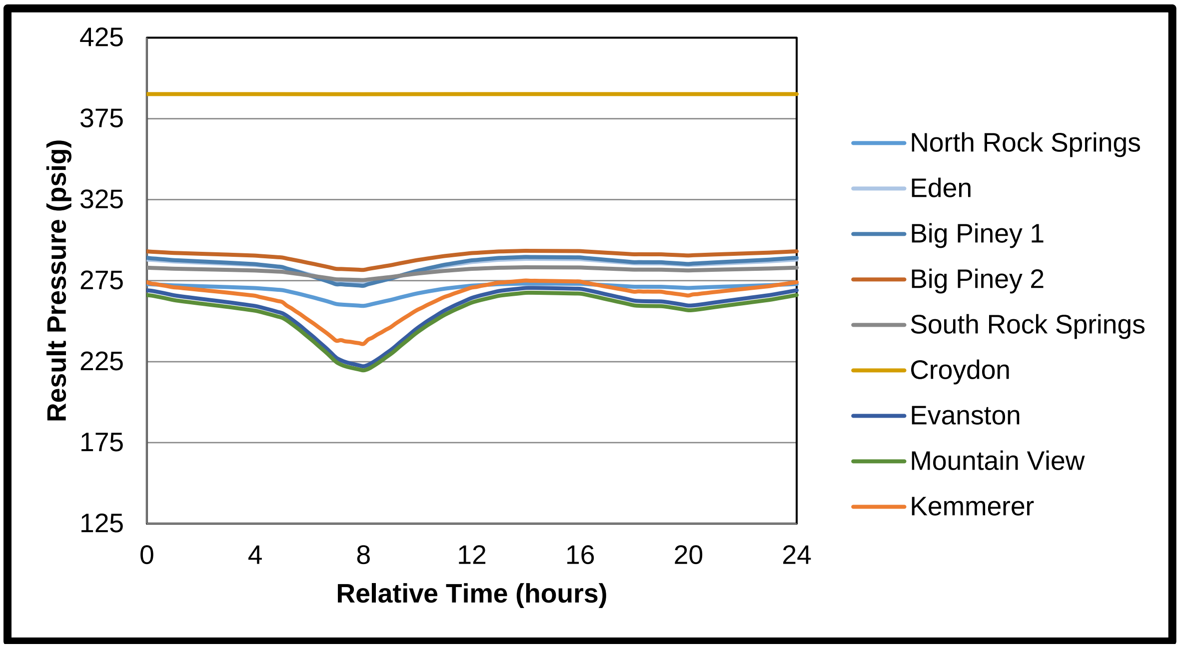


Figure 4.8: 2021-2022 Wyoming Unsteady-State Design Day Pressures

LONG-TERM PLANNING

The Company's modeled Design Day and customer growth for the past 5 years is shown in Table 3.

Table 3: Modeled historical total system peak day growth and customer growth

	2017	2018	2019	2020	2021
Peak Day Growth	2.51%	1.83%	3.03%	0.64%[33]	1.66%
Customer Growth	2.76%	2.28%	2.60%	2.35%	2.45%

[33] Lower peak day demand growth in 2020 was mainly due to a reduction in contracted industrial demand.

The average system growth and customer growth per year over the past 5 years have been about 2.0% and 2.6%, respectively. With a steady customer demand and growth rate expected to continue, long term plans and options must be considered to maintain the existing and growing system. The Company is considering a number of methods to maintain the level of service with the increased demand as well as sustainability. The Company has identified a number of projects that could contribute to a long-term solution.

First, the Company is considering increasing the size of FL85, that runs from the Saratoga KRGT gate station to the Central HP system, to increase supply. Doing so will increase the takeaway capacity downstream of the KRGT gate station at Saratoga Springs and will increase flows to the central HP system.

The Company is also considering the extension of the 720 psig MAOP corridor from Vineyard (it's current termination point) to Hyrum. Doing so will create a line-pack reservoir and will help offset upstream swings in deliverable pressures onto the Company's system. This long-term approach will require considerable investment to uprate the remaining sections of the corridor.

In the long-term, the Company will require investment in upstream pipeline systems to increase capacity to the Wasatch Front.

The Company is considering constructing modular LNG sites throughout its system. Such locations could take advantage of lower gas prices in the summer. As an additional benefit, such facilities could boost pressures in areas that otherwise have lower pressures and are without other supply reliability options.

The Company is also considering constructing RNG sites as possible supply resources that would both provide renewable natural gas on the Company's system and could address system concerns as well.

Finally, the Company is considering constructing a new Ruby Pipeline gate station near Brigham City. The Ruby Pipeline can easily be tapped in the future and could provide additional supply to the northernmost area of the Company's system. While this option has not been economically feasible in the past, it remains a potential option for the future.

The Company is also working towards a sustainable future through a hydrogen pilot program which looks at the benefits of blending hydrogen with natural gas. The hydrogen pilot program is discussed in further detail in the Sustainability section of this report.

The Company will continue to assess long-term challenges as they are discovered and will conduct analysis to identify options to address the challenges in future years. The Company is also evaluating the possibility of expanding service into previously unserved or underserved rural areas including Bear Lake, Kanab, Rockville/Springdale, and East Wendover, Utah.

SYSTEM CAPACITY CONCLUSIONS

The Company's HP system is capable of meeting the current Design Day demands. The Company bases this assessment on GNA modeling that indicates that the gate stations and feeder line systems have adequate capacity to meet average daily (on a Design Day) and peak hourly demands and the supply contracts are adequate. All system models show that pressures do not drop below the design minimum of 125 psig. As the Distribution System Action Plan section of this report discusses, the Company has plans to address any areas with projected pressures near the 125 psig minimum. The system will continue to grow along with the demand, and the Company will conduct an analysis annually and address concerns to ensure that the system continues to meet the Design Day needs.

In the Distribution Action Plan section of this IRP, the Company will discuss the following projects that are identified in this section:

- FL135, Central 20-inch Loop
- Lindon (RE0027) HP Regulator Station
- FL13 East and West HP Stations
- Saratoga (TG0005) Gate Station

DISTRIBUTION SYSTEM ACTION PLAN

The Company is currently planning, designing, and constructing several reinforcement and replacement projects on its system. The following is a brief description of the major planned projects for 2020 and beyond.

HIGH PRESSURE PROJECTS:

Station Projects:

1. LE0021 – District Regulator Station for American Fork and Lehi: The southwest side of American Fork, between I-15 and Utah Lake, is developing rapidly, and the Company needs to construct a new district regulator station in the area to support the growth. The Company is attempting to acquire property near its low-capacity station LE0017 and adjacent to FL85. The tapline will be approximately 70 lf and 6-inch diameter. The Company considered multiple options and selected the lowest cost. Other options would require longer taplines and horizontal directional drilling installation of pipe under Pioneer Crossing, thus significantly increasing costs.

   This project is currently in the design phase. The Company expects to complete construction during 2021, if the property purchase occurs by July 2021. The estimated cost for this project is $750,000. Revenue Requirement for $750,000 investment is $85,600

2. LG0012 District Regulator Station, Nibley, Utah: This pressure regulator station is required to alleviate low pressures in the IHP system in Nibley, Utah. The pipeline required to serve the station is 13,200 lf of 8-inch diameter pipe. The pipeline begins near U.S. Highway 89 on 3200 S, approximately 3 miles north of Wellsville. The alignment then runs east along 3200 S for approximately 2.5 miles until 3200 S and Main Street in Nibley. The Company purchased the property for this station in 2009 in anticipation of a station being required in the area in the future. The pipeline route is a direct line from the tap location on FL23 to the station property. There are, therefore, no other route alternatives to this project.

   The Company first discussed this project on page 4-14 of the 2016-2017 IRP. Over the last year, high level design, including survey and subsurface utility engineering, have allowed the Company to refine the project cost estimate. The project is currently in the construction phase. The updated estimated cost for this project is $4,500,000 with a first-year revenue requirement of $514,000.

3. Eureka – EU0001 District Regulator Station, Gate Station, Feeder Line FL138, and IHP Project: The Company is constructing a district regulator station, a gate station, HP feeder line and IHP distribution facilities to serve the community of Eureka. This project is discussed more fully in the Rural Expansion Projects section below (see section 5.6 below).

   The estimated cost for the district regulator station is $600,000. The first-year revenue requirement is $68,500

4. <u>WA1600 – District Regulator Station to Replace North Temple Capacity for Belt Line:</u> The North Temple district regulator station is slated for retirement and removal in 2022 and currently supplies a large amount of capacity to the Belt Line system for Salt Lake City. With its retirement, a new station is needed. The Belt Line replacement program has recently run new belt line to Flyer Way and will be extending that line to WA1600. Once completed WA1600 will replace the capacity of North Temple, allowing for its retirement next year. WA1600 is located on 2200 W and about ¼ mile north of the Flyer Way Station. The proximity to FL33 will only require approx. 250 lf of 10-inch tapline to serve the station. The Company has purchased an Exclusive Easement for the site.

   The project is currently in the design phase and construction is expected to begin in July 2021. The Company expects to complete the by November 2021. The estimated cost of the project is $750,000. The first-year revenue requirement is $85,600

5. <u>SY0002 Syracuse District Regulator Station, Syracuse, Utah:</u> This district regulator station is required to meet the residential growth in the west side of Davis County. Due to growth, the IHP system continues to be extended away from existing district regulator stations. This has limited the capability of the existing stations to effectively serve the IHP system in this area. SY0002 will provide an additional source of supply and increase pressure in this area of growth. Constructing the district regulator station is the only identified solution to resolving the low IHP pressures in this area. The Company purchased property at 2700 S 3000 W, Syracuse, UT for this project. FL47 will extend from SY0001 to supply the station. The Company first discussed this project on page 5-3 of the 2018-2019 IRP.

   Project is currently in the design phase. The Company estimates that the district regulator station will cost $500,000. The Feeder Line extension to serve the district regulator station will be discussed below. The Company plans to begin and finish construction in 2022. The first-year revenue requirement will be $57,100

6. <u>WA1604 District Regulator Station:</u> This district regulator station will replace WA0866 in South Salt Lake City with high capacity station for South Salt Lake City, UT. The current WA0866 needs to be relocated due to concerns with vehicular traffic in the area. Additionally, the capacity needs to be increased to support the growth in the area of South Salt Lake near 3300 S and 300 W. The project is currently in the proposal stage and the Company is now under contract acquire property for the new district regulator station at 334 W Archard Drive. The 6-inch tapline will be approximately 1,000 lf and will extend from FL4. Replacing the station on a larger piece of property was the only identified solution to the capacity concerns and traffic concerns.

   The Company explored considered retiring the station to address the potential for vehicular damage. However, retiring the station resulted in unacceptable pressures across South Salt Lake City year-round.

   In searching for property for the relocated station, the Company approached several property owners within a half-mile radius of the existing station. None were willing to sell property to the Company at a price that was competitive with market value. The selected location was the close to the existing station and was competitively priced.

Once the initial engineering is complete, the Company will provide updated alignment and project costs as part of the IRP Variance Report process. The Company currently estimates the total cost of the project (including acquiring the property) at $1,500,000. The Company plans to begin construction in 2022. The first-year revenue requirement is $171,300

7. New FL13 West HP Regulator Station and In-line Inspection (ILI) Facilities in Expanded WA 0027Site Near 8000 W and SR-201, Magna, UT: When FL13 is replaced as part of the Feeder Line Replacement Program, FL13 will have an MAOP of 720 psig and be part of the 720 MAOP corridor. This new station will separate the MAOP zones of FL13 at 720 psig MAOP from the rest of the Central HP system which currently operates with a 354 psig MAOP. The site will also include all the connections necessary for an ILI launcher barrel. The Company purchased additional property near the existing WA0027 station, located at 2900 S 8000 W, Magna, UT. This site will now be the new connection between FL13 and FL11 and was the closest location for the new FL13/FL11 tie.

   The project is currently in the design stage. The project's construction is anticipated in 2022. The Company estimates the total cost of the station project (including property acquisition) to be $900,000. The first-year revenue requirement is $102,800

8. WA1587 New FL13 East HP Regulator Station, District Regulator Station and ILI Facilities, Salt Lake City, UT: When FL13 is replaced as part of the Feeder Line Replacement Program, FL13 will have an MAOP of 720 psig. This new station will separate the MAOP zones of FL13 at 720 psig MAOP from the rest of the Central HP system which currently operates with a 354 psig MAOP. The site will still also include two ILI receiver barrels and one launcher barrel. This will allow for the required ILI inspections of FL12 (both north and south of this location) and FL13. Property has been acquired on the SW corner of the 2100 S 900 W intersection in Salt Lake City, UT. Additionally, the site will house a new District Regulator Station with a gas heater

   No other site alternatives were feasible. FL13 currently extends only an additional 0.3 miles east of the Surplus Canal along 2100 S until it ends at the intersect with FL12. The Company looked for property for the new end facility and FL12/FL13 crossover within a 0.5-mile radius of the existing crossover. The seller of the purchased property was the only willing seller with a reasonable purchase price. FL12 also runs through the property.

   The project is currently in the design stages. The project's construction is anticipated in 2022. The Company estimates the total cost of the station project (including property acquisition) to be $2,800,000. The first-year revenue requirement is $319,800

9. Jamestown District Regulator Station, Jamestown, Wyoming: Jamestown is a small community approximately 2.5 miles northwest of Green River in Wyoming. The Company currently serves the town through a one-way feed of 2 miles of IHP main extending from Green River to Jamestown. The Company plans to construct a

regulator station in Jamestown to provide redundant feed. However, at present, all the district regulator stations in the area are fed directly from DEQP and the Company does not have odorized HP pipelines in the area that could be extended to Jamestown. Therefore, in order to provide redundancy in the service to Jamestown, the Company is considering the installation of a new gate station from the nearby DEQP ML116 transmission line and extending 6,300 lf of IHP main to the town. Another option is to reinforce the area with a new supply line directly from the distribution system in Green River. The project's construction is anticipated for 2023. The Company is in the early stages of planning. When it has completed its initial analysis, the Company will provide updated routing information, estimated project costs and construction schedule in future IRPs.

10. <u>White Dome District Regulator Station, St George, Utah:</u> A large master-planned residential community called White Dome is under construction at the far south end of St. George, Utah. It will likely take 10 years, or more, to fully develop the planned 10,000 homes and commercial areas. In order to serve this community, the Company must extend its HP system approximately 2 miles south from the current GE0015 station located on River Road and Commerce Drive and install a full capacity high-pressure regulator station. As the Company completes its initial review of the project, and determines the most appropriate location for the station, it will provide updates to the Commission. At this time, the Company anticipates commencing construction in 2023. The Company first discussed this project on page 5-4 of the 2018-2019 IRP. When the Company has completed its initial analysis, it will provide updated information and estimated project costs and schedule as part of the IRP Variance Report Process or in future IRPs.

11. <u>South Bluffdale District Regulator station, Bluffdale, Utah:</u> As the Bluffdale area continues to grow, the Company's IHP distribution system has extended southward. Currently, the Company's IHP system is served by regulator stations located in the north end of Bluffdale. The Company's system planning models show that IHP pressures will decline to below 25 psig in the near future at the current growth rate. The Company must construct a new district regulator station closer to the growing load in order to maintain reliable operational pressures to the area. Constructing additional IHP main or upsizing current IHP main would not be adequate or cost effective in resolving the future low-pressure concerns.

    The Company is identifying available property and will be analyzing different routes in the near future. Based on development rates and load growth, the Company anticipates construction of this project to commence in 2023. As the Company establishes viable route options and refines the cost estimate, it will provide updates as part of the IRP process in the future. The Company first discussed this project on page 5-4 of the 2018-2019 IRP.

12. <u>TG0005, Saratoga KRGT Gate Station, Saratoga Springs, Utah:</u> This station is a major gate station receiving gas off KRGT and delivering it primarily into FL85, along with FL112 and FL116. Gas from this station serves several Utah County communities including Lehi, Eagle Mountain, and Saratoga Springs. These communities are some of the fastest growing communities in DEUWI's service territory. The Saratoga gate station, while not at capacity on a Design Day, requires

a remodel to address concerns with overpressure protection and anticipating future capacity demands from the quickly growing area. Currently the station has a capacity of 220 MMcfd. The Company's System Planning department is analyzing if additional capacity should be constructed as part of this project. Initial analysis indicates an increase of 100 MMcfd may be warranted. Other required improvements include gas measurement to allow flow control and improved overpressure protection.

This project is currently in the planning stage. The Company is considering expanding at the existing site. Discussions are ongoing with KRGT on costs to increase the existing station footprint and provide additional capacity., As mentioned above, the Company's System Planning department would provide requirements of any additional capacity increase. The Company anticipates constructing this facility in 2023. Total project costs are estimated to be between $2,000,000 and $5,000,000 depending on the most feasible method of increasing supply from KRGT. Based on this estimate, the first-year revenue requirement will be $232,000.

One alternative to this project would be to increase capacity at the existing Eagle Mountain KRGT gate stations to the south. This option would require replacement of approximately 9 miles of 6-inch HP pipe with 12-inch pipe, at a cost of $29,000,000., This is well above the cost of the selected project.

A second alternative would involve constructing a new KRGT gate station somewhere along the KRGT pipeline closer to the load center. The Company estimates a new gate station off KRGT, with a design load of 100 MMcfd, would have an estimated cost of approximately $6,000,000. Additional project costs to construct a feeder line extension from the new gate station to the Company's current high-pressure system would prevent this project option from being cost competitive with the selected option discussed above.

13. <u>Eagle Mountain District Regulator Station, near 4000 N and Hwy 73:</u> Growth between Highway 73 and Eagle Mountain to the east is accelerating, requiring a new station. Large commercial and industrial areas are starting to develop, and additional capacity will be needed. The IHP system was recently extended into the area but will not be able to sustain the growth long-term without additional capacity from a district regulator station. Property will need to be acquired for the station.

    The project is currently in the early planning stages and the Company is looking at the available property options. The Company plans to construct the project in 2023. Preliminary estimates for the district regulator station are $500,000. The first-year revenue requirement is $57,100.

14. <u>RE0027 FL26 HP Regulator Station, Lindon Utah:</u> This is an existing HP regulator station in Lindon, Utah that separates the MAOP zones and reduces pressure on FL26 from 720 psig in the south to 354 psig in the north. Currently the station has a capacity of 120 MMcfd and will eventually need to be increased to 200 MMcfd. Increasing the station capacity may be necessary to ensure reliability in the event that other gate stations in the Salt Lake valley are unable to meet demand requirements. FL26 is a 20-inch pipeline that leaves this station and extends north

into Bluffdale, bringing gas into the Salt Lake valley. Given that RE0027 is an existing station and this project's scope is to increase the capacity, there are no other alternatives to this project.

The project has an estimated cost of $2,500,000 as of 2021. The project is currently in the early planning phase and the Company is identifying when this upgrade in capacity will be required in the future. The first-year revenue requirement is $290,000.

Feeder Line Projects:

1. FL47 Extension for the SY0002 Station: The Company purchased property at 2700 S 3000 W, Syracuse, UT for this project. FL47 will extend from SY0001 west on SR193, south on 3000 W to the new property, approximately 2.7 miles. This is the shortest route to the new yard, following existing roads. The running line for the feeder line extension is the shortest path, as SY0002 is directly south of SY0001. Following any other alignment through city streets would have increased the overall length and cost of the extension.

   Project is currently in the design phase. The Company estimates that Feeder Line extension will cost approximately $5,500,000. The Company plans to begin and finish construction in 2022. The first-year revenue requirement will be $628,000.

2. FL85 Extension for New Eagle Mountain District Regulator Station: The shortest route to the growth area would be to extend FL85 from WA1519 in Cedar Fort south to the 4000 N and Hwy 73 intersection. The Feeder Line extension is expected to be at approximately 2 miles long with 8-inch diameter. Final location will depend on build out of the area and available property.

   The project is currently in the early planning stages and the Company is looking at the available property options. Once a site has been selected the Company will provide an update on the project scope and costs as part of the IRP Variance Report process and in future IRP's.

   The Company evaluated another alternative to tap off of FL116 in Eagle Mountain and extend to the growth area. The extension would be approximately 4 miles long and be twice as long as the preferred option. Additionally, the diameter of FL116 is only 6-inches, whereas FL85 is 8 inches in diameter. Extending FL85 would give the Company the ability to bring more gas to the area.

3. Feeder Line Replacement Program: Pursuant to the Utah Commission's Order approving the Settlement Stipulation in Docket No. 09-057-16, on November 15, 2015, the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information. The Company currently estimates that the program will not be complete until 2036 or later.

Southern System Expansion:

The southern system around St. George has been one of the fastest growing systems in the Company's service territory, and the current HP pipeline infrastructure will not support the growing demand. For the past 10 years, the Company has been considering different options to reinforce this area. This system is currently served by two pipelines: FL71, an 8-inch HP pipeline coming from Cedar City and FL81, an 8-inch HP pipeline coming from Central gate station. The Company's southern system is served by three gate stations which include Indianola, Central and Wecco (Cedar City). Both the Central and Wecco gate stations are served by KRGT. The t 8-inch HP pipelines which extend from the KRGT gate stations do not have enough capacity to meet the growing demand. The Company considered several options to increase supply. The three most viable options were:

1) Tie FL81 to FL71 with a 12-inch pipe across St. George. (Completed in 2020)
2) Loop FL81 with a 20-inch pipe to increase deliverability to St. George from the Central gate station.
3) Install a new gate station at the Shivwits reservation along with a new 20-inch pipeline to feed into St. George.

These options are shown in Figure 5.1 below:

Figure 5.1: Southern System Options

The Company ultimately selected a combination of options 1 and 2, executing them in a four-step phased approach as load growth demanded. Option 3 was deemed infeasible due to permitting roadblocks with the Shivwits Band of Paiutes of Utah (Shivwits), right-of-way challenges and constructability of the pipeline. All of these challenges combined made the Shivwits gate station option more expensive and had more risk than options 1 and 2. The Company has completed the FL133 extension (Option 1) and will continue efforts to completing the remaining work.

1. <u>FL135, Central 20-inch loop, St. George, Utah:</u> In order to meet the long-term demand needs of the growing St. George community, the Company is planning to construct a 24 mile, 20-inch pipeline reinforcement between the Central gate station and the WH0030 Bluff Street high-pressure regulator station in St. George. This new pipeline will allow the Company to bring more gas from the Central gate station, where FL81 taps into KRGT, and deliver it to the St George high-pressure system. The new pipeline will "loop" the Company's existing FL81 by running parallel to the 8-inch pipeline along Hwy 18.

The construction of this project will be executed in three phases, the timing of which will depend on the actual growth in the area. Currently, the Company plans to construct Phase 1, Central to Veyo, between 2021 and 2022 for an estimated cost of $32,813,000. Phase 2, Veyo to Diamond Valley, is expected to be constructed between 2024 and 2025 and the final phase of this project, Diamond Valley to Bluff Street, is expected to be constructed between 2027 and 2028. Actualized load growth in the area will play a role in adjusting the phase lengths and construction years. The Company anticipates the total cost of this project, including all phases, will cost between $120 and $150 million. The Company will provide updates on the timing and estimated costs of Phase 2 and Phase 3 in future IRP's.

The Company first discussed this project on page 5-6 of the 2018-2019 IRP. Additional project justification is given on page 4-13 of the System Capabilities and Constraints section of this report. The first-year revenue requirement for Phase 1 will be $3,806,308.

Preliminary Timeline Summary:

Table 5.1:High Pressure Project Summary Table (Excluding Feeder Line Replacement)

Year	Project	Estimated Cost	Revenue Requirement
2021	LE0021 – District Regulator Station for American Fork and Lehi	$750,000	$85,600
	LG0012 Logan District Regulator Station and Feeder Line Extension	$4,500,000	$514,000
	Eureka – EU0001 District Regulator	$600,000	$68,500
	WA1600 – District Regulator Station -- North Temple Replacement for Belt Line Capacity	$750,000	$85,600
2022	Central 20-inch Loop (Phase 1)	$32,813,000	$3,806,308
	SY0002 Syracuse District Regulator Station	$500,000	$57,100
	FL47 Extension for SY0002 Syracuse District Regulator Station	$5,500,000	$628,000
	WA1604 – Replace WA0866 with High Capacity District Regulator Station for South Salt Lake City, UT	$1,500,000	$171,300
	FL13 West HP Station and ILI Facilities, Magna, UT	$900,000	$102,800
	FL13 East HP Station, District Regulator	$2,800,000	$319,800

Year	Project	Estimated Cost	Revenue Requirement
	Station, and ILI Facilities, Salt Lake City, UT		
2023	Jamestown, WY District Regulator Station	TBD	TBD
	Bluffdale District Regulator Station	TBD	TBD
	White Dome District Regulator Station	TBD	TBD
	TG0005 Saratoga KRGT Gate Station	$2,000,000 to $5,000,000	$232,000+
	Eagle Mountain District Regulator Station, near 4000 N and Hwy 73	TBD	TBD
	FL85 Extension for Eagle Mountain District Regulator Station	$3,000,000	$342,600
2025	Central 20-inch Loop (Phase 2)	TBD	TBD
2028	Central 20-inch Loop (Phase 3)	TBD	TBD
TBD	RE0027 - Lindon HP Station Capacity Upgrade	$2,500,000	$290,000

PLANT PROJECTS:

1. On-System LNG Facility: As discussed in greater detail in the “Supply Reliability” section of this report and in the application and accompanying testimony and exhibits in Docket No. 19-057-13, supply disruptions upstream of the Company’s system have become an increasing concern. The Company is also concerned that, in the event of a significant supply disruption, it would be unable to provide safe and reliable service to its customers. Accordingly, the Company has begun construction of an on-system LNG facility which will provide a reliable supply source that the Company can call upon in the event of unanticipated supply disruption, line damage, or events caused by forces of nature.

   The Company set forth a detailed analysis of alternatives evaluated, and all of required information set forth in the 2009 IRP Guidelines and the Report and Order in the 2017-2018 IRP process (Docket No. 17-057-12) in the Application accompanying testimony and exhibits in Docket No. 18-057-03 and Docket No. 19-057-13. On October 25, 2019, the Commission approved the Company’s application, including its selected alternative to address the supply reliability concerns.

DEU has purchased land for the project. The full Engineering, Procurement and Construction (EPC) contract was awarded on May 15, 2020. Construction started as planned in June 2020 and is on track to be complete in 2022.

The facility will include a 15 million-gallon LNG storage tank, gas liquefaction capabilities of 8.2 MMcfd, and vaporization capabilities of 150 MMcfd. Detailed information regarding the costs, schedule and comparison with alternatives can be found in the Company's pre-approval application (DEU 19-057-13).

INTERMEDIATE HIGH PRESSURE PROJECTS:

1. Belt Main Replacement Program: The Company continues its Belt Main Replacement program in 2021. Pursuant to the Settlement Stipulation of the Utah Commission's Order Approving the Settlement Stipulation, in Docket No. 13-057-05, on November 15, 2015, the Company filed an infrastructure replacement plan detailing the planned projects, the anticipated costs and other relevant information.

2. Aging IHP Infrastructure Replacement (Not Included in the Infrastructure Rate Adjustment Tracker): The Company is reviewing the replacement rate of its aging infrastructure relative to its expected life and may propose to accelerate replacement in the future. At the end of 2019 there was approximately 4,130 miles of pre-regulatory (pre-1971) steel main and service lines that are less than 8-inch diameter and not considered part of the Infrastructure Rate Adjustment Tracker. Some of this pipe dates back to 1929. The Company is currently working towards replacing all 58 miles of its 1929 – 1939 steel IHP main that is not part of the Infrastructure Rate Adjustment Tracker.

   The Company also has approximately 7,000 miles of Aldyl-A pipe, which is early vintage plastic that has a higher than average leak rate. Because of the higher leak rate, many utilities have targeted programs to replace this type of pipe. The Company is evaluating the best approach to replace this pipe in the future.

3. Transponder Replacement Program: The Transponder Replacement Program was completed in 1st Quarter 2021. The Company is now transitioning to a regular maintenance schedule of transponders.

MASTER METERS

The Company currently has 2,600 master meters on its system. The Company tariff prohibits new master meter installations at mobile home parks and discourages them at other locations unless it is determined by the Company that a master meter is the only feasible method of providing gas service.

RURAL EXPANSION

In addition to the reinforcement projects discussed above, the Company has been exploring options to expand into new communities within its service territory. There are many factors influencing which communities are best-suited for an expansion including: 1) cost of expansion; 2) number of potential new customers; 3) impact on current operations; 4) impact on the current system; and 5) risk of low customer growth in expansion areas.

Utah

During Utah's 2017 legislative session, lawmakers amended Utah Code Ann. §§ 54-17-401, 402, and 403 to encourage expansion of natural gas service to rural communities. The referenced statutes, as amended, allow the costs of main extensions to rural communities to be spread among all customers with spending caps in place to prevent large swings to customer bills. During the 2020 legislative session, lawmakers passed HB129, which allows for the Company to purchase existing assets to aid in providing gas service to rural communities.

Eureka Expansion Project

On December 3, 2019, the Company filed an Application in Docket No. 19-057-31 seeking approval to extend natural gas service to Eureka. The original application was amended on April 15, 2020, to include service lines in the proposed program. The Amended Application included a discussion of the alternatives for serving Eureka. The Commission approved the Amended Application, including the selected alternative for providing that service, on August 27, 2020. Construction is scheduled to start May 2021. Completion is still on schedule for the 2021-2022 heating season. The project includes the following: 8.4 miles of feeder line installation, district regulator station, HP gate station, and IHP main installation for the town. Customer sign-ups are ongoing and as of the end of April 2021, over 100 residents have signed up for service.

Goshen/Elberta Expansion Project

On April 5, 2021, the Company filed an Application in Docket No. 21-057-06 seeking Commission approval to expand its natural gas distribution system to the communities of Goshen and Elberta, Utah. That Application contains detail regarding the alternatives considered for serving Goshen and Elberta and the Commission will evaluate those alternatives and the Company's proposal in that docket. Non-applicant direct testimony will be due on July 1, 2021, rebuttal testimony will be due on August 11, 2021, and surrebuttal will be due on August 26, 2021. The hearing on the matter will be held on September 2, 2021. In an effort to avoid the unnecessary inclusion of Confidential Information here, the Company incorporates the discussion in Docket No. 19-057-31 by reference.

Green River Expansion Project

The Company is currently evaluating alternatives for serving the rural community of Green River, Utah. The Company evaluated three alternatives. The preferred alternative is purchasing an existing gas line running through the region and then installing an additional 23 miles to Green River, including a bore of the Green River. The city has been working with the BLM to secure potential ROW for the proposed alignment from the existing gas line. By purchasing the existing line and then extending the additional 23 miles, this alternative provides the lowest cost and shortest timeline. The second alternative would be to connect to NW Pipeline near Moab. This would add an additional 17 miles to the preferred alternative for a total length of 40 miles of installation and thus increase the costs and timeline. The third alternative was a 50-mile extension from the nearest feeder line near Price, UT. The total length and timeline become prohibitive when compared to the first alternative. The Company anticipates filing an application seeking approval of its proposal to expand to Green River in coming months.

The Company is continuing the feasibility evaluation of expanding to several other interested communities including Kanab, Genola, and Rockville/Springdale. The Company will continue working with each of these communities and will work to identify additional candidates for expansion. The Company will provide updates on its analysis and any selected project in the IRP variance report process.

INTEGRITY MANAGEMENT

ACTIVITIES AND ASSOCIATED COSTS FOR TRANSMISSION LINES AND DISTRIBUTION SYSTEMS

Transmission Integrity Overview

The Company continues to implement integrity activities defined in its Transmission Integrity Management Plan for transmission lines as originally mandated by the “Pipeline Safety Improvement Act of 2002” and later codified in the Federal Regulations (49 CFR Part 192, Subpart O). The transmission integrity management regulations require the Company to identify all high consequence areas (HCA) along the segments of feeder lines that are defined as transmission lines.[34]

Once the Company identified these HCAs, it calculated a risk score for each segment located in the HCA. These risk scores established the initial priority for when the Company initially assessed each HCA. The Company verifies HCAs in the year prior to performing integrity assessments for the feeder line the segment is a part of and calculates the risk score on an annual basis. Subsequent to this initial assessment, federal regulations require the Company to reassess each HCA at intervals not to exceed seven calendar years from the initial or previous assessment, or sooner based on results of the previous assessment.

Additionally, the Company is required by the transmission integrity rules to conduct additional ongoing preventive and mitigative measures on feeder lines in HCAs and in class 3 and 4 locations.[35] These additional measures include monitoring excavations (excavation standby) near these feeder lines and performing semi-annual leak surveys.

Distribution Integrity Overview

On December 4, 2009, Pipeline Hazardous Materials and Safety Administration (PHMSA) issued its final rule titled: “Integrity Management Program for Gas Distribution Pipelines.” This final rule became effective on February 12, 2010, with implementation required by August 2, 2011.

The distribution integrity management rule requires the Company to develop, write and implement a distribution integrity management program (DIMP) with the following elements: 1) knowledge; 2) identify threats; 3) evaluate and rank risks; 4) identify and implement measures to address risks; 5) measure performance, monitor results, and evaluate effectiveness; 5) periodically evaluate and improve program; and 6) report results.

The Company continues to implement activities defined in its Distribution Integrity Management Plan for the distribution system. It implements the activities to mitigate the threats that are identified in the plan.

[34] Transmission Lines are those feeder lines (or segments of feeder lines) that are operating (i.e. Maximum Allowable Operation Pressure (MAOP) at or above a pressure that produces a hoop stress of 20% of Specified Minimum Yield Strength (SMYS)).
[35] Class location as defined by 49 CFR Part 192 (§192.5).

TRANSMISSION INTEGRITY MANAGEMENT

Costs

Exhibit 6.1 details the anticipated costs associated with transmission integrity management.

Baseline Assessment Plan

The Baseline Assessment Plan prescribes the methods that the Company will use to assess the integrity of each HCA. The Company determines these methods based upon the known or anticipated threats to these segments. The most common threats on the pipeline include corrosion and third-party damage. The Company has used multiple assessment methods in the past to address these threats, including external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), direct visual examination, pressure testing, and inline inspection. The Company has completed the Baseline Assessment Plan for all segments of pipe.

External Corrosion Direct Assessment

ECDA is an assessment method that evaluates the integrity of the pipeline segments for the threat of external corrosion, including segments of cased gas transmission pipelines. Refer to Figure 6.1 for an overview of the ECDA process.

The ECDA methodology is a four-step process. The four steps of the process include:

- Pre-Assessment - This step utilizes historic and current data to determine whether ECDA is feasible, identifies appropriate indirect inspection tools, and defines ECDA regions. ECDA regions are areas along the pipeline that have similar characteristics. There may be multiple regions along a single pipeline segment. Examples of ECDA regions include segments in casings or segments with different types of external coatings.

- Indirect Inspection - This step utilizes above-ground inspection methods such as close interval survey, pipeline current mapper or DC voltage gradient survey, to identify, and quantify the severity of coating faults and areas of diminished cathodic protection. The analysis of this data can help identify areas along the pipeline segment where corrosion may have occurred or may be occurring. The Company uses a minimum of two indirect inspection tools over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. The Company categorizes indications from indirect inspections according to severity. A third indirect inspection tool is required for initial assessments of the segment.

- Direct Examination - This step includes excavations of the pipe for direct examination to determine if there is corrosion occurring on the pipeline. For initial assessments (i.e. first-time assessments for an HCA), a minimum of two excavations are required for each ECDA region and a minimum of four excavations in total for the ECDA project. The ECDA project may contain more than one pipeline and more than one ECDA region. Reassessments require a minimum of one excavation per ECDA region and a minimum of two excavations in total for the ECDA project. The Company selects excavation sites based on a review of the data collected during the pre-assessment and the indirect surveys.

The Company uses this information to identify the areas on the pipeline within each region where external corrosion is most likely. The Company must also excavate at a location where it has not identified any indications. The Company uses the information gathered at this site to help validate the effectiveness of the ECDA process. When corrosion or other pipeline damage or coating damage is found during the direct examination step, the Company repairs the pipe or coating. The Company may select additional sites for examination based on the findings of the required direct examinations.

- Post-Assessment - This step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals and provide feedback for continuous improvement.

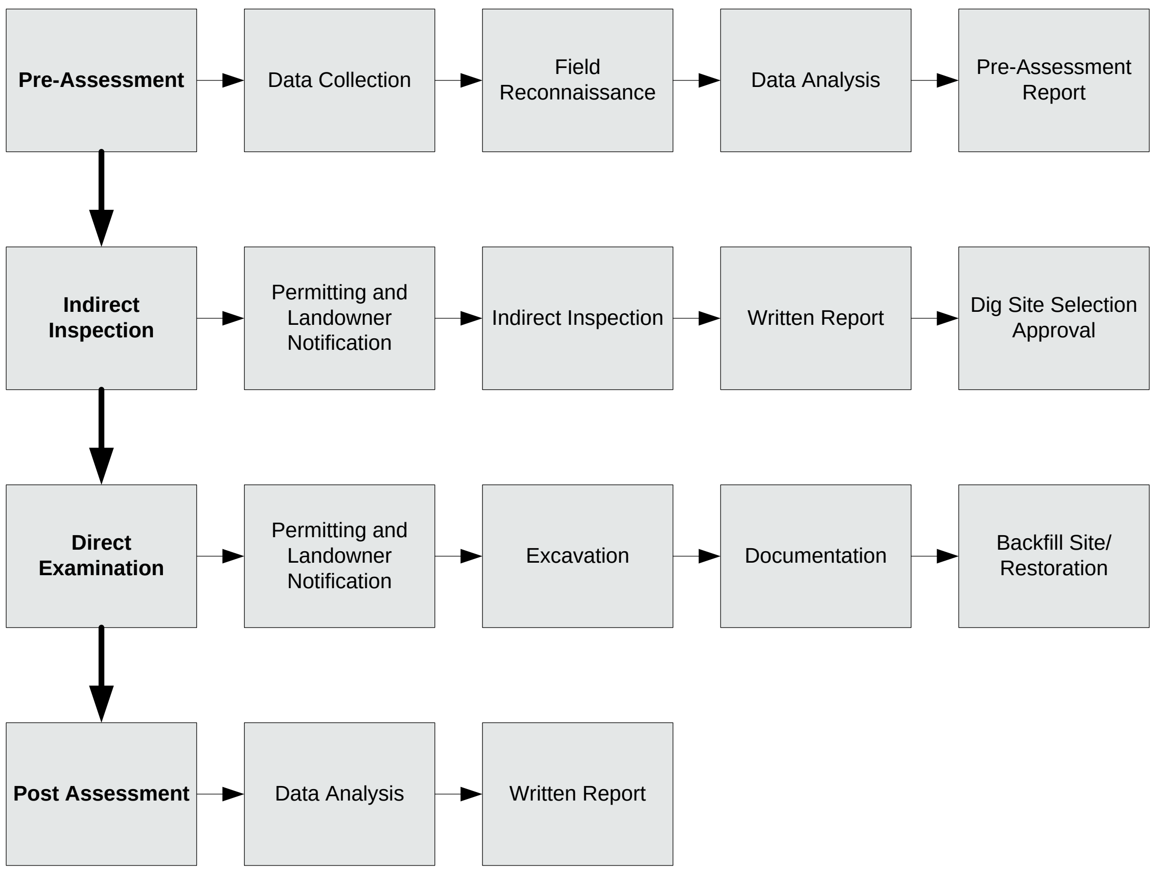


Figure 6.1: ECDA Process Overview

Internal Corrosion Direct Assessment

ICDA is a process used to predict the most likely areas of internal corrosion, including those caused by chemical and microbiologically induced corrosion. ICDA focuses on directly examining locations at which internal corrosion is most likely to occur.

The basis of ICDA is the detailed examination of the most susceptible locations along a pipeline where liquids, if any, would first accumulate in the pipeline. If the locations most likely to accumulate liquids have no indications of internal corrosion, all other locations further downstream are considered to be free from internal corrosion. ICDA relies on the ability to identify locations most likely to accumulate liquids.

The ICDA methodology is a four-step process that is intended to assess the threat of internal corrosion in pipelines and assist in verifying pipeline integrity.

The initial baseline assessment plan included ICDA. The Company was able to eliminate internal corrosion as a threat of concern going forward based on the fact that internal corrosion was not found at the conclusion of completing ICDA on the entire pipeline system as well as the implementation of the Company's ongoing internal corrosion plan.

Visual Examination of Aboveground Pipe and Pipe in Vaults

The Company assesses aboveground piping (e.g. spans and valve assemblies) and piping in vaults by visual examination when the piping is located in a HCA, and the Company cannot assess the pipe utilizing other methods.

Inline Inspection

When a pipeline has been constructed and configured, or retro-fitted in such a way to allow for inline inspection, the Company assesses the pipe using inline inspection tools commonly called "smart pigs." These tools are equipped with sensors that collect data as the tool travels through the pipeline and can reveal areas of wall loss and dents that may require repair or cutout. The Company has 294.5 miles of transmission piping (38% of the Company's transmission system) that can be inspected using smart pigs. As the Company replaces aging infrastructure, it designs and builds the new pipelines to accommodate inline inspection tools. Advancements in technology allow some limited application of inline inspection tools for non-piggable pipelines. The Company has helped fund these advancements through its research and development program. The Company has used these advanced tools to assess locations of its system that it previously could not.

The inline inspection tools provide specific data on the condition of the pipeline segment being inspected. The Company analyzes data that it collects along the pipeline segment for defects and areas of concern (e.g. wall loss or dents) and excavates for further evaluation and repair, or cut out, if necessary.

High Consequence Area Validation

Each year, the Company conducts a field survey of all transmission line segments where integrity management assessment will be performed the following year, to validate the current HCA as well as identify any new potential sites that may trigger a new HCA. Sites that may trigger a new HCA include the following: office buildings, businesses, community centers, churches, day care centers, retirement centers, hospitals, and prisons.

The Company maintains this information in its mapping system and uses it to calculate HCAs on an annual basis.

DISTRIBUTION INTEGRITY MANAGEMENT

Costs

Exhibit 6.2 details the anticipated costs associated with distribution integrity management.

Implementation

The Company implemented its written Distribution Integrity Management Plan in August of 2011. Implementation included identifying the threats associated with the distribution system within each operating region as well as calculating a risk score for each identified threat. The Company utilizes known infrastructure data, leak history, and subject matter experts (SME) to identify threats, and calculate risk scores for each threat, in each operating region. The threats and the associated risk scores are validated by comparison to a second geographic information system (GIS) risk model. Once the Company identifies the threats and calculates the risk scores for each threat, each operating region identifies possible measures that could be implemented or are currently being implemented that would help mitigate the risks on the distribution system. The process of identifying threats and calculating the risk for each threat is ongoing and is evaluated on an annual basis.

COST SUMMARY

Table 6.1 shows the total costs for the transmission and distribution integrity management programs.

Table 6.1: Integrity Management Costs

	2021	2022	2023
Transmission Integrity Management Program	8,509	7,316	7,891
Distribution Integrity Management Program	1,862	2,089	2,193
Total Integrity Management Cost ($ Thousands)	10,370	9,405	10,083

KEY PERFORMANCE INTEGRITY METRICS

Table 6.2 details specific performance metrics associated with the transmission integrity management program.

Table 6.2: HCA Miles Assessed/Anomalies Repaired

Year	HCA Miles Assessed	Anomalies Repaired
2012	26.470	28
2013	50.367	27
2014	54.555	20
2015	11.040	2
2016	37.226	4
2017	12.935	8
2018	30.212	9
2019	25.571	3
2020	54.624	8
NOTE: Approximately 17 miles of HCA were assessed in 2014 that were originally planned to be completed in 2015. Due to favorable circumstances for completing the direct examinations these assessments were completed early.		

NEW REGULATIONS

The following regulations may have significant impact on the Company:

Safety of Gas Transmission and Gathering Lines (Mega Rule)

PHMSA initially published an advanced notice of proposed rulemaking (ANPRM) for the Mega Rule on August 25, 2011. On April 8, 2016, PHMSA published a notice of proposed rulemaking (NPRM) in the Federal Register. The Mega Rule is intended to increase the level of safety associated with the transportation of gas by imposing regulations to prevent failures like those involved in recent incidents. The Mega Rule also seeks to clarify and enhance some existing requirements and address certain statutory mandates and National Transportation Safety Board (NTSB) recommendations.

The Trump administration delayed the publication of the Mega Rule regulation. In March 2018 PHMSA's Gas Pipeline Advisory Committee (GPAC) gathered to continue its work on developing the proposed rule for Transmission and Gathering Pipelines. PHSMA outlined that it intended to break the rule up into 3 rulemakings to address: i) issues contained in the Congressional mandates; ii) topics outside the Congressional mandates; and iii) issues related to gathering lines. On October 1, 2019, PHMSA published part one of the rule. Among other topics, this rulemaking addressed MAOP reconfirmation, assessments of pipelines outside of HCAs, in-line inspection, launcher and receiver safety, expanded records requirements, and a moderate consequence area definition.

Part 1 includes requirements that impact the Company's integrity management program, including the addition of pipeline integrity management measures for pipelines that are not in HCAs, as well as clarifications and selected enhancements to integrity management activities related to pipelines within HCAs. These requirements will increase the costs associated with the Company's integrity management program.

When remaining proposed parts of the Mega Rule are published, the entirety of the rule will address several integrity management topics, including:

- Revision of integrity management repair criteria for pipeline segments in HCAs to address cracking defects, non-immediate corrosion metal loss anomalies and other defects
- Codifying functional requirements related to the nature and application of risk models consistent with current industry standard
- Codifying requirements for collecting, validating, and integrating pipeline data models consistent with current industry standards
- Strengthening requirements for applying knowledge gained through the integrity management program models consistent with current industry standards
- Strengthening requirements on the selection and use of direct assessment methods models by incorporating recently issued industry standards by reference
- Adding requirements for monitoring gas quality and mitigating internal corrosion, and adding requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys
- Codifying requirements for management of change consistent with current industry standards

With respect to non-integrity management requirements, the published Part 1 and remaining 2 proposed parts of the Mega Rule would impose:

- A new ‘‘moderate consequence area’’ definition
- Requirements for monitoring gas quality and mitigating internal corrosion
- Requirements for external corrosion management programs including above ground surveys, close interval surveys, and electrical interference surveys
- Requirements for management of change, including invoking the requirements of ASME/ ANSI B31.8S, Section 11

- Repair criteria for pipeline segments located in areas not in an HCA
- Requirements for verification of maximum allowable operating pressure (MAOP) and for verification of pipeline material for certain onshore steel gas transmission pipelines including establishing and documenting MAOP if the pipeline MAOP was established in accordance with §192.619(c) or the pipeline meets other criteria indicating a need for establishing MAOP

The published Part 1 and remaining 2 proposed parts of the Mega Rule also propose requirements for additional topics that have arisen since issuance of the ANPRM including:

- Requiring inspections by onshore pipeline operators of areas affected by an extreme weather event such as a hurricane or flood, landslide, an earthquake, a natural disaster or other similar event
- Allowing extension of the 7-year reassessment interval upon written notice
- Requiring operators to report each instance when the MAOP exceeds the margin (build-up) allowed for operation of pressure limiting or control devices
- Adding requirements to ensure consideration of seismicity of the area in identifying and evaluating all potential threats
- Adding regulations to require safety features on launchers and receivers for in-line inspection, scraper, and sphere facilities
- Incorporating consensus standards into the regulations for assessing the physical condition of in-service pipelines using inline inspection, internal corrosion direct assessment and stress corrosion cracking direct assessment

Plastic Pipe Rule

PHMSA published this regulation as a final rule on November 11, 2018, with an effective date of January 22, 2019. The rule amends natural and other gas pipeline safety regulations addressing regulatory requirements involving plastic piping systems used in gas service lines. The amendments change the design factor from 0.32 to 0.40 in determining design pressure of plastic pipe; permit increasing the maximum pressure and diameter for Polyamide-11 (PA-11) pipe and components; allow the use of newer Polyamide-12 (PA-12) pipe and components; impose new standards for risers and more stringent standards for plastic fittings and joints; require stronger mechanical fitting requirements; incorporate by reference certain new or updated consensus standards for pipe, fittings, and other components; update the qualification of procedures and personnel for joining plastic pipe; the installation of plastic pipe; and include a number of additional general provisions.

Valve Installation and Minimum Rupture Detection Standards Rule

On November 16, 2018, PHMSA issued its latest update pertaining to this rule and indicated that it planned to publish this rule as a NPRM in January 2019. The NPRM was published February 6, 2020. This rule is proposing installation requirements pertaining to automatic or remote-controlled shut-off valves, or equivalent technology on newly constructed or fully replaced transmission pipelines that are greater-than-or-equal to 6 inches in diameter. The objective of the rule is to improve response time to large-volume, uncontrolled release events to reduce the consequence of these events.

Miscellaneous Rule

PHMSA published this regulation as a final rule on March 11, 2015, with an effective date of October 1, 2015. One component of this rulemaking includes the performance of post-construction inspections and qualification of plastic pipe joiners. New post-construction inspection could have a significant impact on the Company. PHMSA is currently in the process of developing guidance for the interpretation and implementation on the requirements associated with post-construction inspection. PHMSA has indefinitely extended the effective date for the post-construction inspection requirements. The Company anticipates publication of further guidance in the future.

INDUSTRY AND COMPANY BEST PRACTICES

Interstate Natural Gas Association of America (INGAA) Integrity Management Continuous Improvement Initiative (IMCI)

The Company has adopted an industry and Company best practices for transmission pipelines that align with the direction and intent of PHMSA's proposed Mega Rule. INGAA's IMCI extends the application of Integrity Management from HCAs to 90% of the population living adjacent to transmission pipeline corridors, with a first-time assessment to be complete by the end of 2020. The Company achieved the 2020 requirement with over 91% of the population living adjacent to a transmission pipeline corridor having been assessed by Integrity Management practices. The Company will continue to extend the application of Integrity Management completing a first-time assessment for the remaining population as we start to apply Integrity Management in Class 3 and 4 areas and MCAs per Mega Rule requirements. DEUWI estimates that it will be able to maintain average year-over-year costs level as it completes this commitment and the Mega Rule's expansion of Integrity Management Part One starts.

Interstate Natural Gas Association of America (INGAA) Fitness for Service (FFS)

The Company has adopted industry and Company best practices for transmission pipelines that align with the direction and intent of PHMSA's proposed Mega Rule. INGAA's FFS applies current pressure testing requirements to transmission pipelines constructed prior to the pipeline safety regulation publication in 1970, exceeding current PHMSA requirements for pre-regulatory transmission pipelines and meeting proposed Mega Rule requirements. This will assess potential integrity construction defect threats and improve the Company's knowledge of these pipelines. The FFS practices were adopted during the delayed implementation of the Mega Rule. Part One of the Mega Rule is now in effect, including the MAOP reconfirmation requirements. Therefore, the FFS will stop and DEUWI will transition resources to activities directed at compliance with Part One of the Mega Rule.

Close Interval Survey (CIS)

The Company has initiated an internal best practice to conduct CIS on its transmission pipelines of its cathodic protection system. The goal is to complete this initial survey by 2024. As a result of this initiative, CIS inspection costs were added in 2018, and will vary from year to year depending on the mileage of the lines needing to be surveyed.

Transmission Integrity Management Costs

Activity	2021	2022	2023
ECDA			
Pre-Assessment			
2021 (FL 68-4, 69, 83, 84, 99, 104) (2.19 HCA miles; 7.13 CA miles @ $4K/FL)	24		
2022 (FL10, 14, 41, 48, 52, 88) (5.42 HCA miles; 3.8 CA miles @ $4K/FL)		24	
2023 (FL34, 103, 11, 26, 85)(20.43 HCA miles; 10.3 CA miles @ $4k/FL)			20
Indirect Inspections			
2021 (FL 68-4, 69, 83, 84, 99, 104) (2.19 HCA miles; 7.13 CA miles @ $16K/mile)	149		
2022 (FL10, 14, 41, 48, 52, 88) (5.42 HCA miles; 3.8 CA miles @ $16K/mile)		148	
2023 (FL34, 103, 11, 26, 85)(20.43 HCA miles; 10.3 CA miles @ $16k/mile)			492
Direct Examinations			
2020 (FL19,23,28,71,73, 74, 125, 40) (4 excavations @ 34.5 K ea.)	138		
2020 (FL19,23,28,71,73, 74, 125, 40) (Pipetel 1 site, 1 casings @ 150K/site)	150		
2021 (FL68-4, 69, 83, 84, 99, 104) (6 excavations @ 34.5 K ea.)		207	
2021 (FL68-4, 69, 83, 84, 99, 104) (Pipetel 2 sites, 2 casings @ 150 K/site)		300	
2022 (FL10, 14, 41, 48, 52, 88) (6 excavations @ 34.5 K ea.)			207
2022 (FL10, 14, 41, 48, 52, 88) (Pipetel 2 sites, 2 casings @ 150 K/site)			300
Post Assessment			
2020 (FL19,23,28, 40, 71, 73, 74, 125) (9.85 HCA miles; 12.06 CA miles @ $1.5K/FL)	12		
2021 (FL 68-4, 69, 83, 84, 99, 104) (2.19 HCA miles; 7.13 CA miles @ $1.5K/FL)		9	
2022 (FL10, 14, 41, 48, 52, 88) (5.42 HCA miles; 3.8 CA miles @ $1.5K/FL)			9
CIS			
Indirect Inspections			
2021 (FL064, 28-6, 65, 66, 68-4, 69, 83, 84, 99, 104) (134.8 miles @ 6.5K)	876.2		
2022 (FL72, 66, 67, 68, 10, 14, 41, 48, 52, 88) (116.8 miles @ 6.5 K/mile)		759.2	
2023 (FL068, 71, 34, 103, 11, 4, 26, 85) (43.2 miles @ 6.5K/mile)			280.8
Reports			
No additional cost under current contract			
ACCDA			
Pre-Assessment			
2021 (FL68, 69, 83, 84, 99, 104) (2.18 HCA miles; Fixed)	6.5		
2022 (FL10, 88) (0.31 HCA miles; Fixed)		2.5	
2023 (FL11, 26, 85, 103) (6.18 HCA miles; Fixed)			5
Indirect Inspections			
2021 (FL68, 69, 83, 84, 99, 104) (2.18 HCA miles; @ 15K/mile)	32.7		
2022 (FL10, 88) (0.31 HCA miles; @ 32K/mile)		9.9	
2023 (FL11, 26, 85, 103) (6.18 HCA miles; @ 14K/mile)			86.5
Direct Examinations			
2020 (FL19, 23, 28, 71, 73, 74, 125) (2 excavations @ 34.5 K ea.)	69		
2021 (FL68, 69, 83, 84, 99, 104) (2 excavations @ 34.5 K ea.)		69	
2022 (FL10, 88) (2 excavations @ 34.5 K ea.)			69
Post Assessment			
2020 (FL19, 23 28, 71, 73, 74, 125) (6.69 HCA miles; Fixed)	7.5		
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; Fixed)		3	
2022 (FL10, 88) (6.18 HCA miles: Fixed)			6
ICDA			
ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan).			
Inline Inspection			
2020 Excavations/ Validations Digs/ Remediation (10 excavations @ 34.5 K ea)	345		
2021 (FL064)	400		
2021 (FL065/FL066)	400		
2021 (FL028-6)	400		
2021 (FL023)	400		
2021 Excavations/ Validations Digs/ Remediation (12 excavations @ 34.5 K ea)	207	207	
2022 (FL072)		400	
2022 (FL066, FL067, FL068)		400	
2022 (FL010)		400	
2022 Excavations/ Validations Digs/ Remediation (8 excavations @ 34.5 K ea)		138	138
2023 (FL068, FL071)			400
2023 (FL035/41)			400
2023 (FL053, FL022, FL019)			400
2023 (FL026)			400
2023 Excavations/ Validations Digs/ Remediation (10 excavations @ 34.5 K ea)			172.5
Direct Examination (Spans and Vaults)			
2021 - Vaults (0 @ 3.5 K/ vault)	0		
2021 - Spans First Time (4 @ 75 K/ span)	300		
2021 - Spans Reassessment (3 @ 10 K/ span)	30		
2022 - Vaults (3 @ 3.5 K/ vault)		10.5	
2022 - Spans Reassessment (1 @ 10 K/ span)		10	
2023 - Vaults (6 @ 3.5 K/ vault)			21
2023 - Spans First Time (4 @ 10 K/ span)			40
2023 - Spans Reassessment (3 @ 75 K/ span)			225

Transmission Integrity Management Costs

Activity	2021	2022	2023
Pressure Test Assessment			
2021 - 0 pipeline segments @ 150 K/segment	0		
2022 - 3 pipeline segments @ 150 K/segment		450	
2023 - 3 pipeline segments @ 150 K/segment			450
Material Verification			
2021 - (FL021), Insitu testing to meet opportunistic sampling requirements	15		
2022 - 8 Opportunistic Samples @ 4 K/sample, 2 Opportunistic Samples @ 20K		72	
2023 - 8 Opportunistic Samples @ 4 K/sample, 2 Opportunistic Samples @ 20K			72
MAOP Verification MAOP, for MAOP established in accordance with §192.619(c)			
2021 - HYDRO Test (FL004, 11, 21)	850		
Excavation Standby			
Distribution Tech (5 employees (2080 hrs x $70/hr))	728	728	728
Contractors (3 x 312 days x 3 x $580/day)	543	543	543
Additional Leak Survey			
Leak Survey Tech (3 employees (2,080 hrs x 3 x $45/hr))	281	281	281
Additional Cathodic Protection Survey			
Corrosion Tech (2 employees (2,080 hrs x 3 x $62/hr)	258	258	258
Administration			
Project Coordination (5 employees (2080 hrs x 5 x $60/hr))	624	624	624
Data Integration Specialists (2 employees (2080 hrs x 2 x $60/hr))	250	250	250
Constrution Records Tech (2080 hrs x $45/hr)	94	94	94
Supervisor (2080 hrs x $65/hr)	135	135	135
Engineer (3 employees (2080 hrs x $60/hr))	374	374	374
Engineer Tech (2080 hrs x $ 45/hr)	94	94	94
Damage Prevention Tech (3 employees (2080 hrs x $45/hr))	281	281	281
Training (IM personnel)	35	35	35
Transmission Integrity Management Total ($ Thousands)	8,509	7,316	7,891

Distribution Integrity Management Costs

Activity	2021	2022	2023
NOTE: The costs estimated here are based on additional and accelerated actions initiated based on the threats identified. The costs also reflect the administration costs associated with this new regulation.			
Additional and Accelerated Actions			
Stray Current Surveys (UTA Reimbursed)	85	85	85
Damage Prevention (IHP Standby)	1,323	1,323	1,323
Meter Paints	281	281	281
Direct Assessments			
2020 (FL110, 98) (5 excavations @ 34.5K ea.)	172.5		
ILI			
2022 (FL025, FL007)		400	
2022 ILI digs (FL025, FL007) (3 excavations @ 34.5K ea.)			103.5
2023 (FL008)			400
2023 ILI digs (FL008) (2 excavations @ 34.5K ea.)			
Administration			
Consultant - 3rd Party Plan Review			
Distribution Integrity Management Total ($ Thousands)	1,862	2,089	2,193

ENVIRONMENTAL REVIEW

The Company is fully committed to meeting the energy needs of our customers in an environmentally responsible manner. Protecting natural and cultural resources is our duty, and it is also good business practice. Our commitment is always to comply with laws and regulations and to act consistently with our core values. While we always strive to meet our legal and regulatory obligations, we set our sights higher. The information provided below, along with additional information provided in the Sustainability section of this report, describes some of the actions we take to meet and exceed our compliance obligations as well as to ensure protection of human health and the environment.

The Company is subject to substantial laws, regulations, and compliance costs with respect to environmental matters. Some of the laws and regulations with which the Company must comply include the National Environmental Policy Act, the Endangered Species Act, the Clean Air Act, the Clean Water Act, the Toxic Substance Control Act, the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Emergency Planning, and Community Right to Know Act, the Oil Pollution Act, and the National Historic Preservation Act, as well as similar state and local laws and regulations that can be more strict than their federal counterparts.

These laws and regulations affect future planning and existing operations as a result of compliance, permit, remediation, containment and monitoring obligations and requirements. For example, the U.S. Fish and Wildlife Service may designate critical habitat areas to protect certain threatened and endangered species. A critical habitat designation for a protected species, such as the desert tortoise, can result in restrictions to federal and state land use. Species protections such as these may restrict Company activities to certain times of year. Project modifications may be necessary to avoid harm, or a permit may be needed for unavoidable taking of the species. These requirements and time of year restrictions can result in delays or adverse impacts to project plans and schedules as the Company's infrastructure crosses many miles of federal and state lands that include the critical habitat of protected plant and animal species.

The Clean Water Act and similar state laws and regulations regulate discharges of storm water, hydrostatic test water, wastewater, and other pollutants to surface water bodies such as lakes, rivers, wetlands, and streams. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of penalties for noncompliance, including fines, injunctive relief and other sanctions.

The Company is subject to various federal and state laws and implementing regulations governing the management, storage, treatment, reuse and disposal of waste materials and hazardous substances that can affect the Company's operations and construction activities. One of these laws, CERCLA, provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment. CERCLA also authorizes the U.S. government to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, as amended, generators and transporters of hazardous substances, as well as past and present owners and operators of contaminated sites, can be jointly, severally and strictly liable for the cost of cleanup. These potentially responsible parties can be ordered to perform and pay for cleanup, or voluntarily do so by beginning a site investigation and site remediation under state oversight.

As a result of these laws and regulations, the Company must determine soil disposition prior to construction (when presence of the contamination is suspected), properly train employees, equip employees with protective equipment, and invoke proper disposal and decontamination procedures. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of penalties for noncompliance, including fines, injunctive relief, and other sanctions.

The Company reviews proposed projects for adverse effects on historic resources in compliance with Section 106 of the National Historic Preservation Act. This often includes intensive field surveys to identify archaeological and architectural sites of potential historic significance (e.g., sites eligible for listing on the National Register of Historic Places). Once identified, the project's effects on eligible sites are reviewed and can include the need for additional historic resource surveys (Phase II) or mitigation plans (resource protection, view shed mitigation, or Phase III data recovery). In most cases this requires consultation with State Historic Preservation Offices and Tribal Historic Preservation Offices.

The Company embraces the tenets of environmental justice to create meaningful involvement and fair treatment for all people regardless of race, color, national origin, or income. As such, the Company has formalized its ongoing commitment to environmental justice by adopting a corporate policy establishing the framework whereby specific environmental justice considerations and increased public outreach is incorporated early in project planning.

New and revised environmental policies to address climate change, energy use, and development could impact the Company in the future.

For more than a decade the Company has been committed to reporting and reduction its Greenhouse Gas (GHG) emissions. In 2020, Dominion Energy announced that by 2050, it will achieve net zero GHG emissions across its electric and natural gas operations nationwide where Dominion Energy and its subsidiaries do business. As discussed in the Sustainability section of this report, DEUWI is taking immediate action to reduce emissions and exploring new technologies to accelerate future emissions reductions.

In 2010, the EPA adopted Greenhouse Gas Reporting Regulations requiring the measurement and reporting of carbon dioxide equivalent (CO2e) emissions emitted from combustion at large facilities (emitting more than 25 thousand metric tons/year of CO2e). Although the Company does not have any single facilities that exceed that threshold, local distribution companies are required to account for the GHG emissions of their customers (residential, commercial, and industrial customers using less than 460 MMcf per year of natural gas) annually.

In 2011, the EPA expanded reporting under this regulation to include measurement and reporting of GHG emissions attributed to fugitive methane emissions, requiring on-going measurement and monitoring of methane emissions at the Company's regulator and gate-stations. In 2020, the Company reported a total of 6.4 million metric tons of CO2e emissions in Utah and 247 thousand metric tons of CO2e emissions in Wyoming. The Company also reported approximately 3,700 metric tons attributed to fugitive methane sources in Utah and approximately 120 metric tons of fugitive methane emissions in Wyoming. Figure 7.1 shows the Company's CO2 emission rate per million BTU (greenhouse gas intensity) over the last six years.

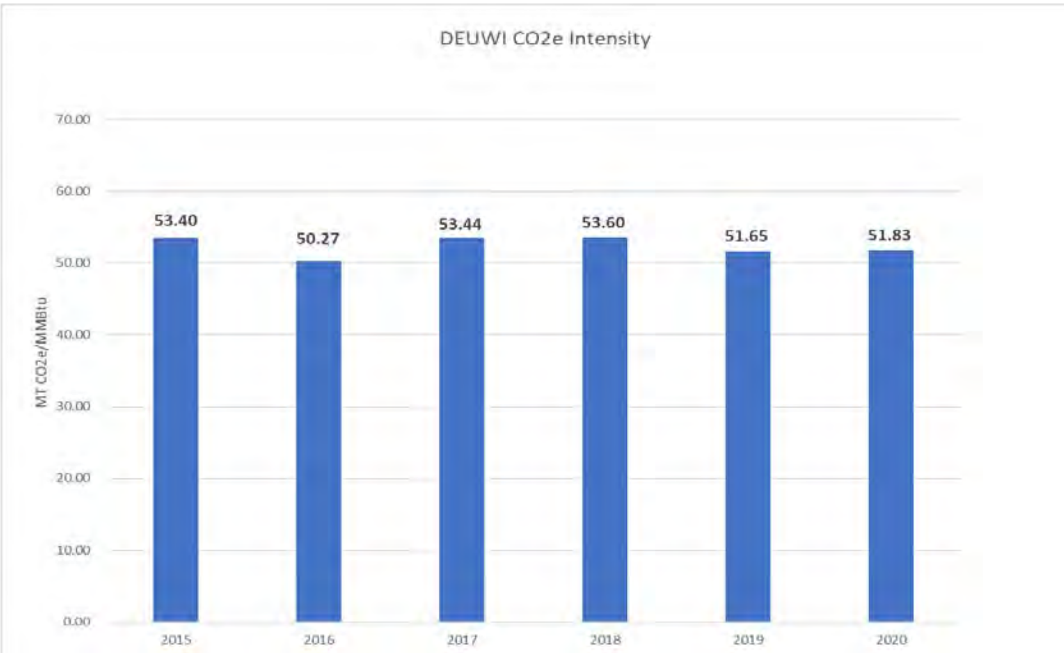


Figure 7.1: Greenhouse Gas Intensity

In March 2016, the Company became a Founding Partner with the EPA in the Methane Challenge Program, committing to voluntary practices that will reduce methane emissions. Additionally, the Company joined the One Future Coalition in 2018, which commits the Company to limit methane emissions to below 1% of gas throughput across the Company.

The Company expects that greater awareness regarding the benefits of natural gas for high-efficiency residential, commercial, transportation, industrial, and electricity generation purposes will result in the advancement of these applications and increased utilization of natural gas-fueled equipment. Greater utilization of natural gas should result in significantly lower U.S. greenhouse gas emissions in comparison with more carbon intensive fuels. For a more detailed discussion about full fuel-cycle efficiency, refer to the Customer and Gas Demand Forecast section of this report.

Reduction in methane emissions will continue to have a positive environmental impact. For example, the Company estimates annual savings of nearly 1.2 MMDth of natural gas in 2020 through the ThermWise program. The savings represents the equivalent of over 63 thousand metric tons of CO_2e or nearly 14 thousand passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime savings attributable to the ThermWise® program totals more than 486 thousand metric tons of CO_2e or the equivalent of almost 106 thousand passenger vehicles each driven for one year.

The Company remains committed to meeting reduction goals and maintaining compliance with all laws and regulations while continuing to meet the energy needs of our customers in an environmentally responsible manner.

PURCHASED GAS

LOCAL MARKET ENVIRONMENT

Local prices during the 2020 calendar year averaged $2.07 per Dth. This was lower than the 2019 average price of $2.59 per Dth, a decrease of $0.52 per Dth or about 20.1%. The 2019 and 2020 monthly index prices are provided in Table 8.1 below.

Table 8.1: NPC First-of-Month (FOM) Index Price per Dth

Month	2019	2020	Difference
Jan	$4.22	$3.16	($1.06)
Feb	$3.38	$1.95	($1.43)
Mar	$3.77	$1.54	($2.23)
Apr	$2.48	$1.29	($1.19)
May	$1.88	$1.59	($0.29)
Jun	$1.89	$1.54	($0.35)
Jul	$1.92	$1.53	($0.39)
Aug	$2.01	$1.69	($0.32)
Sep	$1.81	$2.39	$0.58
Oct	$2.01	$2.23	$0.22
Nov	$2.32	$3.03	$0.71
Dec	$3.44	$2.94	($0.50)
Average	$2.59	$2.07	($0.52)

The local market price for natural gas during the 2020-2021 heating season (November-March) averaged $3.00 per Dth compared to an average price of $2.48 per Dth during the 2019-2020 heating season, an increase of $0.52 or about 21%. The monthly-index prices for the two heating seasons are provided in Table 8.2 below.

Table 8.2: NPC FOM Index Price per Dth - Heating Season

Month	2019-2020	2020-2021	Difference
Nov	$2.32	$3.03	$0.71
Dec	$3.44	$2.94	($0.50)
Jan	$3.16	$3.23	$0.07
Feb	$1.95	$2.75	$0.80
Mar	$1.54	$3.04	$1.50
Average	$2.48	$3.00	$0.52

March 2020 PIRA Energy Group (PIRA) and IHS Energy (IHS) forecasts of Rockies indices reflect an average price of approximately $2.67 per Dth through October 2021. Prices for the 2021-2022 heating season are forecasted to be approximately $3.32 per Dth.

ANNUAL GAS SUPPLY REQUEST FOR PROPOSAL

One of the fundamental results of the IRP modeling is the selection of the portfolio of natural gas purchase contracts for the coming year. The Company expects that a significant portion (up to 55%) of the annual gas supply needs of the Company's sales customers will be met with cost-of-service supplies provided under the Wexpro I and II Agreements (see Cost-of-Service Gas section of this report). Supply needs not met by cost-of-service gas must be purchased from natural gas providers. Accordingly, the Company issues an RFP to potential suppliers each year.

On February 23, 2021, the Company sent its RFP to 61 prospective suppliers. The RFP sought proposals for both baseload and peaking supplies on the two major interstate pipeline systems interconnected with the Company; DEQP and KRGT. The Company requested heating season proposals on both pipelines with terms ranging from one to five years. The Company also sought proposals for peaking supplies on both pipeline systems with supply availability of two to four months to meet customer demands during the coldest winter heating season months. The Company specified needs at specific locations such as MAP 285(Overthrust), MAP 421(Chipeta), MAP 420(Spire – Bell Butte), and other locations that were determined to be operational needs.

Reliability of supplies is a critical issue for the Company. The Company thoroughly reviews creditworthiness of all counterparties and includes contract language specifying the minimum advance notice before nomination deadlines for gas flow.

As part of the RFP this year, the Company requested offers for responsibly sourced natural (RSG) gas. These offers were evaluated along with the rest of the RFP responses. None of these offers were selected this year. The Company also requested a survey to determine the counterparty's sustainability plans. A summary of the responses can be found in the "Sustainability" section of this report.

Responses to the purchased-gas RFP were due on March 4, 2021. The Company received proposals for 126 gas supply packages from 13 potential suppliers. As part of the RFP requirements, submissions must specify if the same gas supply is offered under multiple proposals. This year, supplies offered under baseload proposals totaled 596,000 Dth/D, up from the 373,000 Dth/D offered last year. Peaking supplies offered on the DEQP system totaled 137,000 Dth/D, down from the 165,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 175,000 Dth/D, down from last year's level of 180,000 Dth/D.

Each spring, following the receipt of all the proposals, the Company reviews all the packages offered and extracts the parameters needed as data inputs to the SENDOUT model.[36] The Company must identify the pricing mechanisms utilized for each package and

[36] The SENDOUT model and the Monte Carlo method are described in more detail in the Final Modeling Results Section of this report.

link each to the appropriate index price in the model. Also, the Company must resolve the availability of receipt and delivery point capacity on the interstate pipeline system. To the extent that the same underlying gas supplies have been offered under different price and term packages, the Company must identify each to prevent the purchasing of more gas than is actually available. This year, the SENDOUT model evaluated 126 supply packages.

After the Company enters these purchased-gas packages into the SENDOUT model, it allows the model to find an optimal linear-programming solution for any one or all of the packages of natural gas. During this optimization process, the SENDOUT model only incurs costs for a package of gas if it elects to include that package. This gives the model freedom to look at all packages and optimize them in a way that results in the least-cost combination of resources.

This year the model evaluated 1,199 Monte Carlo draws during the modeling process. At the conclusion of the modeling, the Company analyzed the draws to see which were preferred. Using a statistical analysis package, the Company used a procedure to group (or cluster) optimized draws in similar ways. Clustering is the assignment of a set of observations into subsets so that observations in the same cluster are similar. The Company performs the clustering for Design Day and annual demand.

The Company then used a follow-up statistical procedure to split clusters at cluster designed levels as shown in Exhibit 8.1. This year, as in other years, the Company broke the cluster analysis into 30 groups and plotted them as representations of optimized solutions. A point on the graph represents a cluster and a cluster represents like draws. The resulting plot shows demand on the X axis of the graph, and Design Day on the Y axis. This plot shows how the SENDOUT model met high or low demand during Design Day events.

The Company then selected the clusters that most closely met the forecasted annual demand for the coming year. The Company examined the preferred draws that make up the clusters looking at the number of times a given package of gas was chosen and the volume of that package most often used.

The Company also reviewed the original packages in order to verify that the Company did not entrust too much of its purchased gas to one vendor, that peaking versus baseload contracts seemed reasonable, that packages were within the transportation limits of both KRGT and DEQP and verified that a cluster combined with cost-of-service, storage, and spot purchases would meet Design Day requirements. Once this screening was completed, the most often used packages emerged from the RFP process and were then finalized with suppliers.

The levels of purchased-gas packages selected from the SENDOUT modeling process this year are shown in the Final Modeling Results section of this report. The median purchased-gas volumes from the Monte Carlo simulation for the upcoming gas-supply year are shown by month in Exhibits 13.53 to 13.64 along with each probability distribution. Individual packages of purchased-gas supplies for the normal case are shown for the first two plan years in Exhibits 13.85 and 13.88. Of the 11 companies submitting proposals this year, 6 had at least one package selected by the modeling process. The Company made commitments to purchase from the selected suppliers starting on April 28, 2019. The

Company is in the process of finalizing the agreements with a few of the counterparties that had packages selected in the RFP. The Company will make purchase commitments for these packages once the agreements are in place.

PRICE STABILIZATION

On May 31, 2001, the Utah Commission approved a Stipulation submitted May 1, 2001, in Docket Nos. 00-057-08 and 00-057-10 proposing that the Company use stabilization measures in conjunction with natural gas purchases during the winter months (October – March). Pursuant to the Stipulation, the Company hedged portions of its baseload winter natural gas portfolio.

In Wyoming Docket No. 30010-GP-01-62, the Company sought to include costs to reduce price volatility, like those that occurred during the winter of 2000-2001. In its October 30, 2001, Order, the Wyoming Commission approved the Company’s request to include stabilization costs in the 191 Account. The Company does not engage in any speculative hedging transactions by limiting these price stabilization efforts to contracts that fix or cap prices for gas supplies that are contractually committed to the Company’s system for delivery to end-use retail customers.

For the October 2020-2021 heating season, the Company did not financially hedge the price of any of its baseload purchased gas supplies. The Company continues to utilize other alternatives to offset the potential risk of price increases such as cost-of-service production from Wexpro, storage withdrawals, and baseload contracts with FOM pricing.

In 2021, the Company analyzed its exposure to daily price risk based on its existing price stabilization techniques. The results of this evaluation showed that based on 2020-2021 contracts, on a typical winter day, the Company has about 40% of supply purchases exposed to daily price risk. On a Design Day, that exposure increases to 66%.

This situation was highlighted during the high-pricing event that occurred in February 2021. Fortunately, the Company was able to utilize cost-of-service production and high storage withdrawals to minimize gas purchases which would have been exposed to record-high pricing. Had this event also corresponded with a high demand event in the DEUWI service territory, any additional supply would have been purchased at extremely high cost.

As a result of this analysis, the Company is considering additional price stabilization resources to minimize this exposure on high demand days. The resources being considered include additional storage capacity, additional FOM based supply contracts, and financial hedges. The Company is also working with Wexpro to review any opportunities for increasing cost-of-service production. The Company will continue to review these alternatives with stakeholders prior to adding any alternatives for the 2021-2022 heating season.

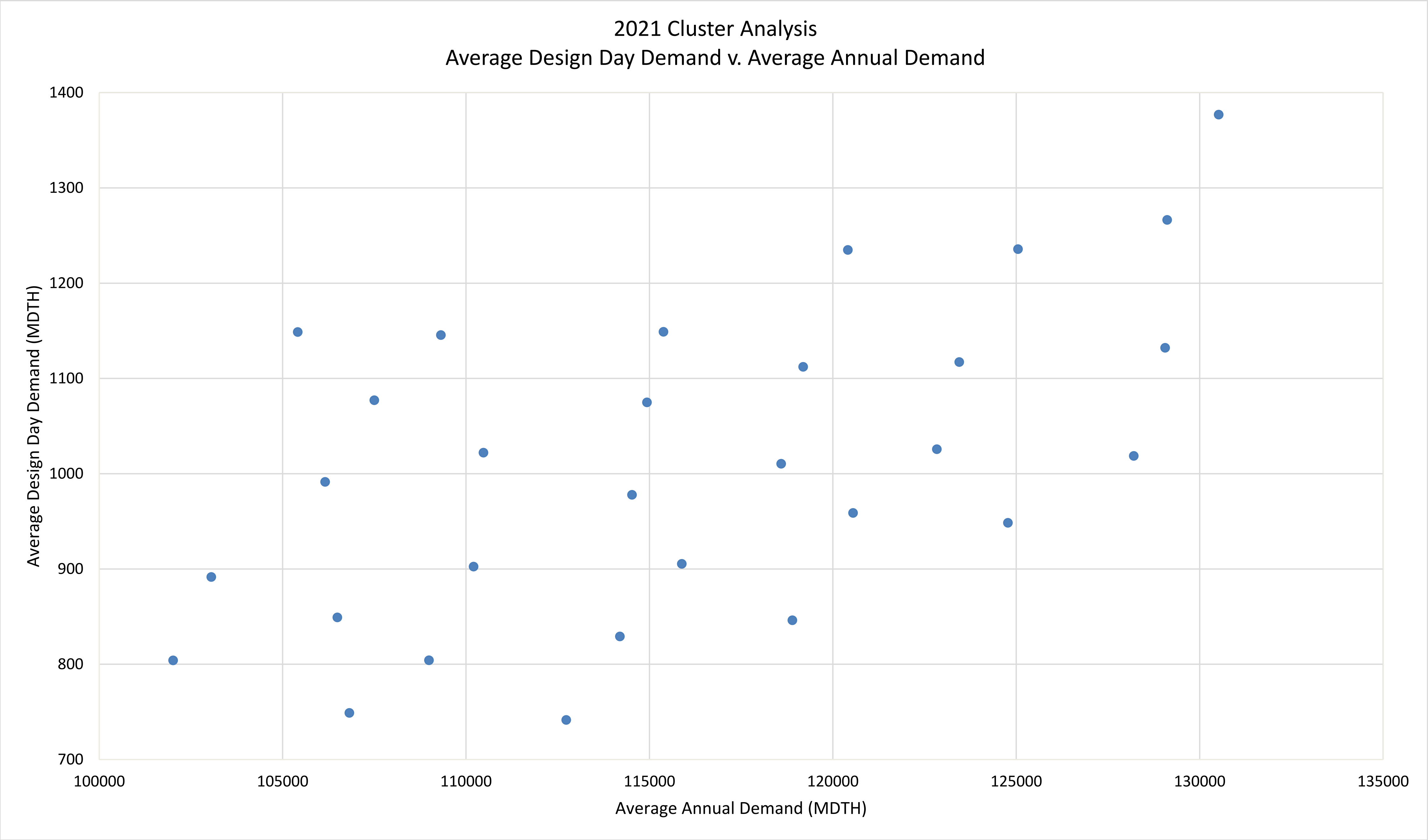

2021 Cluster Analysis
Average Design Day Demand v. Average Annual Demand
1400
1300
1200
1100
1000
900
800
700
Average Design Day Demand (MDTH)
100000
105000
110000
115000
120000
125000
130000
135000
Average Annual Demand (MDTH)

Exhibit 8.1

COST-OF-SERVICE GAS

COST-OF-SERVICE MODELING FACTORS

The Wexpro Agreement, signed in 1981, defines the relationship between Wexpro and the Company. Under this agreement, Wexpro manages and develops natural gas reserves within a limited and previously established group of properties. Production from these reserves is delivered to the Company at cost-of-service. Since its inception, the Company's customers have received a net benefit from natural gas produced pursuant to the Wexpro Agreement. In recent years, natural gas supplies provided pursuant to the Wexpro Agreement have exceeded one half of the total annual supplies required to meet the needs of Company customers.

During 2013, both the Utah and the Wyoming Commissions approved the Wexpro II Agreement. This agreement was designed to continue the delivery of cost-of-service natural-gas supplies to the customers of the Company through the acquisition of oil and gas properties or undeveloped leases.

In January of 2014, the Utah and Wyoming Commissions approved the Trail Unit Acquisition as a Wexpro II Property. As part of this approval, Wexpro must manage cost-of-service production to less than 55% of the forecasted demand for the Company's sales customers each IRP year, beginning with the 2020-2021 IRP year. In calculating the production percentage, pursuant to the Trail Stipulation, the total wellhead volume of cost-of-service production received as part of the Wexpro I and Wexpro II Agreements will be divided by the total forecasted demand for the Company's sales customers as provided in each year's IRP (see Exhibit 3.10). Wexpro may also sell cost-of-service production in order to manage to the 55% level. Under the terms of the Trail Settlement Stipulation, any production sold will be credited to the Company at the greater of the sales price or the cost-of-service price.

In November of 2015 the Utah and Wyoming Commissions approved the Canyon Creek Unit Acquisition as a Wexpro II Property. As part of this approval, the Company, Wexpro, the Division, the Office, and the Wyoming Office of Consumer Advocates (WY OCA), submitted the Canyon Creek Stipulation to the Wyoming and Utah Commissions in their respective dockets. On November 17, 2015, the Utah Commission approved the Canyon Creek Stipulation, and on November 24, 2015, the Wyoming Commission issued its approval of the Stipulation.

In addition to adding the Canyon Creek acquisition as a cost-of-service property under the Wexpro II Agreement, the Canyon Creek Stipulation included certain requirements as follows:

- Wexpro will design its annual drilling program or drilling programs that are more frequent than the annual cycle to provide cost-of-service production that is, at the time Wexpro incurs an obligation in connection with a drilling program, on average, at or below the 5-Year Forward Curve price that was agreed to in the Trail Settlement Stipulation.

- The rate of return on post-2015 Wexpro I and Wexpro II development drilling, or any other capital investment, will be the Commission-Allowed Rate of Return as defined in the Wexpro II Agreement. The return is currently 7.19% as a result of DEU's ROE in its general rate case (Docket No. 19-057-02). The pre-2016 investment base and returns will not be affected.

- Wexpro will reduce the cost-of-service gas supply to the Company from 65% of annual demand to 55% beginning in the 2020 IRP Year.

- Post 2015 dry-hole and non-commercial well costs will be expensed and shared on a 50/50 basis between utility customers and Wexpro.

- When the annual weighted average price of cost-of-service gas produced under both Wexpro agreements is less than the current market price, then the annual savings on post-2015 development will be shared on a 50/50 basis between utility customers and Wexpro. When shared savings occurs, Wexpro's return will be capped at the Base Rate of Return + 8%.

During calendar year 2020, Wexpro produced 65.0 MMDth of cost-of-service supplies measured at the wellhead, down from the 71.8 MMDth level produced during calendar year 2019. As development drilling continues to occur, Wexpro anticipates that there will be many more years of production from these sources, due in part to technological improvements in drilling and production methods.

From calendar year 2019 to 2020, the total costs, net of credits and overriding royalties, for cost-of-service production declined by approximately 4.3% (the sixth consecutive year of declining net costs). This decrease was caused by a 13.2% reduction in the Wexpro operating service fee and a 41% reduction in royalty costs. This was partially offset by the cumulative credits decreasing by 34%. More information on Wexpro's planned development drilling programs are contained in the Future Resources discussion later in this section.

One of the important results of the SENDOUT modeling process is a determination of the appropriate production profiles for the cost-of-service gas. This year, the Company modeled 120 categories of cost-of-service production. Last year, it modeled 116 categories. Both years, the Company used a modeling time horizon of 31 years. A relatively long time-horizon better reflects the fact that cost-of-service gas is a long-term resource.

The Company created these categories of cost-of-service gas to naturally group wells which have common attributes including factors such as geography, economics, and operational constraints. A large amount of data must be compiled to provide the inputs to the SENDOUT modeling process. The Company has relied on the expertise of Wexpro personnel in assembling the data elements needed to model each category. Some of those data elements are reserve estimates, production decline parameters, depreciation, and amortization rates, carrying costs, general and administrative costs, operating and maintenance costs, production taxes, royalties, income taxes, and oil revenue credits. The Final Modeling Results section of this document contains the probability curves and median levels of production for cost-of-service gas resulting from the SENDOUT modeling process this year.

The Utah Commission, in its Report and Order issued October 22, 2013, concerning the Company's 2013 IRP, required the Company to provide a scenario analysis in future IRPs.[37] The IRPs should contain an analysis consisting of the results from multiple SENDOUT modeling scenarios. These scenarios should include varying percentages of cost-of-service gas with varying levels of Company demand (e.g., low, normal, and high). For each scenario, the Company should provide expected management actions, such as projected well shut-ins. Scenario results should include the impacts of those management actions on overall costs. The requested scenario analysis is included at the end of the Final Modeling Results section of this IRP.

Since the late 1990s, the Company has submitted confidential quarterly variance reports to Utah regulatory agencies, as required under the Utah Commission's IRP standards and guidelines. These reports detail the material deviations between planned performance and actual performance of cost-of-service natural gas supplies. Under the 2009 IRP Standards, that process will continue into the future.

There are many reasons the confidential quarterly variance reports often show variance between anticipated volumes and actual production. As part of the IRP modeling process, Wexpro and the Company are required to anticipate the production capability of approximately 1,360 wells. Some of these wells have not been drilled yet but are included in the planning process. Forecasting production from existing wells is not a precise science and forecasting for wells not yet drilled involves even more uncertainty. New wells can be, and occasionally are, dry holes. Production from new wells can vary from non-commercial quantities to levels several times that anticipated during the planning process. Fortunately, non-commercial wells occur very rarely.

Unanticipated delays during the partner approval process can also postpone planned production. Delays during permitting, drilling, and completion can also affect the timing of production volumes. An unexpected archeological find on a drill site can either cause extensive delays for all the wells planned for the site or cause the wells not to be drilled at all. Even small delays can cause schedules to conflict with environmental windows for the migration, mating, and/or nesting of local species, resulting in greater delays. Pad drilling, with all its inherent cost efficiencies can also create delays. Since all the wells on a pad are typically connected to a single gathering system, any delay in one well affects the production timing of all the pad wells.

For existing wells, a number of geotechnical factors can affect production levels. Although reservoir engineers are skilled in the utilization of sophisticated techniques to forecast future production decline rates, precisely predicting the performance of reservoirs many thousands

[37] In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2013, to May 31, 2014, The Public Service Commission of Utah, Report and Order, Docket No. 13-057-04, Issued: October 22, 2013.

of feet deep is complex and uncertain. The fact that the pressures of the connected gathering lines are constantly changing due to fluctuating supplies into, and demands from, the local gathering system further complicates the production process (a phenomenon often totally out of the control of the producers). New wells drilled by any party typically come in at very high pressures and, in the short term, can “pressure-off” old wells temporarily reducing existing production levels from a field. While compression can remedy such problems, those costs must be factored into the overall economics of the production stream. Also, the design and construction of compression facilities takes additional time to complete. There are many reasons for variances between planned and actual cost-of-service gas volumes.

PRODUCER IMBALANCES

In most cost-of-service wells, there are multiple working interest partners. Each of these partners generally has the right to nominate its legal entitlements from a well subject to restrictions as defined in the operating agreement and/or gas balancing agreement governing that well. As the individual owners in a well each nominate supplies to meet their various marketing commitments, imbalances between the various owners are created. Imbalances are a natural occurrence in wells with multiple working interest owners. There are no fields or wells with multiple owners having individual marketing arrangements where an imbalance does not exist. No individual working interest owner can control, in the short term, the level of producer imbalances associated with a well because it does not have control over the volumes that the other working interest owners are nominating.

Anytime allocated wellhead volumes differ from legal entitlements for any one party, an imbalance is created for all the parties in the well. The fact that it is not uncommon for the market of a working interest owner to be lost unexpectedly, either in part or in full, for a variety of reasons, further complicates matters. This can happen without the knowledge of the other parties for a significant period of time and will contribute to an imbalance.

For some wells with multiple working interest owners, contract-based producer- balancing provisions exist. These provisions generally allow for parties that are under-produced to nominate recoupment volumes from parties that are over-produced. Given the time lag in the accounting flow of imbalance information, delays of several months can occur. The process becomes more complicated because several weeks’ advance notice is typically necessary before imbalance recoupment nominations can occur.

Over the past year, producer-imbalance recoupment has taken place in several areas where the Company is entitled to cost-of-service supplies. Exhibit 9.1 shows the monthly volumes nominated in these areas for recoupment during calendar year 2020 and for the first two months of 2021. The Company has been taking recoupment in the Canyon Creek, Pinedale and Moxa Arch areas for most of the January 2020 through February 2021 period.

As can be seen in Exhibit 9.1, other parties have been recouping gas from the Company. A working interest partner in the Hiawatha Deep wells has been recouping gas from the Company since May 2019 through the end of the period. Recoupment from the Company also occurred in the Moxa Arch and Pinedale areas throughout the period. In the Moxa Arch field, recoupment from the Company has been occurring for several years.

As of December 31, 2020, the Company had a total net producer imbalance level for all of the fields from which it receives cost-of-service production of a negative 56.5 MMcf.[38] By way of comparison, the total net producer imbalance level for December 31, 2019, was a negative 458.6 MMCF. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In the most recent audit report, the Hydrocarbon Monitor did not express any concerns about the total producer imbalance levels.[39]

FUTURE RESOURCES

The current market price of natural gas coupled with future price expectations directly drives the level of drilling in the U.S. Multiple other factors also play into the drilling decision. For example, it may make sense to drill when prices are low because drilling costs are generally lower. By the time a well is drilled and turned to production, prices may have rebounded.

In many situations, lease obligations and drilling permits dictate that leases must be developed within a specified period of time. Lease obligations may require that a property be developed within 5-10 years or the leases may be lost. Drilling permits typically expire after 2 years. Allowing drilling permits to expire would result in additional costs by requiring the process to start over. These provisions generally prevent exploration and production companies from holding leases indefinitely without creating value for royalty owners. In the current price environment, a substantial portion of drilling in shale-gas plays continues in order to hold leases.

There can be other factors affecting the rate of leasehold development. For example, the Company's customers benefit from the receipt of significant quantities of cost-of-service production from wells in the Pinedale Anticline Project Area (PAPA) in Sublette County, Wyoming. Development in the PAPA is governed by a Record of Decision (ROD), issued by the U.S. Department of Interior, Bureau of Land Management during September of 2008. The ROD was issued in response to certain environmental mitigation measures and operational safeguards proposed by the partners in PAPA.[40]

As a means of minimizing environmental impacts, the Pinedale ROD, in an orderly and systematic way, allows for concentrated development by limiting the number of well pads and requiring the maximum use of existing well pads before constructing new well pads. Operators

[38] A positive imbalance means volumes are owed to other parties.
[39] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, June 2021.
[40] Record of Decision for the Supplemental Environmental Impact Statement, Pinedale Anticline Oil and Gas Exploration and Development Project, U.S. Department of the Interior, Bureau of Land Management, Cheyenne Wyoming, September 12, 2008.

are required to “stay on a well pad until the well pad is completely drilled out”.[41] Drilling is fundamentally sequential with time limitations for development in certain areas.

Wexpro’s focus is to maintain its long-term drilling plans, thereby continuing to benefit the Company’s customers. For calendar year 2021, Wexpro plans on completing to production, approximately 11.3 net wells with a capital budget for those wells of approximately $18 million.[42] Assuming market prices don’t deviate dramatically from current expectations for the years 2022 through 2025, the total planned net wells are approximately 15, 17, 19, and 18 respectively, with total annual investments in the range of $1 to $18 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2021 will focus on the Trail, Church Buttes and Canyon Creek in the Vermillion Basin.

Wexpro II drilling plans for 2021 through 2025, broken out from the total net wells stated above, are approximately 8, 8, 11, 9, and 13 net wells respectively to be drilled with total annual capital costs ranging from approximately $11 million to $16 million.

Plans, forecasts, and budgets for drilling development wells under the Wexpro Agreements are always subject to change. Many factors including economic conditions, ongoing success rates, partner approval, availability of resources (rigs, crews and services), access issues associated with environmentally sensitive areas, re-completion requirements, drainage issues, and demand letters all have an impact on drilling and capital budget projections.

PRODUCTION SHUT-INS

The Company utilizes the SENDOUT model to optimize the use of cost-of-service production. The SENDOUT model will choose to shut in the production when it determines this is the most optimal solution considering gas costs, storage availability, and demand. The Company creates operational model updates on a weekly basis to incorporate near-term weather forecasts, updated pricing forecasts, and/or production forecast changes. The Company uses these updated models to make operational decisions regarding production shut-ins, storage use, and purchases on a day-to-day basis. However, since the model optimizes based only on cost, the Company may override the model guidance due to other factors. These factors can include operational activities such as testing or well, pipeline, or storage maintenance.

Based on the 2020 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 928 MDth of cost-of-service production shut-in for June 2020 through October 2020. As shown in Table 9.1, the Company shut in less than forecasted due to actual prices about $.30 higher in June compared to the IRP modeled price forecast. This coupled with the uncertainty of pricing due to do COVID related factors, caused hesitancy by the Company to initiate shut ins. As price volatility subsided, the Company began

[41] Ibid., Summary, Page 20.
[42] “Net wells” are the summation of working interests (total and partial ownership).

shutting in production in July. The shut ins in August through October were slightly less than projected by the IRP model due to significantly higher actual pricing during this period.

Table 9.1: 2020 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	184,608 Dth	189,367 Dth	187,993 Dth	180,603 Dth	185,268 Dth	**927,839 Dth**
Actual Shut-in Production	0 Dth	72,005 Dth	168,547 Dth	146,834 Dth	115,682 Dth	**503,068 Dth**

Based on the 2021 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 707 MDth of cost-of-service production shut-in for June 2021 through October 2021.

Table 9.2: 2021 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	214,743 Dth (7,158 Dth/day)	220,679 Dth (7,119 Dth/day)	58,243 Dth (1,879 Dth/day)	138,608 Dth (4,620 Dth/day)	74,717 Dth (2,410 Dth/day)	**706,991 Dth (4,621 Dth/day)**

Exhibit 9.1

Recoupment Nominations (Dth per month by Field) Dominion Energy					
	Moxa	**Butcherknife**	**Church Buttes**	**Canyon Creek**	**Pinedale**
Jan-20	3,552	0	0	13,876	1,685
Feb-20	2,876	0	0	12,275	1,757
Mar-20	2,750	0	0	13,075	929
Apr-20	3,451	0	0	12,574	1,414
May-20	4,007	0	0	12,747	1,414
Jun-20	3,920	0	0	12,119	1,262
Jul-20	3,757	0	0	0	1,210
Aug-20	4,323	0	0	0	1,210
Sep-20	4,293	0	0	0	1,236
Oct-20	4,096	0	0	0	1,151
Nov-20	4,059	0	0	0	1,211
Dec-20	4,195	0	0	12,187	1,574
Jan-21	4,094	0	0	12,587	1,440
Feb-21	3,653	0	0	10,759	1,376
Total	53,026	0	0	112,199	18,869

Recoupment Nominations (Dth per month by Field) Other Parties				
	Canyon Creek	**Hiawatha Deep**	**Moxa**	**Pinedale**
Jan-20	0	726	3,513	7,060
Feb-20	0	712	3,319	6,936
Mar-20	0	381	2,091	7,286
Apr-20	0	0	4,055	7,615
May-20	0	381	3,773	7,515
Jun-20	0	368	3,438	7,520
Jul-20	0	381	2,958	7,214
Aug-20	0	365	3,929	7,214
Sep-20	0	0	2,773	7,015
Oct-20	0	360	3,620	6,603
Nov-20	0	354	1,991	6,516
Dec-20	0	376	2,817	5,959
Jan-21	0	371	3,527	5,741
Feb-21	0	330	3,550	5,680
Total	0	5,105	45,354	95,874

GATHERING, TRANSPORTATION, AND STORAGE

GATHERING AND PROCESSING SERVICES

The Company acquires a substantial portion of its natural gas supplies each year pursuant to the Wexpro Agreements. In many situations, gathering and/or processing services are required for these supplies before they can enter the interstate pipeline system to travel to the Company's city gates. Therefore, the Company has several gathering and processing agreements.

The Company has gathering agreements with Williams Field Services (J88, K07, L116, R06 and L39) and Occidental Petroleum (WGR #6236). However, the majority of the cost-of-service production is gathered under agreements between the Company and QEPM Gathering I, LLC (QEPM). Andeavor Logistics LP (formerly Tesoro Logistics LP) acquired these midstream assets from QEP Resources Inc. in December of 2014. On October 1, 2018, Marathon Petroleum Corp (Marathon) and Andeavor Logistics LP closed on their merger. The combined company is known as Marathon Petroleum Corp. These agreements are managed by Marathon Petroleum Logistics (MPLX). These agreements include the #163 contract, commonly known as the System Wide Gathering Agreement (SWGA), the #4485 contract, the #2091 contract, and the #683 contract. In 2020, Wexpro assumed operations for a portion of the gathering and processing services. The cost for these services is included in the operator service fee.

The Company includes cost data for the gathering and processing functions each year in the SENDOUT modeling process. The SENDOUT model uses a logical gas supply network to define the relationships between modeling variables. Exhibit 10.1 illustrates those logical relationships for the gathering, processing, and transportation functions as utilized by the model.

TRANSPORTATION SERVICES

The Company evaluates all transportation options using assumptions that ensure the Company provides safe, reliable, diverse, and cost-effective service to its customers. As customer demand grows, the Company continues to review options for firm transportation capacity to ensure reliable deliverability of gas supplies. The Company bases contracting decisions on current and forecasted needs, as well as current and projected capacity availability, to ensure supply diversity and reasonable cost. The Company holds firm transportation contracts on DEQP, KRGT, Northwest Pipeline, and Colorado Interstate Gas (CIG).

On July 5, 2021 Dominion Energy announced an agreement to sell substantially all of its Gas Transmission and Storage assets to Berkshire Hathaway Energy (BHE)[43]. The sale of all of the assets, other than the assets in the west including DEQP and DEOP, closed on November 2, 2021. The sale of the remaining assets remains pending.[44]

Dominion Energy Questar Pipeline

The Company has four transportation contracts with DEQP: (1) Contract #241 for 798,902 Dth/D, (2) Contract #2945 for 12,000 to 87,000 Dth/D (volume changes seasonally), (3) Contract #2361 for 30,000 Dth/D and (4) Contract #6136 for an additional 100,000 Dth/D. These contracts provide capacity from multiple receipt points, including Clay Basin, Vermillion Plant, Blacks Fork Plant, Kanda, and interconnects with Northwest Pipeline, Overthrust Pipeline, and White River Hub.

Contract #241 currently has a term expiration of June 30, 2027. Contract #6136 is the contract for the additional capacity associated with the Hyrum gate station expansion. This contract has a term expiration of June 30, 2027 which coincides with the term expiration of Contract #241. Contract #6136 has a receipt point of DEQP Whitney Canyon.

Contract #2945 is currently in evergreen. The primary term of Contract #2361 will expire on November 1, 2021 and will then go into evergreen. BHE and Dominion Energy have negotiated extension of these contracts as part of closing on the pending portion of the BHE transaction.

The #2945 contract is very beneficial because it provides seasonal capacity with valuable receipt points. The #2361 contract is necessary because it provides capacity to serve the southern portion of the DEUWI system through the Indianola gate station.

No-Notice Transportation Service

The Company has a contract with DEQP for No-Notice Transportation (NNT) service for 203,542 Dth/day. This contract is in an annual evergreen. BHE and Dominion Energy have negotiated extension of this contract as part of closing on the pending portion of the BHE transaction.

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[43] Dominion Energy, (July 5, 2020), *Dominion Energy Agrees to Sell Gas Transmission, Storage Assets to Berkshire Hathaway Energy-- Strategic Repositioning Toward 'Pure-Play' State-Regulated, Sustainability-Focused Utility Operations* [Press Release]. https://news.dominionenergy.com/2020-07-05-Dominion-Energy-Agrees-to-Sell-Gas-Transmission-Storage-Assets-to-Berkshire-Hathaway-Energy-Strategic-Repositioning-Toward-Pure-Play-State-Regulated-Sustainability-Focused-Utility-Operations#:~:text=Dominion%20Energy%20has%20executed%20a,Berkshire%20Hathaway%20Energy%20in%20a

[44] Dominion Energy, (November 2, 2020), *Dominion Energy Closes on Sale of Majority of Gas Transmission & Storage Assets* [Press Release]. https://news.dominionenergy.com/2020-11-02-Dominion-Energy-Closes-on-Sale-of-Majority-of-Gas-Transmission-Storage-Assets#:~:text=2%2C%202020%20%2FPRNewswire%2F%20%2D%2D,(NYSE%3A%20BRK.

DEQP provides NNT service pursuant to its FERC Gas Tariff and the NNT Service Agreement, as amended, between DEQP and the Company. DEQP's NNT Service is offered as an enhanced service to supplement its firm transportation service. DEQP updated its NNT rate schedule in its Tariff effective November 1, 2019. This update intended to clarify the NNT service. NNT service utilizes the contracted reserved daily capacity (RDC) of the underlying firm transportation service (T-1) and offers additional flexibility in intraday variation of the supply and demand of that transportation. Specifically, NNT service allows the Company's level of supply to adjust in real time, subject to certain constraints as described herein, to accommodate the increases or decreases in demand throughout the Gas Day.

NNT provides for the reservation of firm transportation capacity in excess of Shipper's nomination up to the level of service specified in the NNT contract, not to exceed the RDC of the associated firm contract. NNT supplements firm transportation services with no-notice service, to allow DEQP to adjust a shipper's supply in order to accommodate daily demand, which may vary from nominations within the level of service stated in the NNT contract and where total deliveries do not exceed the level of service in the associated T-1 contract.

NNT allows DEQP to utilize Shipper's available Storage injection or withdrawal service, together with Shipper's available firm transportation service, to balance supply in order to meet actual demand, and to adjust nominations to reflect the change in supply and demand. This enables DEQP to automatically adjust the Delivery and Receipt Point nomination(s). When the quantity of gas delivered at Primary Delivery Points specified is less than the quantity of gas nominated for delivery at such points, DEQP will automatically inject the difference into storage, subject to available injection allocation capacity. When the quantity of gas delivered at Primary Delivery Points specified in is greater than the quantity of gas nominated for delivery at such points, DEQP will automatically withdraw the difference from storage, subject to available withdrawal capacity. While no-notice service is "firm up to the RDC," adjustments above the RDC are subject to actual physical constraints on the pipeline and contractual constraints.

The Company relies on the use of NNT service on a daily basis for delivery in response to non-forecasted demand swings, with adjusted Gas Day nominations resulting on 348 days during the 2020-2021 IRP year. Different drivers affect the need for the NNT service between summer and winter seasons. In winter, NNT allows the Company to adjust to cold-weather-driven demand changes, while in summer, NNT service provides the Company the flexibility to adjust to demand changes based on changes in customer usage.

The Company used NNT service 173 days during the 2020-2021 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 175 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 114,182 Dth with an average daily supply reduction to the city gate of 31,616 Dth. The maximum daily supply increase to the city gates was 203,542 Dth with an average daily increase to the city gate of 42,934 Dth. The NNT usage for the 2020-2021 IRP year is shown in Figure 10.1 below.

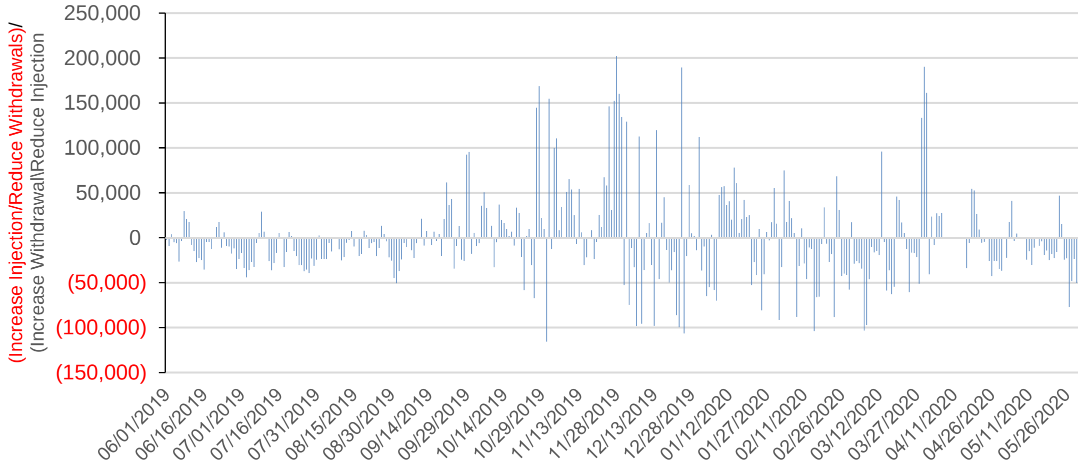


Figure 10.1: NNT Usage – 2020-2021 IRP Year

As part of NNT service, DEQP's tariff allows delivery of volumes that exceed the Company's RDC for short periods of time on an operationally available or interruptible basis. The Company and DEQP regularly model their systems to quantify this ability to deliver gas at rates that exceed the Company's RDC to ensure that the systems can meet peak-hour demand and peak-flow requirements. While this process quantifies the ability to meet Design Day requirements, the service is only provided on a best-efforts basis and could be interrupted. This analysis is part of the JOA process described in the System Capabilities and Constraints section of this report.

Dominion Energy Overthrust Pipeline

On February 23, 2021 Dominion Energy Overthrust Pipeline (DEOP) advertised an open season for 8,542 Dth/day of capacity to become available on June 1, 2021. This posted capacity offered a variety of receipt points and delivery points that would give the Company access to more liquid supply locations for supply to transport under DEQP Contract #6136. The Company bid in the open season and was awarded the 8,542 Dth/day of capacity. The resulting new contract, Contract #6546 has a term that begins on June 1, 2021 and ends on June 30, 2027 in order to coincide with the termination date for DEQP Contract #6136.

Kern River Gas Transmission

The Company has two existing transportation contracts with KRGT: (1) Contract #20029 for 83,000 Dth/D, and (2) Contract #20039 for 1,885 Dth/D. Contract #20029 is a 10-year contract at the Alternative Period Two rate with an expiration of April 30, 2028. Of that capacity associated with contract #20029, 33,000 Dth/day of the capacity is available all year. The remaining 50,000 Dth on this contract is only available from November 1st through March 31st each year.

Contract #20039 is the new contract number for the extension of Contract #1829. This contract began on November 1, 2020 under the Alternative Period Two firm transportation service for a Period 2A term of 10 years. The current term expiration for Contract #20039 is November 1, 2030.

To meet growing customer demand and ensure access to reliable supply sources, the Company also contracted for released capacity on KRGT. This seasonal release contract provides firm transportation capacity that will allow the Company to purchase gas at locations with available supply and transport the gas to the Company's city gate stations.

The contract for seasonal release of capacity on KRGT consists of a release of 27,000 Dth/D for the months of November through the succeeding March with a term of November 1, 2017, through March 31, 2032. It also includes a release of 56,925 Dth/D for the months of December through the succeeding February, and 6,000 Dth/D for November and March with a term of November 1, 2017, through March 31, 2031. This capacity has a path from Opal/Muddy Creek to Goshen with full segmentation rights. This effectively allows the Company to use this as 167,850 Dth/D of firm capacity to serve the Company's system.

Northwest Pipeline

The Company has a contract with Northwest Pipeline for 4,311 Dth/D of transportation capacity with a term expiration of April 30, 2026. This contract has a unilateral cancellation provision under which the Company can terminate the agreement by providing 5 years advanced notice. Unless the contract is terminated, each year the contract is extended for an additional year. Northwest Pipeline cannot terminate the contract. The Company uses this contract to serve the towns of Moab, Monticello, and Dutch John. This contract is segmented in order to provide additional capacity to serve these towns. The Company releases capacity to two contracts that were both renewed on April 4, 2017. These segmentation contracts have no additional reservation costs but allow for the segmentation of 2,016 Dth/D of this capacity. This allows for a total effective capacity on this contract of 6,327 Dth/D.

Colorado Interstate Gas

The Company has a contract with CIG for 400 Dth/D of transportation capacity with a term expiration of October 31, 2025. The Company uses this capacity to serve the town of Wamsutter, Wyoming. The Company also uses the Foothill gate station to serve Rock Springs, Wyoming from CIG with purchases at the city gate.

FIRM PEAKING SERVICES

Most customers do not use natural gas evenly throughout the day. Usage rates are typically higher in the morning hours. The apex of these periodic increases in instantaneous flow is the peak-hour demand. Hourly demand exceeds the average daily demand for a few hours each day (see Figure 10.2). As the Company's customer base and associated demand has grown, the Company has seen a corresponding increase in peak-hour demand. It is important to note that transportation capacity is scheduled on a daily basis, not hourly.

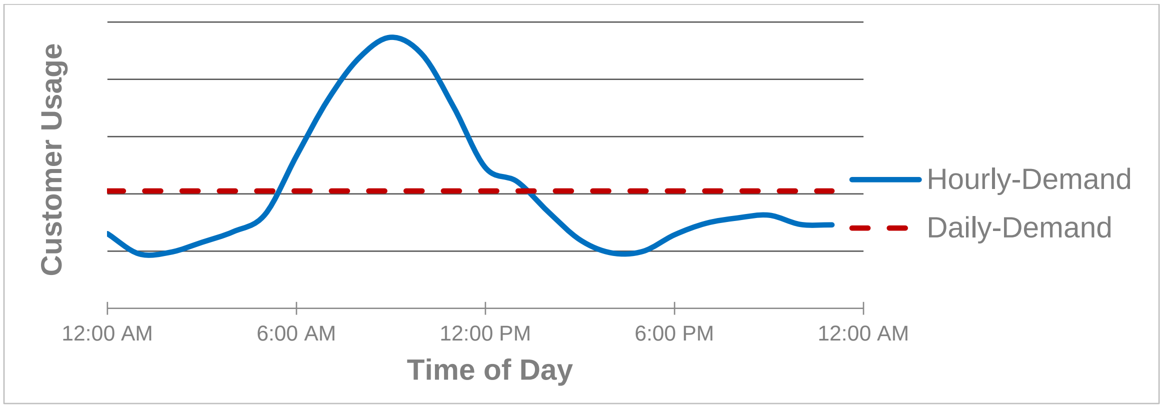


Figure 10.2: Hourly vs. Daily Demand

As shown in Figure 10.3, the Company forecasts that projected peak-hour demand across the system will materially exceed the Company's total firm capacity on a Design Day for each of the next ten heating seasons. This excess peak-hour demand is forecasted to increase from 315,828 Dth/day during the 2021-2022 heating season to 352,018 Dth/day during the 2030-2031 heating season.

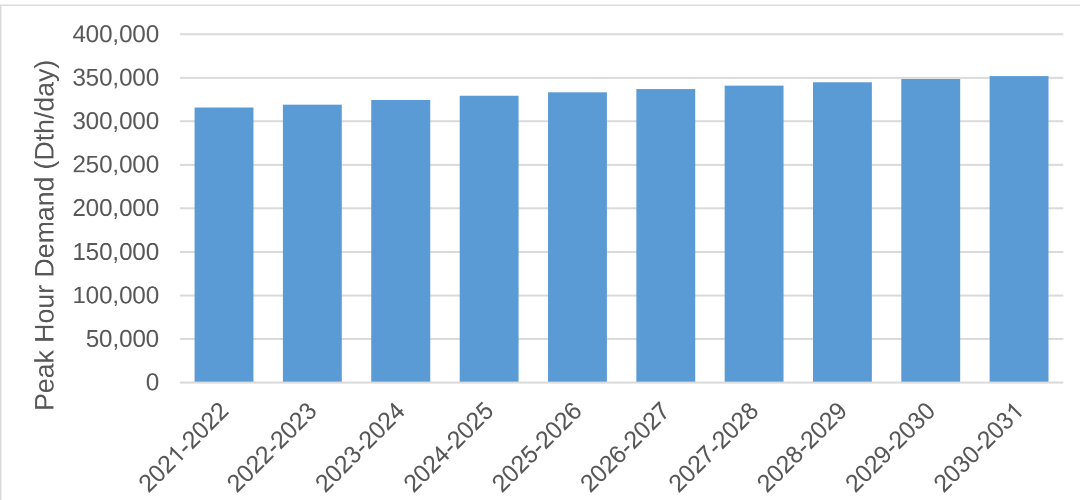


Figure 10.3: Peak-Hour Demand Requirements Above Firm Capacity

The Company continues to evaluate options for meeting the peak-hour demand requirements. In the past, the Company determined that Firm Peaking Services offered by both KRGT and DEQP were the most cost-effective and reliable solution. The Company will continue to review available options for meeting peak-hour demand requirements in order to determine the most cost-effective and reliable solution for future heating season

Kern River Gas Transmission

For the 2020-2021 heating season, the Company extended the contract with KRGT for 28,752 Dth of Firm Peaking Service (Contract #1691) for November 15, 2020 through February 14, 2021. BHE and Dominion Energy have negotiated extension of this contract as part of closing on the pending portion of the BHE transaction.

The KRGT Firm Peaking Service for 28,752 Dth allows the Company to flow 4,792 Dth/hr during the 6 peak hours (28,752/6 = 4,792). In order to get the same 4,792 Dth/hr flow on a standard transportation capacity contract, the contract would need to be for 115,008 Dth/day (4,792 x 24 = 115,008). This contract was cost effective because it allowed the Company to pay for capacity during the peak hours when the service was needed instead of paying for the capacity all day. This Firm Peaking Service cost the Company less than the equivalent Firm Transportation Service on KRGT for the same period making the Firm Peaking Service the most cost-effective solution.

Dominion Energy Questar Pipeline

For the 2020-2021 heating season, the Company extended the contracts with DEQP for 150,000 Dth/day of maximum flow rate with delivery to MAP 164 and 49,000 Dth/day of maximum flow rate to other DEUWI delivery points on the DEQP system for November 15, 2020 through February 14, 2021. BHE and Dominion Energy have negotiated extension of these contracts as part of closing on the pending portion of the BHE transaction.

STORAGE SERVICES

The Company holds firm contracts for storage services with DEQP at four underground gas storage fields to respond to seasonal winter and Design Day demands. This includes the Leroy, Coalville, and Chalk Creek aquifer facilities (Aquifers). The Company also holds contracts for the Clay Basin storage facility. The Company commenced service on its negotiated Firm Storage Service (FSS) agreement with what is now Spire Storage West on April 1, 2017.

DEQP owns the Aquifers and the Company utilizes them primarily for short-term peaking needs. The Company fully subscribes the Aquifer facilities. The Company reviewed these storage resources as part of its planning process and extended these contracts through August 2023.

DEQP also owns Clay Basin, a depleted dry gas reservoir, and its shippers utilize the facility for both baseload and peaking purposes. The Company's contracted inventory for storage facilities is outlined in

Table 10.1 below:

Table 10.1: Contracted Storage Inventory

Facility	Maximum Inventory (MDth)
Clay Basin	13,419
Leroy	886
Coalville	720
Chalk Creek	321
Spire Storage West	2,500

Clay Basin Storage

The Clay Basin storage facility is located in the northeast corner of Utah, roughly 50 miles from Rock Springs, Wyoming. The Clay Basin field has two producing sandstone formations, the Frontier and the Dakota. The Frontier formation is still producing natural gas today and the Dakota formation is used for storing gas. The Dakota formation was largely depleted in 1976 when construction of the storage facilities began. Today, the Clay Basin reservoir has the largest capacity of any underground storage facility in the Rocky Mountain Region.

The Company receives storage service at Clay Basin under rate schedule FSS. Billing under rate schedule FSS consists of two monthly reservation charges and separate per unit usage fees for injection and withdrawal. The first reservation charge is based on each shipper’s minimum required deliverability (MRD) as stated in each shipper's storage service agreement. The second monthly reservation fee is an inventory capacity charge based on each shipper’s annual working gas quantity.

The tariff provisions governing Clay Basin ensure that customers will receive their MRD, at a minimum. To the extent that shippers have inventory in excess of their MRD, additional deliverability is available for allocation according to predetermined formulas. The Company exceeds its contract MRD regularly throughout the heating season, but, for purposes of Design Day analysis, the Company assumes that only its MRD will be available during a Design Day.

The Company currently has three FSS storage contracts at Clay Basin. Contract #988 contract has an inventory capacity of 3,727,500 Dth and withdrawal capacity of 31,063 Dth/day. The current term expiration for this contract is April 30, 2022. Contract #997 has an inventory capacity of 3,727,500 Dth and withdrawal capacity of 31,063 Dth/day. The current term expiration for this contract is March 31, 2025. Contract #935 contract has an inventory capacity of 5,964,000 Dth and withdrawal capacity of 49,700 Dth/day. The current term expiration for this contract is April 30, 2024. BHE and Dominion Energy have negotiated extension of these contracts as part of closing on the pending portion of the BHE transaction.

Between October 1, 2020, and April 30, 2021, the Company utilized the Clay Basin storage facility to provide more than 10,981 MDth of supply to meet customer demand. This included 52 days with withdrawals that exceeded 100 MDth and 17 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 66 days of injection during this period.

Leroy and Coalville Storage

The Company has a Peaking Storage (PKS) (Contract #985) for 886,996 Dth of inventory capacity and 79,540 Dth/day of withdrawal capacity at the Leroy aquifer facility. The Company also has PKS Contract #986 for 720,372 Dth of inventory capacity and 67,635 Dth/day of withdrawal capacity at the Coalville aquifer facility. BHE and Dominion Energy have negotiated extension of these contracts as part of closing on the pending portion of the BHE transaction.

Following the end of the withdrawal season, the inventories in these facilities have maintained a working gas inventory of approximately 30–50% of maximum capacity through the summer months. Previous practice was to completely deplete the facilities each year at the end of the withdrawal season. The advantages of this revised mode of operation are as follows:

- Wells in the Leroy and Coalville facilities are not “watered out” at the end of the withdrawal cycle, which improves well efficiency when storage injections are initiated in the fall.
- Injection compression fuel gas requirements are reduced (only 50-70% of the working capacity needs to be injected in the fall to fill the reservoir).
- A shorter, more predictable, and easily managed withdrawal/depletion schedule occurs at the end of the heating season.
- A shorter injection season for reservoir refill is required in the fall.

With the Leroy and Coalville inventories at 50%, the flexibility exists to inject significant volumes due to gas displacing water in the reservoir.

In general, current operating practices at both the Leroy and Coalville facilities are as follows:

- Injections into the reservoirs commence in August or September from an initial inventory of approximately 45-55% of maximum working inventory. Injections continue until an inventory of approximately 75% of maximum is reached by early October. Injections follow a specific schedule determined by well and reservoir characteristics which minimizes the potential for “fingering” (gas being trapped behind water in the aquifer and resulting in gas loss).

- In early October, scheduled injections are halted to facilitate DEQP's testing conducted at the Clay Basin storage facility. The testing requires two days of injection at a controlled rate followed by a 7-day no flow period for pressure stabilization. Depending upon system demand and the gas supply situation during the no flow period, the 75% inventory at Leroy and Coalville affords the flexibility to either inject or withdraw to help meet system balancing requirements.

- Following the Clay Basin test, controlled injections again commence in Coalville and Leroy and they typically reach maximum inventory by early November.

- The Company utilizes both Coalville and Leroy to meet peak-load requirements through the heating season, to manage the morning and evening load swings and to offset the cost of purchased gas during a high-pricing event. During periods of lower winter demand, the Company refills the reservoirs to maximum inventory when possible.

- During March, when the need for peaking withdrawals has passed, the Company partially draws down the reservoirs to inventories of approximately 50-70% in preparation for Clay Basin testing (conducted during April). The April Clay Basin test consists of a few days of a withdrawal period followed by 2 days of controlled withdrawal. Following the withdrawal period, DEQP shuts Clay Basin in for pressure stabilization. Maintaining Coalville and Leroy at the indicated inventory range during this period provides the flexibility to either inject or withdraw based upon system balancing needs.

- At the end of the spring Clay Basin test, the Company draws Leroy and Coalville down to inventory levels of approximately 45–55% and then maintains both at that level until refill commences in the fall. Periodically, the Company will completely draw down one aquifer when necessary to conduct an inventory volume verification analysis.

Chalk Creek Storage

The Company also has a PKS (Contract #984) for 321,000 Dth of inventory capacity and 37,450 Dth/day of withdrawal capacity at the Chalk Creek aquifer facility. BHE and Dominion Energy have negotiated extension of this contract as part of closing on the pending portion of the BHE transaction.

Chalk Creek is utilized differently than the Leroy and Coalville facilities. This facility has more restrictive injection requirements but still provides high deliverability. Due to the nature of the Chalk Creek storage formation and in order to minimize losses, DEQP does not currently practice partial inventory maintenance during the summer. Operation at Chalk Creek is as follows:

- Historically, injections weren't allowed in the Chalk Creek facility until November. Injections may now commence in September following a controlled injection profile.

This is an operational change that DEQP requested and the FERC approved in 2018.

- By mid-December, the reservoir reaches maximum inventory.
- In early March, gas in the reservoir is withdrawn in a controlled manner and it remains empty until refill injections commence in the fall.

2020-2021 Aquifer Usage

The Company used the Aquifers to provide supply during periods of cold temperatures in 2020-2021 heating season in October, December, January, and February. All of the Aquifer's deliverability will be required to provide about 135 MDth of supply on a Design Day.

The Company used high withdrawals during a cold period in late January and also maximized withdrawals during the high-pricing event that occurred in February 2021. These withdrawals were able to mostly offset daily purchases. Additional daily purchases at the high prices experienced in February would have resulted in significant additional costs.

Also, in order to continue to provide operational flexibility during the Clay Basin testing period in April 2021, the Company withdrew inventory from the Aquifers in March. The Company adjusted the inventory in the Aquifers to provide maximum flexibility during the Clay Basin test in April.

The Company usage during January, the February event, and the utilization for both injection and withdrawal during the Clay Basin test are shown in

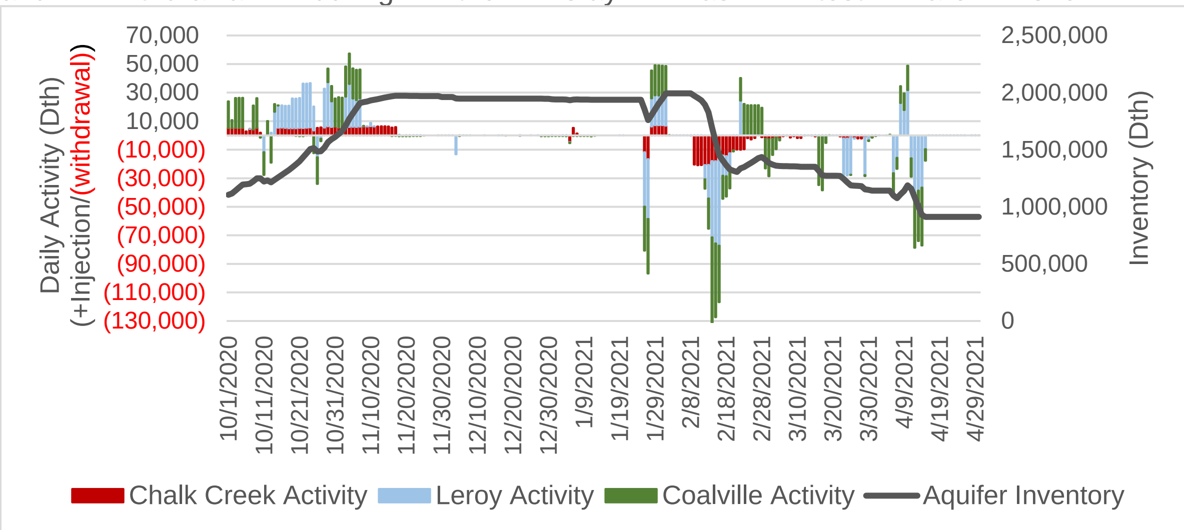


Figure 10.4 below. This flexibility is critical to operations when Clay Basin is not available.

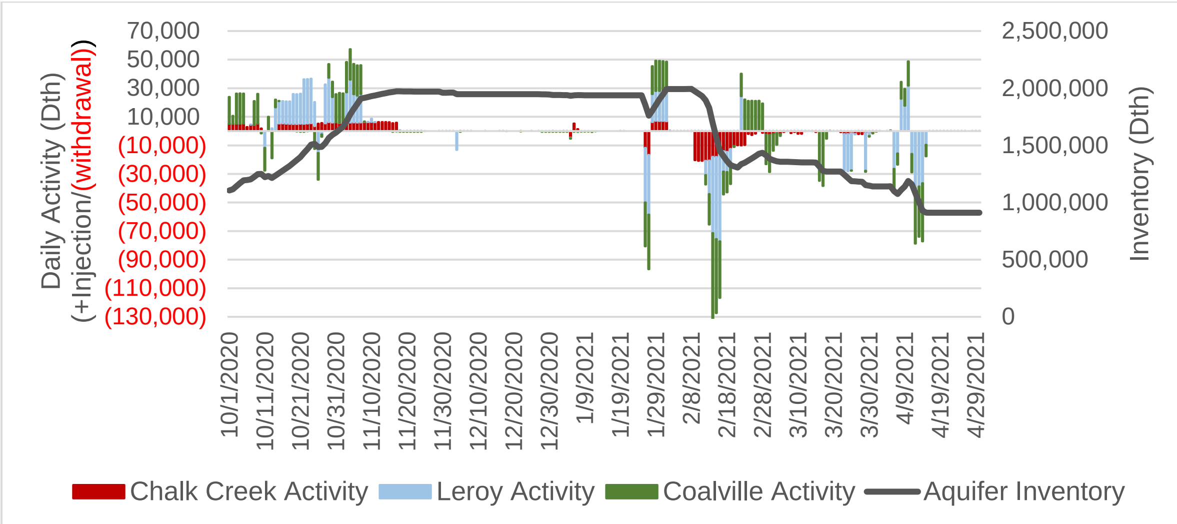


Figure 10.4: Aquifer Usage 2020-2021 Heating Season (Oct 2020through April 2021)

Spire Storage West Gas Storage

The Spire Storage West storage facility involves the utilization of a partially depleted oil and gas field, now referred to as the Belle Butte facility, located approximately 25 miles southwest of the Opal Hub in southwestern Wyoming. The facility interconnects with KRGT, DEQP, Northwest Pipeline, Overthrust Pipeline, and the Ruby Pipeline.

Effective April 18, 2011, the Company entered into a Firm Gas Storage Service Precedent Agreement with Ryckman (now known as Spire Storage West LLC) for 2.5 MMDth of inventory capacity and 16,600 Dth/day of withdrawal capacity. After evaluating the cost and operational utility of this contract, the Company opted not to renew the contract going forward. This analysis was conducted, and notice was given prior to the high pricing event that occurred in February 2021. The contract expired on March 31, 2021. The Company will continue to evaluate available capacity at this facility as future needs arise, including as a potential hedge for extreme pricing.

Between October 1, 2020, and March 31, 2021, the Company utilized the Spire Storage West storage facility to provide 2,229,362 MDth of supply to meet customer demand. This included 134 days of withdrawals, usually at the contract maximum withdrawal rate of 16.6 MDth. Spire Storage West also supplied operational flexibility by providing 35 days of injection during this period. During this period there were no operational issues at the facility that resulted in an inability to perform.

Storage Modeling in SENDOUT

The Company models the costs, contractual terms, and operating parameters for each of its contracts with storage facilities in SENDOUT. The Company also needs a forecast of the storage inventory available at the beginning of the first gas-supply year for each storage facility for the SENDOUT modeling process. When the Company modeled storage and inventory, it expected that the inventory at Clay Basin on June 1, 2020, would be approximately 3.2 MMDth.

RELATED ISSUES

Gas Quality/Interchangeability

Almost all of the gas delivered to the Company's system comes from interstate pipelines (DEQP, KRGT, CIG, and Northwest Pipeline). Each of these interstate pipelines manages gas quality to limits defined in its tariff. These limits have been effective in equitably meeting the delivery needs of shippers and downstream customers.

The most prevalent measure of fuel gas interchangeability in the U.S. is the Wobbe Index.[45] Natural gas appliances are rated to operate safely and efficiently within a specific Wobbe Index range. The Company used a consulting firm to establish the Wobbe operating ranges for its service areas. Exhibit 10.2 shows the upper and lower Wobbe operating limits and the specific gravity and BTU values measured for gas delivered to the Utah Wasatch Front (North) region during 2020. The daily averages for 2020 for other Utah regions can be seen in Exhibits 10.3 and 10.4. Exhibit 10.5 shows the most recent quarterly data reported to the Public Service Commission of Wyoming in accordance with Chapter 3, Section 30 of the Public Service Commission Rules. The green dots indicate volume-weighted Wobbe values for each distribution area within ± 4% of the Wobbe set point. Should Wobbe values become a concern in the future at any point delivering gas to the Company, there are a number of tools that the Company can use to manage gas interchangeability including injecting inert gases (or air) in the gas stream, injecting propane, and blending supplies from various sources.

It is difficult to predict the interchangeability of future gas streams. The Company may need to arrange for additional processing or blending in the event it is required to ensure that the gas received from the transmission systems of any of its upstream pipelines are compatible with the needs of the Company's customers. The Company will evaluate this on an ongoing basis as it bears the burden of processing pipeline-quality gas to meet its specific requirements.

The Company has been contacted by parties with renewable gas supplies, such as biomethane producers, interested in delivering gas directly into the Company's system. In response to these requests, the Company set gas quality requirements for non-interstate-pipeline supplies and allow for the delivery of biomethane into the Company's system. The Company is currently working with a biomethane supplier to take deliveries into the DEUWI system. The Company began accepting injection of biomethane into its distribution system in

[45] The Wobbe Index number consists of the higher heating value of a fuel gas divided by the square root of the specific gravity (relative to air) of the fuel gas. Fuel gases with the same index number generate the same heat output over time from a burner given constant pressure and orifice size.

December 2020. Equipment and testing are in place to ensure that the gas quality of these supplies meets Company requirements.

System Diagram 2021

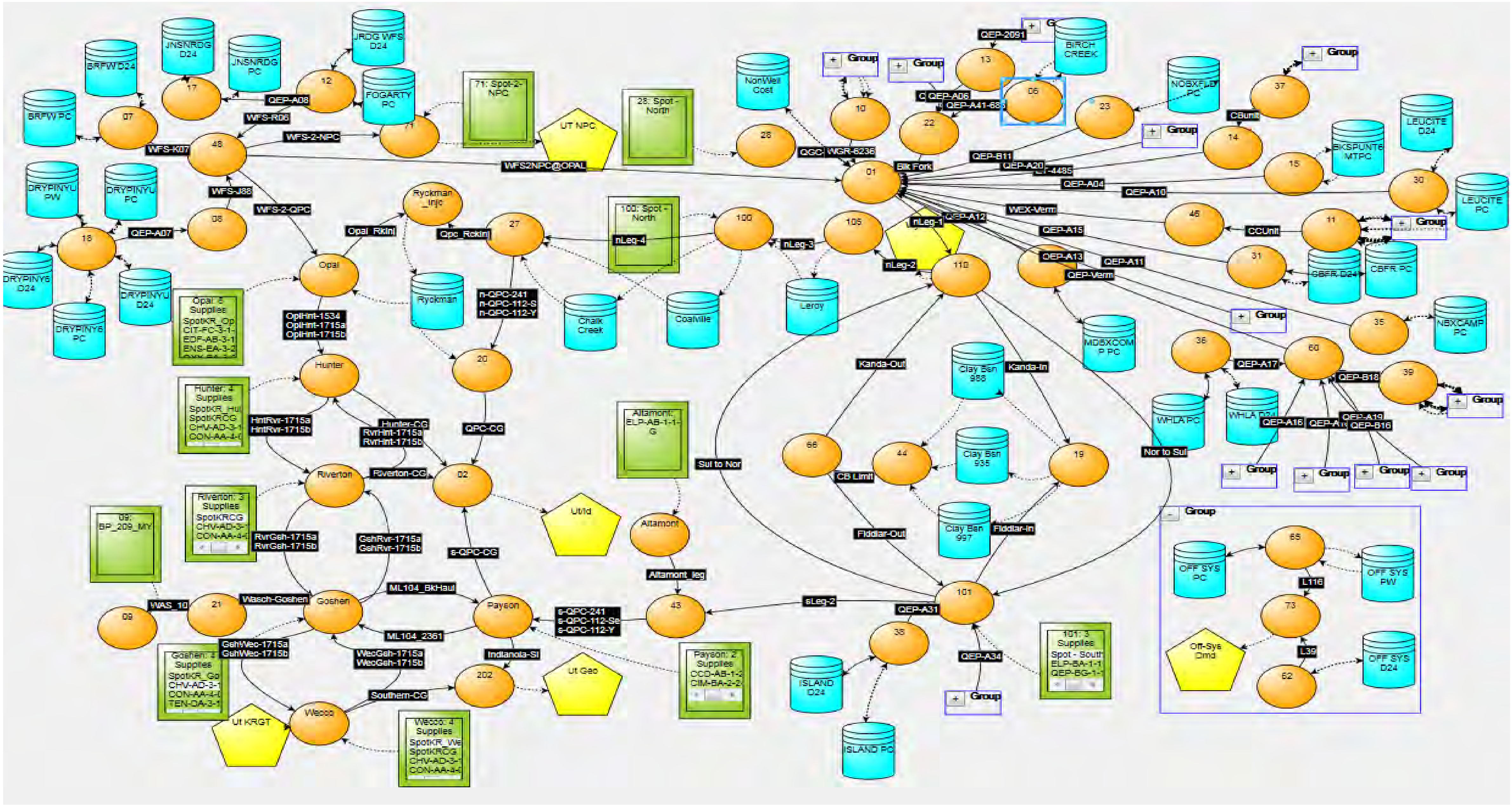
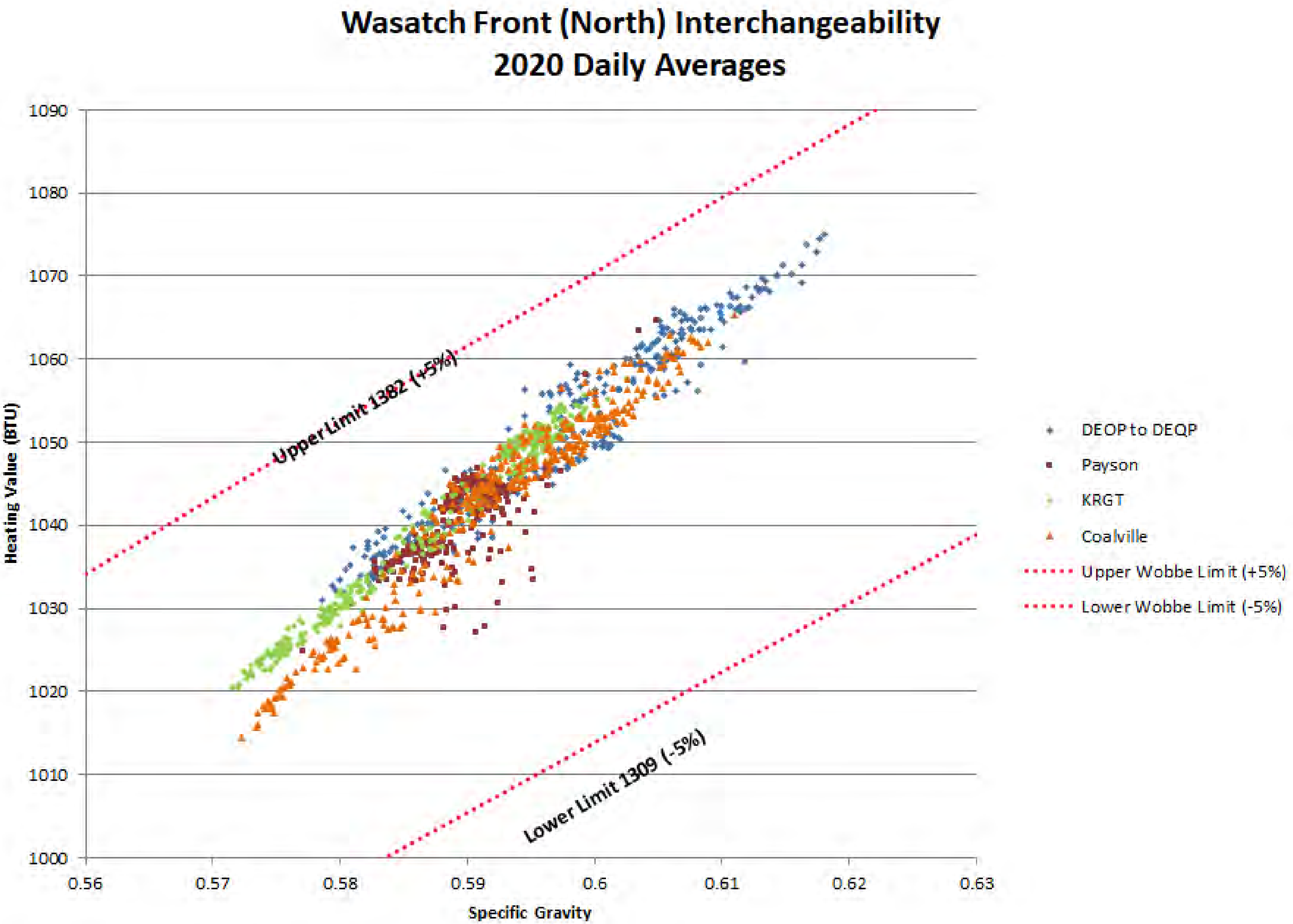
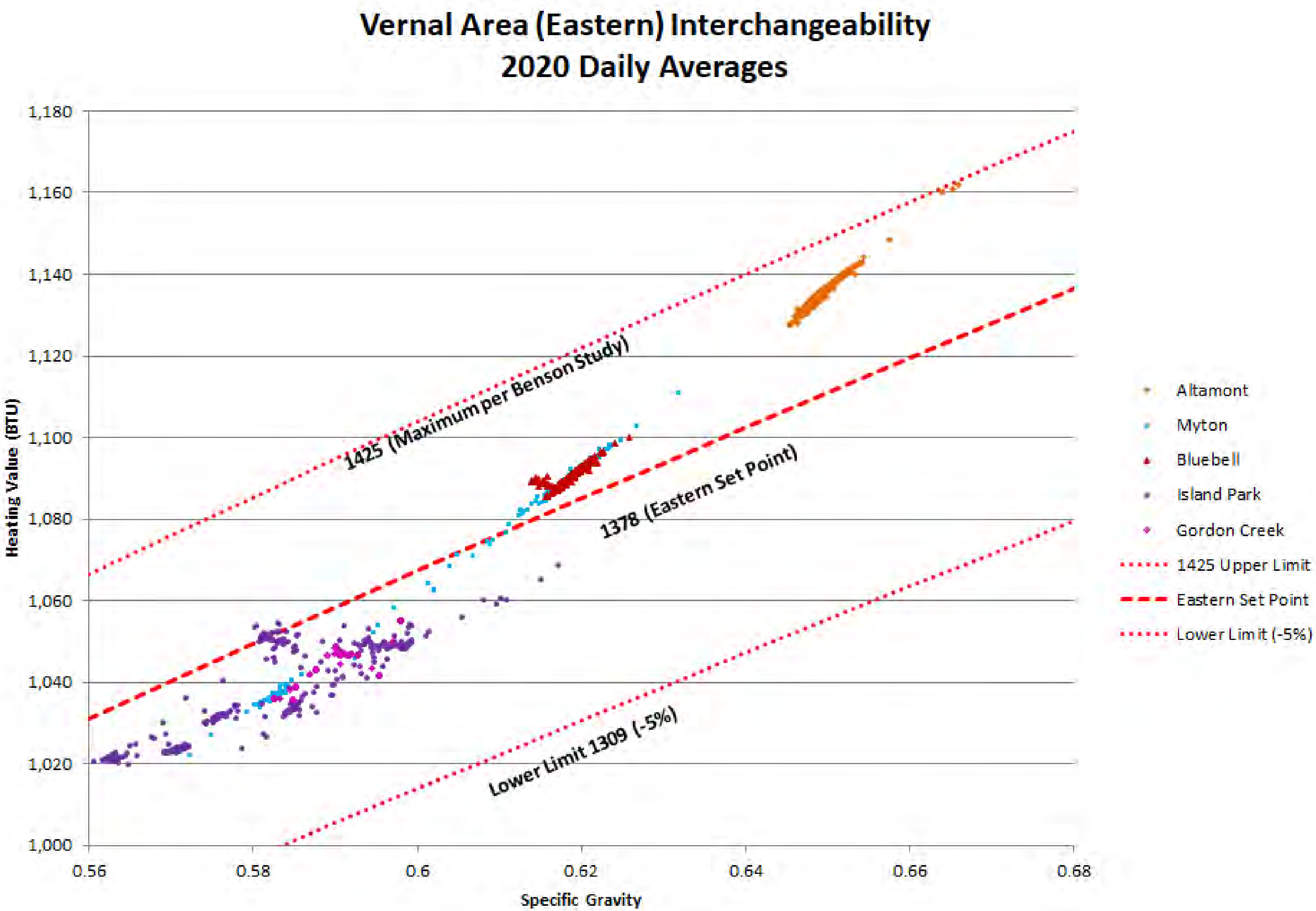


Exhibit 10.1



Wasatch Front (North) Interchangeability
2020 Daily Averages
Heating Value (BTU)
1090
1080
1070
1060
1050
1040
1030
1020
1010
1000
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
Specific Gravity
Upper Limit 1382 (+5%)
Lower Limit 1309 (-5%)
DEOP to DEQP
Payson
KRGT
Coalville
Upper Wobbe Limit (+5%)
Lower Wobbe Limit (-5%)

Exhibit 10.2



Vernal Area (Eastern) Interchangeability
2020 Daily Averages
1,180
1,160
1,140
1,120
1,100
1,080
1,060
1,040
1,020
1,000
Heating Value (BTU)
0.56
0.58
0.6
0.62
0.64
0.66
0.68
Specific Gravity
1425 (Maximum per Benson Study)
1378 (Eastern Set Point)
Lower Limit 1309 (-5%)
Altamont
Myton
Bluebell
Island Park
Gordon Creek
1425 Upper Limit
Eastern Set Point
Lower Limit (-5%)

Exhibit 10.3

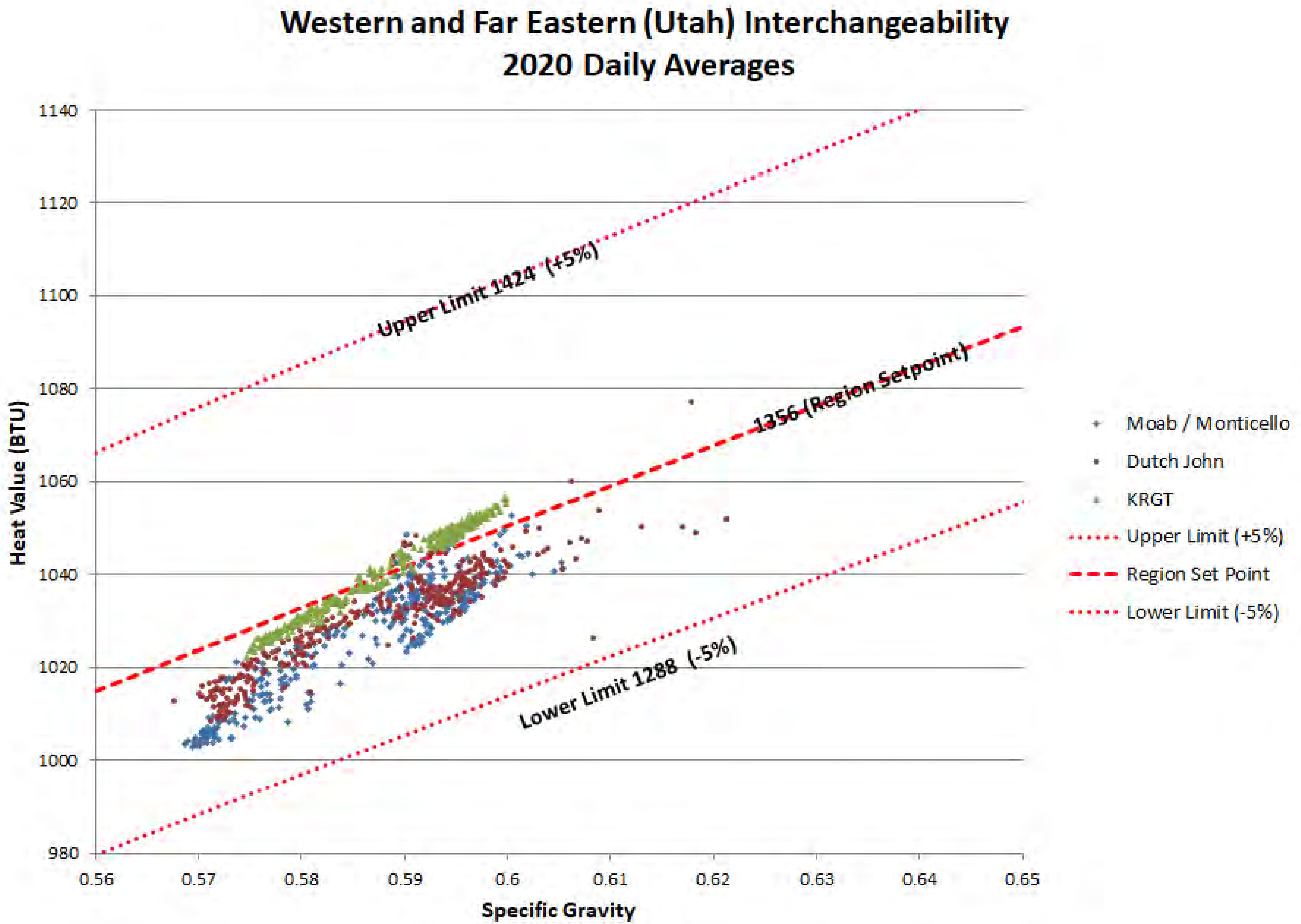

Western and Far Eastern (Utah) Interchangeability
2020 Daily Averages
Heat Value (BTU)
1140
1120
1100
1080
1060
1040
1020
1000
980
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
0.64
0.65
Specific Gravity
Upper Limit 1424 (+5%)
1356 (Region Setpoint)
Lower Limit 1288 (-5%)
Moab / Monticello
Dutch John
KRGT
Upper Limit (+5%)
Region Set Point
Lower Limit (-5%)

Exhibit 10.4

DEW Pipeline System BTU Report MAP
Quarter 1 2021

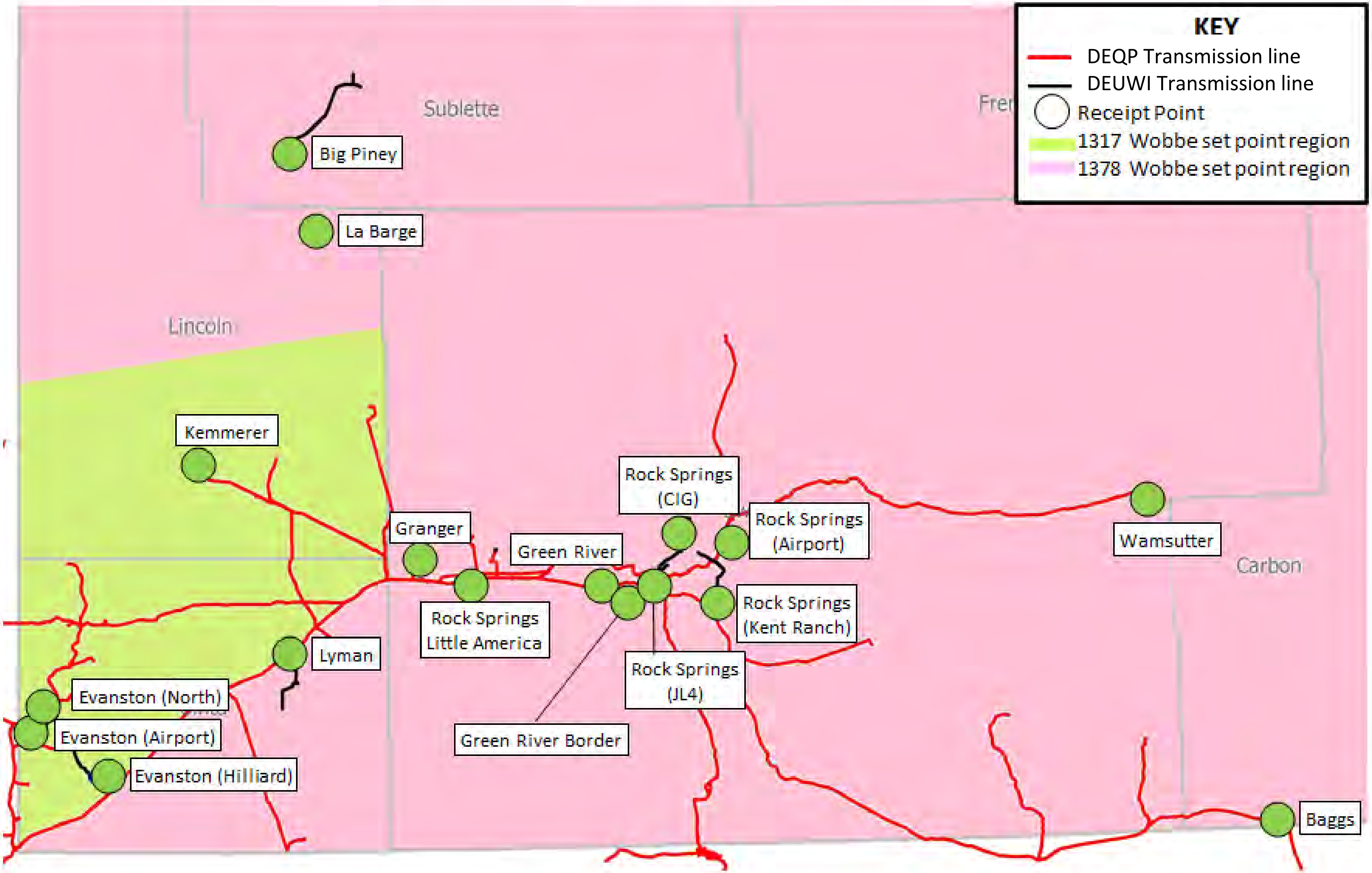


Exhibit 10.5

SUPPLY RELIABILITY

Beginning in 2017, Dominion Energy Utah became concerned about the reliability of its upstream supply. That year, several local distribution companies in other states experienced significant supply shortfalls due to upstream well freeze-offs, interstate pipeline transportation disruptions and other causes. In February 2021, similar events occurred in Texas and the midcontinent resulting in widespread supply shortages. Dominion Energy Utah sought to ensure that its customers do not experience similar outages. After conducting extended review of possible solutions to the supply reliability concerns, Dominion Energy Utah determined that the best available long-term supply reliability solution to address future supply shortfalls would be to construct an LNG facility with liquefaction near the center of the Company's demand center – near Salt Lake City, Utah.

The proposed facility would be located in Magna, Utah. Natural gas may be delivered to the plant from connected pipelines, cooled to the point of changing physical state to a liquid, and stored in a cryogenic holding tank. The stored liquified natural gas is referred to as LNG. DEUWI would re-vaporize the LNG at its discretion by pumping the LNG out of the storage tank, warming it to the point where its physical state changes back to a vapor, and send it back out via pipeline to the connected natural gas distribution system.

The Company provided the Utah Commission and interested parties with information relating to its supply reliability concern, and some ways to address the concern in a March 13, 2018 technical conference in docket No. 18-057-01.

On April 30, 2018, the Company filed an Application for Voluntary Request for Approval of Resource Decision in Docket No. 18-057-03, seeking Commission pre-approval of the construction of a DEU-owned LNG facility. The Company also discussed the issue in the Supply Reliability section of its 2018-2019 IRP, Docket No. 18-057-01. On October 22, 2018, the Commission denied the request in Docket No. 18-057-03 stating, among other things, "that because DEU did not follow the common industry practice of requesting proposals from the market to address the risk it seeks to mitigate through the LNG Facility, it has not adequately supported its conclusion that its chosen solution is in the public interest." October 22, 2018 Order, Docket No. 18-057-03 at p. 16 (Order).

Pursuant to the Commission's Order, DEUWI conducted a request for proposal (RFP), and revisited its evaluation of available options. After reviewing the responses to that RFP, the Company determined that the proposed LNG facility was still the best option for providing long term supply reliability. On April 17, 2019, the Company filed a second application in Docket No. 19-057-13 seeking the Utah Commission's pre-approval to construct the proposed LNG facility. The Company further reported on its efforts in a "Supply Reliability" section its 2019-2020 IRP, Docket No. 19-057-01 where the Company discussed the supply reliability concerns, the options it considered to address those concerns, and its decision to advance the construction of an LNG facility. On October 25, 2019, the Utah Commission approved that application in Docket No. 19-057-13, and provided the Company with pre-approval for the decision to build the LNG facility.

In its 2020-2021 IRP, the Company updated the Utah Commission and interested parties of its progress toward constructing the LNG facility. Dominion Energy Utah's 2020-2021 Integrated Resource Plan, Docket No. 20-057-02, p. 5-10.

LNG FACILITY UPDATE

The facility is designed to liquify natural gas at a rate of 100,000 gallons per day and re-vaporize it at a rate of 150,000 Dth per day. The LNG storage tank is designed with a net storage capacity of 15,000,000 gallons.

In July of 2020, the Company commenced construction of the LNG facility. Since that time the Company has made substantial progress on construction. The LNG tank's outer wall is complete, and the roof was raised into place in May 2021. The LNG tank's inner cryogenic wall and hydrotest should be complete in March 2022.

Aside from the LNG tank, construction progress has progressed on the balance of plant as well. The site has been grubbed, brought to rough grade and perimeter fences and gates installed. Construction of ground improvements (aggregate columns and helical piles required to support equipment and buildings) has begun and should be complete in August 2021. Construction of concrete foundations and equipment placement began in May 2021 and should be complete around December 2021. The main pipe rack erection should begin July 2021 and complete around August 2021. All buildings should be erected and complete by March 2022.

SUSTAINABILITY

DOMINION ENERGY'S COMPANY-WIDE SUSTAINABILITY COMMITMENTS

Across every part of the company, Dominion Energy is transforming the way we do business to build a more sustainable future for the planet, our customers, our team, and our industry. This includes a commitment to expand greenhouse gas emissions-reduction goals to achieve net zero emissions by 2050.

This goal covers carbon dioxide and methane emissions, the dominant greenhouse gases from electricity generation and gas infrastructure operations. This strengthened commitment builds on Dominion Energy's strong history of environmental stewardship, while acknowledging the need to further reduce emissions consistent with the findings of the United Nations' Intergovernmental Panel on Climate Change. It is also a recognition of the increased expectations and interest among customers, as well as employees, in building a clean energy future.

Reducing emissions as fast as possible, and achieving net zero emissions, requires immediate and direct action. That is why Dominion Energy is moving to extend licenses for its zero-carbon nuclear generation fleet, promoting customer energy efficiency programs, and investing in wind and solar power, lower-carbon natural gas, and carbon-beneficial renewable natural gas (RNG). Over the long-term, achieving this goal will also require supportive legislative and regulatory policies, technological advancements, and broader investments across the economy. This includes support for the testing and deployment of such technologies as large-scale energy storage, hydrogen, advanced nuclear, and carbon capture, all of which have the potential to significantly reduce greenhouse gas emissions.

As part of these goals, Dominion Energy has committed to reduce methane emissions from its natural gas businesses by 65 percent by 2030 and 80% by 2040[46]. Dominion Energy in Utah, Wyoming, and Idaho will play a key role in meeting these goals. Dominion Energy is also working to make all of the natural gas distribution systems "Future Ready". DEUWI is committed to promoting renewable natural gas and including it as 4% of throughput by 2040. As discussed more fully below, all of DEUWI's systems will be prepared to receive up to 5 percent hydrogen by 2030.

DEUWI SUSTAINABILITY INITIATIVES

DEUWI shares these same goals. Its efforts thus far to achieve these goals are described below.

Methane Reduction Program

Dominion Energy implemented a Methane Reduction Program in Utah, Wyoming and Idaho that includes:

[46] Methane emission reductions are in reference to 2010 baseline levels.

- Replacing Aging Infrastructure – continuing the ongoing program of replacing parts of DEUWI's aging distribution system.

- Hot Taps – continuing to use hot taps, the process of tying into a live gas main without blowing down the pressure completely first, to reduce the amount of methane required to be blown down during maintenance operations.

- Leak Survey, Detection, and Repair – regularly conducting leak surveys and performing system maintenance as required. The Company conducts additional leak surveys in Class 3 and Class 4 locations. In 2020 more than 21 million feet of pipeline and 200,000 services were surveyed. Resulting in the discovery of 448 leaks, all of which were fixed.

- Reduce Third-Party Damages – continuing on-going programs focused on reducing 3rd party damages to Company facilities. Programs include excavator outreach, stand-by on excavations, participation in state-wide damage prevention seminars, and educational materials mailed to residents along the pipeline rights-of-way and our customers. In 2020 the Company implemented a process for fining excavators who do not call 811 before digging and consequently hit a line. The fine is remitted to the State of Utah as outlined in the 811 law. In recent months the Company has hired additional damage prevention specialists and implemented a risk modeling software to identify high-risk excavations. Once identified the Company sends personnel to monitor the excavations.

- Research and Development – conducting research. The Company is participating in the International HyReady study which evaluates the potential to blend renewable Hydrogen into natural gas systems. DEUWI is participating in ten other RNG research projects with GTI and NySearch.

Sustainability Legislation

The Company is committed to investing in clean air solutions using natural gas, renewable natural gas, and other innovative technologies. The Company participated in the 2019 legislative session and supported Utah House Bill 107 (HB 107). This bill was signed into law by the Governor of Utah on April 22, 2019.

HB107 modified the Sustainable Transportation Energy Plan Act (STEP), Utah Code Ann. §54-20-105, to allow DEUWI to invest in sustainable solutions that include clean-air initiatives, subject to Utah Commission approval. In addition, HB107 introduced the Natural Gas Clean Air Program (NGCAP). This program modified the Utah Code Ann. §54-4-13.1 and is designed to improve air quality through increased use of natural gas and renewable natural gas. Any project under this legislation is subject to approval by the Commission.

The STEP program will benefit Utah customers by reducing emissions and improving air quality. With Commission approval, the Company can advance programs and projects that reduce emissions and improve air quality. The Company could advance a variety of projects including projects that would incentivize the use of compressed natural gas (CNG) combined with RNG production in natural gas vehicle fleets. The Company could propose to fund research and development of new efficiency technologies that would reduce NOx, carbon and greenhouse gas emissions. The Company has already begun work on programs that will improve air quality and reduce greenhouse gases.

On December 31, 2019, the Company filed an application seeking approval to fund the Intermountain Industrial Assessment Center (IIAC) at the University of Utah. On August 31, 2020, the Commission issued an order in Docket 19-057-33 approving a two-year pilot program to fund the IIAC at a level of $500,000 annually. This funding will allow the IIAC to expand energy audits of commercial and industrial energy users and provide data-driven recommendations to help improve air quality. The Company plans to continue work with the IIAC to identify projects that it could then propose under the STEP legislation.

Sustainability of Natural Gas Supply

As part of the annual gas supply RFP for 2021-2022, the Company requested counterparties to disclose any existing sustainability plans. Six respondents provided goals of emissions reductions, including two respondents that indicated plans to achieve net zero emissions by 2050. These six respondents also indicated memberships in organizations such as One Future, The Environmental Partnership, The Nature Conservancy, the S&P ESG Index, as well as other sustainability-focused organizations.

One Future

Dominion Energy is a member of One Future. “The ONE Future Coalition is a group of more than 40 Natural Gas companies working together to voluntarily reduce methane emissions across the Natural Gas value chain to 1% (or less) by 2025.” This coalition includes member companies across the natural gas supply chain, including natural gas production, gathering and processing, transmission and storage, and distribution. This coalition of companies actually exceeded this 1% goal in 2019, registering a methane intensity score of .334%. Currently the Dominion Energy methane intensity score for operations in the west is also below the 1% goal.[47]

Responsibly Sourced Natural Gas (RSG)

Also, as part of the annual RFP for natural gas supply for 2021-2022 and beyond, the Company included a request for responsibly sourced natural gas from respondents. The Company received specific offers from four different counterparties. These offers were provided with addition cost premium to the traditional supply. One additional counterparty offered to negotiate for potential RSG supply outside of the RFP. The Company considered these options in its analysis and stated it would select a responsibly sourced option over a traditional option if costs were equivalent. No offers for RSG were selected this year. Wexpro does provide responsibly sourced natural gas through the well certification program described below.

[47] https://onefuture.us/

Renewable Natural Gas

Renewable Natural Gas is pipeline quality gas derived from waste sources such as wastewater, animal waste, food waste, and other organic waste. If left in place, these waste sources emit methane, CO_2, and other constituents over time to the atmosphere. By capturing, processing, and injecting this renewable natural gas, these harmful emissions can be eliminated and put to use as energy in homes, buildings, and vehicles throughout the Company's service territory.

Renewable Natural Gas Transportation Service

In Docket No. 18-057-T05, filed on November 1, 2018, the Company requested changes to its Tariff that would allow RNG suppliers to transport RNG to their own fleet customers through DEUWI's CNG stations. The Utah Commission approved this service, and the new Section 5.07 of the Company's Tariff, Renewable Natural Gas Transportation (RNGT) service became effective January 1, 2019. This service facilitates and supports a more robust RNG market within the state of Utah.

In November 2019, Fleet Saver, LLC became the first approved RNG supplier to deliver RNG to its fleet customers under RNGT service. In 2020, Fleet Saver delivered 44,580 Dth of renewable natural gas to its customers through DEUWI CNG stations.

Renewable Natural Gas for CNG Vehicle Sales Customers

In 2019, Dominion Energy Utah partnered with Bluesource, LLC, an RNG supplier, to provide renewable natural gas to its CNG refueling customers. Because RNG qualifies for high-value RIN credits when used as transportation fuel, this RNG did not increase the cost of gas to customers.[48] In 2020, renewable natural gas made up over half of the gallons sold to CNG sales customers. Including RNGT service volumes, two thirds of all gallons distributed through Dominion Energy Utah CNG stations was made up of renewable natural gas. The amount of RNG to be distributed in 2021 will largely depend on the availability of RNG supply.

Voluntary Renewable Natural Gas Program – GreenTherm™

In Docket No. 19-057-T04, filed on March 29, 2019, the Company applied for approval to create a voluntary RNG program called GreenTherm™. This program was approved on July 30, 2019, and the Company began taking customer subscriptions in early 2020. This program allows customers to purchase renewable natural gas attributes for their own usage. In 2020, the Company sold approximately 10,500 Dth of RNG to GreenTherm™ customers.

Inclusion of RNG in DEUWI's Natural Gas Supply Portfolio

DEUWI is currently evaluating ways to include renewable natural gas in its own natural gas portfolio. It will report on these efforts in future IRPs.

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[48] Through March 2021, the Bluesource partnership has generated $78,334 in RIN credits to Dominion Energy that have reduced the CNG commodity rate to sales customers.

Carbon Offset Program

DEUWI is currently designing a voluntary carbon offset program that it plans to submit to the Commission for approval in 2021. If approved, the program would allow customers to subscribe to monthly purchases of carbon offsets. A carbon offset represents a quantified reduction in greenhouse gas (GHG) emissions by a mitigating activity. For example, a carbon offset could be generated by funding a reforestation project that absorbs and stores carbon dioxide (CO2) from the atmosphere. An offset could also be generated by installing equipment that captures stray methane (CH4) emissions at an emission source. This voluntary program would allow customers to fund these types of carbon mitigating activities.

Hydrogen Pilot Program

DEUWI is exploring the benefits of blending hydrogen with natural gas in a project coined ThermH_2. The project is broken into four phases to verify existing research on blending as well as determine if there are any impacts on the DEUWI system. The first phase is initial testing of hydrogen blending at the Company's Salt Lake Operations Training Facility, which contains an isolated, but representative, subsystem of piping and customer appliances. Phases two and three, planned for 2023 and later, will progressively introduce hydrogen into the natural gas distribution system in order to gauge customer experience and blend percentage control on a more expansive basis than can be tested at the training facility. The final phase of testing will introduce the methanation process, conversion of hydrogen and carbon dioxide to methane.

The first phase of the ThermH_2 project will validate research in four areas: residential end-use appliances, leak survey capabilities, materials compatibility, and gas quality. Starting in the second quarter of 2021 DEUWI's research and development group started testing the limitations of blended control and measurement, as well as determined the Wobbe effects of adding hydrogen to the gas stream. The remaining tests to be performed are to determine: if current leak survey equipment will function properly, any impacts on odorant and leak detection, burner tip effects along with any changes in emissions, and if material changes will occur at IHP pressures with a 5% blend. These items are intended to confirm that a 5% hydrogen blended gas stream will not adversely impact system or customer safety.

Wexpro Sustainability Initiatives

From 2010 to 2019 Wexpro has reduced its Methane Emissions by over 50%. First, in 2012 and 2013, Wexpro replaced all of the high bleed pneumatic devices at its production locations with low bleed intermittent controllers. In 2017 Wexpro removed all pneumatic pumps on production locations and installed electric driven units.

Well Certification Program

In 2020 Wexpro self-certified gas from more than 250 wells, utilizing an extensive scoring system, as responsibly produced. A third-party, independent company then audited this process by reviewing 25 of these wells at random. The audit evaluated conformance with regulatory criteria in environmental, safety, downhole, and operations, as well as criteria beyond regulatory requirements. Overall, the audit results showed Dominion Energy Wexpro's operational management systems and dedication to regulatory compliance to be outstanding and identified a few opportunities for improvement. In addition, performance exceeded regulatory requirements. In 2021, Wexpro will be evaluating more than 250 wells. The 2021 inspections will complete the initial 3-year certification program. This will complete the certification of all 771 Wexpro operated wells.

Pneumatic Controller Replacement

Wexpro continues to work toward removing the largest remaining methane emissions source, pneumatic controllers. Pneumatic controllers constituted 73% of Wexpro's methane emissions in 2019. Wexpro has replaced some of its pneumatic controllers with electric controllers, and it has installed a solar powered air compressor to drive the existing pneumatic controllers on a well location. Both systems have proven successful during the winter of 2020-2021 and appear to be viable options. Wexpro will test more of this equipment at additional locations in the winter of 2021-2022. Once Wexpro has completed the test, it will evaluate the economics of the solutions and select the best option for deployment in 2022.

Trailer Mounted Combustor

Wexpro is also evaluating trailer mounted combustors for use during well liquid unloading events. Currently, producing wells will load up with liquids in the wellbore and require periodic unloading, during which the well is opened to the atmosphere to bring the fluid in the wellbore to surface. The associated natural gas (methane) that is brought to surface is vented to atmosphere. Wexpro plans to evaluate the use of trailer mounted combustor to be taken to the well location during unloading in order to combust the natural gas that would otherwise vent to the atmosphere. Though there will be an increase in CO2 emissions, those emissions are far less harmful to the environment than methane emissions.

Air Quality Initiatives

Beginning in 2019, all Wexpro-operated production unit and tank burners, which are used to heat the natural gas, produced water and condensate to assist in separation, were lowered in BTU output to better match the demand of the declined production. The burners were originally sized for higher initial production rates and as the production declines the required heat input (BTU) to obtain separation is reduced. This project better matched the equipment BTU rating to the declined production rates. Once the burner ratings were reduced, all units were stack tested via an analyzer to further optimize and ensure complete combustion.

To reduce emissions, Wexpro has committed to the following:

- Replace or repair high emitting pneumatic devices with low or no-bleed devices.
- Switch natural gas-powered pneumatic devices to devices that use alternative power.
- Replace natural gas-powered chemical injection pumps with pumps that use alternate power.
- Conduct voluntary leak surveys and repair programs at aboveground production sites.

- Reduce gas well liquids unloading emissions.

- Replace compressor rod packing either every 26,000 hours or every 3 years.

Instrument Air Systems

Wexpro has also advanced Dominion Energy's overall goal of emission reductions by installing instrument air systems (air compressors and air dryers) to 31 end devices at Canyon Creek and Church Buttes, eliminating 46,000 MCF of gas lost and related emissions.

Community Programs

In October or 2020 Dominion Energy partnered with the City of Salt Lake to undertake the City's largest tree planting event in history. As part of Mayor Mendenhall's initiative to plant 1,000 trees per year, more than 100 Dominion Energy employees planted 205 trees on Salt Lake City's west side. The trees replaced trees that were torn out as part of a power line upgrade project along 1000 West Street.

ENERGY-EFFICIENCY PROGRAMS

UTAH ENERGY-EFFICIENCY RESULTS 2020

The Company's 2020 Commission-approved ThermWise® energy-efficiency programs and measures were similar to programs in 2019, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. ThermWise® results for 2020 were strong with participation for all of the programs exceeding 97% of original projections. Spending for the 2020 program year totaled $27.07 million or 102% of the $26.4 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for nearly 85% of the total ThermWise® spending in 2020 (76% in 2020 budget) and resulted in annual natural gas savings of more than 1,000,000 Dth. Actual gross natural gas savings were 102% of the amount projected in the Company's 2020 budget filing.

Utah ThermWise® Appliance Rebates

The Company continued this program in 2020 with the elimination of 95% and 98% annual fuel utilization efficiency (AFUE) furnaces which included an additional $50 rebate for electrically commutated motors (ECM). Though the ECM does not contribute to natural gas savings, the Company first introduced an additional $50 rebate for its inclusion with 95% or higher AFUE furnaces in 2012. This was done in cooperation with Rocky Mountain Power (RMP) and with the purpose of advancing overall energy efficiency in the state of Utah. The Company's cost effectiveness results have supported this additional rebate amount since it was first introduced. However, a July 3, 2020, change to the United States Department of Energy's (DOE) fan efficiency standards (10 Code of Federal Regulations (CFR) 430.32(y)) have mandated that ECM technology will be the industry-standard beginning January 1, 2021. Because of the elimination of the ECM, the Company proposed to rebate $\geq$95% and $\geq$98% AFUE furnaces at $300 and $350 respectively in 2021.

The Company also added smart water heater controllers as rebate-eligible measures in the Appliance Program in 2020. The smart water heater controller is a device which, when added to an existing storage water heater, allows a homeowner to cycle water heating on and off remotely from any location using a smartphone application or internet-connected computer. Additional benefits include the ability to learn and report on a home's hot water usage patterns, ability to suggest and implement a water heating schedule to prevent standby firings during periods of non-use, water heater maintenance scheduling, and messaging on water heater activity including water heater leak detection. The system is designed to be self-installed by anyone, as described by a manufacturer, with "…enough experience and confidence to install a new water faucet." Smart water heater controllers are designed to be used with storage natural gas water heaters but are not compatible with tankless and condensing systems. These controllers first entered the marketplace in the 2015-2016 timeframe and the Company has studied and continued to monitor available information since that time. The Company estimates a customer who purchases and installs a smart water heater controller will save, on average, 2.5 dekatherms (Dth) annually. The average cost of these devices is $150 and they are available for purchase from several different online and traditional retailers. The Company introduced a $50 rebate in 2020 for smart water heater controllers which meet certain equipment specifications

The Company continued to perform outreach and marketing work in-house in 2020. Nexant provided technical assistance and continued to perform rebate processing work for this program in 2020.

Utah ThermWise® Builder Rebates

The Company continued this program in 2020 by eliminating the $50 ECM rebate and establishing the tiered rebate amounts for >95% and >98% AFUE furnaces at $300 and $350 respectively in 2021 for the reasons outlined in the 2020 Appliance Program discussion. The Company also added the smart water heater controller as a rebate-eligible measure in the Builder Program for the same reasons as described in the 2021 Appliance Program discussion.

Additionally, the Company continued this program in 2020 by restructuring the pre-2020 Home Energy Rater Score (HERS) Index rebate tiers (HERS Index 62 or lower at $100 per home, HERS Index 55 or lower at $200 per home, and HERS Index 48 or lower at $300 per home) and Pay-for-Performance multifamily measure to a single Pay-for-Performance rebate measure which would incent builders to achieve increasing levels of efficiency. The new rebate structure is established at $3 per therm ($30 per Dth) saved. Prior to the 2020 rebate structure change, a builder would receive an incentive for reaching the specified HERS levels and then also receive rebates for the high-efficiency equipment (e.g. $400 per 98% AFUE furnace, $300 per tankless water heater, $50 per smart thermostat) that had been installed in the new home. Under the 2020 Pay-for-Performance measure, builders will receive a rebate for each therm of natural gas saved with no additional rebate for specific high-efficiency equipment. Natural gas savings for the Pay-for-Performance measure is determined by comparing the energy usage of new properties against a software-designed user defined reference home (UDRH). The UDRH would be based on common construction practices for new single and multifamily homes in Utah.

Incentives for this measure are based on the software's calculation of the difference between the natural gas usage of the reference and subject homes and would be capped at a maximum of $1,400 per single family home and $800 per multifamily unit. In order to receive the maximum rebate for the Pay-for-Performance measure, single family homes need to achieve modeled natural gas savings of 47 Dth or greater and multifamily units need savings of 27 Dth or greater. The Company forecasted that the average Pay-for-Performance 2020 participant single and multifamily homes would achieve savings, when compared against the UDRH home, of 20 Dth and 10 Dth respectively.

The Company kept the pre-existing $50 bonus incentive (for 2020 HERS tiers) in place for Pay-for-Performance homes that sought to receive the ENERGY STAR® 3.0 certification. Additionally, the Company added a $50 bonus incentive for homes that meet the qualifications for the DOE Zero Energy Ready Home designation. This would mean that a home reaching the maximum Pay-for-Performance rebates and achieving both certifications would receive $1,500 per single family home and $900 per multifamily unit.

The Company continued to perform outreach and marketing work in-house in 2020. Nexant provided technical assistance and continued to perform rebate processing work for this program in 2020.

Utah ThermWise® Business Rebates

The Company continued this program with the elimination of the \$50 ECM rebate and to establish the tiered rebate amounts for $\geq$95% and $\geq$98% AFUE furnaces at \$300 and \$350 respectively for the reasons outlined in the 2020 Appliance Program discussion.

The Company also added two new tiers for high efficiency boilers, and one new tier for tankless water heaters to the list of previously rebate-eligible equipment in the 2020 ThermWise® Business Program. Both boiler rebate tiers (Tier 1: > 300,000 Btu/hour < 2.5 million Btu/hour; Tier 2: > 2.5 million Btu/hour) apply to boilers which can meet and exceed 95% thermal efficiency (TE) in water heating. The new tankless water heater tier is > 200,000 Btu/hour with TE of 90% or greater. With this change, the Company also increased the rebate for 95% TE boilers (\$3.50 per kBtu/hour versus the 2020 amount of \$3.25 per kBtu/hour) and a rebate amount of \$3.00 per kBtu/hour for the 90% TE tankless water heater in 2021. Though these efficiency levels were rebate-eligible under the 2019 Business Program, the Company made these rebate-tier distinctions to increase customer uptake of the most efficient boilers and tankless water heaters in 2020.

The Company additionally introduced a pilot midstream incentive in 2020. Under this rebate method, the Company pays rebates to boiler distributors, rather than directly to customers, as had been done historically. Rebate eligibility and documentation of the participating customer (e.g. active GS account and service agreement numbers) are collected and verified by the Company before a rebate is paid to the equipment distributor. Equipment distributors are also required to share both traditional and high-efficiency boiler stocking and sales data with the Company in order to be included as a participant in the proposed 2020 pilot midstream incentive. The goal of this midstream incentive is to encourage dealers to stock and actively sell the most efficient boilers in 2020. The Company believes that receiving the stocking and sales data of all boilers will help it better monitor penetration of high-efficiency boilers in the short-term and overall market transformation over time. The Company's limitation of the 2020 pilot midstream incentive to high-efficiency boilers, a historically low participation measure, is intended to increase uptake while also informing future proposals for midstream rebate offerings in other ThermWise® programs and rebate measures.

Nexant continued to perform rebate processing and assisted with design, outreach, marketing, and technical assistance for this program in 2020.

Utah ThermWise® Weatherization Rebates

The Company continued this program in 2020 with a two-year extension of the pilot direct-install program, first proposed and approved by the Commission as a three-year pilot in Docket No. 16-057-15. The direct-install weatherization pilot program has seen great success throughout the three-year period, performing work in more than 12,000 homes and realizing participation rates in some targeted zip codes which more than doubled the historic levels. The Company has also found over the pilot period that many of the homes in the targeted zip codes were moderate to low-income, though often beyond the income requirements for participation in the State Weatherization Agency's programs. Another finding has been that many of the participant homes were in more need of a tighter structure/building envelope, thereby requiring greater air sealing (instead of the projected need for additional attic, wall, or floor insulation).

As of the beginning of October 2019, approximately 110 direct-install participant homes (or fewer than 1% of participant homes) had met the Company's evaluation requirement criteria of one-year pre-participation and two-year post-installation natural gas usage data. Therefore, the Company proposed and received Commission approval for a two-year extension, beginning in 2021, in order to report on the actual savings achieved through the direct-install initiative. The number of evaluation-ready homes increased to nearly 1,000 by the end of 2019 and will continue exponential growth throughout 2020 and 2021. The Company committed to updating the Advisory Group on the savings values achieved by direct-install participant homes throughout 2020. The Company also committed to file a natural gas savings summary of all evaluation-ready homes with the Commission as part of its 2021 budget filing in October, 2020.

Nexant continued to perform rebate processing and assisted with technical assistance for this program in 2020.

Utah ThermWise® Home Energy Plan

In Docket No. 20-057-T03, the Commission granted DEUWI permission to temporarily suspend in-home Home Energy Plans in response to the COVID-19 pandemic. The Company instituted virtual home energy assessments as a replacement to the in-home option, beginning in March 2020. These were conducted by one of the Company's Energy Experts who, through a video call, directed customers to areas of their home in order to collect the information necessary to complete an assessment. The Company then mailed the customized report to the customer as is done with in-home energy plans. In the early months after the virtual energy plan was introduced, many customers preferred to be put on a waiting list for when in-home energy plans resumed. However, as the as the pandemic extended beyond initial estimates, increasing numbers of customers began to opt for the virtual energy plan over the wait list. The program finished the year with 1,879 home energy plans completed or 84% of the expected 2020 participation. Virtual energy plans accounted for over 90% of total energy plans completed in 2020.

Utah Low-Income Efficiency Program

The Company continued funding the Low-Income Efficiency Program in 2020 at $500,000 per year from the energy-efficiency budget ($750,000 total Company funding). The Company will disburse $250,000 every six months, with the disbursements occurring in January and July. The Company also continued this program with the elimination of the $50 ECM rebate and established the tiered rebate amounts for ≥95% and ≥98% AFUE furnaces at $300 and $350 respectively for the reasons outlined in the 2020 Appliance Program discussion.

Utah ThermWise® Energy Comparison Report

The ThermWise® Energy Comparison Report allows customers to compare their natural gas usage with neighboring homes that are similarly sized and situated. The Comparison Report encourages customers to employ energy efficiency measures and behaviors. The Company developed the Comparison Report and first offered it to customers in November 2011.

In 2020 the Company sent the ECR to more than 266,000 of its customers. As of the end of September 2020, the Comparison Report had been generated over 330,000 times online by nearly 130,000 unique customers.

The Company increased delivery of the Comparison Report to 266,000 in 2020. The Company realizes this total number by restarting Group D beginning November 2020 and adding Group I which will be delivered to 25,000 additional customers in 2021.

While program participants increase from 2019, natural gas savings will decrease by 11% in 2020. The Company expected savings to decrease because of the Company-conducted study in 2019 that focused savings analysis on all recipients of the report (Groups D and E). As a result, the Company updated the natural gas savings number from 1.62 Dth/year in the 2019 Model, to 1.21 Dth/year in the 2020 Model. Throughout the life of the ECR Program, the Company has observed that peak dekatherm savings occur approximately in years two through four, and then slightly decrease and moderate. Historically Group C has been the highest performing group and is currently moving toward the moderating phase. Groups B and D are also past peak savings years. Groups C and D represent the majority of participants evaluated and therefore, their slight decrease reduces the total saving value for the ECR Program.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2020 budget filing is shown in Table 13.1.

Table 3.1 - Utah 2020 Projected & Actual B/C ratios by program and California Standard Practice Test

Program	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	2020 Projected B/C	2020 Actual B/C	2020 Projected B/C	2020 Actual B/C	2020 Projected B/C	2020 Actual B/C	2020 Projected B/C	2020 Actual B/C
ThermWise® Appliance Rebate	1.65	1.69	4.97	4.69	1.75	1.76	0.78	0.78
ThermWise® Builder Rebates	1.29	1.23	3.27	2.73	1.56	1.94	0.80	0.86
ThermWise® Business Rebates	1.04	1.29	3.39	3.31	1.63	2.18	0.76	1.01
ThermWise® Weatherization Rebates	1.15	1.47	2.90	3.29	1.21	1.80	0.72	0.85
ThermWise® Home Energy Plan	1.17	2.06	50.46	94.30	1.15	2.04	0.61	0.80
Low Income Efficiency Program	1.42	2.74	6.96	6.25	1.52	3.53	0.75	1.03
Energy Comparison Report	1.11	1.94	5.25	5.36	1.11	1.94	0.49	0.74
Market Transformation Initiative	0	0	N/A	N/A	0	0	0	0
Totals	1.23	1.36	**3.72**	3.30	**1.41**	1.84	**0.73**	0.84

Actual benefit/cost results for 2020 mirrored corresponding budget projections. The ThermWise® programs as a whole passed the Total Resource, Participant, and Utility Cost tests. Actual cost-effectiveness results were higher than projected (with the exception of the Participant Test) primarily due to greater than expected participation in high-savings energy-efficiency measures and higher than forecasted avoided natural gas costs than were used in cost-effectiveness modeling for the 2020 ThermWise® budget filing (Docket No. 19-057-26).

Customer participation in the ThermWise® programs remained high in 2020 (86,169 actual rebates paid) finishing the year at 97% of the Company's original 2020 estimate (88,476). Actual participation surpassed estimated participation in the Builder (30,963) and Weatherization (36,793) programs. The Weatherization program had the highest total number of participants and finished at 115% of the 2020 goal.

The DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Two meetings were held on the following dates: July 14, 2020 and September 24, 2020.

ENERGY EFFICIENCY EFFECTS ON DESIGN DAY & DEMAND RESPONSE

Beginning in Docket No. 13-057-04 the Commission first ordered the Company to discuss the "…effect of energy efficiency programs on peak demand and the need for new infrastructure and how energy efficiency programs could reduce or offset the need for future capital projects" in both a DSM Advisory Group and IRP public input meeting. (Report and Order dated October 22, 2013, Docket No. 13-057-04.) The Company has since addressed this topic in various

DSM Advisory Group meetings in 2014, 2015, 2016, 2017, and 2018. Additionally, the Company has addressed this issue in Dockets 14-057-15, 15-057-07, 16-057-08, 16-057-15.

In 2017, the Company began to explore opportunities for DSM pilot programs that might alleviate peak demand. As part of these efforts, the Company contacted natural gas utilities who might have demand response programs, searched utility websites, reviewed industry conference papers, contacted large demand response vendors, and contacted national energy efficiency organizations. The Company also began a study of water heaters with the purpose of reducing peak demand in 2017. The study, which relied on the Company's system data from 2012-2016 paired with actual five-minute usage data from 7,000 electric storage water heaters taken over a three-month period, showed water heaters (both tankless and storage) peaking roughly 2 to 3 hours earlier than the hours when peaking risk for the Company's system is highest.

In recent years, the Company's efforts on energy efficiency programs and peak demand reduction have focused on studying emerging natural gas demand response programs, administered in customer homes through smart thermostats, throughout the country. The most prominent of these programs began as a pilot in 2017 with SoCalGas and was limited to 500 participants. A third-party evaluation on the impacts of the SoCalGas demand response program was performed and published August 14, 2018. The evaluation concluded that while the demand response program had reduced natural gas usage during the targeted window in time, overall usage for the entire day was not impacted in a statistically significant way. The study theorized that the lack of daily natural gas savings may have been caused by the post event "snap back", when a customer's preferred temperature settings are restored. Ultimately, the evaluation stated that, "without statistically significant net daily therm savings there is an open question regarding whether the program created value from a reliability or economic perspective."[49]

The Company has explored natural gas demand response programs, including receiving proposals from three different program administrators, in 2019 and early 2020. The Company reviewed the 2019 proposals and ultimately determined that the estimated natural gas savings and system benefits did not justify proposing inclusion in the 2020 or 2021 ThermWise® programs.

WYOMING ENERGY-EFFICIENCY RESULTS FOR 2020

The Company filed for approval (Docket No. 30010-186-GT-19) of the eleventh year of the Wyoming ThermWise® programs on October 31, 2019. The eleventh year Wyoming programs were modified to closely align with the 2020 Utah ThermWise® programs in an effort to achieve cost savings for both states while also taking current energy-efficiency and equipment standards into account. The Wyoming Public Service Commission approved the eleventh year programs (January 22, 2020, Order) and ordered the changes be effective January 1, 2020.

The Wyoming energy-efficiency programs (Appliance, Builder, Business, Home Energy Plan, and Weatherization) have seen good participation and interest from customers since the Company launched the programs on July 1, 2009. In the eleventh full program year (January

[49] SoCalGas Demand Response: 2017/2018 Winter Load Impact Evaluation, August 14, 2018, Nexant, Inc.

through December 2020) the Wyoming ThermWise® programs had 406 participants or 1.6% of the Company's December 31, 2020, Wyoming GS customer base.

UTAH ENERGY-EFFICIENCY PLAN FOR 2021

Based on work with the DSM Advisory Group, Utah-based trade allies, program administrators, and other energy-efficiency stakeholders, the Company proposed, and the Utah Public Service Commission approved, the continuation of seven energy-efficiency programs for 2021 as well as the ThermWise® Market Transformation initiative. The ThermWise® energy-efficiency programs continuing in 2021 are: 1) the ThermWise® Appliance Rebates Program; 2) the ThermWise® Builder Rebates Program; 3) the ThermWise® Business Rebates Program; 4) the ThermWise® Weatherization Rebates Program; 5) the ThermWise® Home Energy Plan Program; 6) funding of $500,000 for the Low-Income Efficiency Program administered by the Utah Department of Workforce Services; and 7) the ThermWise® Energy Comparison Report.

Utah ThermWise® Appliance Rebates

The Company continues this program in 2021 program with the addition of dual-fuel heating systems to the mix of rebate-eligible equipment. The Company added an $800 rebate for single family homes and a $450 rebate for multifamily properties that purchase and install a qualifying air source (also referred to as air-to-air) dual-fuel heating system beginning in 2021. A dual-fuel heating system is defined as a heat pump coupled with high efficiency natural gas combustion backup. For the purposes of the rebate, the Company defined qualifying dual-fuel systems as an ENERGY STAR® Certified ducted heat pump, heating seasonal performance factor (HSPF) > 9.0, and seasonal energy efficiency ratio (SEER) > 14. Further, the customer is required to purchase and install an ENERGY STAR® Certified natural gas heating system to provide heat at low ambient outside air temperatures.

While heat pumps can provide both space heating and cooling, for the purposes of the ThermWise® programs and natural gas savings, the Company is solely focused on the high efficiency performance of the heating operations. Operating in heating mode, an air source heat pump can deliver space heat at efficiency levels nearing 300% under the right conditions. This is accomplished by stripping heat from the ambient air outside of a building's envelope and, using the basic refrigeration cycle with a reversing valve, deliver heat to condition the inside of a home.

Because of the process by which air source heat pumps generate heat, heating capacity and efficiency performance are greatly impacted by the temperature of outside air. As the outside air temperature drops, the heating capacity and efficiency performance of the typical air source system also drops because it cannot remove as much heat from the air. If the outside air temperature drops enough, the typical air source heat pump loses capacity to provide a structure's necessary heating load. For this reason, typical air source heat pumps have auxiliary heating systems, usually provided by electric strip heaters, at a certain outside air temperature. This type of auxiliary heating is inefficient, particularly in Utah's climate zones, and can be especially costly to operate in the coldest months of the year. For this reason, air source heat pumps with auxiliary electric heat have traditionally seen the greatest uptake in the United States in climate zones 3-5 where heating degree days average less than 5,500 annually. For contrast, the majority of Utah is situated in climate zones 1 and 2 (with only Washington County located in climate zone 4) where heating degree days ranged between 5,500 and more than 8,600 in 2019.

The Company believes that the most cost-effective and most efficient air source heat pump system is a dual-fuel system that includes natural gas for supplemental heat. The Company estimates that the kind of dual-fuel system outlined above, installed in a typical single-family home using 80 dekatherms (Dth) annually, would reduce their natural gas usage related to space heating by 26 Dth. For the typical existing multifamily unit, the Company estimates that annual natural gas usage would be reduced by 15 Dth annually. The Company expects that most natural gas usage reductions, resulting from the installation of a dual-fuel system, to occur in the shoulder months of the heating season. Additionally, the Company expects that even with substantial customer uptake and installations of dual-fuel systems (which is not forecasted for 2021), peak day usage would remain unchanged assuming outside air temperatures didn't rise above 40°F in that specific 24-hour period.

The Company will also add energy recovery ventilation (ERV) to the mix of rebate-eligible equipment in 2021. ERVs are devices which are used to recover energy contained in normally exhausted building or space air and is then used to treat (or precondition) the incoming outdoor ventilation air in residential and commercial HVAC systems. The Company's first experience with ERVs was as a Business Custom measure for several years. This gave the Company a chance to evaluate performance and observe natural gas savings before it introduced the ERV as a prescriptive rebate measure in the Business Program (Docket No. 18-057-20). The Company now believes there is good potential for natural gas savings from the use of ERVs in existing homes.

Additionally, the Company will change the rebate efficiency standard for the fireplace rebate measure from annual fuel utilization efficiency (AFUE), used in 2020 and earlier program years, to fireplace efficiency (FE) in 2021. FE is a Canadian standard that was established in mid-2020 and is beginning to be more widely adopted by manufacturers and other utility efficiency programs throughout the country.

The Company will continue to perform outreach and marketing work in-house in 2021. Nexant will provide technical assistance and continue to perform rebate processing work for this program in 2021.

Utah ThermWise® Builder Rebates

The Company continued this program with the addition of the dual-fuel heating system and ERV rebates for the reasons outlined in the 2021 Appliance Program discussion. The Company also eliminated the builder rebate credit, first proposed in the 2014 ThermWise® budget (Docket No. 13-057-14). The builder rebate credit was introduced as a new streamlined rebate method that was intended to replace a large percentage of traditional paper rebate applications. This rebate method has been successful over the years and has seen good participation. However, beginning in 2019, the Company began to encourage builders to shift from receiving rebates through the rebate credit to participation in pay-for-performance measures. The pay-for-performance measures have a higher requirement for documentation and testing by builders that does not function well with the builder rebate credit. The pay-for-performance model has seen good market uptake to this point, and the Company sees this as the future direction, in 2021 and beyond, for the Builder Program.

The Company will continue to perform outreach and marketing work in-house in 2021. Nexant will provide technical assistance and continue to perform rebate processing work for this program in 2021.

Utah ThermWise® Business Rebates

The Company continued this program with the addition of the dual-fuel heating system rebate for the reasons outlined in the 2021 Appliance Program discussion.

The Company also added Advanced Rooftop Controls (ARCs) as a new rebate measures in the 2021 Business Program. ARCs are a digital system that allows remote monitoring, and enables control of fan speed, economizer functions, and a thermostat, making it easier to maintain occupant comfort and system efficiency in commercial buildings. ARC rebates are divided into three tiers: 1) Advanced Rooftop Control ≥ 5 tons and ≤ 10 tons; 2) Advanced Rooftop Control > 10 tons and ≤ 15 tons; 3) Advanced Rooftop Control < 15 tons. The proposed rebate and expected annual natural gas savings are $500 and 34 Dth for ARC tier 1; $650 and 42 Dth for ARC tier 2; and $800 and 76 Dth for ARC tier 3.

Additionally, the Company added Monitoring Based Commissioning (MBCx) to the list of simplified analysis rebates as part of the Business Custom measure. Monitoring-Based Commissioning (MBCx) is an evolution of the energy efficiency industry standard measure, known as retrocommissioning, whereby major building components and equipment are tuned up after a period of time in order to achieve efficiency gains. The difference between retrocommissioning and MBCx is that MBCx introduces software and analytics into the process to provide actionable information that can be used to optimize facility operations. For example, the software might identify a fan in an HVAC system that is cycling defectively and notify the customer of the performance issue. The customer would then remedy the issue and achieve efficiency gains. The Company limited MBCx eligibility to large facilities (>150k square feet) and facilities that have savings potential ≥ 1,000 Dth per year. Additional MCBx participation requirements are kept in the Business Custom Program Manual, available at ThermWise.com.

Nexant will continue to perform rebate processing and assist with design, outreach, marketing, and technical assistance for this program in 2021.

Utah ThermWise® Weatherization Rebates

The Company continues this program in 2021 by moving the direct-install program, first approved by the Commission as a three-year pilot in Docket No. 16-057-15, from pilot status to an ongoing initiative. This change in status is made based on the findings of an evaluation of the pilot initiative conducted in 2020. The detailed findings and descriptions of the methodologies used in the evaluation are included as part of the filing in Docket No. 20-057-20 as DEU Energy Efficiency Exhibit 1.13. At a summary level, the evaluation found that the natural gas savings achieved by the sample of direct-install program participant was 77.81% of the Company's estimated savings. At this savings level, the direct-install initiative is cost effective. The Company adjusted natural gas savings in its 2021 cost effectiveness model to match the realization rate found in the evaluation.

Nexant will continue to perform rebate processing and assist with technical assistance for this program in 2021.

Utah ThermWise® Home Energy Plan

The ThermWise® Home Energy Plan program is offered and administered by the Company with periodic consulting and assistance from Nexant. In Docket No. 20-057-T03, the Commission granted DEUWI permission to temporarily suspend in-home Home Energy Plans in response to the COVID-19 pandemic. The Company instituted virtual home energy assessments as a replacement to the in-home option, beginning in March 2020. The Company will continue virtual assessments in 2021 until it is deemed safe to return to customer homes, at which time it will provide the Commission with notice of its intent to do so pursuant to the Commission's Order in Docket No. 20-057-T03.

Utah Low-Income Efficiency Program

The Company will continue funding the Low-Income Efficiency Program in 2021 at $500,000 coming from the energy-efficiency budget ($750,000 total Company funding). The Company will disburse $250,000 every six months, with the disbursements occurring in January and July of 2021.

Utah ThermWise® Energy Comparison Report

In 2021 the Company will send the ECR to more than 226,000 of its customers. As of the end of September 2020, the Comparison Report had been generated over 355,000 times online by over 135,000 unique customers.

The Company will decrease delivery of the Comparison Report to 226,000 in 2021. The Company realizes this total number by discontinuing Group B and Group D, while adding Group J which will be delivered to 50,000 additional customers in 2021. For Group J, some customers from previously discontinued groups may be considered in the selection process.

While proposed program participants decrease from 2020, natural gas savings per customer increases moderately by 4% in 2020. The Company conducted a study in 2020 that focused savings analysis on all current recipients of the report (Groups E and F). As a result, the Company updated the natural gas savings number from 1.21 Dth/year in the 2020 Model, to 1.26 Dth/year in the 2021 Model. Throughout the life of the ECR Program, the Company has observed that peak dekatherm savings occur approximately in years two through four, and then slightly decrease and moderate.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2021 budget filing is shown in Table 13.2 below.

Table 3.2 - Utah 2021 projected NPV & BC ratios by program and California Standard Practice Test

2021 Projections	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	NPV	B/C	NPV	B/C	NPV	B/C	NPV	B/C
ThermWise® Appliance Rebate	$3.91	1.86	$19.52	5.26	$3.58	1.74	-$2.48	0.77
ThermWise® Builder Rebates	$4.93	1.56	$26.30	3.60	$6.00	1.77	-$2.90	0.83
ThermWise® Business Rebates	$1.28	1.22	$11.27	3.11	$3.56	2.04	-$0.16	0.98
ThermWise® Weatherization Rebates	$2.38	1.26	$18.29	2.95	$3.79	1.48	-$3.03	0.79
ThermWise® Home Energy Plan	$0.37	1.76	$2.28	60.25	$0.36	1.73	-$0.30	0.74
Low Income Efficiency Program	$0.57	1.70	$2.78	8.55	$0.58	1.72	-$0.39	0.78
Energy Comparison Report	$0.42	1.79	$2.13	5.36	$0.42	1.79	-$0.38	0.71
Market Transformation Initiative	-$1.32	0.00	$0.00	N/A	-$1.32	0.00	-$1.32	0.00
Totals	$12.55	1.40	$82.58	3.73	$16.97	1.63	-$10.96	0.80

*Shown in millions

Table 13.3 shows the Utah cost-effectiveness results using the projections included in the budget filing updated to include the gas cost forward curve used in the SENDOUT model.

Table 13.3 - Utah 2021 NPV & B/C ratios using gas cost forward curve from SENDOUT model

2021 IRP Forward Curve	Total Resource Cost		Participant Test		Utility Cost Test		Ratepayer Impact Measure Test	
	NPV	B/C	NPV	B/C	NPV	B/C	NPV	B/C
ThermWise® Appliance Rebate	$3.47	1.76	$19.52	5.26	$3.14	1.65	($2.92)	0.73
ThermWise® Builder Rebates	$4.12	1.46	$26.30	3.60	$5.19	1.67	($3.71)	0.78
ThermWise® Business Rebates	$0.91	1.16	$11.27	3.11	$3.19	1.93	($0.53)	0.93
ThermWise® Weatherization Rebates	$1.64	1.18	$18.29	2.95	$3.04	1.39	($3.77)	0.74
ThermWise® Home Energy Plan	$0.32	1.65	$2.28	60.25	$0.31	1.62	($0.35)	0.70
Low Income Efficiency Program	$0.50	1.61	$2.78	8.55	$0.51	1.62	($0.46)	0.74
Energy Comparison Report	$0.40	1.76	$2.13	5.36	$0.40	1.76	($0.39)	0.70
Market Transformation Initiative	($1.32)	0	$0.00	N/A	($1.32)	0	($1.32)	0
Totals	$10.04	1.32	$82.58	3.73	$14.46	1.53	($13.46)	0.76

*Shown in millions

WYOMING ENERGY-EFFICIENCY PLAN FOR 2021

The Company expects eleventh-year participation in the portfolio of Wyoming ThermWise® programs to reach 536 customers which would be an increase of 32% from the 2020 actual participation levels.

SENDOUT MODEL RESULTS FOR 2021

The Company entered projections from the approved 2021 energy-efficiency budget into the SENDOUT model in response to the Utah Commission's request. Data entries for the 2021 energy-efficiency programs included participants and associated deemed lifetime Dth savings per program measure. The Company also incorporated incentive (variable) and administration (fixed) costs for each program measure into the SENDOUT model.

The SENDOUT model used the projected 2021 participation and administration costs as the baseline for its analysis of each program. For each program, the model examined what would happen if participation reduced to 25% or increased to 150% of the 2021 projection. The model also examined different scenarios involving the escalation of annual administration costs per program. In these scenarios, administration costs per program were increased to 150% and 200% of the 2021 projection. SENDOUT then made the judgment as to whether a program should be "accepted" (100% on the included graph) or "rejected" (0% on the included graph) based on a given level of participation and administration costs. Please see Exhibit 13.1 for the SENDOUT results in a table format.

The model accepted the 2021 ThermWise® Appliance, Builder, Business, and Weatherization programs at 25% of 2021 projected participation if administration costs were increased to 200% of the 2021 budget projection. The model accepted the Energy Comparison Report and Home Energy Plan program at 100% of participation and 200% of the 2021 budget projection.

Another way to view the results of the SENDOUT model is to analyze how much administration costs could increase and still be accepted if participation was held at 100% of the 2021 projection. In this scenario, the administration costs for the Appliance, Builder, Business, and Weatherization programs could increase by eight times the 2021 budget projection and still be accepted. The Energy Comparison Report and Home Energy Plan program could increase projected administration costs by one hundred percent and still be accepted.

In summary, the SENDOUT model results indicate that as a gas supply resource at the approved budget and participation levels, the 2021 energy-efficiency programs are accepted as qualifying and cost-effective resources when compared to other available resources. Furthermore, this holds true when participation rates are held constant and program administrative costs are increased.

The SENDOUT model is a comprehensive resource planning and evaluation tool. In comparison, the Company developed its Energy-Efficiency Model in-house, with the assistance of the Company's DSM Advisory Group and the Utah Commission's review. The Company uses its Energy-Efficiency Model for the sole purpose of modeling the Company's energy-efficiency programs. To this end, the Company relies on the Energy-Efficiency Model for energy-efficiency program planning purposes and more importantly energy-efficiency program cost effectiveness (based on the California Standard Practices Manual).

Using the Energy-Efficiency Model, the Company analyzed the approved 2021 energy-efficiency programs at a “break-even” benefit / cost ratio (B/C = 1.00) by holding participation (and incentive payments) constant and increasing all other costs in a linear manner. The analysis is based on projected natural gas savings of 1,003,745 Dth in 2021. This analysis resulted in a projected potential total energy-efficiency spending limit of $41.5 million per year using the Utility Cost Test. The currently-approved $27.1 million per year is well below this threshold. This analysis indicates that the maximum potential spending on energy-efficiency is directly related to the cost-effectiveness of realizing each Dth saved. Therefore, as long as the Company’s energy-efficiency programs are determined cost-effective in the Energy-Efficiency Model, accepted by the SENDOUT model when compared to other available resources, and do not negatively impact company operations, energy-efficiency programs are an appropriate resource.

AVOIDED COSTS RESULTING FROM ENERGY EFFICIENCY

The ThermWise® Cost-Effectiveness Model calculates the avoided cost of gas purchases as the sole benefit of the energy-efficiency programs. In 2020, the avoided gas cost attributable to energy-efficiency was calculated to be $44 million. For 2021, the avoided gas cost attributable to energy-efficiency was calculated to be $41.5 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

2021 Energy-Efficiency Modeling Results from SENDOUT

Program @ <u>100%</u> of 2021 Budget $	% of 2021 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT Model as a resource =

Program @ <u>150%</u> of 2021 Budget $	% of 2021 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT Model as a resource =

Program @ <u>200%</u> of 2021 Budget $	% of 2021 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThermWise Home Energy Plan Program					
ThermWise Weatherization Program					
ThermWise Energy Comparison Report					

Accepted by SENDOUT Model as a resource =

Not Accepted by SENDOUT Model as a resource =

FINAL MODELING RESULTS

LINEAR PROGRAMMING OPTIMIZATION MODEL

The Company uses a computer-based linear-programming optimization model to evaluate both supply-side and demand-side resources. Ventyx maintains this software product and markets it under the name of "SENDOUT." Ventyx is owned by ABB, a global power and automation technology group headquartered in Zurich, Switzerland with approximately 132,000 employees. Roughly 100 utilities use SENDOUT for gas supply planning and portfolio optimization.

SENDOUT has the capability of performing Monte Carlo simulations thereby facilitating risk analysis. The Monte Carlo method utilizes repeated random sampling to generate probabilistic results. It is best applied where relative frequency distributions of key variables can be developed or where draws can be made from historic data. Because of the need for numerous random draws, the availability of high-speed computer technology helps facilitate this process.

The Company is using Version 14.3 of the SENDOUT modeling software. In performing gas supply modeling, the Company works closely with consultants from Ventyx. The Ventyx consultants are very familiar with the gas-supply modeling conceptual approach of the Company and they are comfortable with how the Company utilizes and configures the SENDOUT model. The Company has concerns regarding future support for the SENDOUT software as no updates are currently planned. As a result, the Company is evaluation potential alternatives with enhanced support and longevity.

CONSTRAINTS AND LINEAR PROGRAMMING

While the concepts of linear programming date back to the early 19th century, it was not until the middle of the 20th century that this approach began to be more widely accepted as a method for achieving optimal solutions in practical applications. In summary, linear programming problems involve the optimization of a linear objective function subject to linear constraints.

Constraints are necessary in determining a maximum or minimum solution. Constraints must be linear functions that represent either equalities or inequalities. An example of an inequality constraint in the natural gas business would be the quantity of natural gas that is physically transported over a certain segment of an interstate pipeline must be "less than or equal to" a certain level of transportation previously contracted for with that pipeline company. Another example of an inequality constraint would be the forecast production available from a group of cost-of-service wells. The amount this resource can be taken can never exceed the forecast maximum level available as production naturally declines over time. All resources are defined by constraints.

Constraints must accurately reflect the problem being solved. The arbitrary removal of required constraints results in an unacceptable solution. For example, if the Company removed the constraint on how quickly it filled Clay Basin, the model would assume that it could be done instantaneously, resulting in an unrealistic solution. The removal of all constraints in a linear programming problem would result in no solution ever being able to be reached.

The Company periodically reevaluates the constraints in its SENDOUT model to determine if they accurately reflect the realities of the problem being solved. The only adjustments to the constraints for the 2021-2022 IRP modeling were to adjust the constraints related to the available spot purchase amounts by location.

MODEL IMPROVEMENTS

The Company made one modification to the SENDOUT model for the 2020-2021 IRP. The discount rate used in the model was adjusted to 3.04% to reflect the Carrying Charge stated in the Tariff.

MONTE CARLO METHOD

To have a meaningful Monte Carlo simulation, it is important to have a sufficient number of draws (typically hundreds). Each draw consists of one deterministic linear programming computer run. With the complexity of the Company's modeling approach, one simulation can take as long as several days to run. The base Monte Carlo simulation developed by the Company this year utilized 1,278draws.

When the developers of SENDOUT incorporated the Monte Carlo methodology, they limited the number of variables for which stochastic analysis can be applied to avoid excessive computer run times. The two variables determined necessary are price and weather (within SENDOUT, demand is modeled as a function of weather). No other variables have a more profound impact on the cost minimization problem being solved by SENDOUT.

The output reports generated from the SENDOUT modeling results consist primarily of data and graphs. Most of the graphs are frequency distribution profiles from a Monte Carlo simulation. Many of the numerical-data reports show probability distributions for key variables in a simulation run. The heading "max" in these reports refers to the value of the draw in a simulation with the highest quantity. The heading "min" refers to the value of the draw in a simulation with the lowest quantity. The heading "med" refers to the median draw (or the draw in the middle of all draws).

The Company believes that the mean and median values are good indicators of likely occurrence, given the underlying assumptions in a simulation. Many exhibits in this report also include a normal case number to show how the normal case compares to the mean and median. The Company will discuss the normal case in more detail later in this section. Also, in these reports are the headings "p95," "p90," "p10," and "p5." The label "p95" on report means, based on input assumptions, that a 95% confidence exists that the resulting variable will be less than or equal to that number. Likewise, a "p10" number suggests that there is a 10% likelihood that a variable will be less than or equal to that number. These statistics, and/or the shape of a frequency curve, define the range and likelihood of potential outcomes.

NATURAL GAS PRICES

It is extremely difficult to accurately model future natural gas prices. Most of the Company's natural gas purchases are tied contractually to one or more of four price indices. Two of those indices are published first-of-month prices for deliveries to the interstate pipeline systems of Kern River and Northwest Pipeline. The remaining are two published daily indices for Kern River and one basket containing a combination of two additional Kern River indices.

To develop a future probability distribution, the Company assembles historical data and determines the means and standard deviations associated with each price index. The Company then uses the average of two price forecasts developed by PIRA (67 months) and CERA (271 months) as the basis for projecting the stochastic modeling inputs. The Company adjusts forecasted standard deviations pro rata based on the historical prices to more accurately mirror reality. Exhibits 14.01 through 14.36 show, for the first model year, the resulting monthly price distribution curves for the first-of-month prices and the daily prices for each of the price indices used in the base simulation.

Given the extreme pricing scenario in Feb 2021 the standard deviations calculated as inputs to the Monte Carlo were significantly higher than normal and as such the simulations had very high price spikes in February.

WEATHER AND DEMAND

Weather-induced demand is the single most unpredictable variable in natural gas resource modeling. The Company provides 89 years of weather data to the SENDOUT model. When forecasting future demands, heating degree days are stochastic with a mean and standard deviation by month. The Company uses this number, along with usage-per-customer-per-degree-day and the number of customers, to calculate the customer demand profile used by the model.

The stochastic nature of the heating-degree-days creates a normal plot for degree days based on the 1,278draws. For each month of simulation, the model randomly selects a monthly-degree-day standard-deviation multiplier to create a draw-specific monthly-degree-day total. It scans through 89 years of monthly data to find the closest matching month. Then the model allocates daily degree-day values according to the degree-days in this historic month pattern. Exhibits 14.37 through 14.49 show the annual and the monthly demand distribution curve for the first year of the base simulation. Exhibit 14.50 shows the annual heating-degree-day distribution.

DESIGN DAY AND BASELOAD PURCHASE CONTRACTS

Another important consideration in the modeling process is the need to have adequate resources sufficient to meet a Design Day. The sales-demand Design Day for the 2021-2022 heating season is approximately 1.229 MMDth per day at the city gates. The most likely day for a Design Day to occur is on December 26 although, the probability of a Design Day occurring on any day between mid-December and mid-February is relatively the same.

Selecting a draw from a Monte Carlo simulation that utilizes, on the maximum demand day, a level of resources approximately equaling the Design Day has proven to be problematic in that it results in the SENDOUT model selecting too much baseload purchased gas for a typical weather year. The draws which have a Design Day occurrence also tend to be much colder than normal throughout the entire year. The solution to this dilemma is to perform a statistical clustering analysis of all the Monte Carlo draws for first-year Design Day demand versus the median level of first-year annual demand.[50] The result of this clustering exercise is a scatter plot that shows groups of draws. These cluster points or groups represent draws that are most closely alike in terms of Design Day requirements and annual demand. The Company then chooses a cluster point that it believes will meet annual demand without falling short on Design Day.

The Company then executes a series of deterministic SENDOUT scenarios, removing the unused RFP packages, and leaving those “cluster point” packages. One of the purposes of these runs is to verify that adequate purchased gas resources, at the lowest cost, will be available in the event that a Design Day were to occur. The optimizing nature of the SENDOUT model helps to make this happen. This year, of the 1,278draws generated in this process, seven draws would exceed the Design Day requirement of 1.229 MMDth. In other words, these scenarios have enough resources to meet a Design Day event. Most of the seasonal baseload purchased-gas resources are committed prior to the beginning of the IRP year. Storage, daily spot gas, and cost-of-service gas supply do not need to be committed to before the IRP year begins. This modeling approach also lends itself to performing operational analysis during the year as natural gas prices change.

Exhibit 14.51 shows the resources utilized to meet the Design Day. Exhibit 14 .52 shows the firm Design Day demand distribution for the base simulation for the first plan year. As expected, the Design Day for the Company is in the upper portion of the curve.

NORMAL TEMPERATURE CASE

In this document, the normal temperature scenario can be seen in Exhibits 14.83 through 14.88. These show additional planning detail for the first two years of the normal case. The Company lists monthly data for each category of cost-of-service gas and each purchase-gas package. The Company also includes planned injections and withdrawals for each of the storage facilities currently under contract. Although no actual gas-supply year will ever perfectly mirror the plan, these exhibits are among the most useful products of the IRP process. They are used extensively in making monthly and day-to-day nomination decisions.

PURCHASED GAS RESOURCES

Exhibits 14.53 through 14.64 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 14.65 shows the annual distribution from the simulation. Exhibit 14.66 shows the numerical monthly data with confidence limits. Gas purchased for the first plan year under the normal case is approximately 60 MMDth. The Company is confident that, for a colder-than-normal year,

[50] See the cluster analysis discussion in the Modeling Issues subsection of the Purchased Gas section of this report.

sufficient purchased gas resources will be available in the market. Likewise, the Company is confident that in the event of a warmer-than-normal year, it has not contracted for too much gas.

COST-OF-SERVICE GAS

Another important output from the SENDOUT modeling exercise each year is a determination of the level of cost-of-service gas to be produced during the upcoming gas-supply year. Exhibits 14.67 through 14.78 show the distributions for cost-of-service gas for each month of the first plan year from the base simulation. Exhibit 14.79 shows the annual distribution from the simulation. Exhibit 14.80 shows the numerical monthly data with confidence limits. Cost-of-service production for the first plan year from the normal case is approximately 58.4 MMDth.

FIRST YEAR AND TOTAL SYSTEM COSTS

The linear-programming objective function for the SENDOUT model is the minimization of variable cost. A distribution curve for first-year total cost from the base simulation is shown in Exhibit 14.81. The first-year total cost from the normal case is approximately $612 million. A similar curve for the total 31-year modeling time horizon is shown in Exhibit 14.82. The normal case cost for this time period is approximately $12.08 billion.

GAS SUPPLY/DEMAND BALANCE

Exhibits 14.89 and 14.90 show monthly natural gas supply and demand broken out by geographical area, residential, commercial and the non-GS categories of commercial, industrial and electric generation.

This report is available in SENDOUT and is titled “Required vs. Supply.” The data in these exhibits represent the normal case. The Company slightly adapted the SENDOUT report to show geographical areas and lost-and-unaccounted-for gas. Because the Company measures demand at the customer meter and modeling occurs at the city gate, in years past the Company grossed-up demand by the estimated lost-and-unaccounted-for volume to model natural gas demand at the city gate.[51] The Company models lost-and-unaccounted-for gas as a percent of the other demand classes and lists it as its own specific demand class.

Exhibit 14.89 of the report shows the requirements of the system. Those are specifically demand, fuel consumed, and storage injection. This results in a total requirement of 133 MMDth for the normal case. Exhibit 14.90 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the 133 MMDth demand for the normal case.

[51] Also included are compressor fuel, Company use, and gas loss due to tear outs.

SHUT-IN SCENARIO ANALYSIS

The Utah Commission, in its Report and Order issued October 22, 2013, concerning the Company's 2013 IRP, required the Company to provide a scenario analysis for future IRPs that includes varying percentages of cost-of-service gas with varying levels of the Company demand (e.g., low, normal and high).[52]

The tables below illustrate different scenarios that may occur with differing levels of cost-of-service gas and demand. Table 14.1 shows the estimated annual volume of cost-of-service gas that would be shut in under different scenarios. Table 14.2 shows the anticipated total annual costs under different scenarios. The cost differences are, in part, a result of estimated shut-in costs when cost-of-service gas exceeds demand as well as the cost of having to replace cost-of-service gas (with purchased gas) when demand exceeds the amount of cost-of-service gas available.

Table 14.1: Annual Shut-In Production

		Demand (Thousands of Dths)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	1,541.3	1,003.4	929.7
	IRP Forecast	2,100.3	1,132.1	1,033.8
	High 10%	4,521.1	2,072.9	2,391.8

Table 14.2: Total Annual System Costs

		Demand (Millions of Dollars)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	526.5	615	710
	IRP Forecast	523.4	611.7	706.7
	High 10%	504.7	508.5	686.6

[52] In the Matter of Questar Gas Company's Integrated Resource Plan for Plan Year: June 1, 2013, to May 31, 2014, The Public Service Commission of Utah, Report and Order, Docket No. 13-057-04, Issued: October 22, 2013.

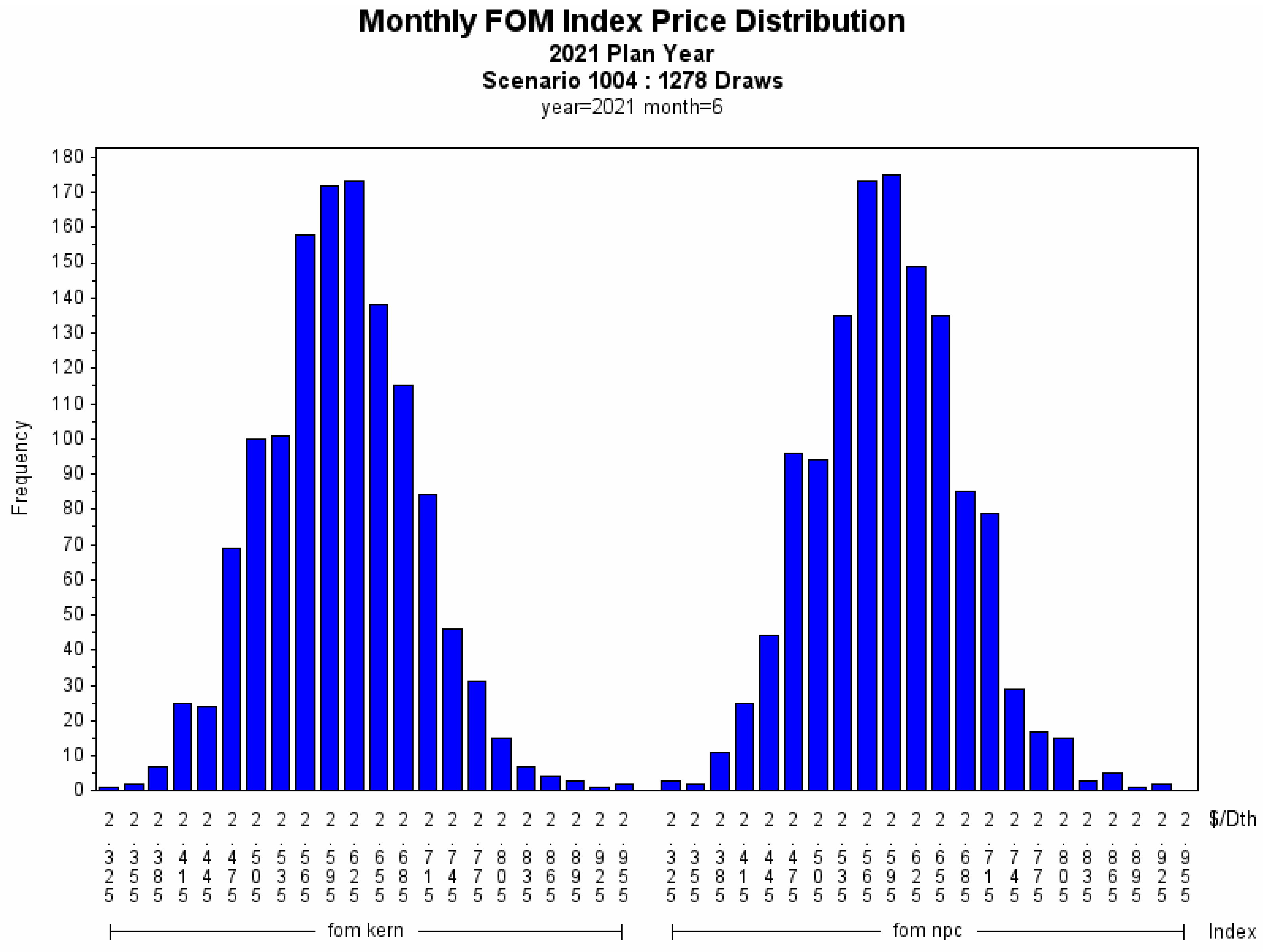
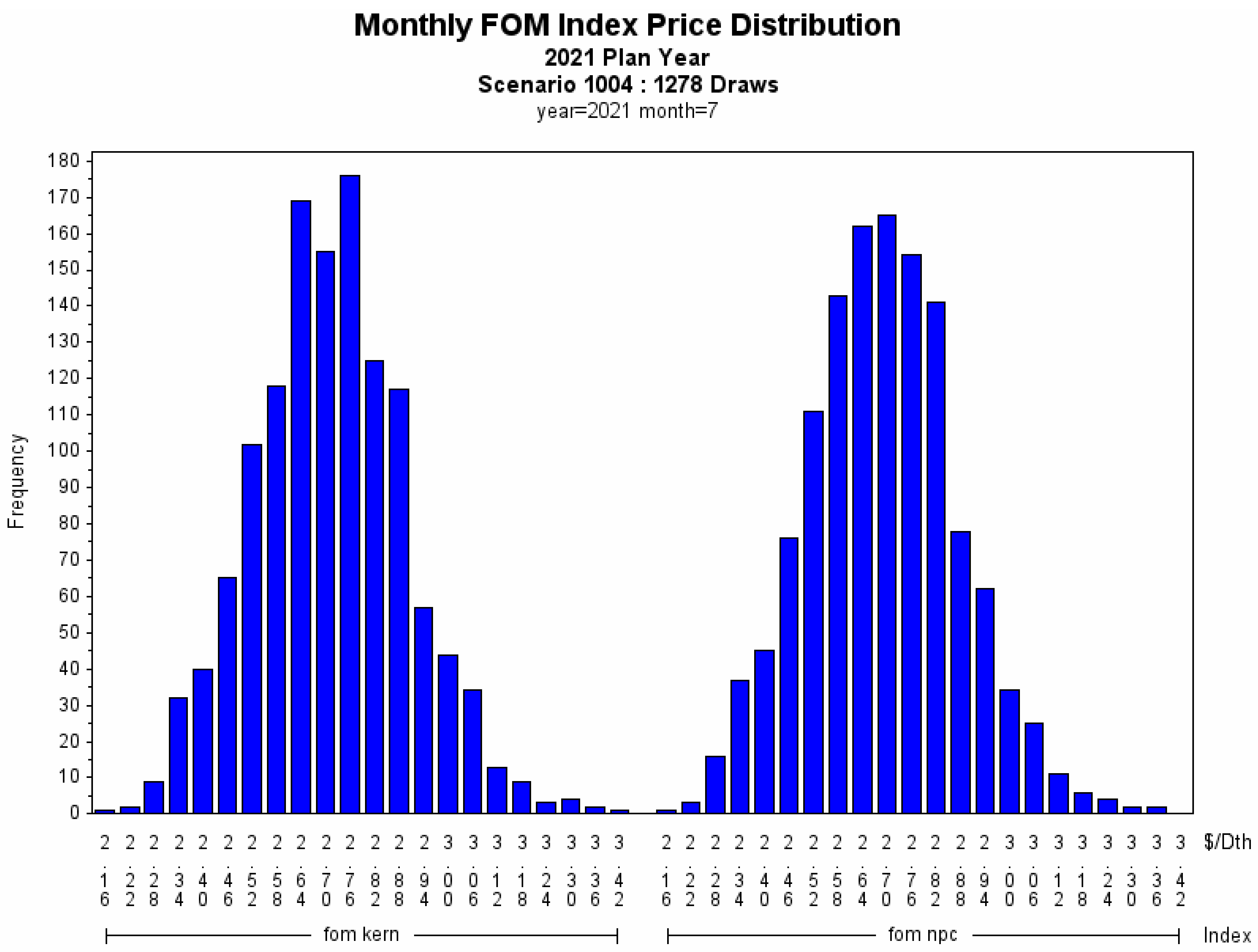


Exhibit 14.01



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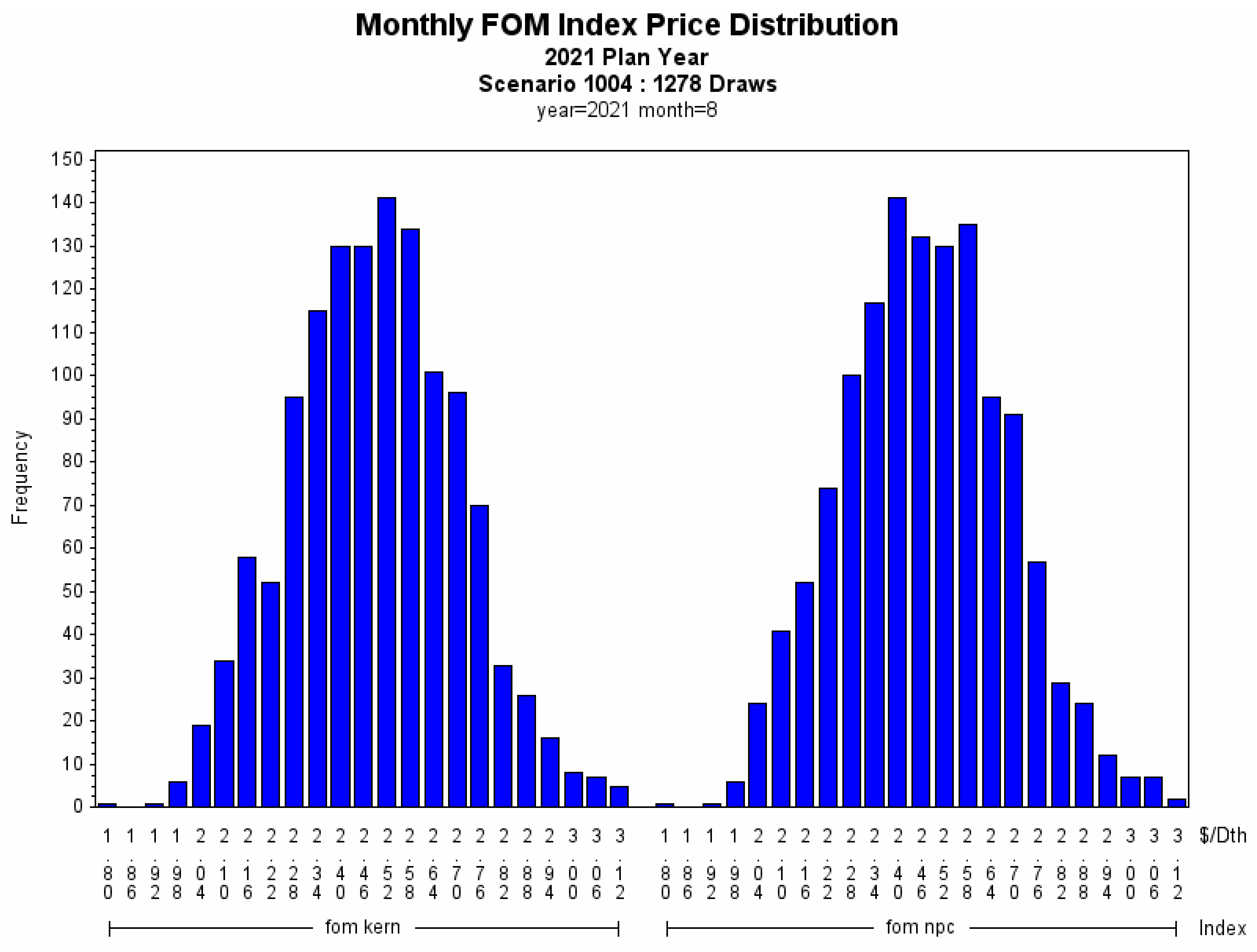

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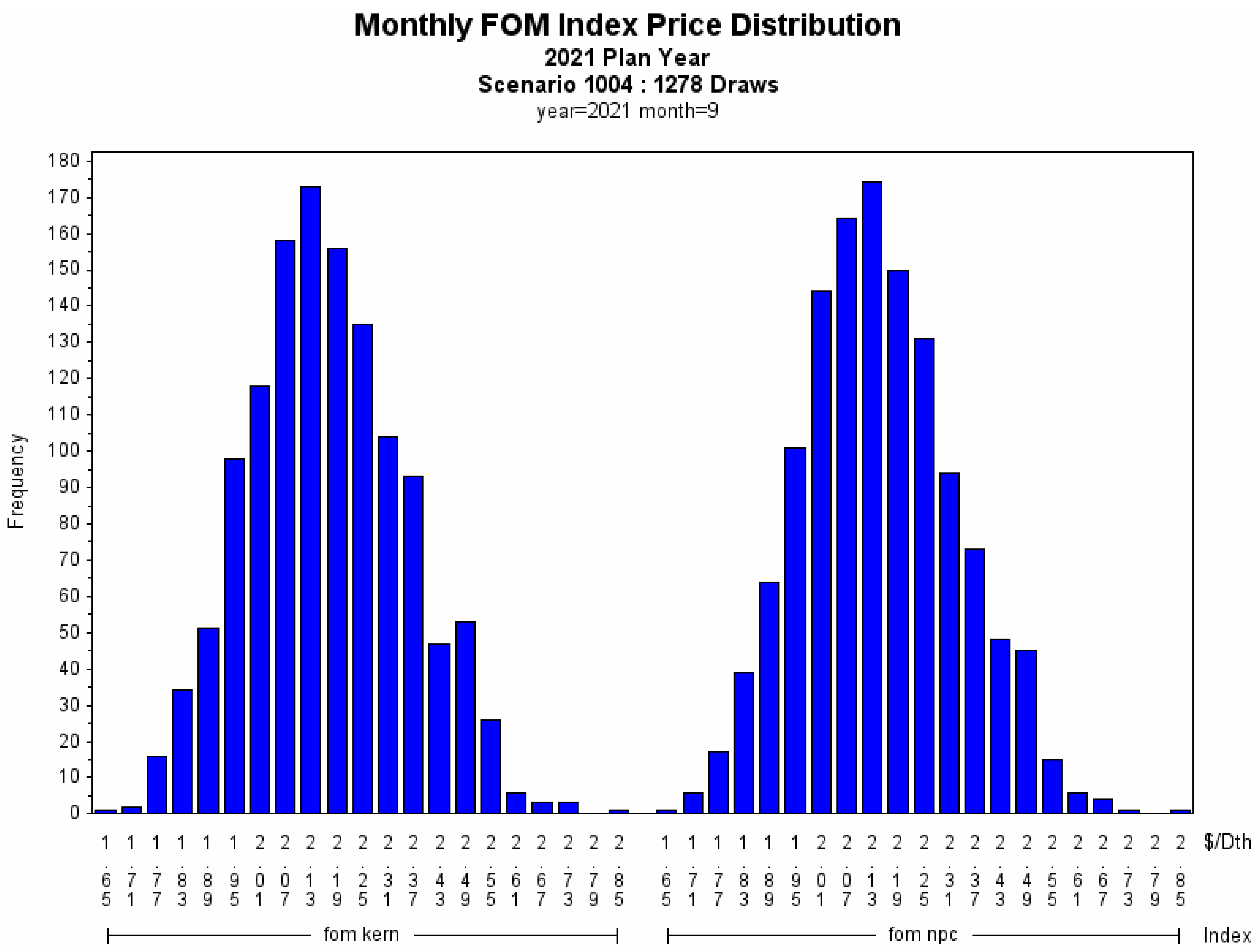

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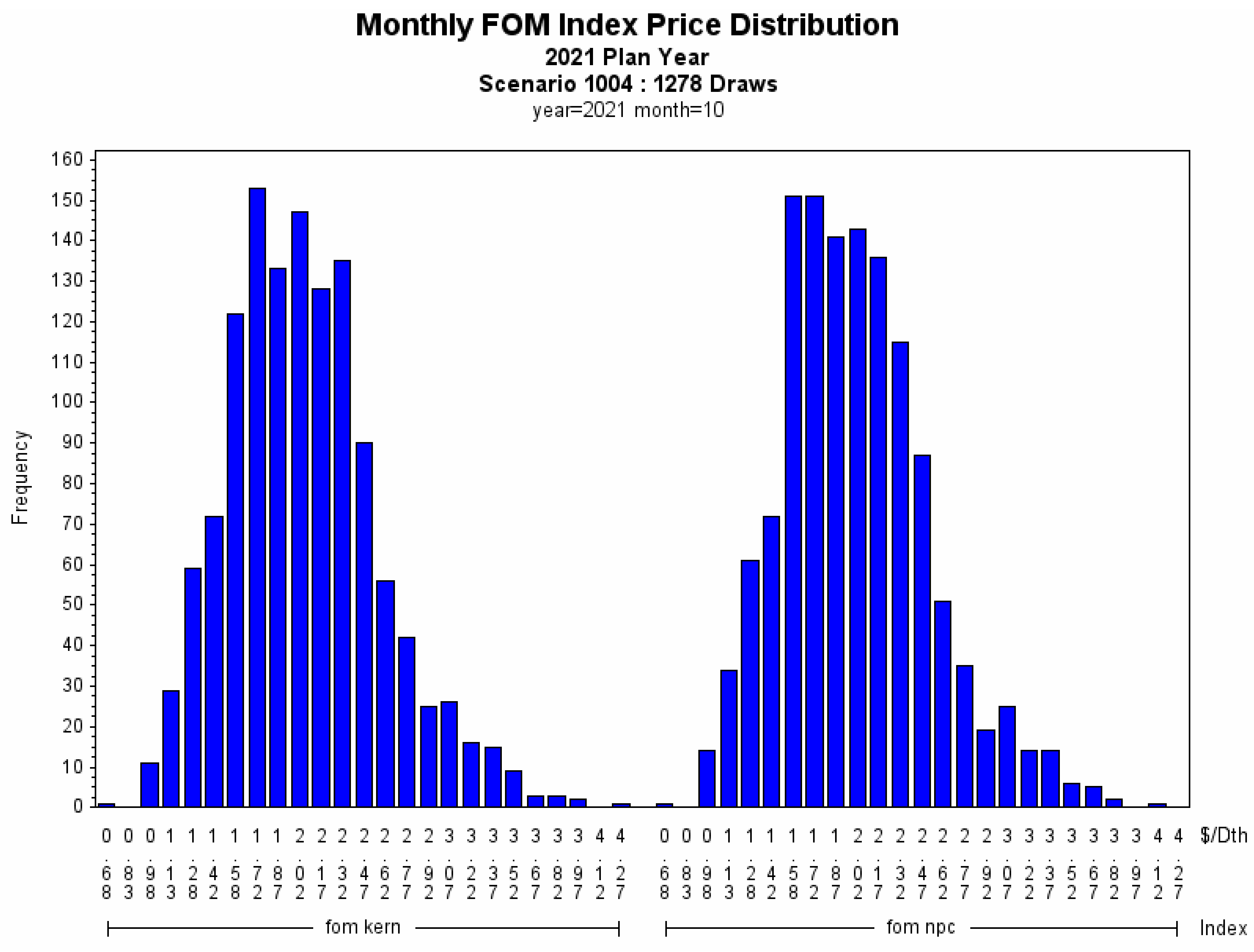

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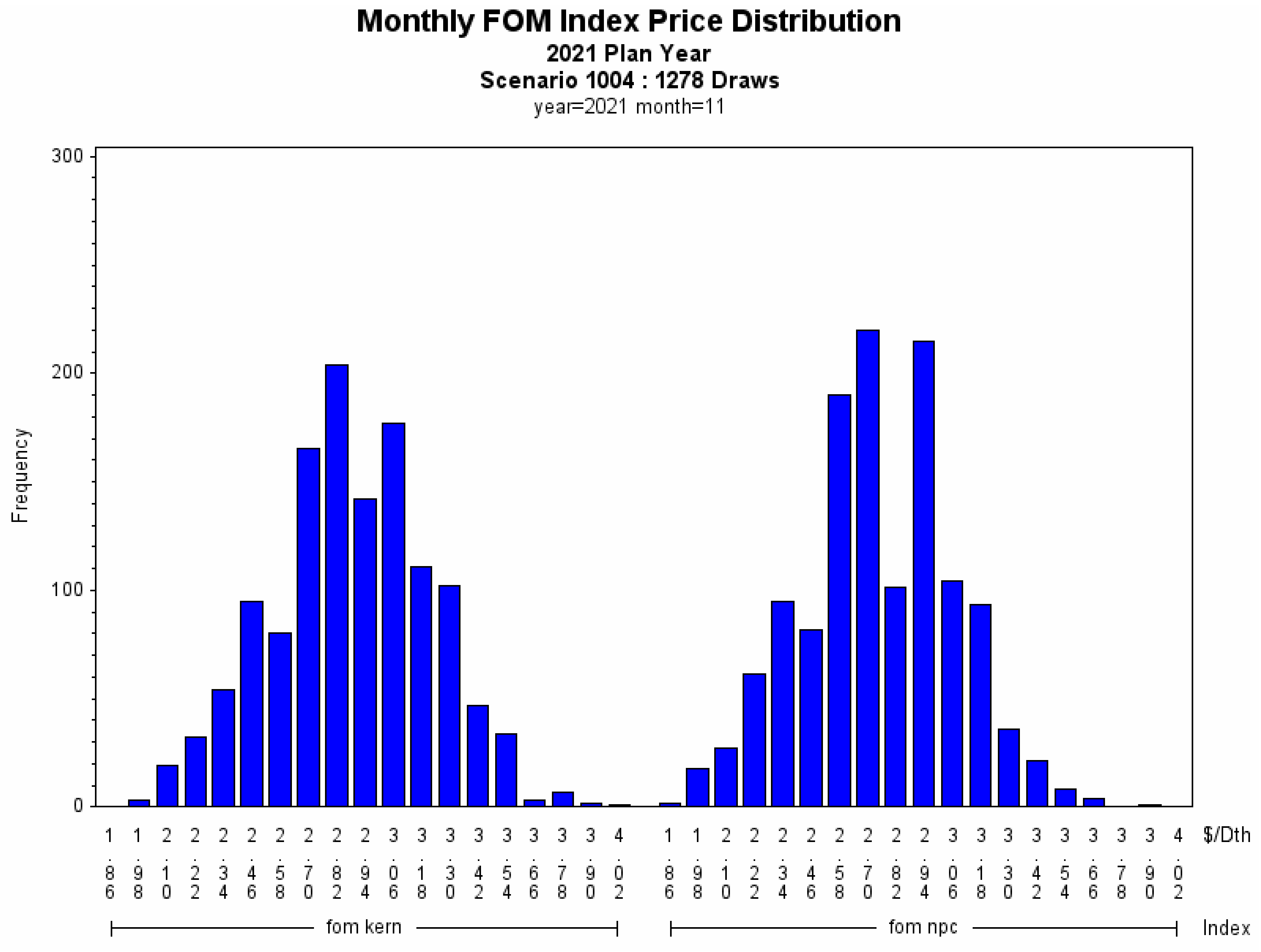

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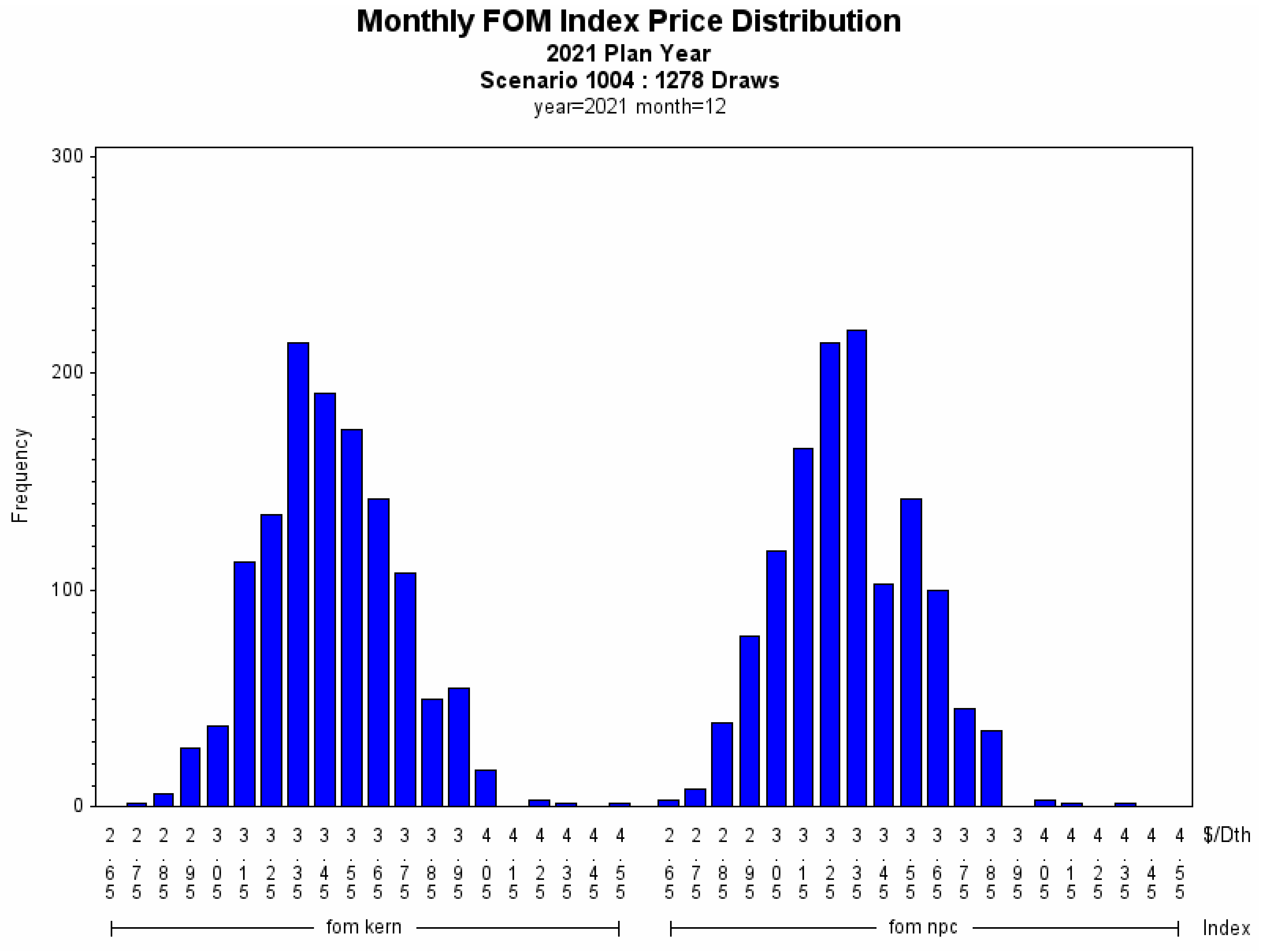

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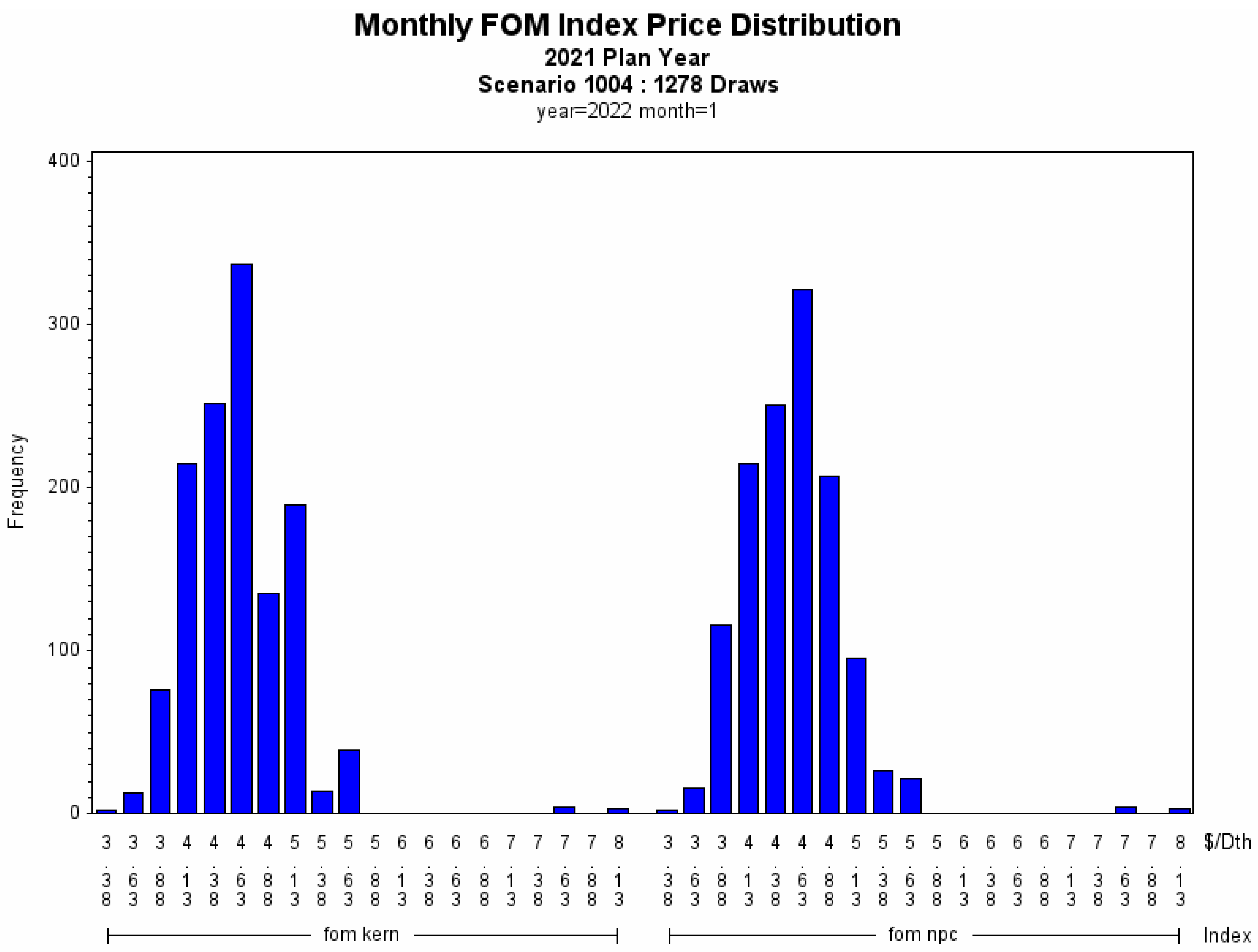

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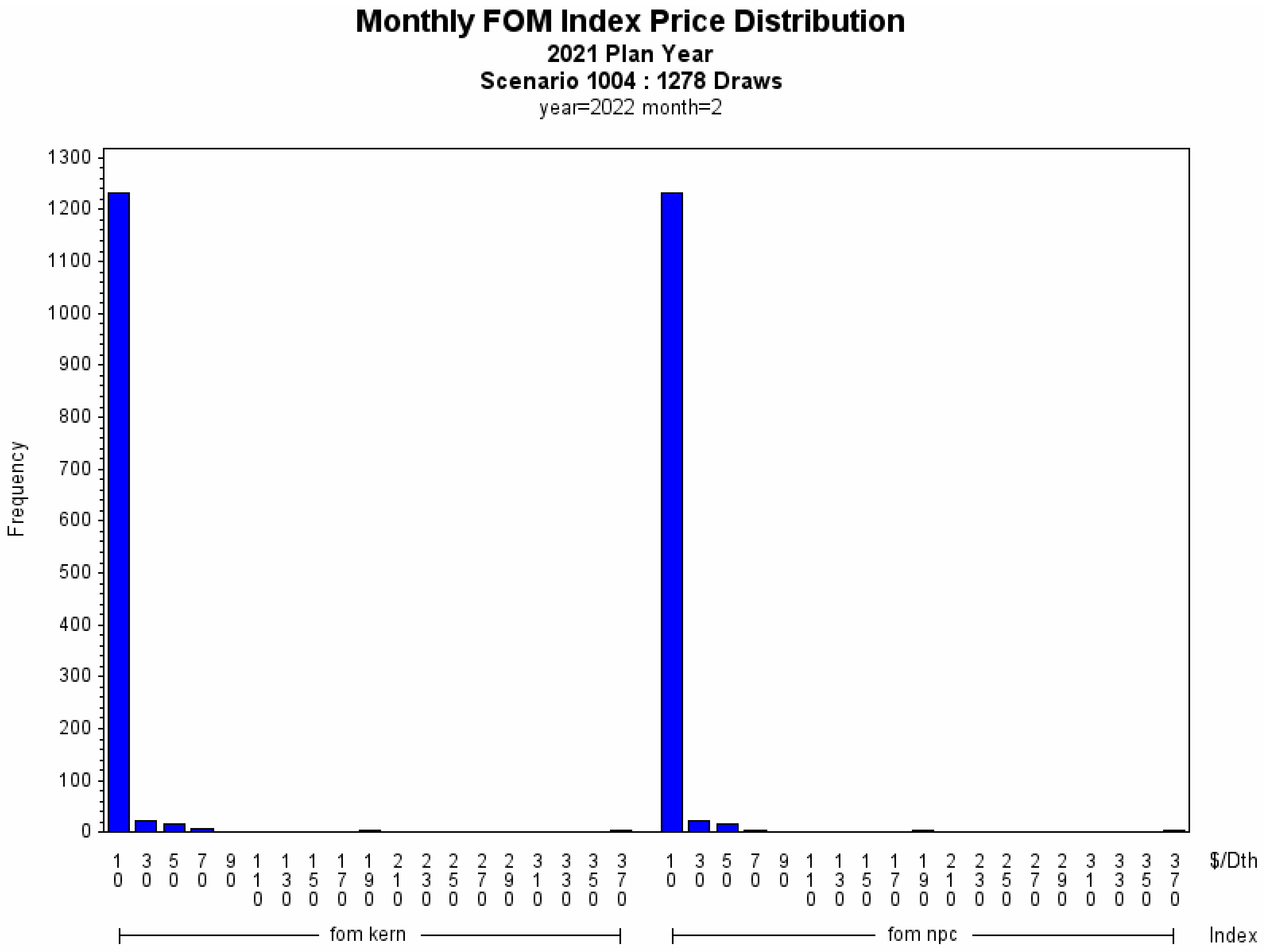


Exhibit 14.09

Monthly FOM Index Price Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=3

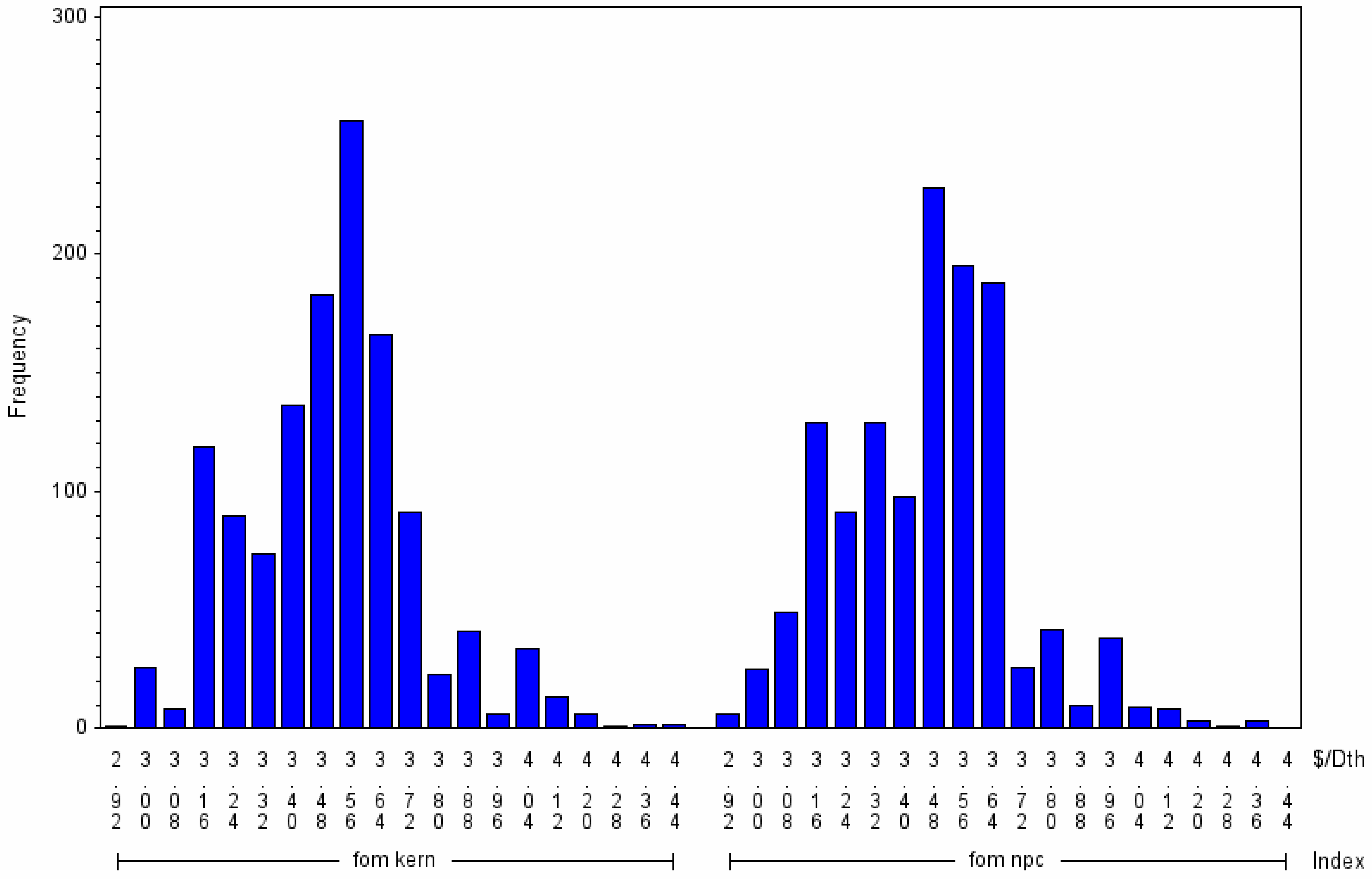


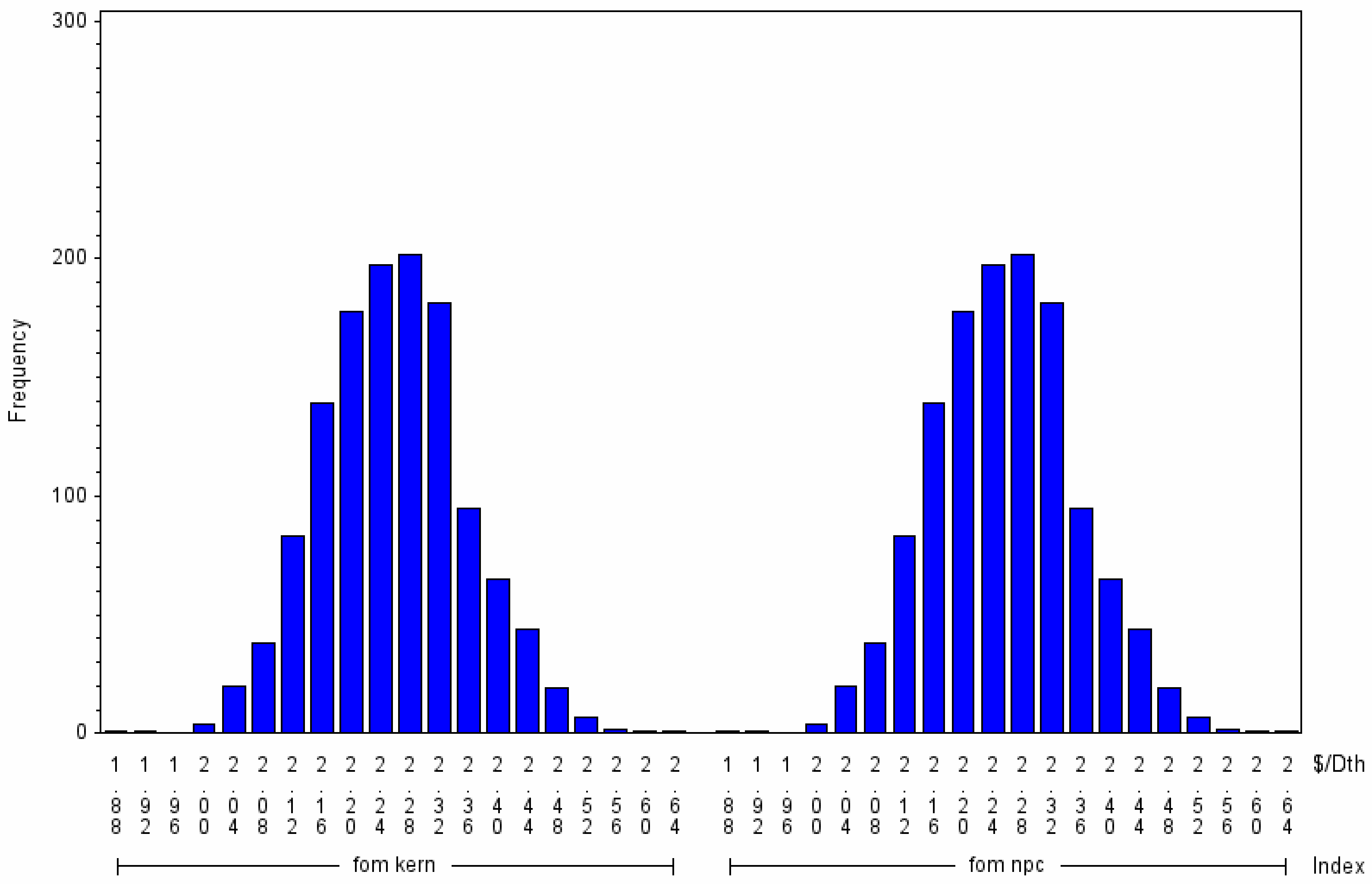
Exhibit 14.10

Monthly FOM Index Price Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=4



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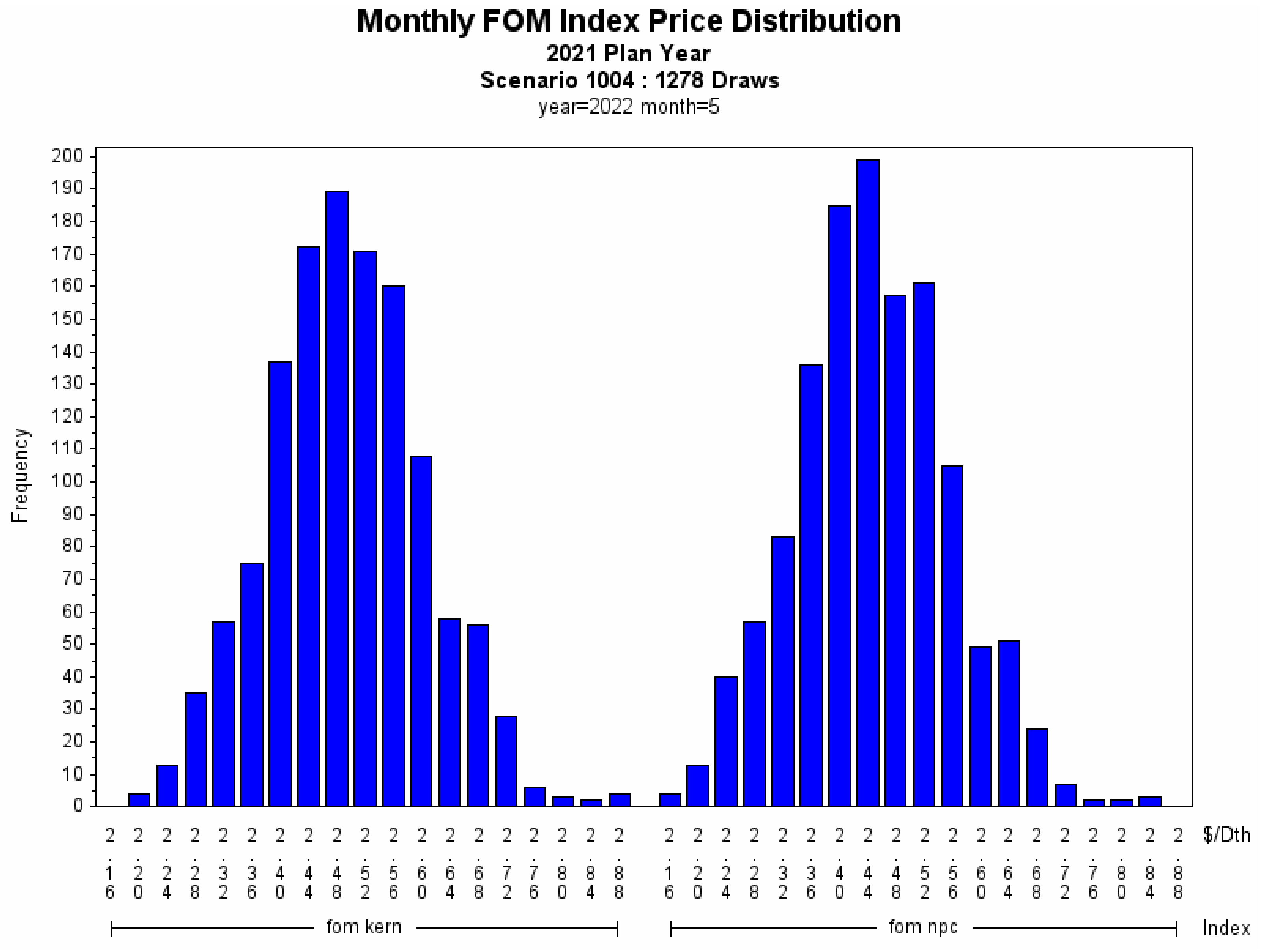

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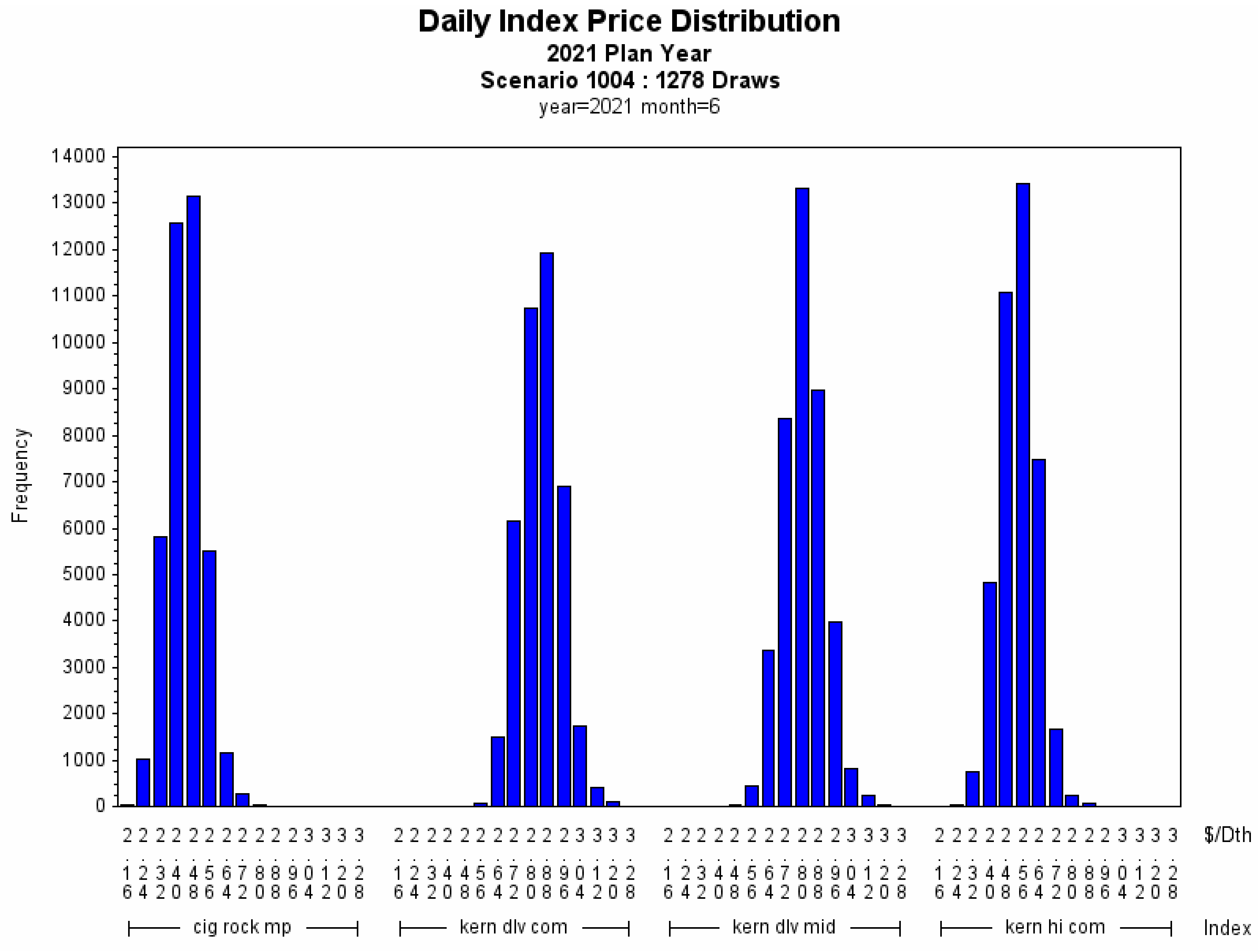

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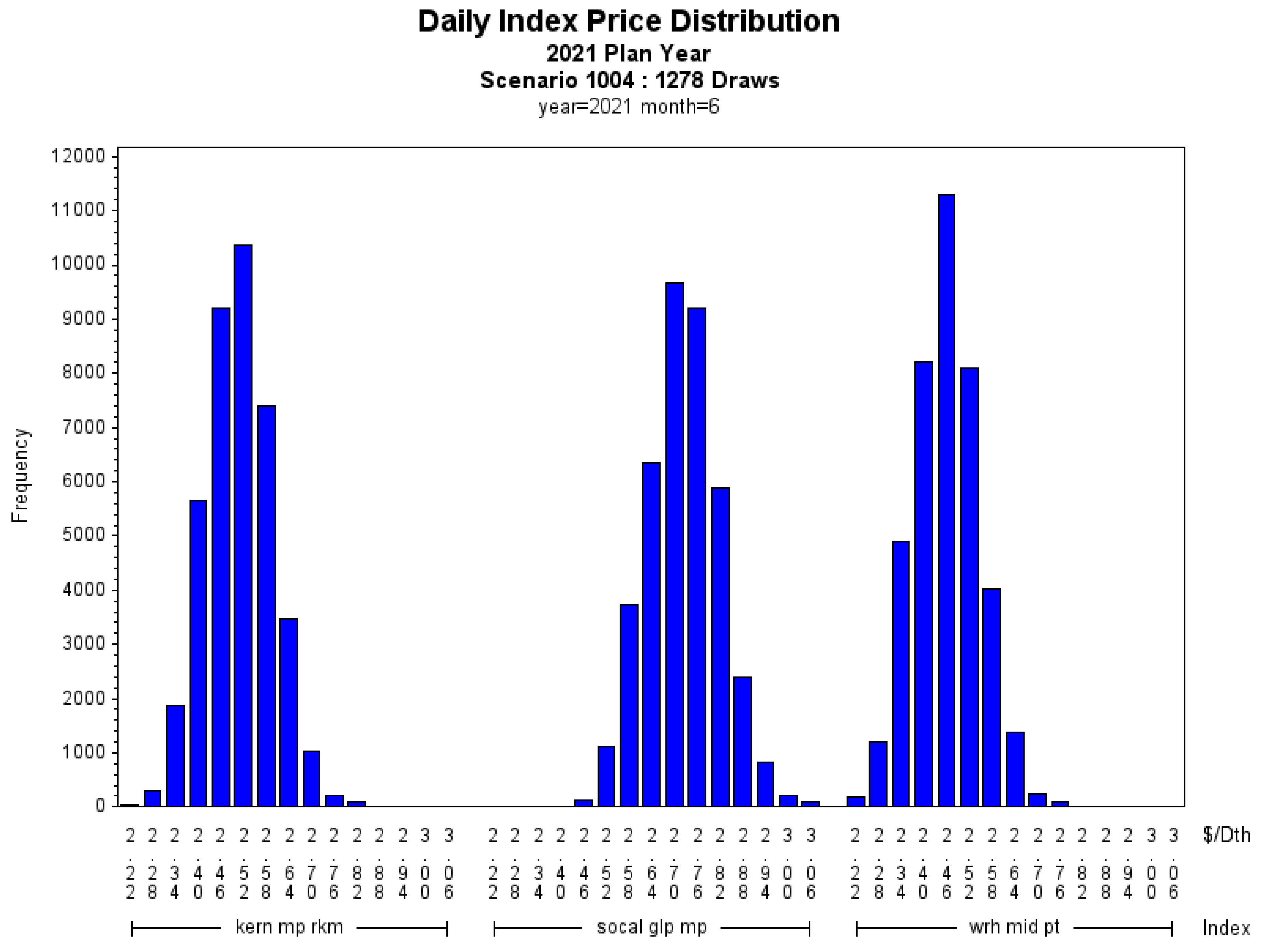

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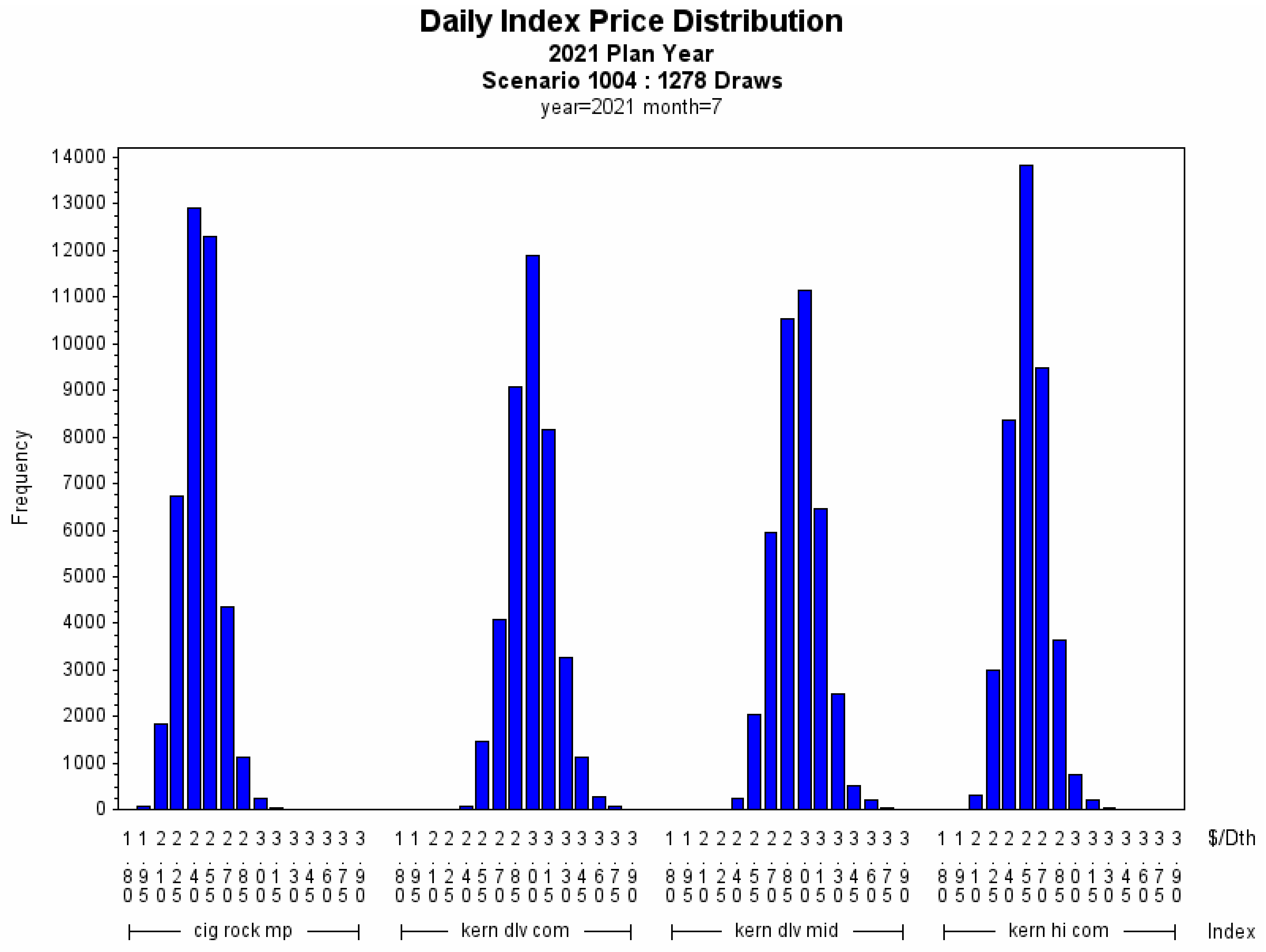

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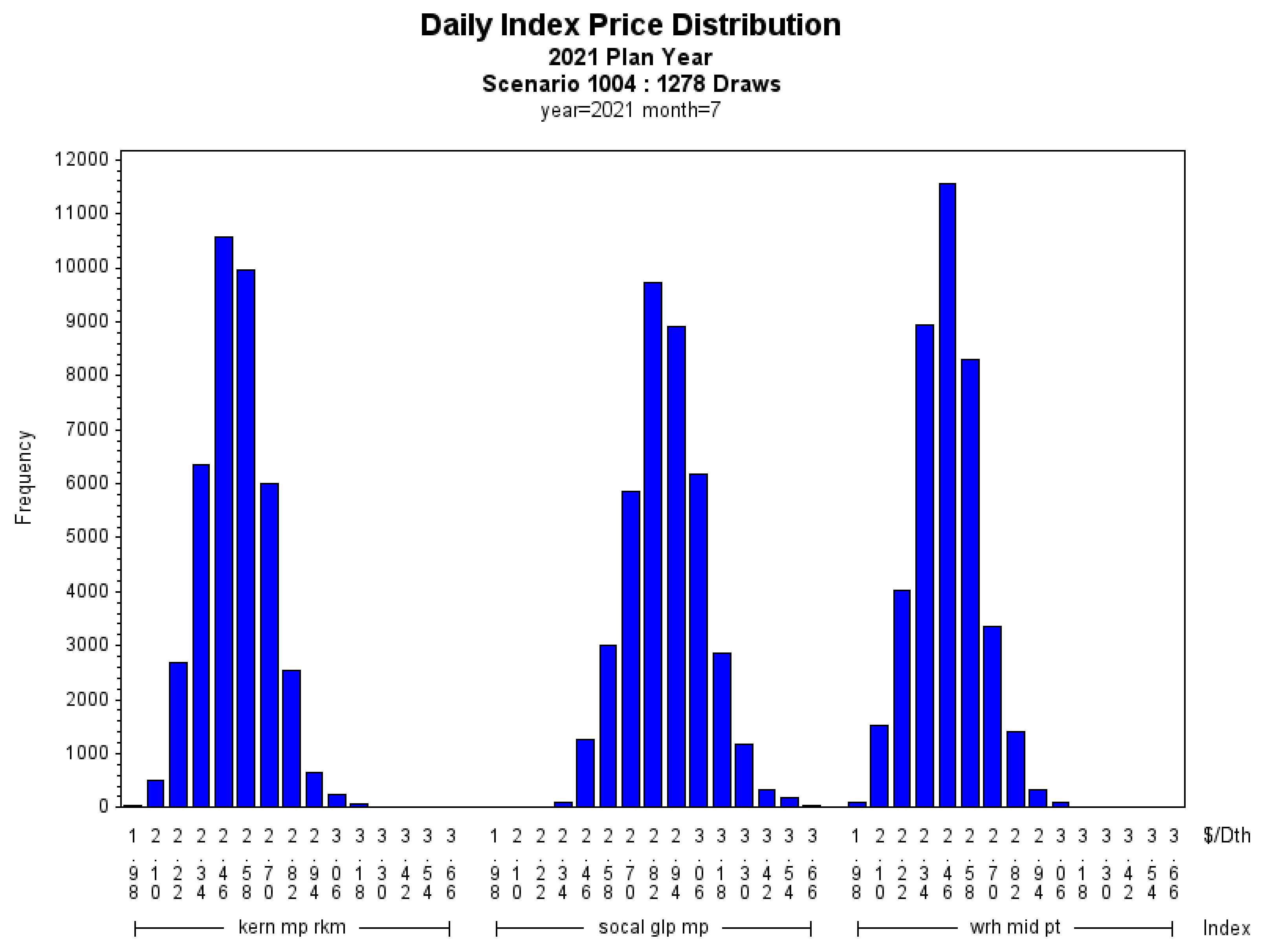

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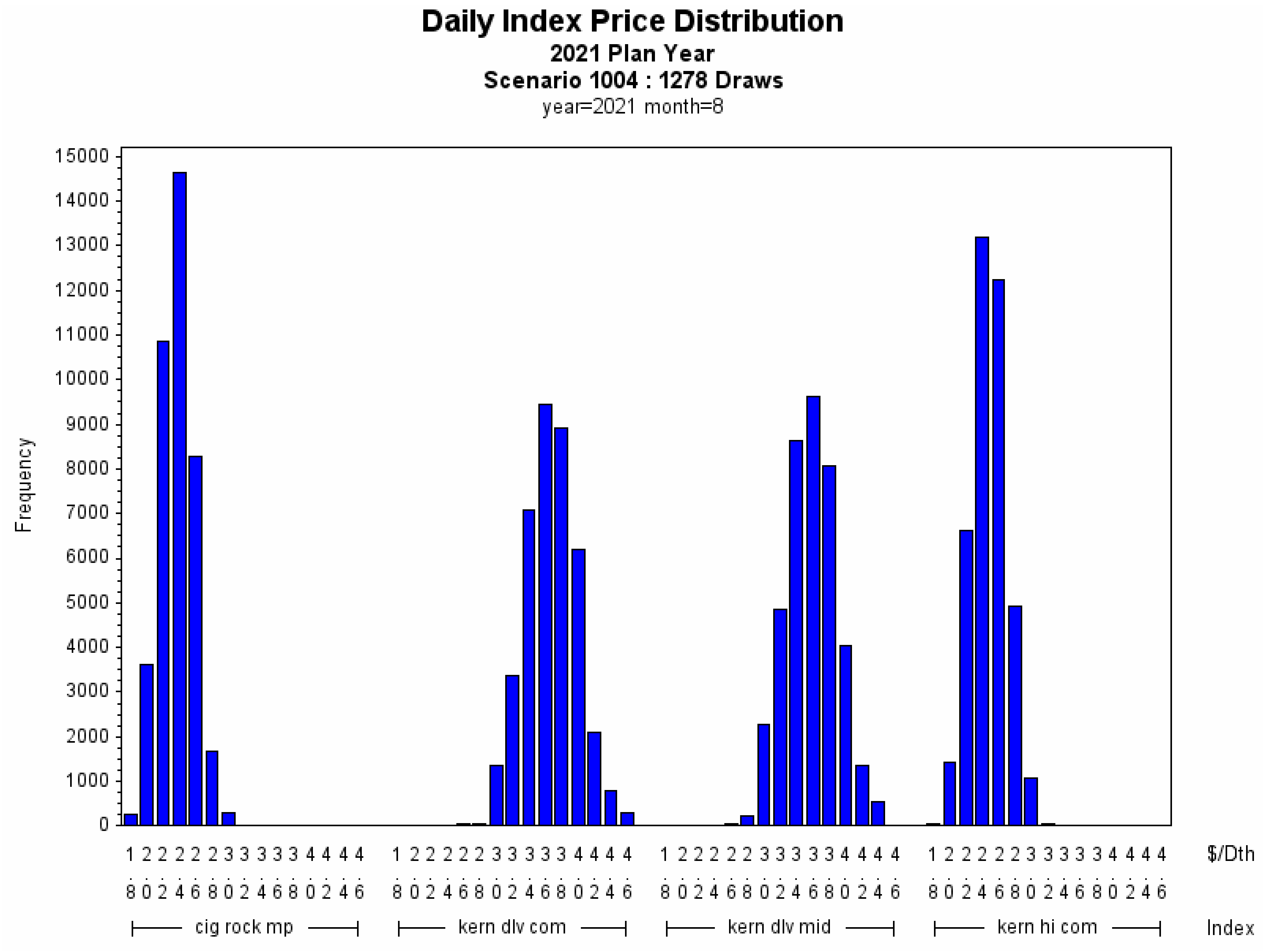

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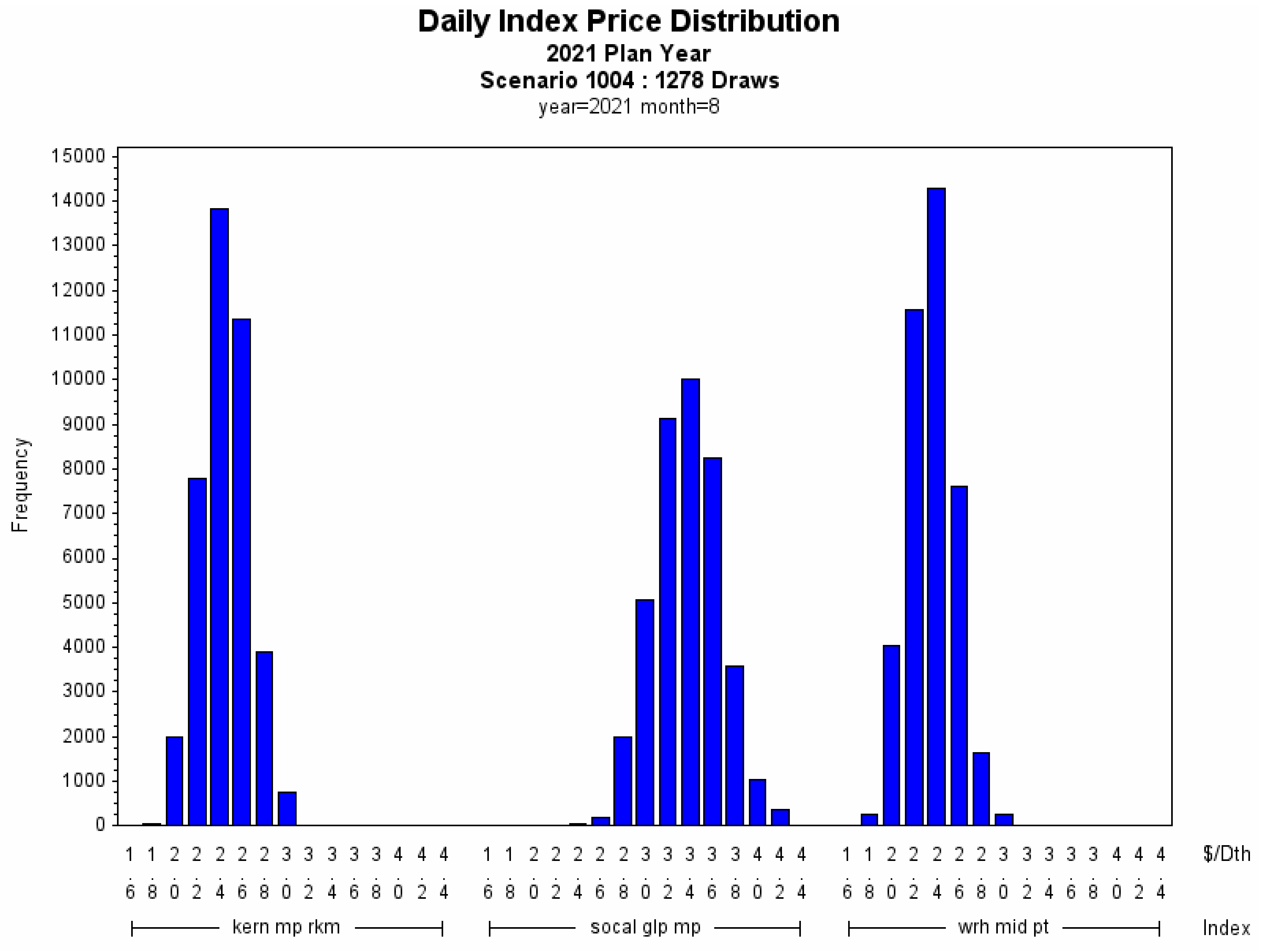

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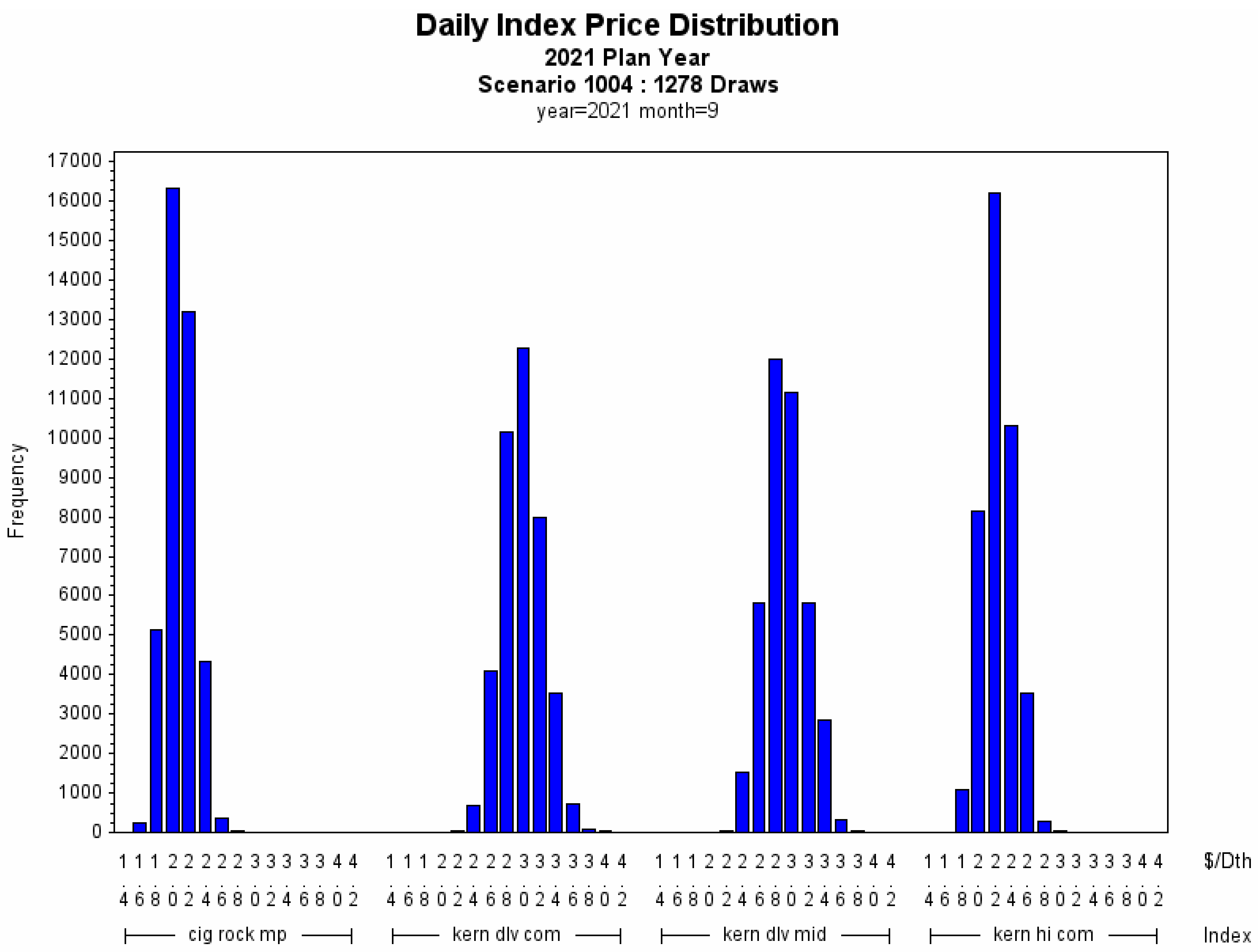

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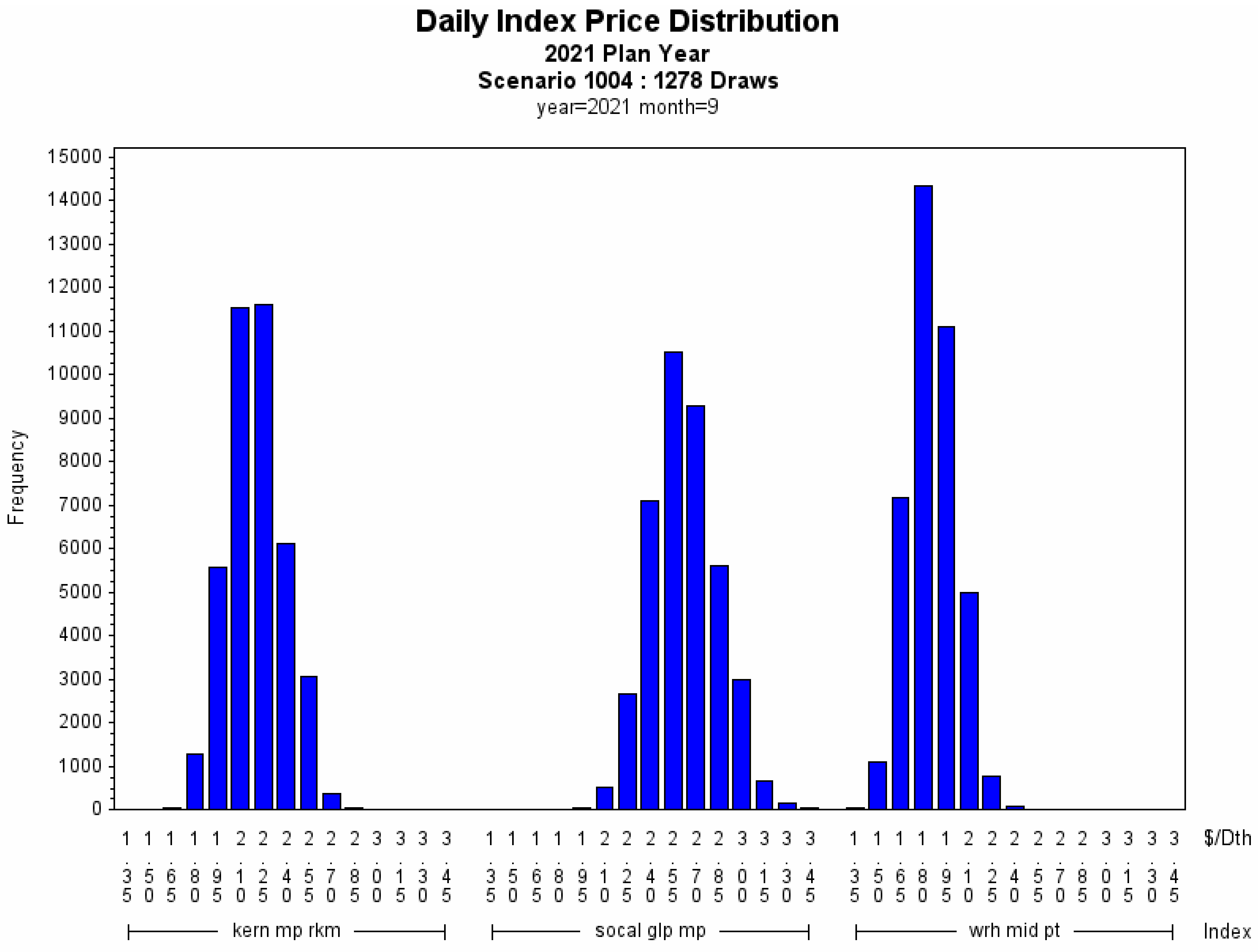

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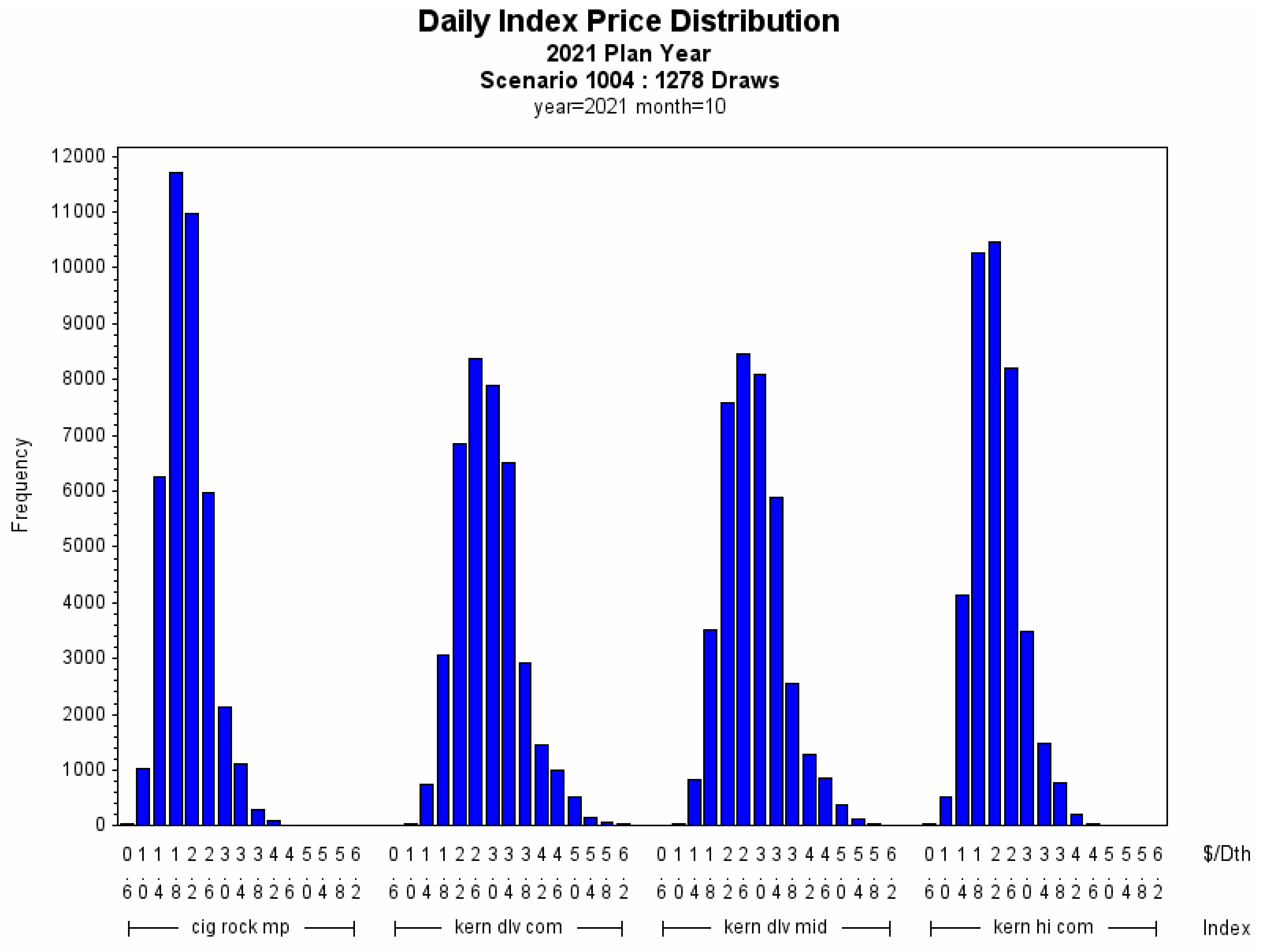

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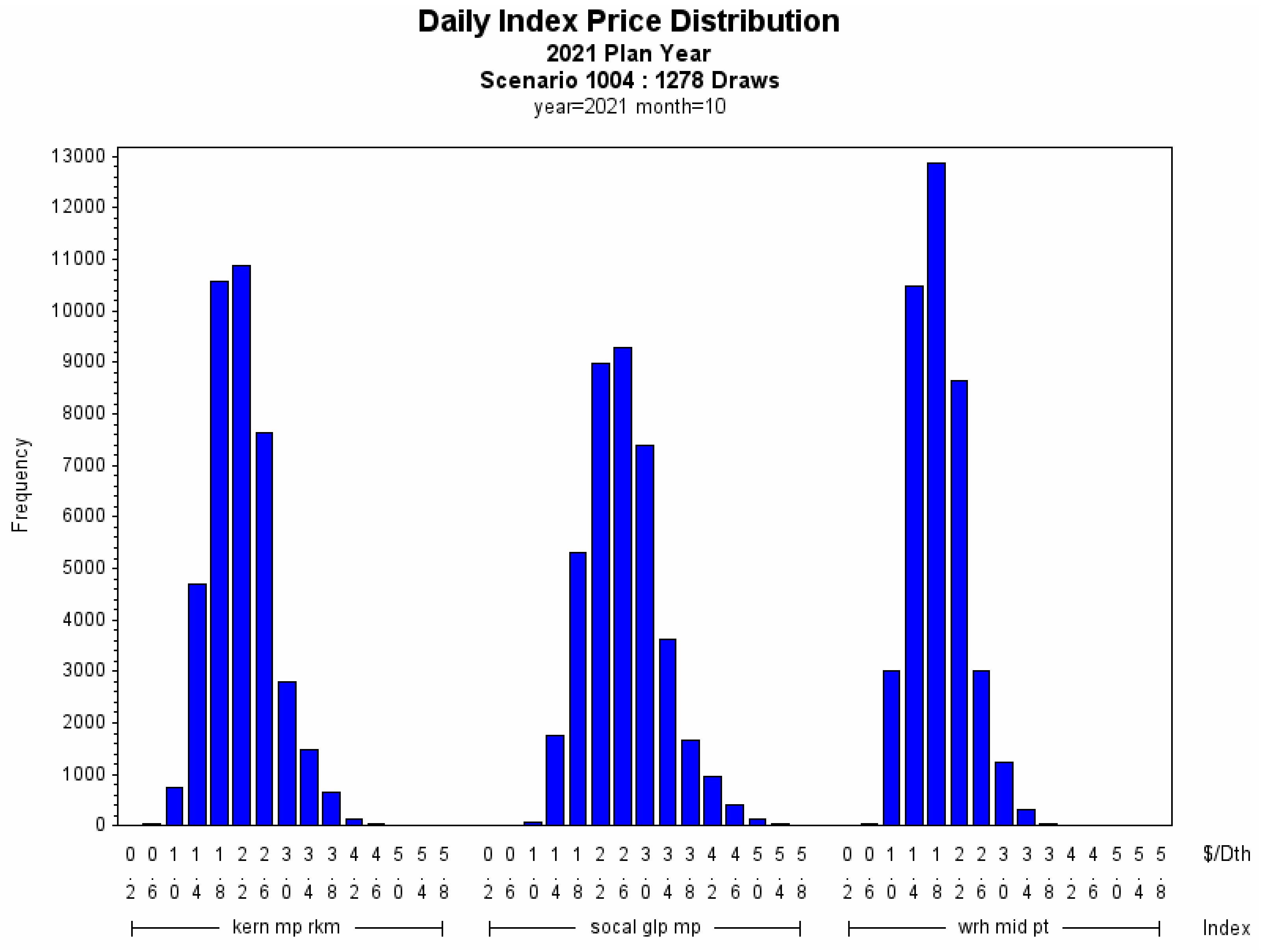

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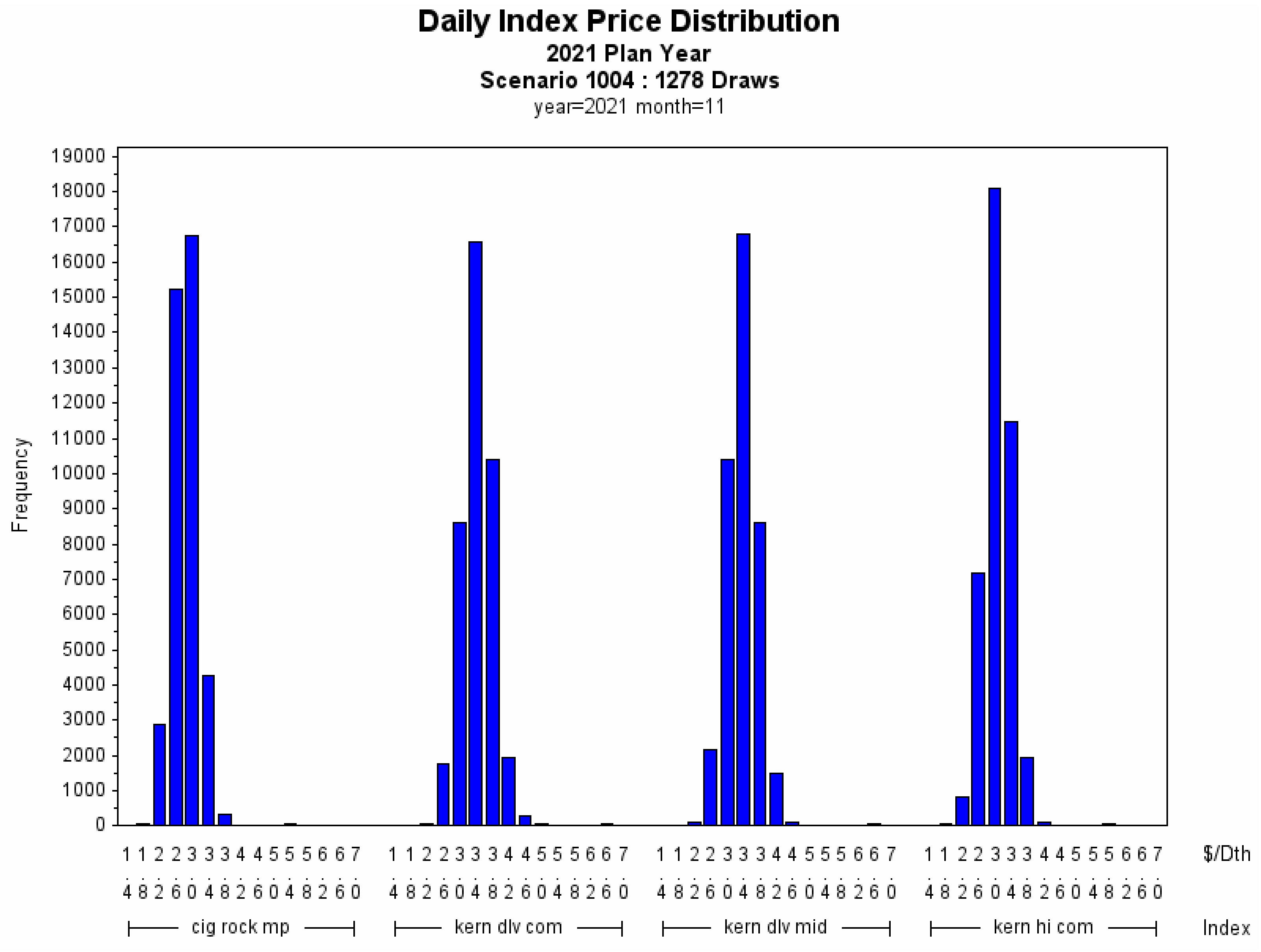

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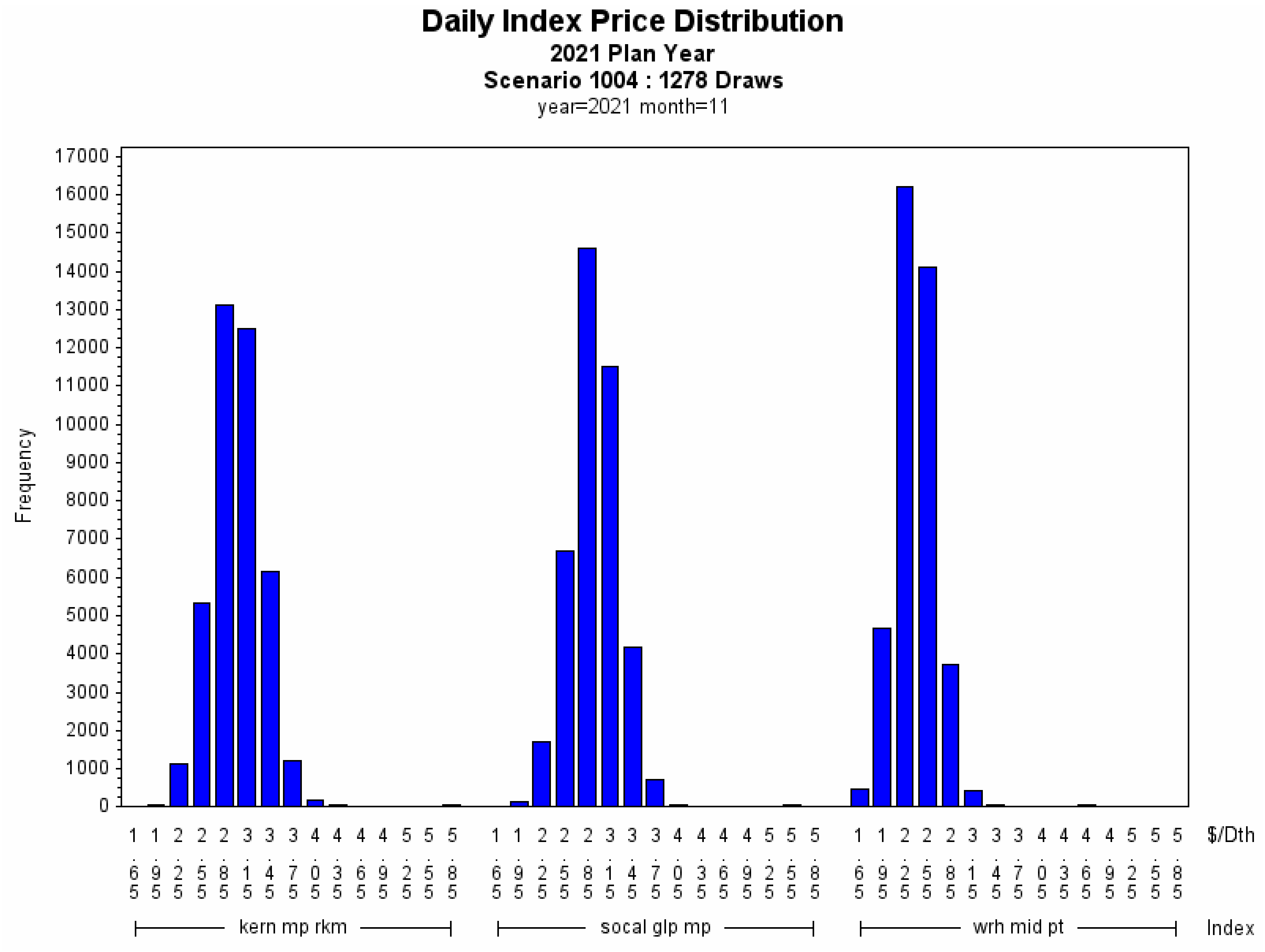

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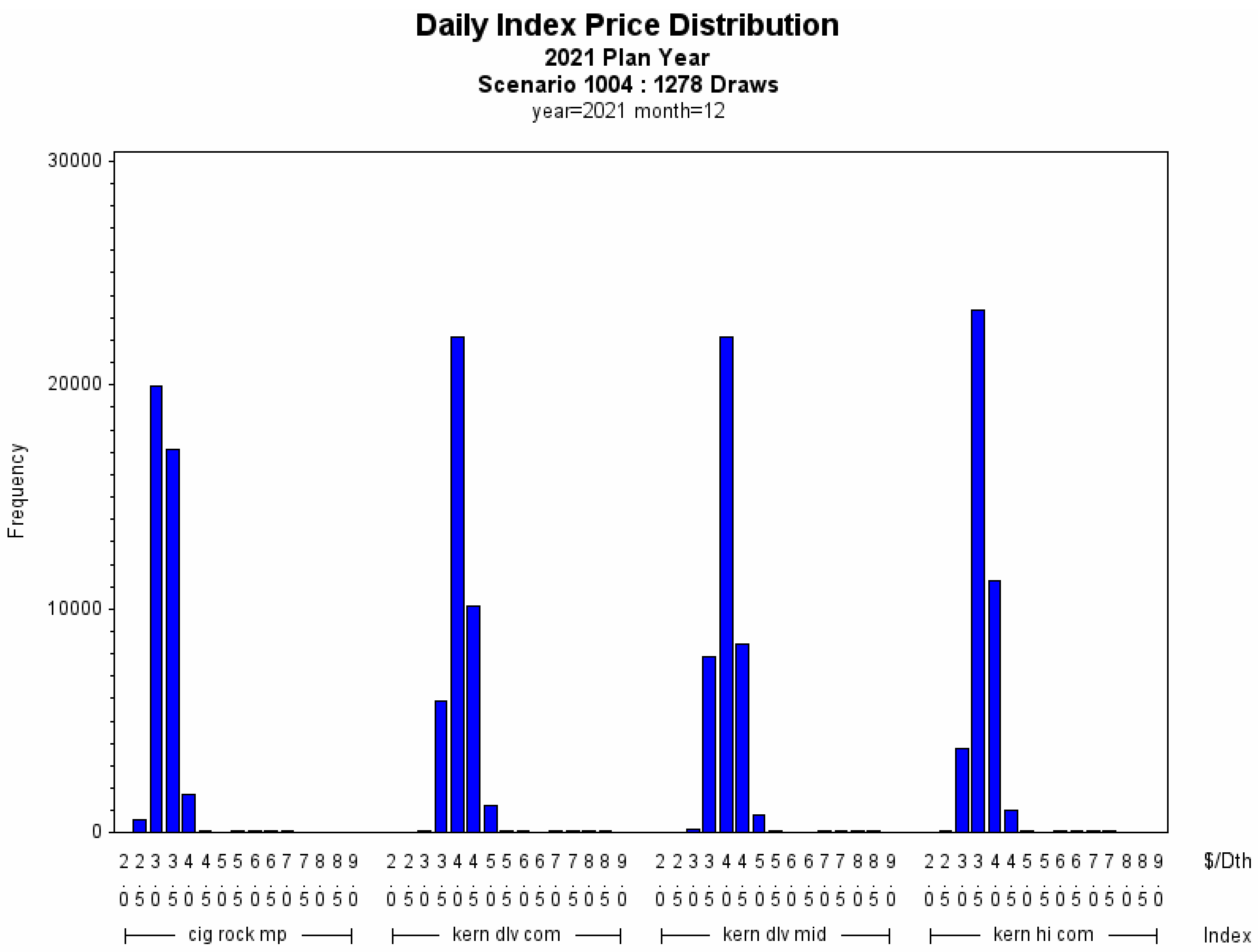

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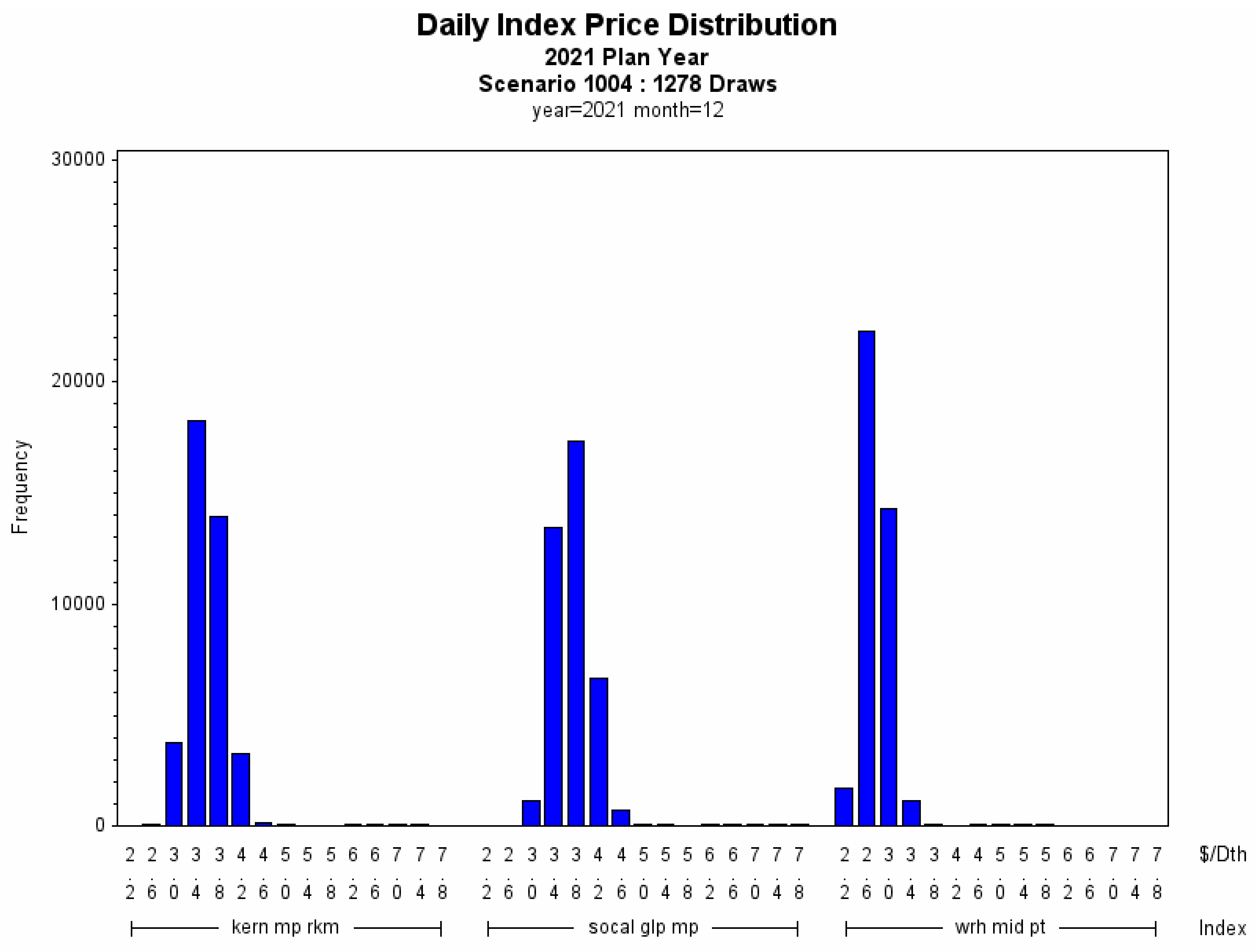


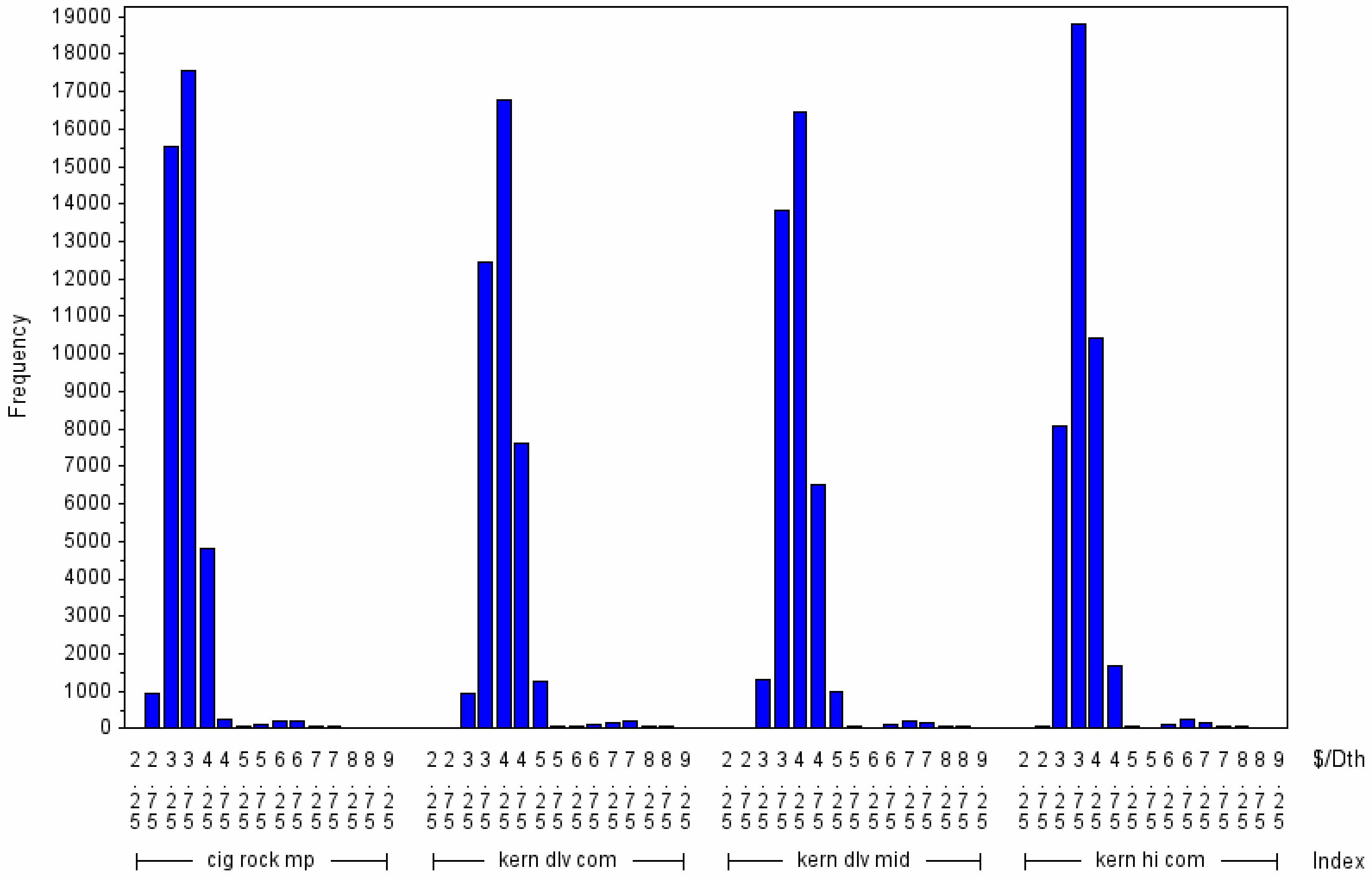
Exhibit 14.26

Daily Index Price Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=1



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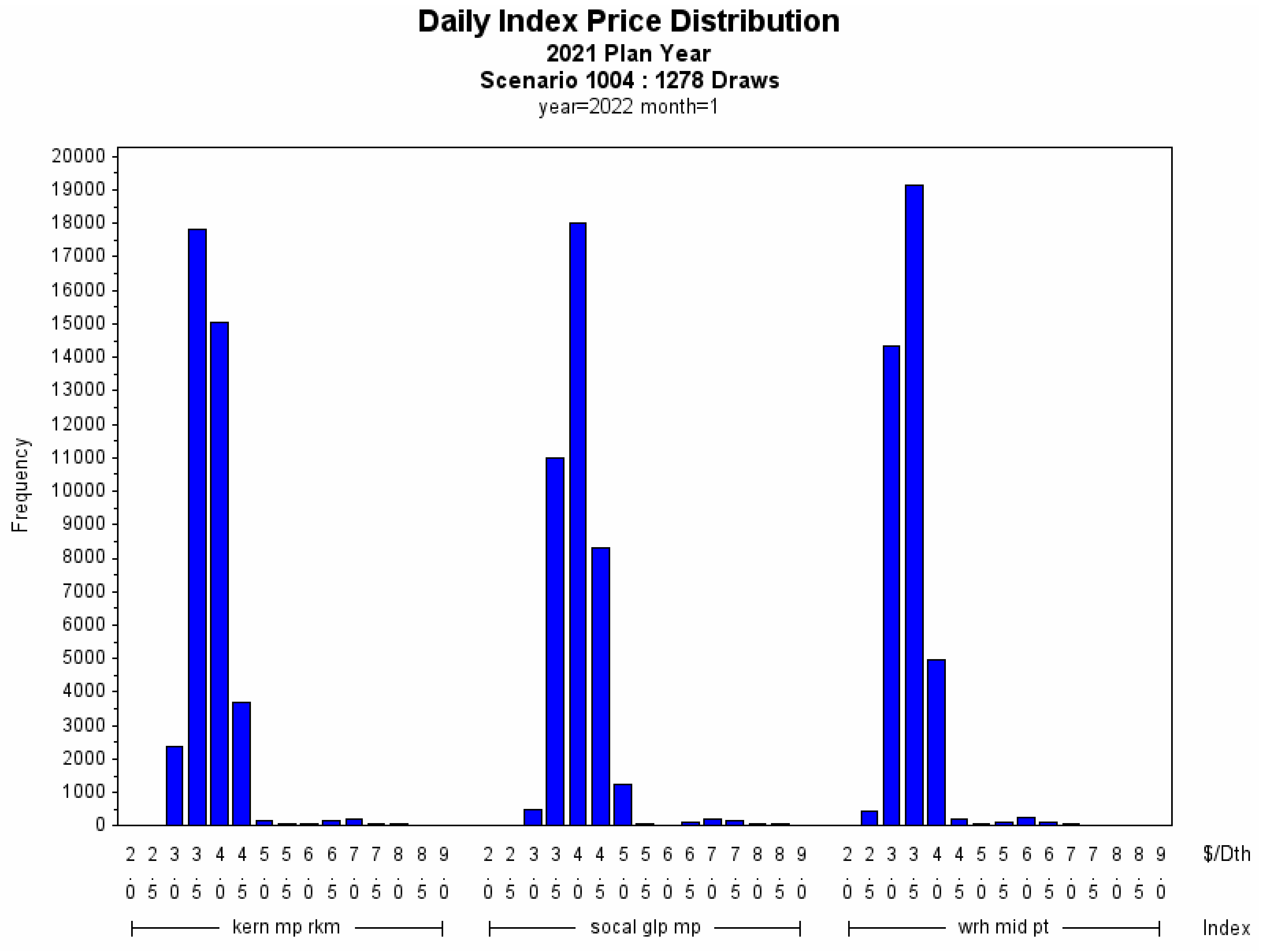


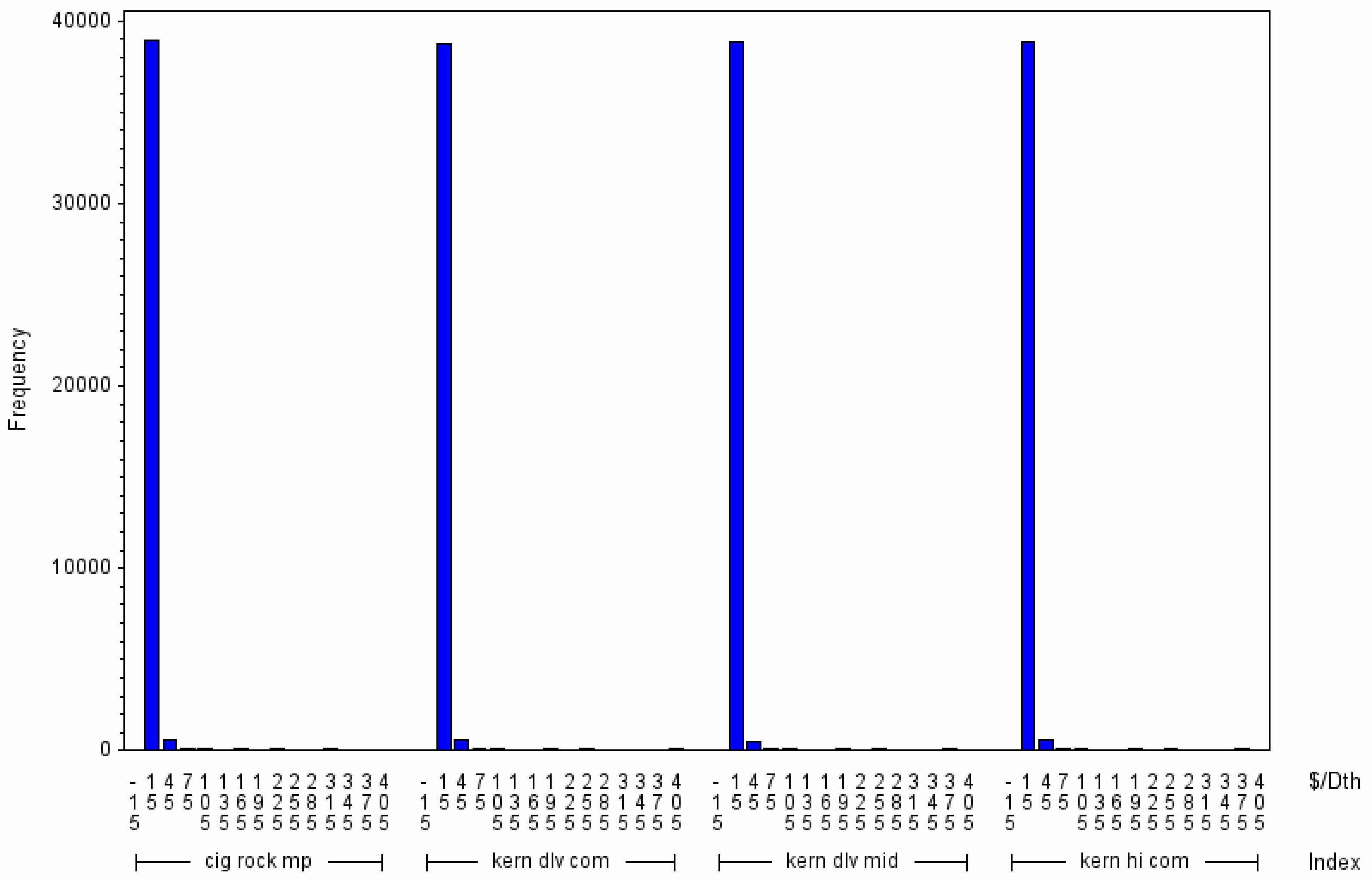
Exhibit 14.28

Daily Index Price Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=2



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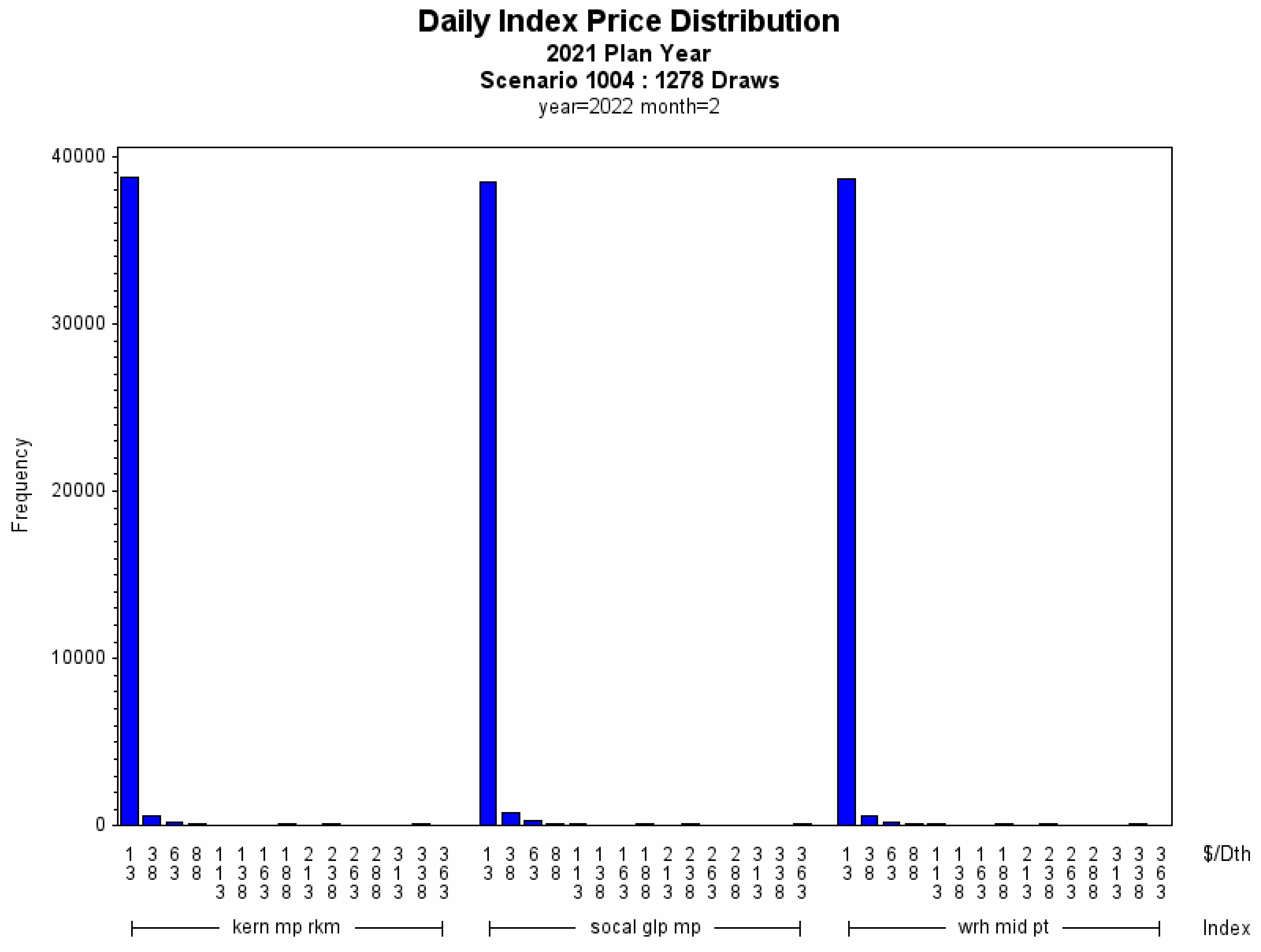

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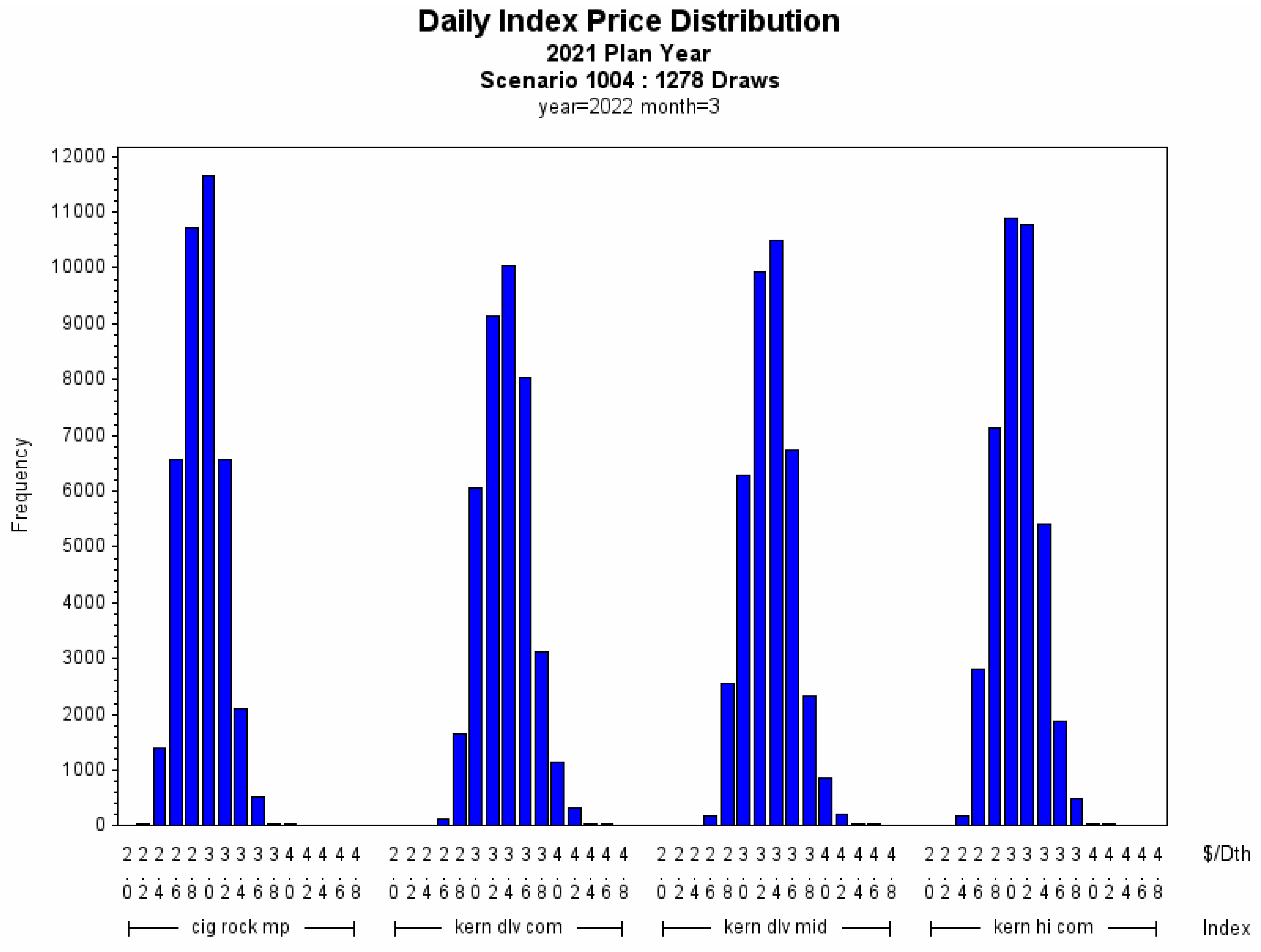


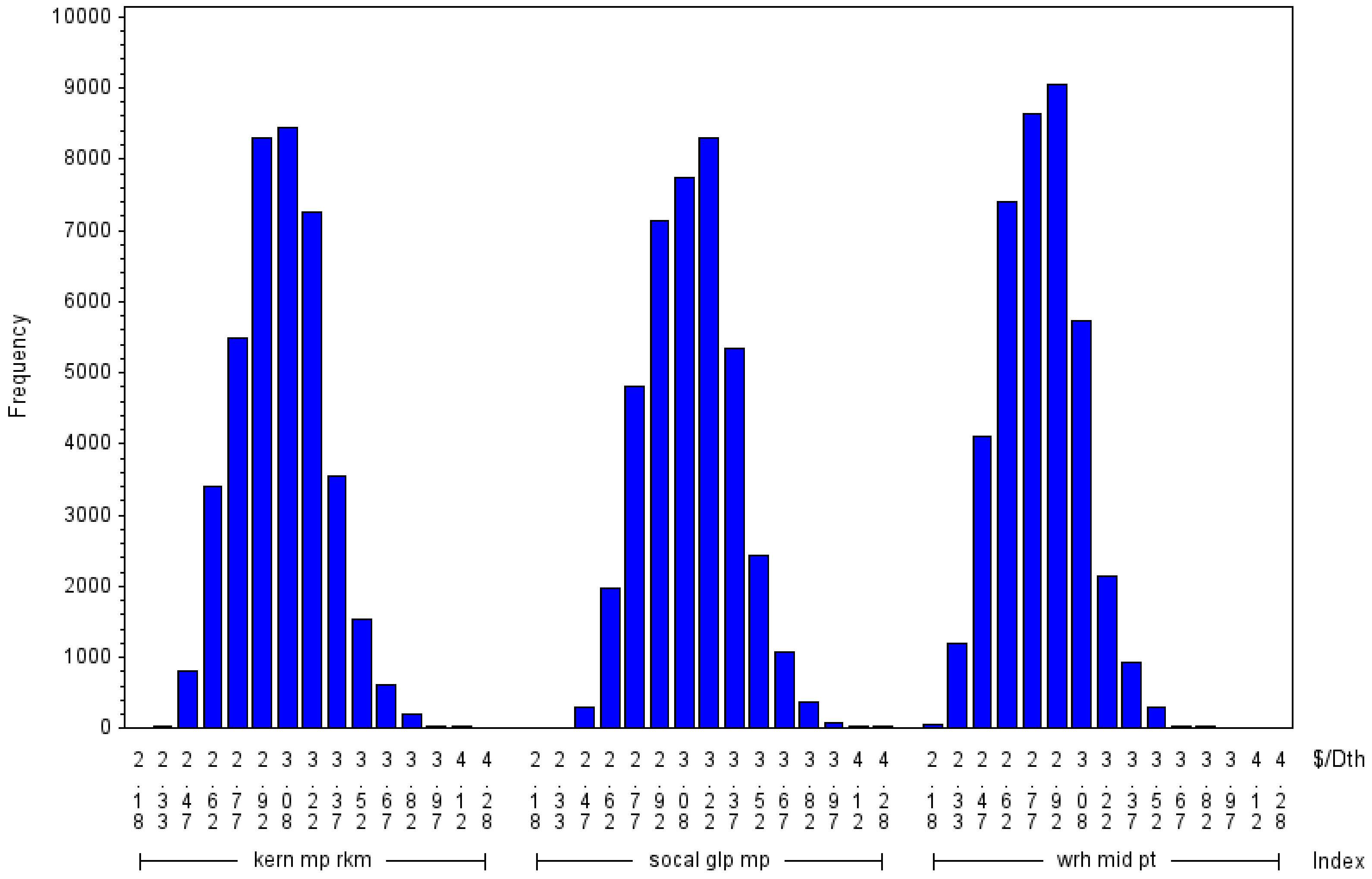
Exhibit 14.31

Daily Index Price Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=3



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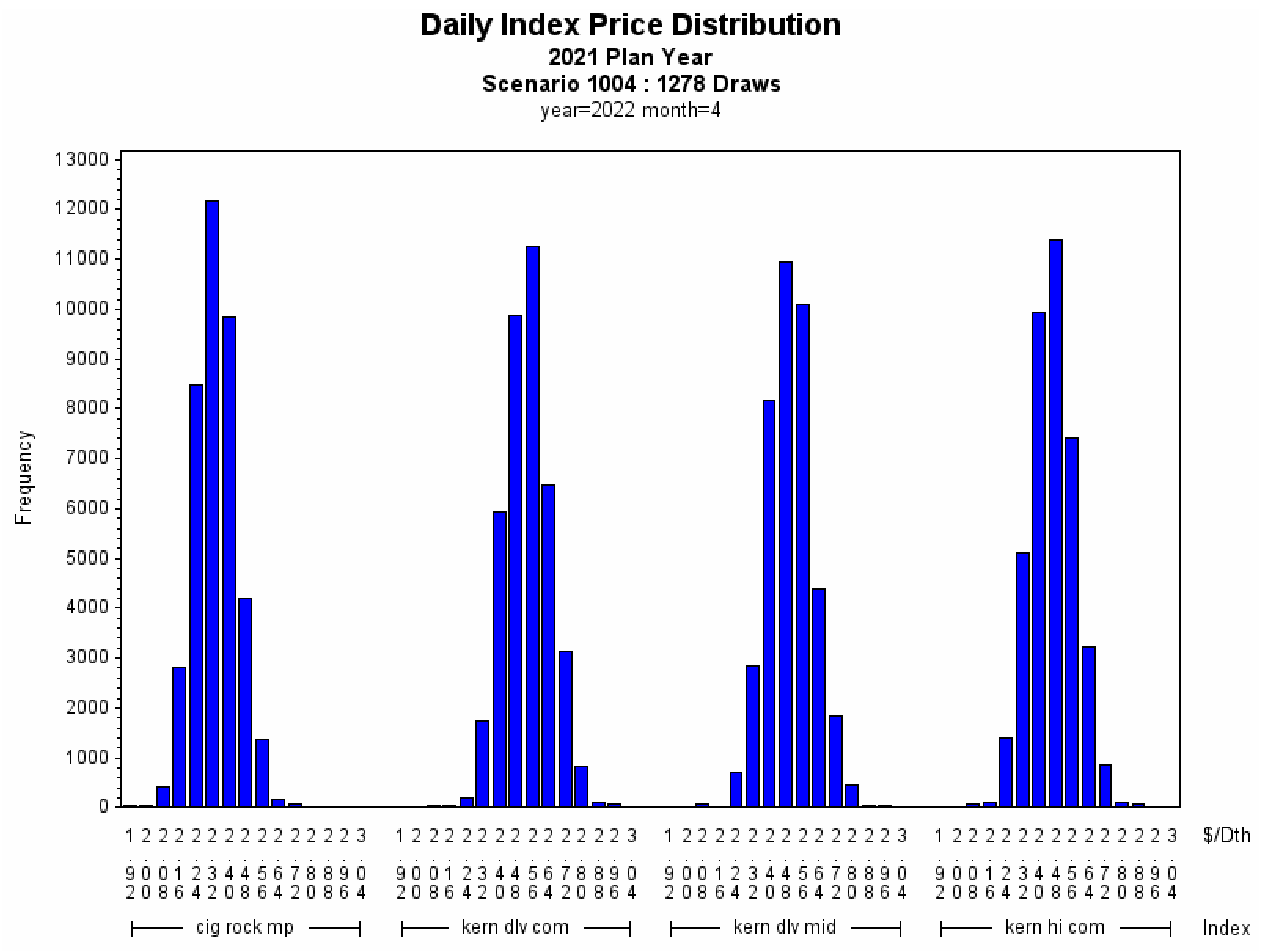

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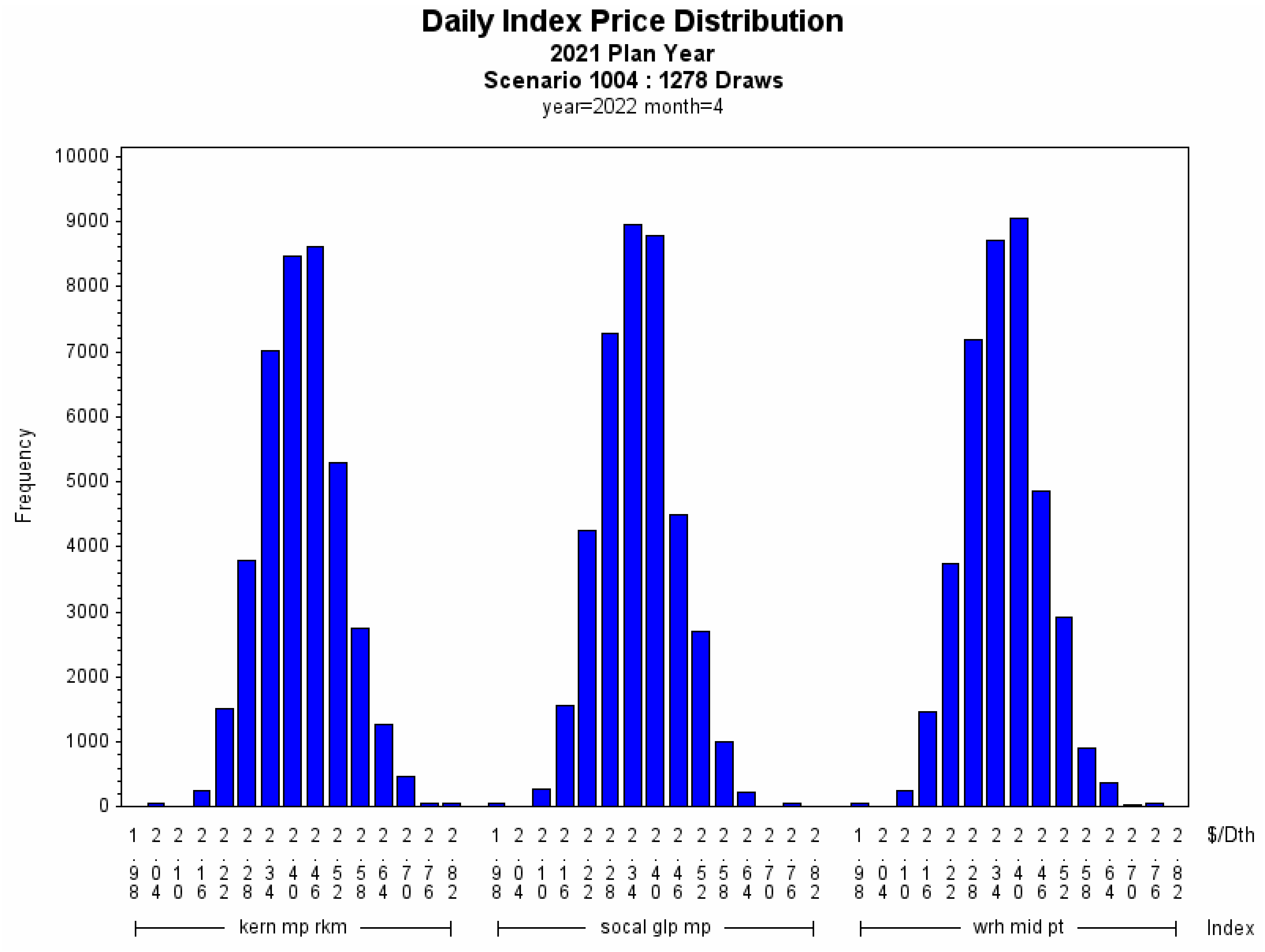

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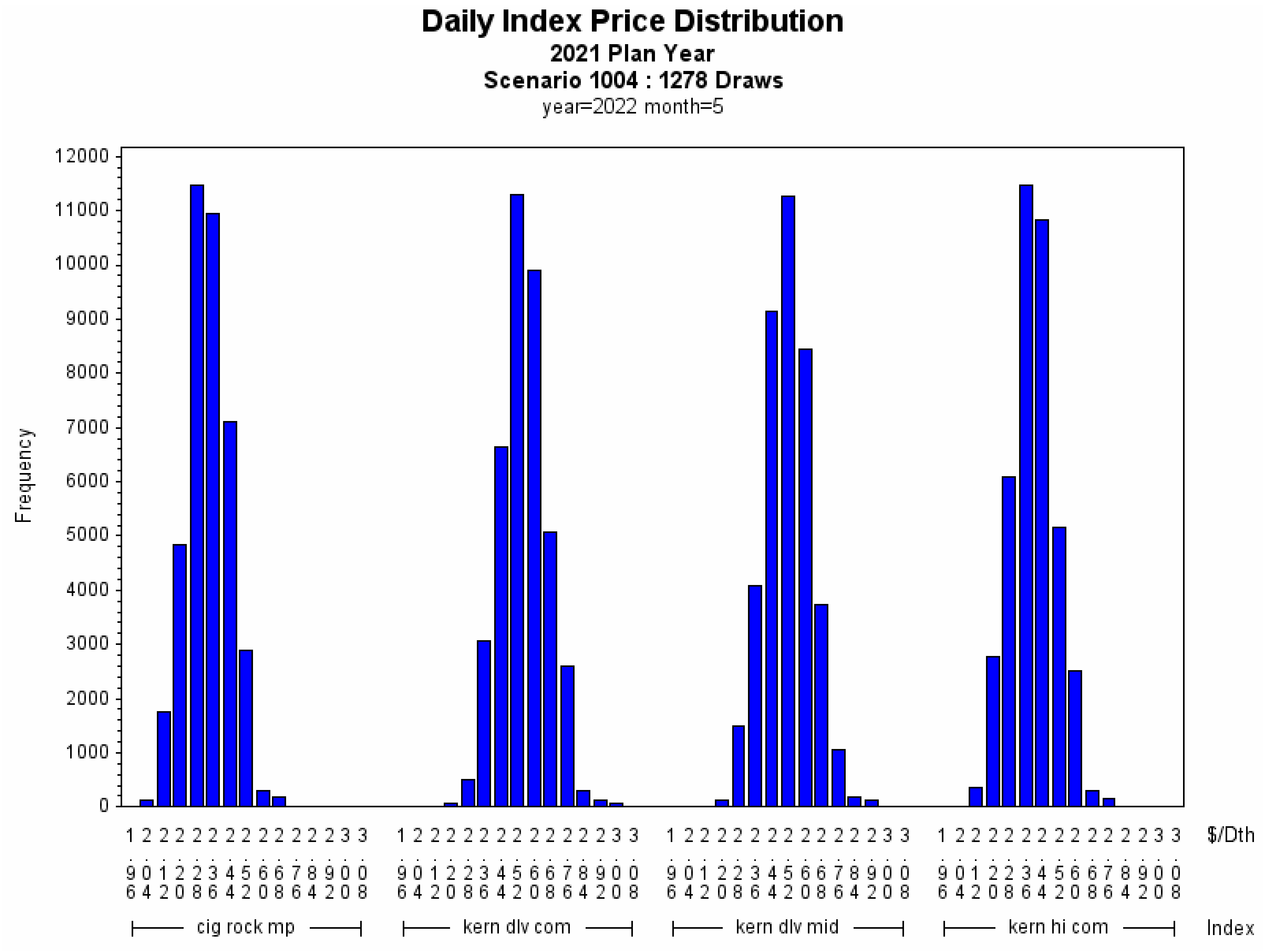

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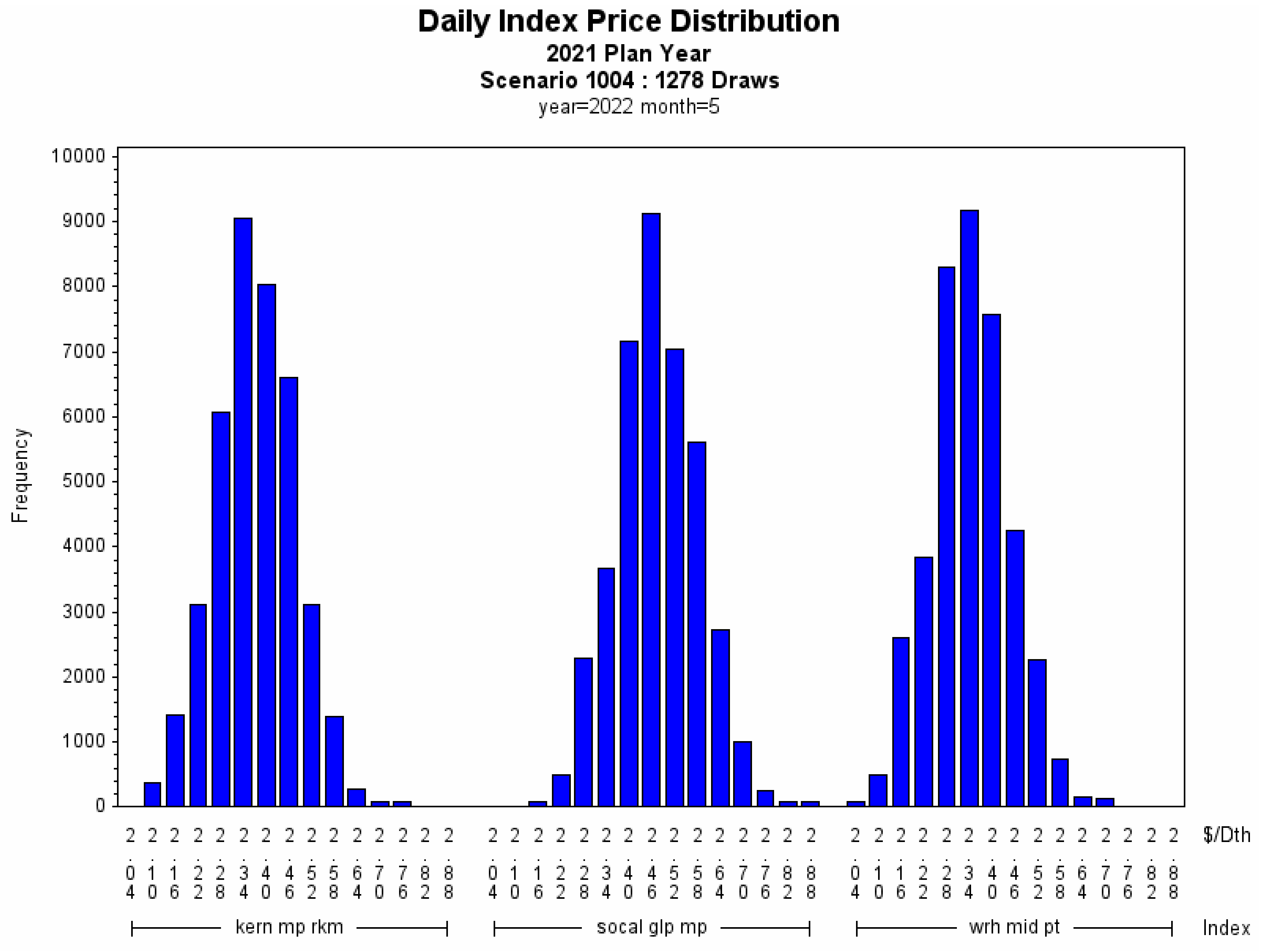
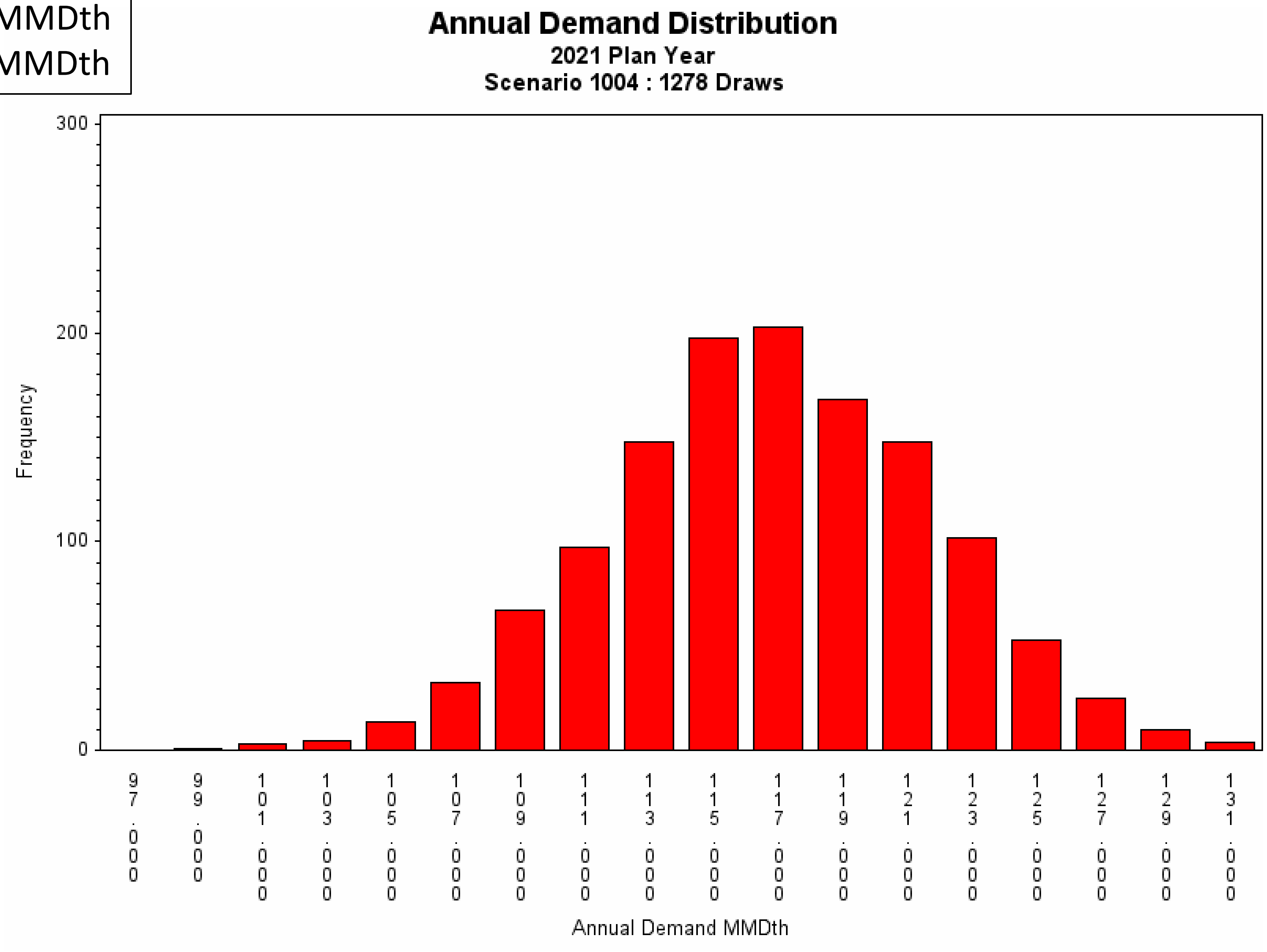


Exhibit 14.36

Mean:	116.3 MMDth
Median:	116.2 MMDth
Normal Case:	116.4 MMDth



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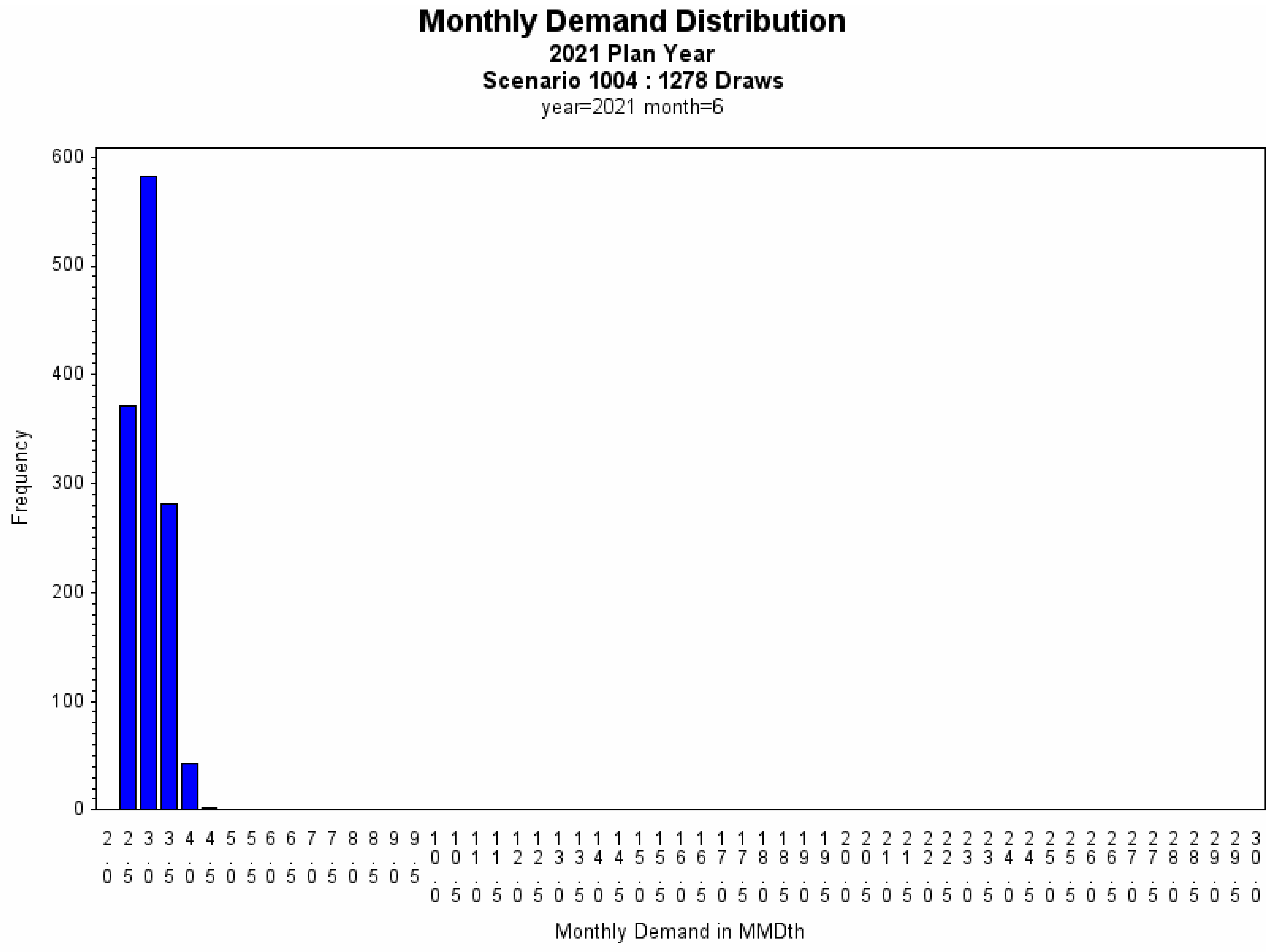

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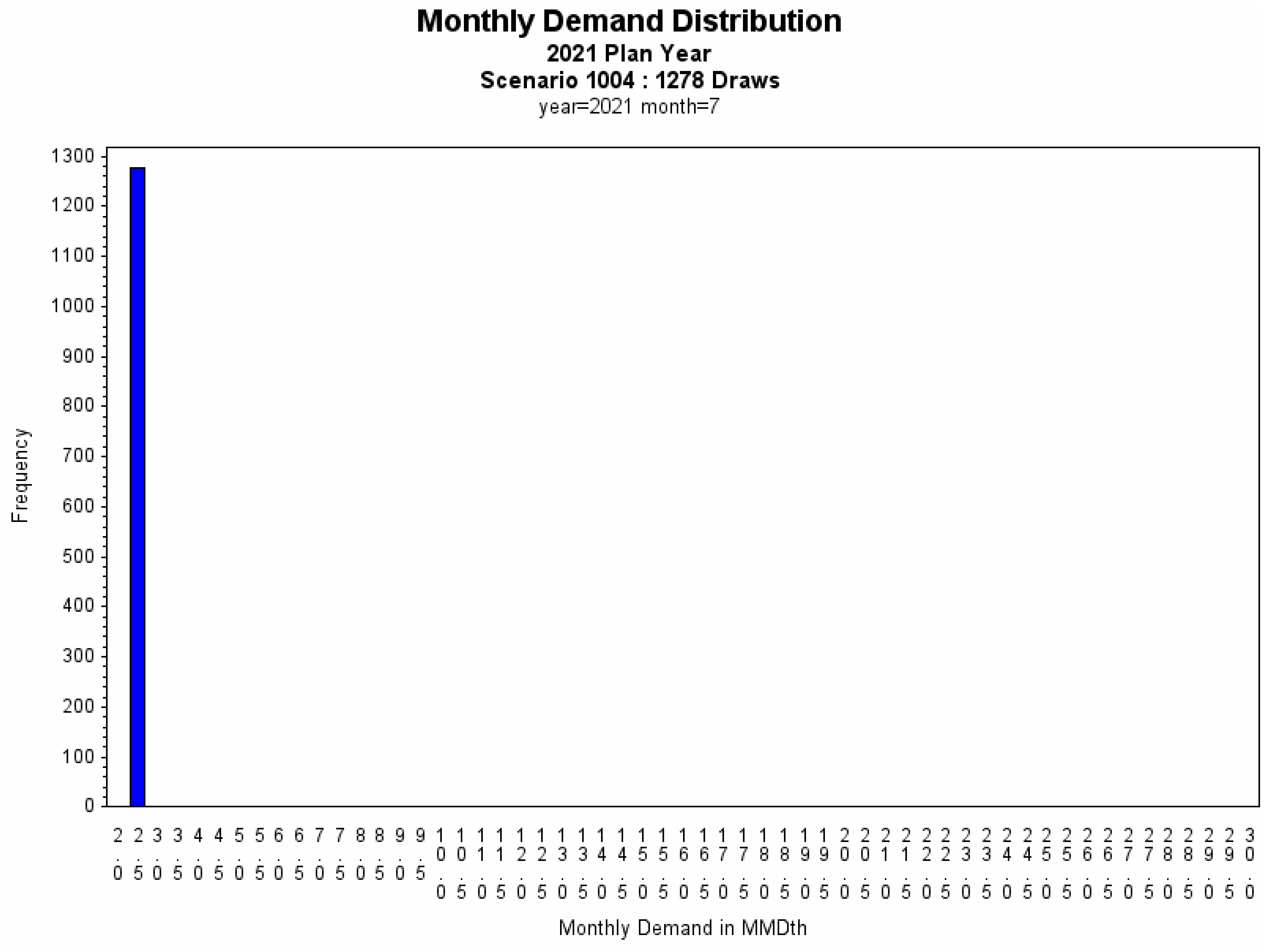

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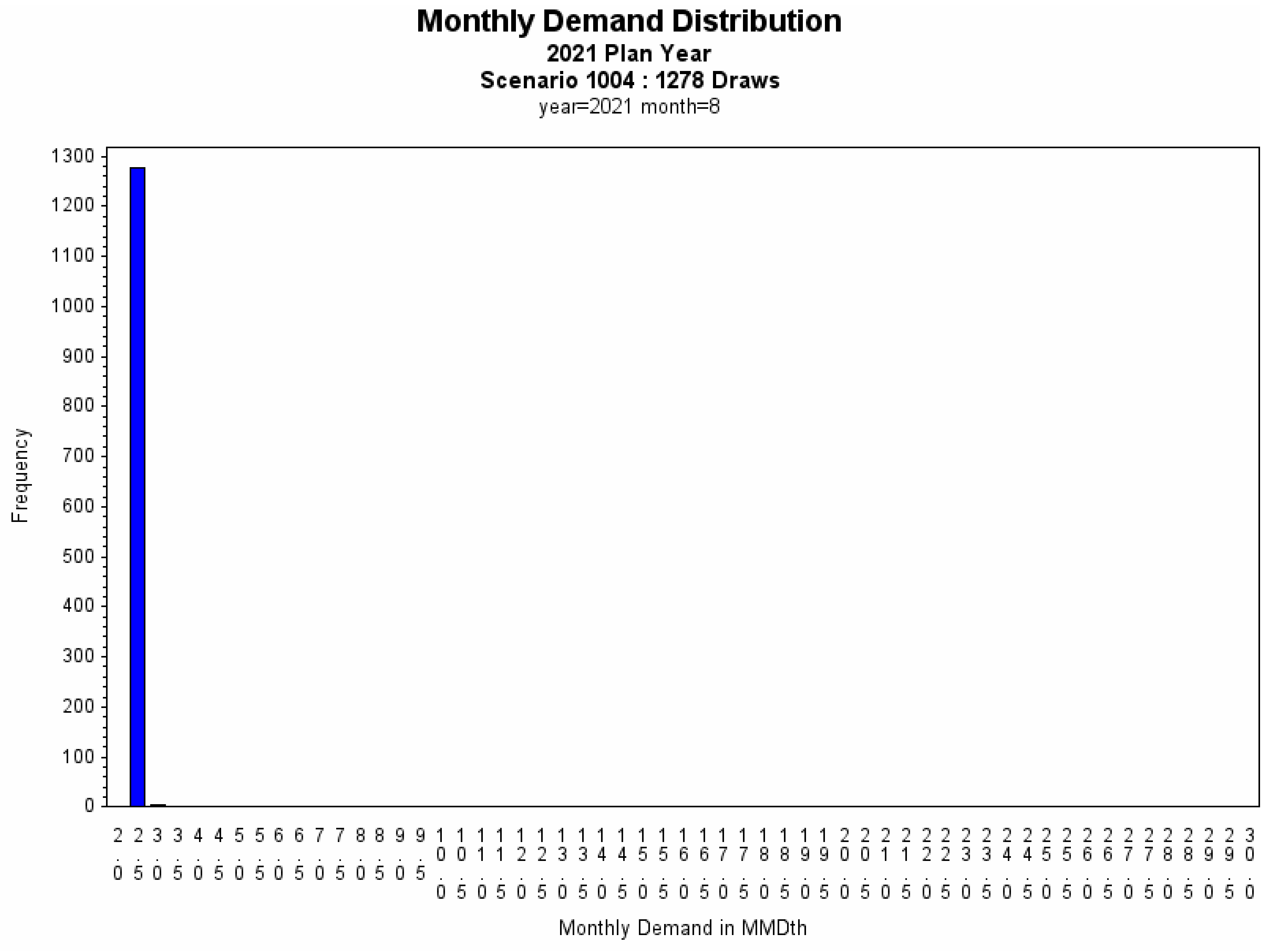

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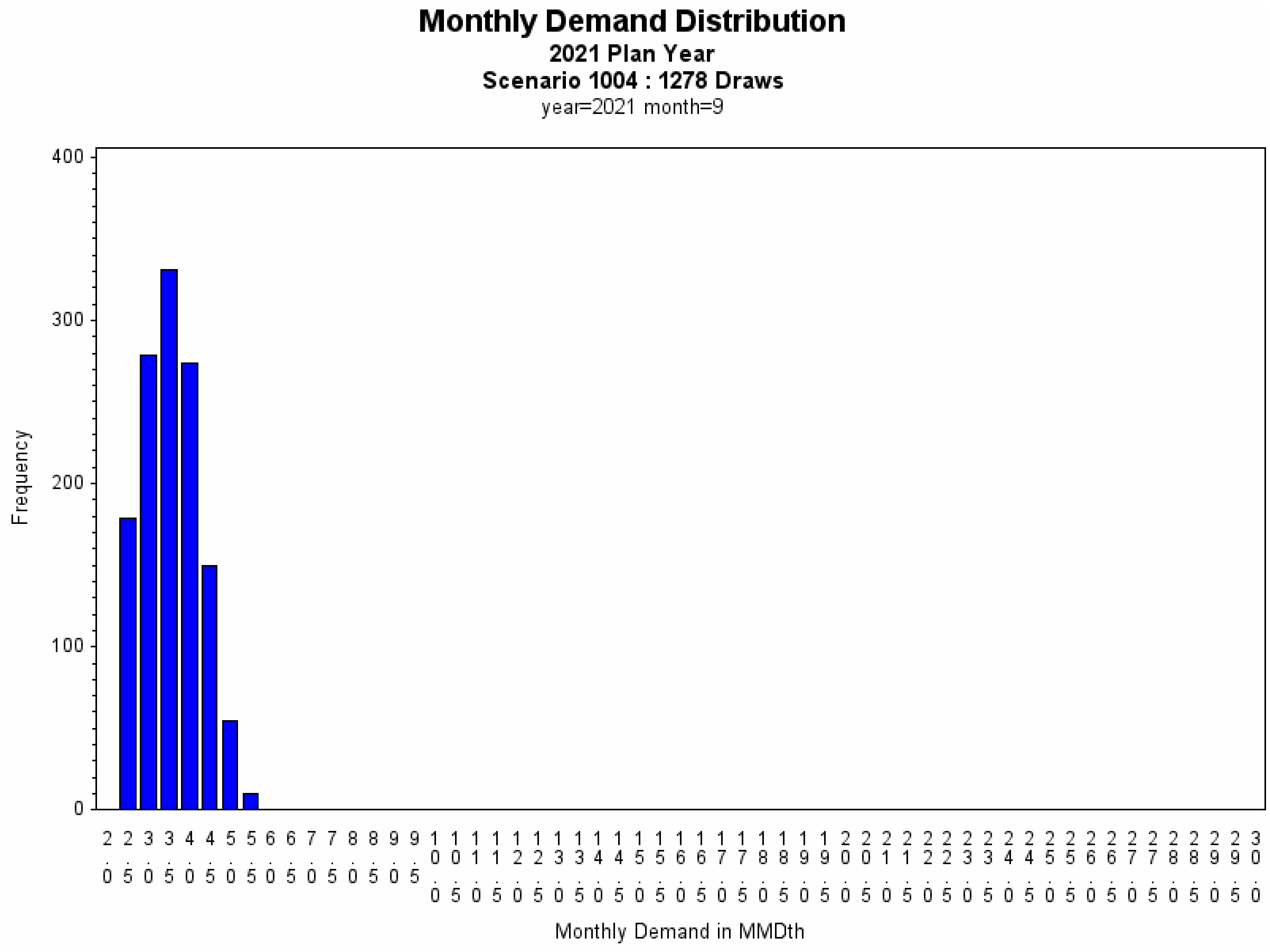

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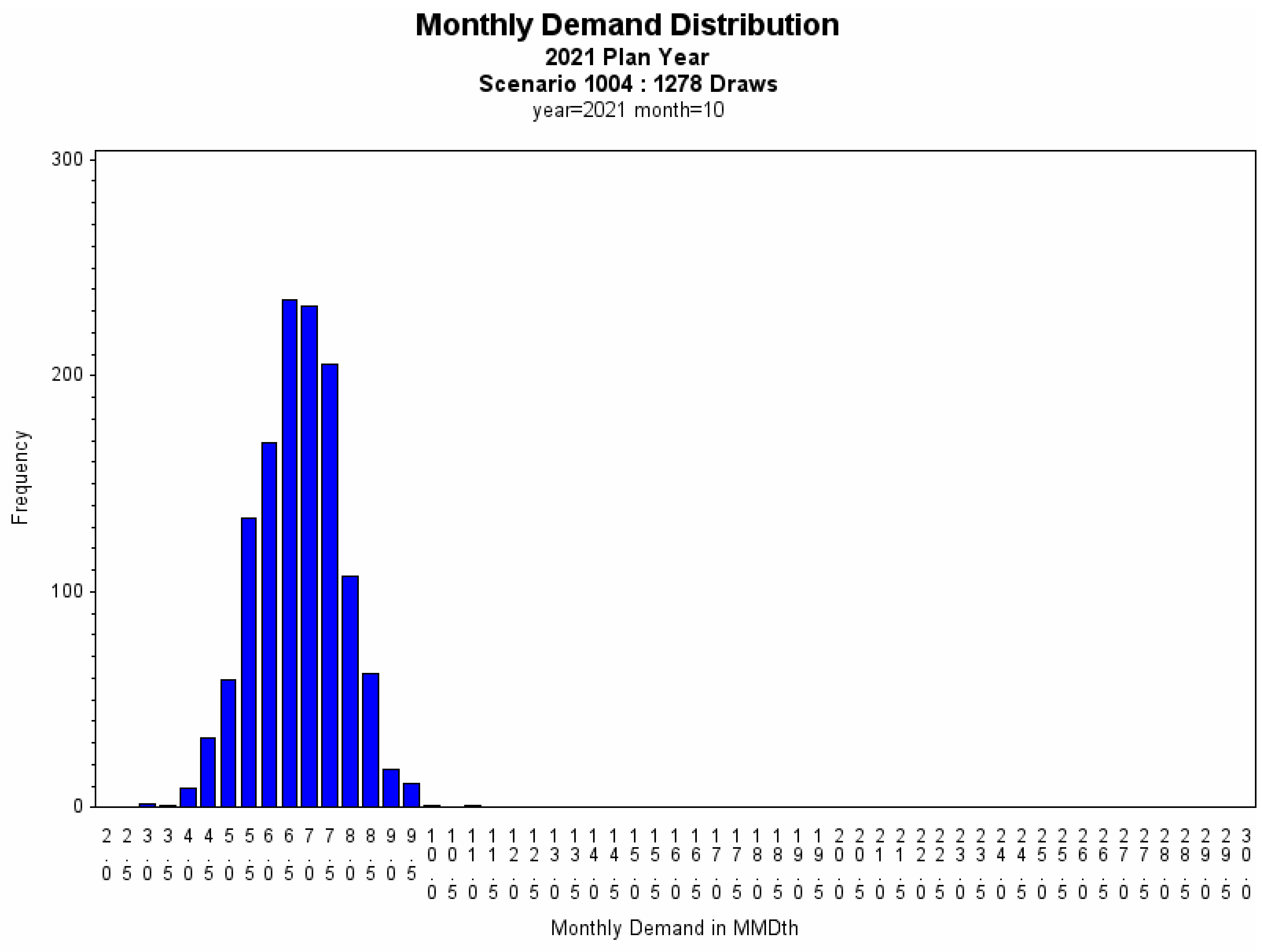

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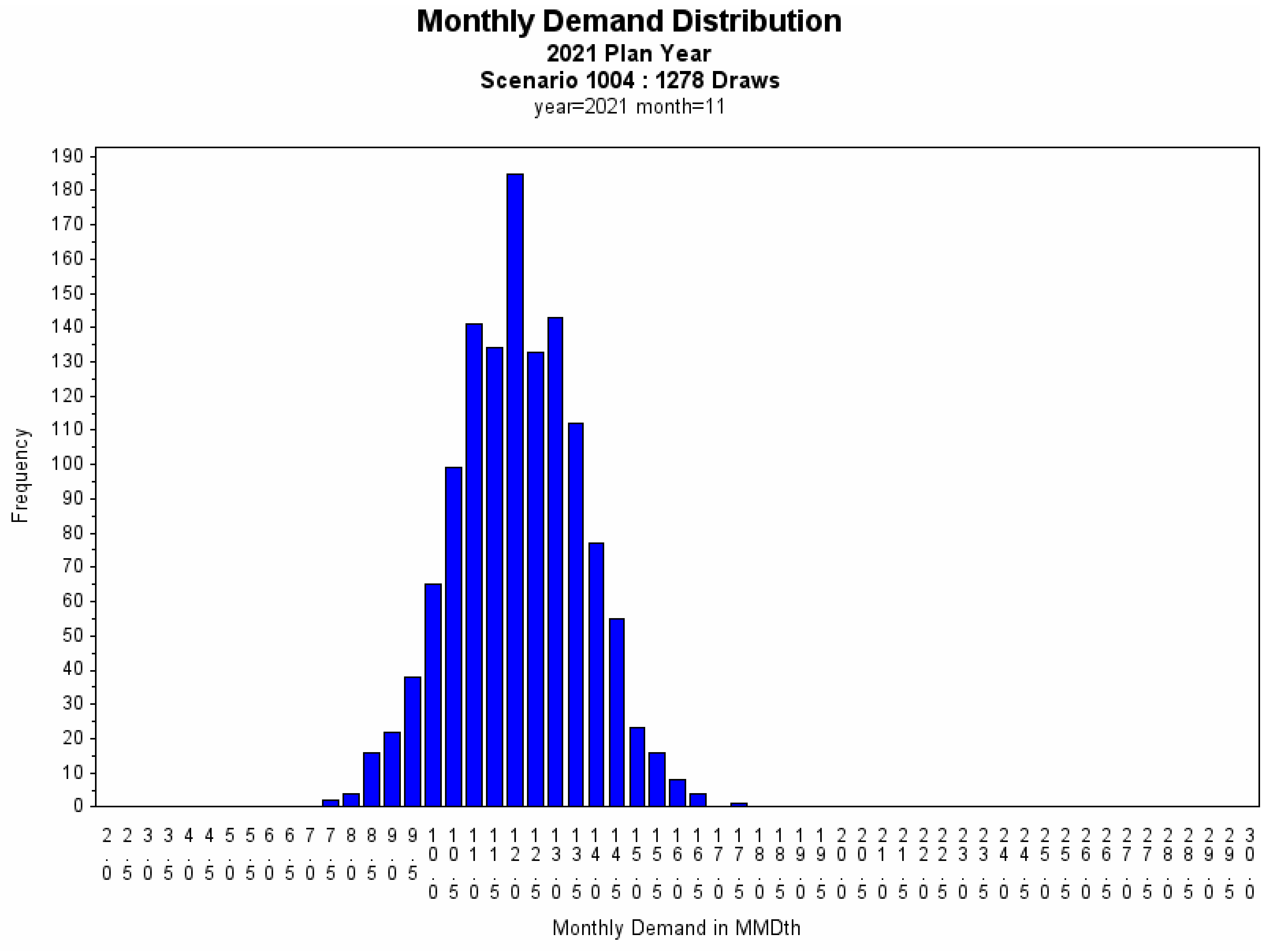

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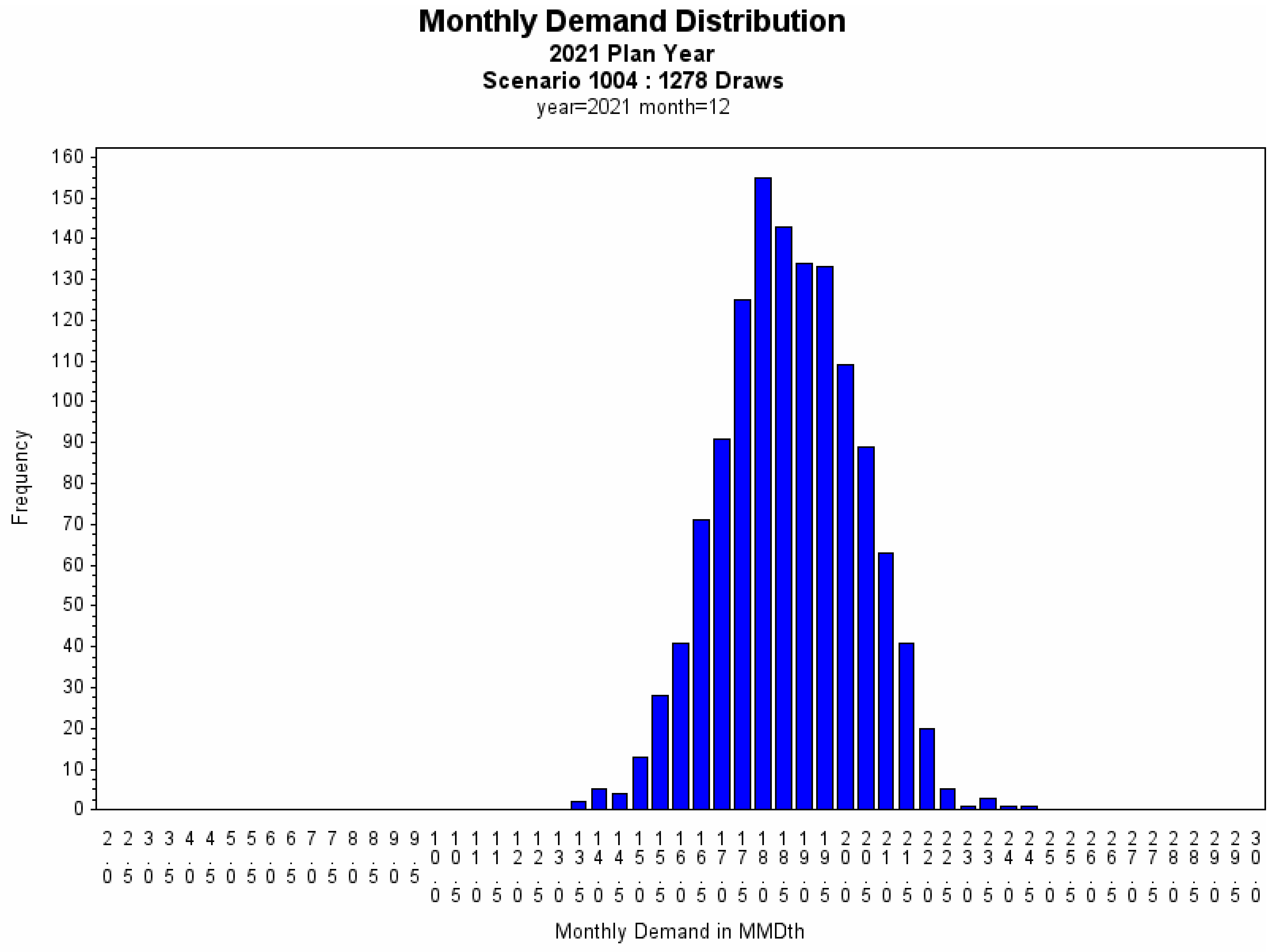

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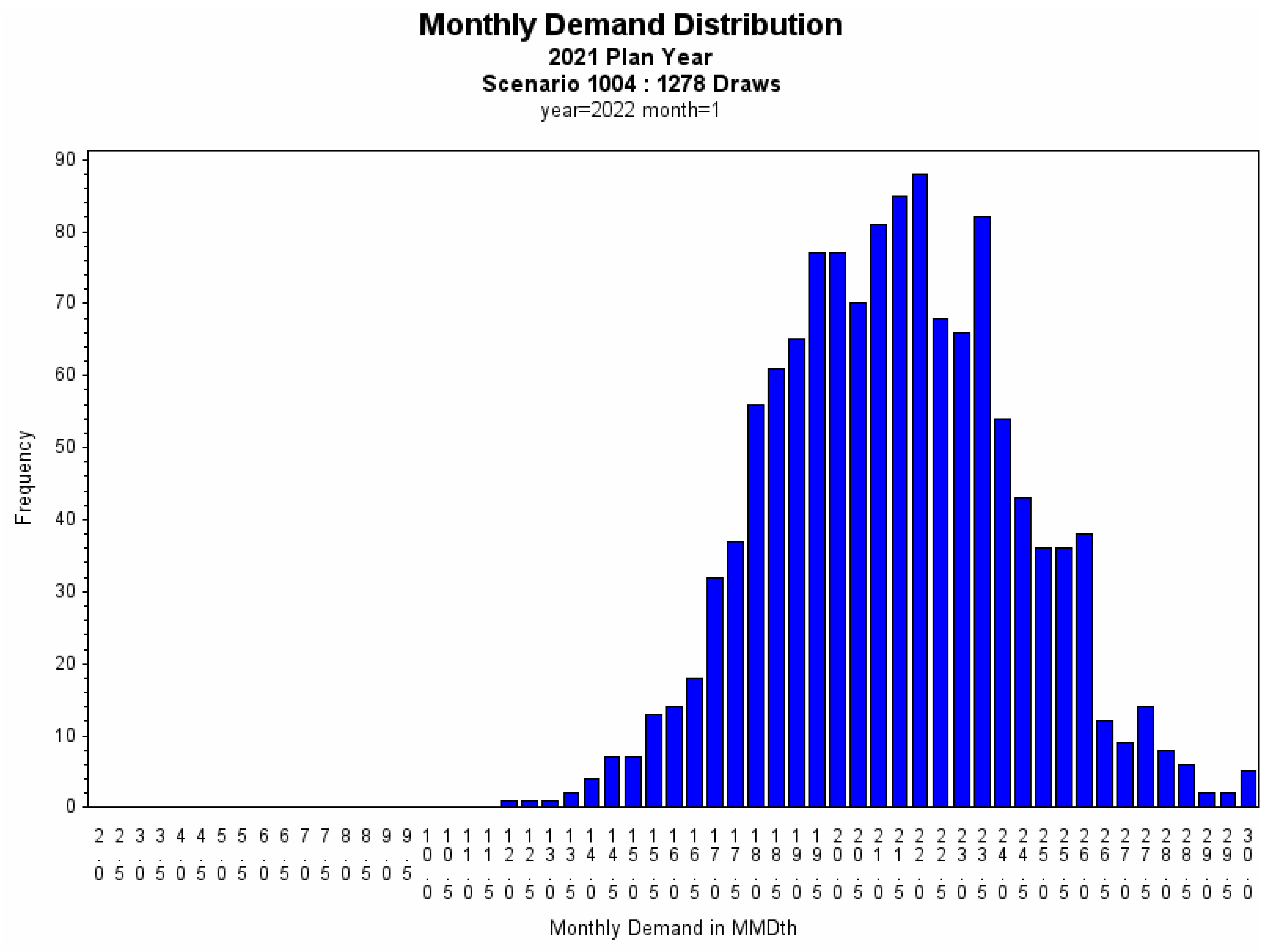

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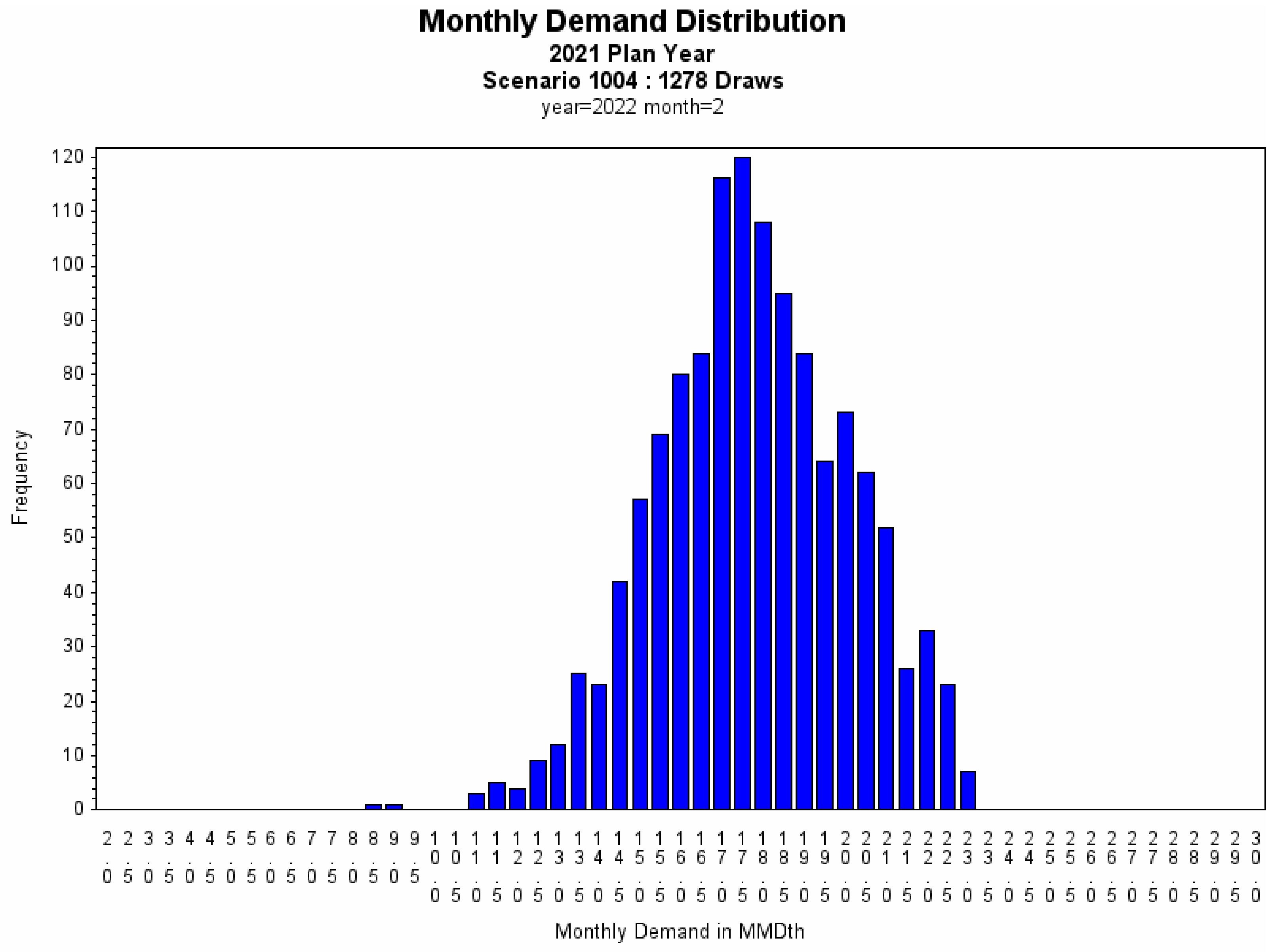

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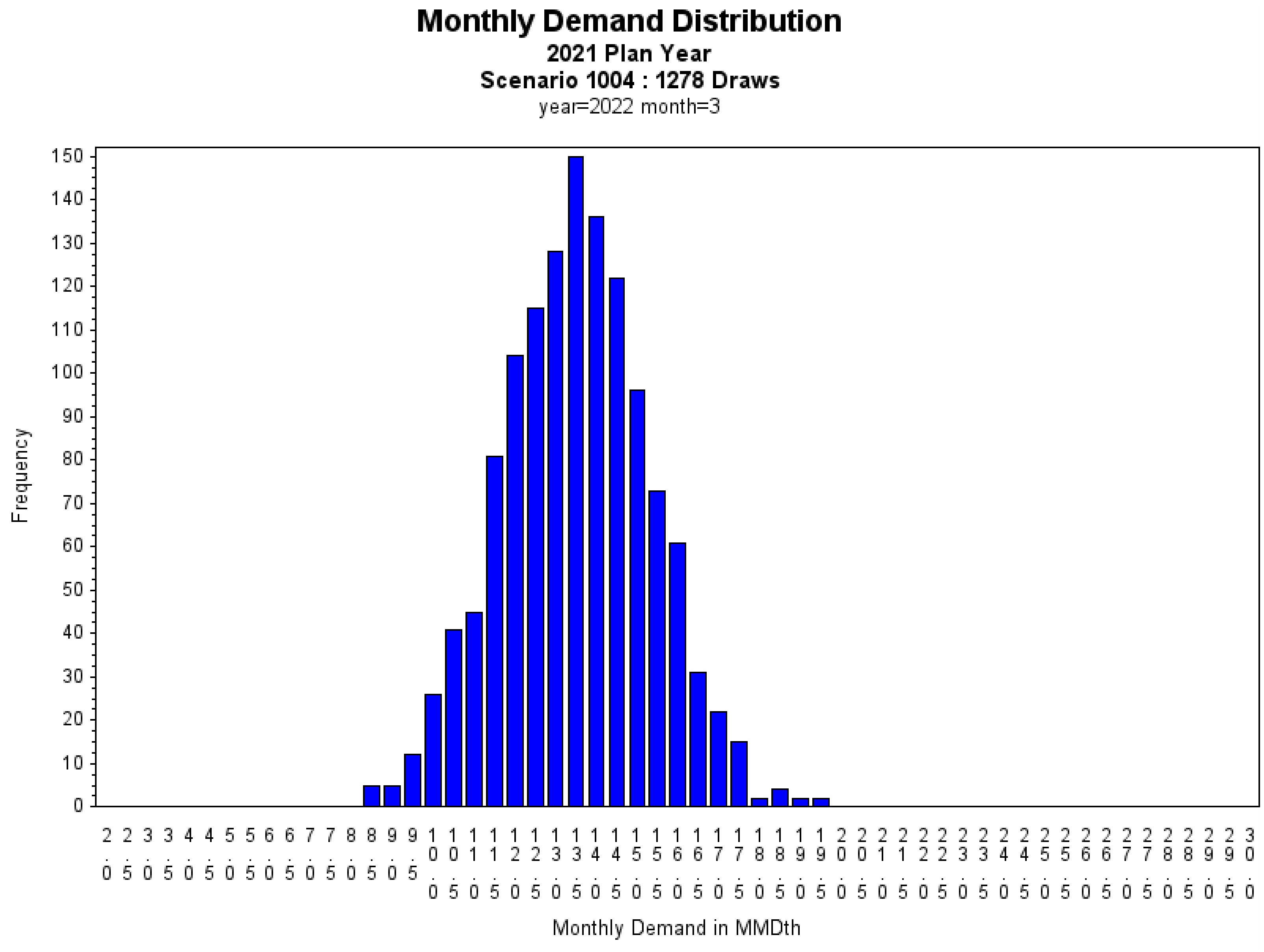

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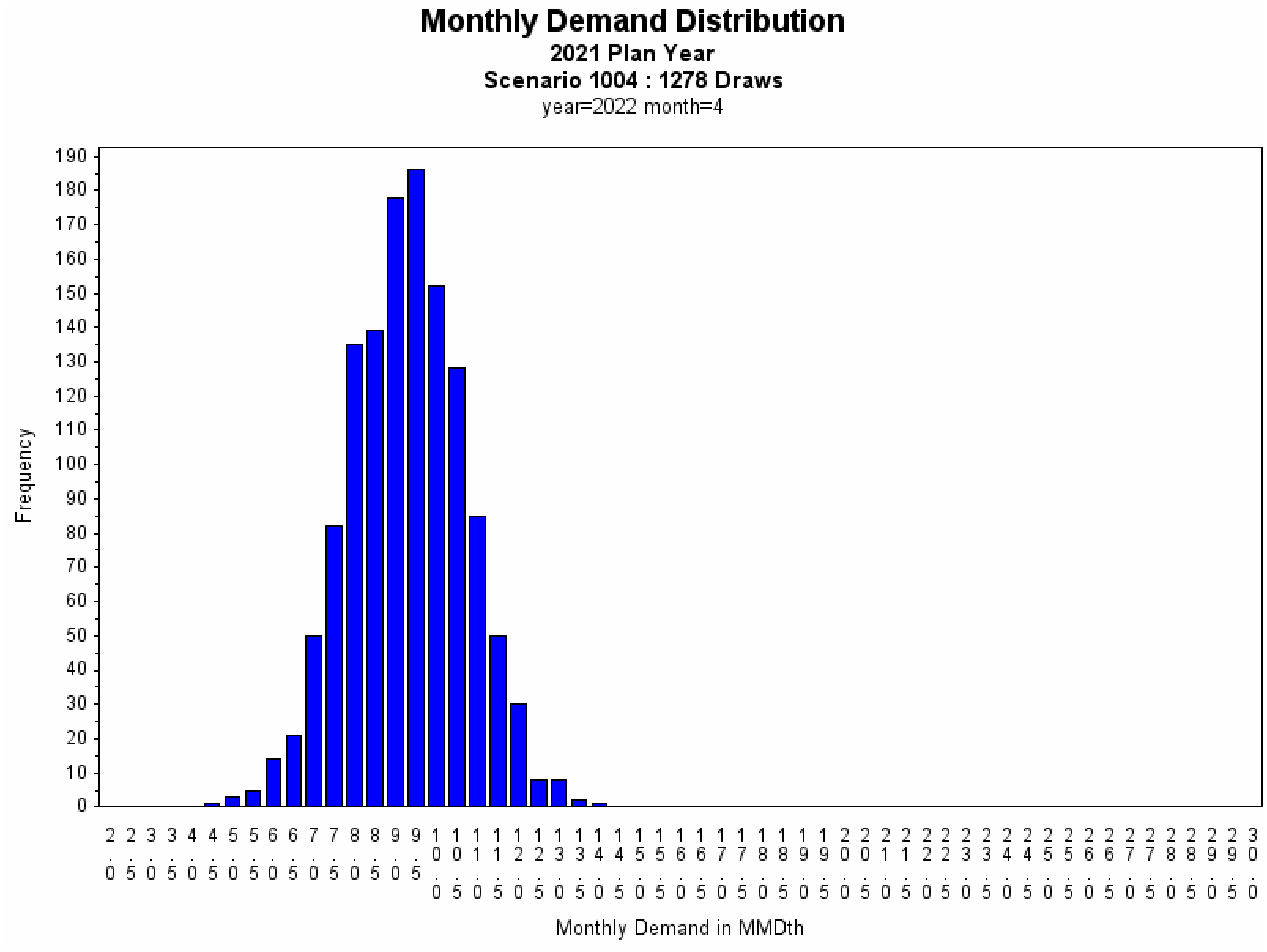

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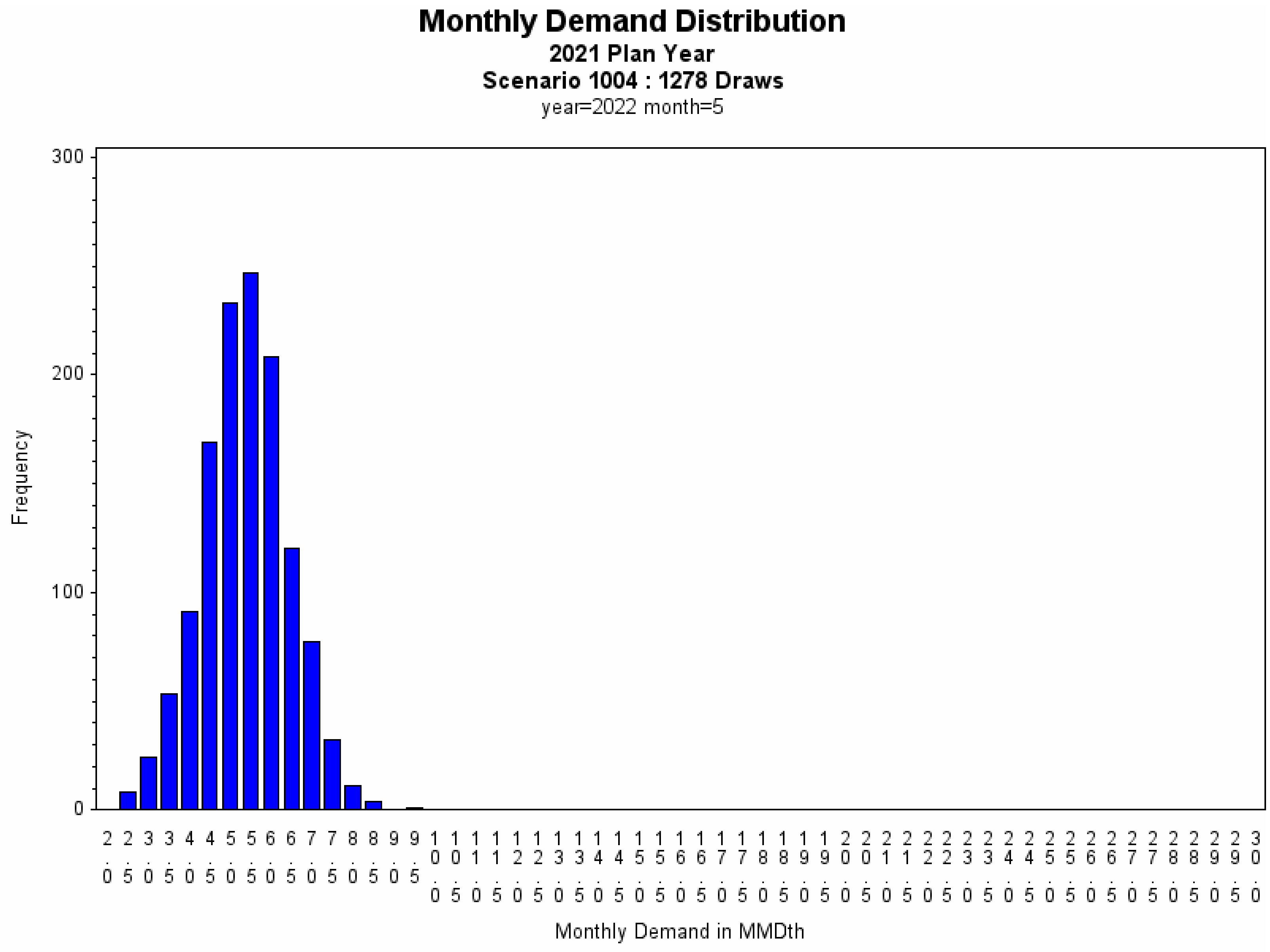
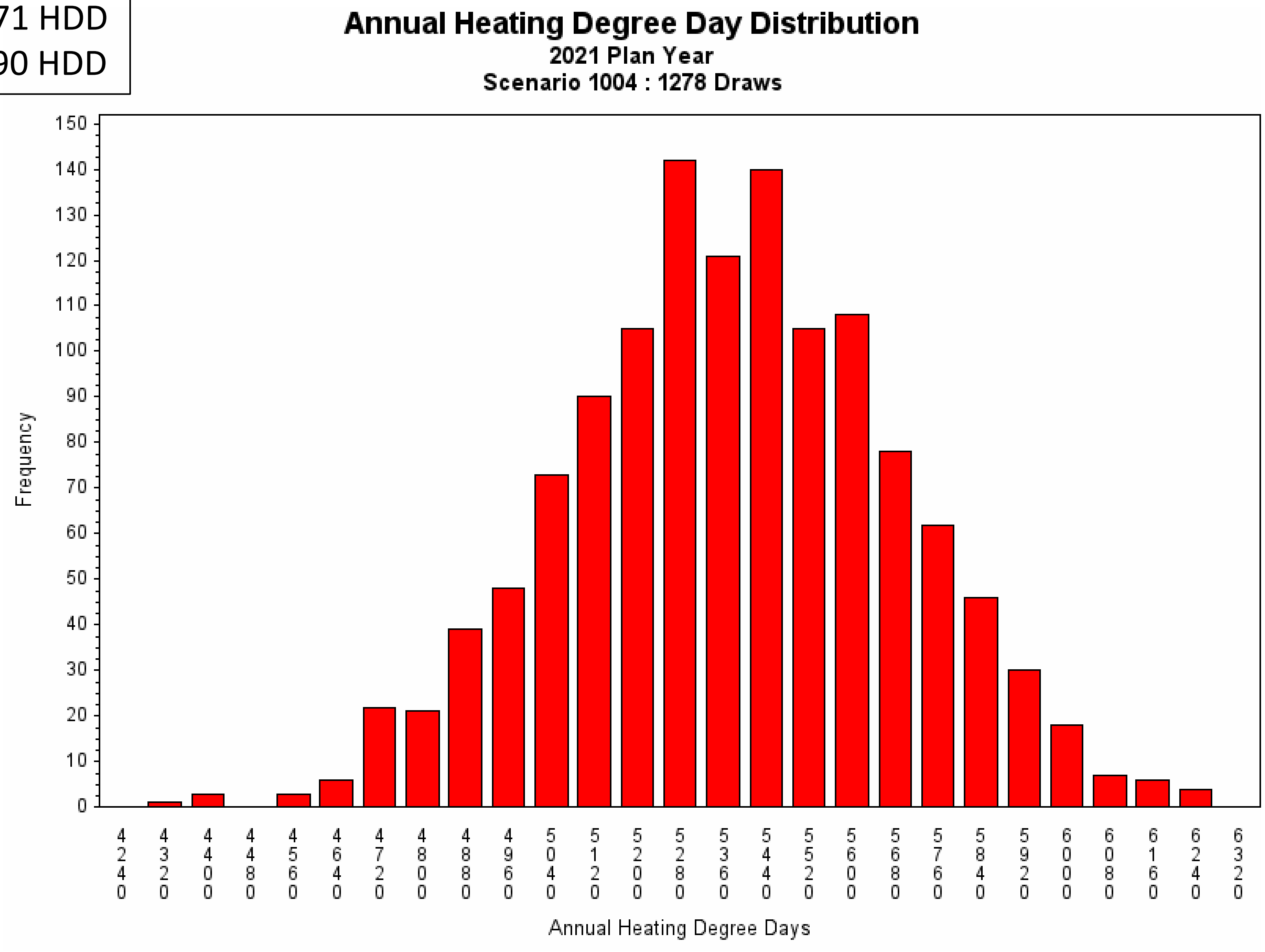


Exhibit 14.49

Mean:	5,376.25 HDD
Median:	5,381.71 HDD
Normal Case:	5,352.90 HDD



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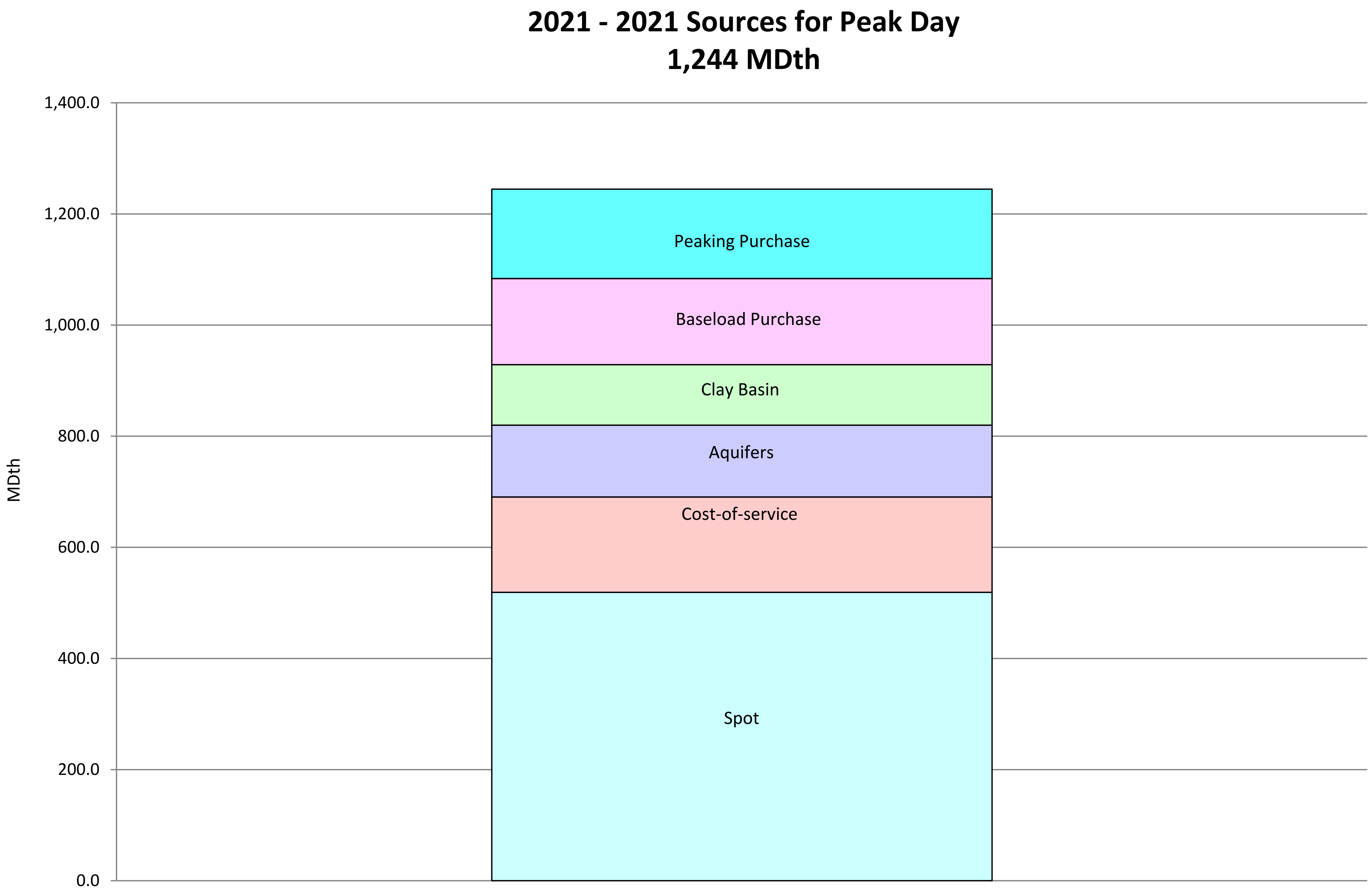

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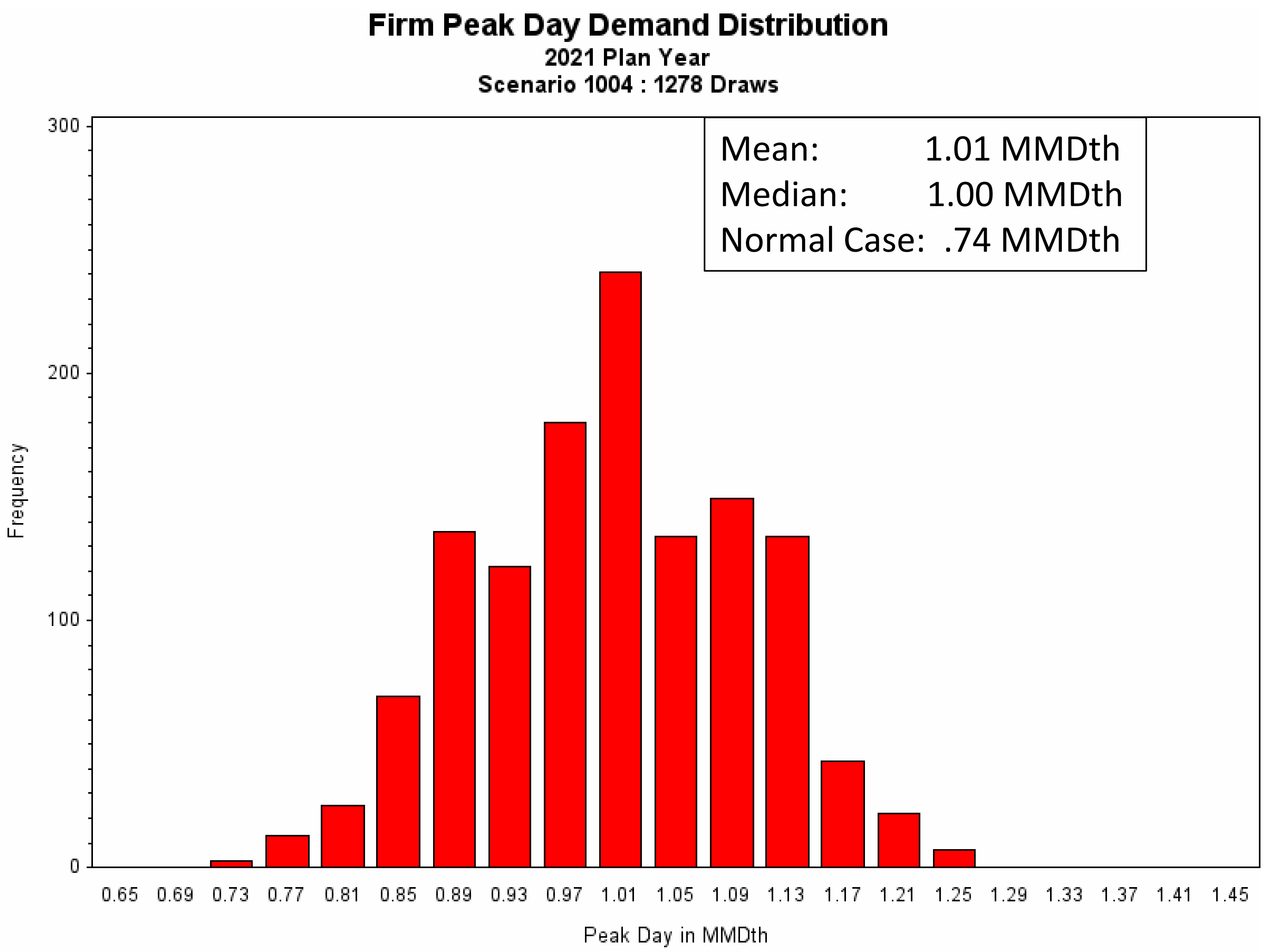

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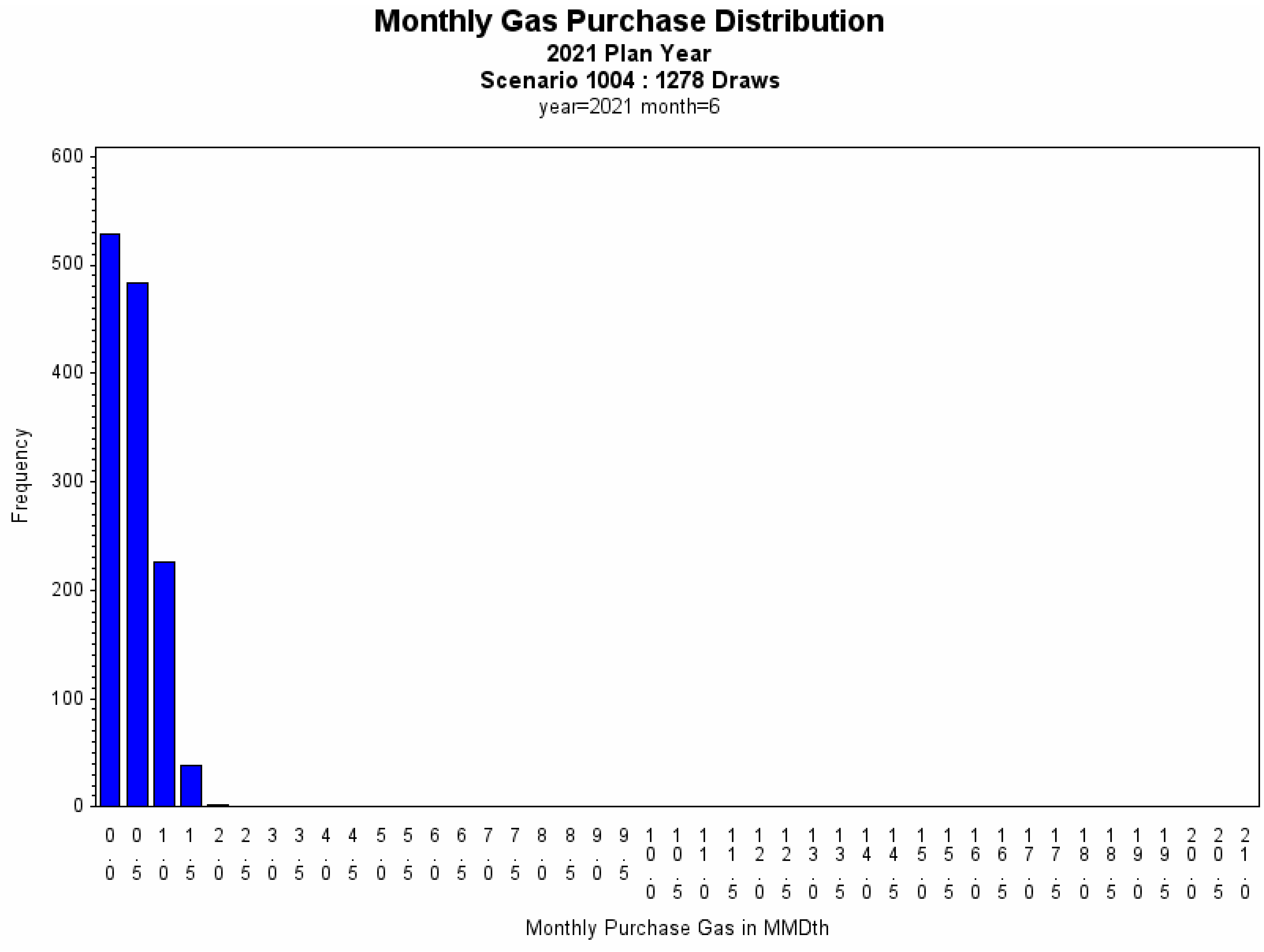

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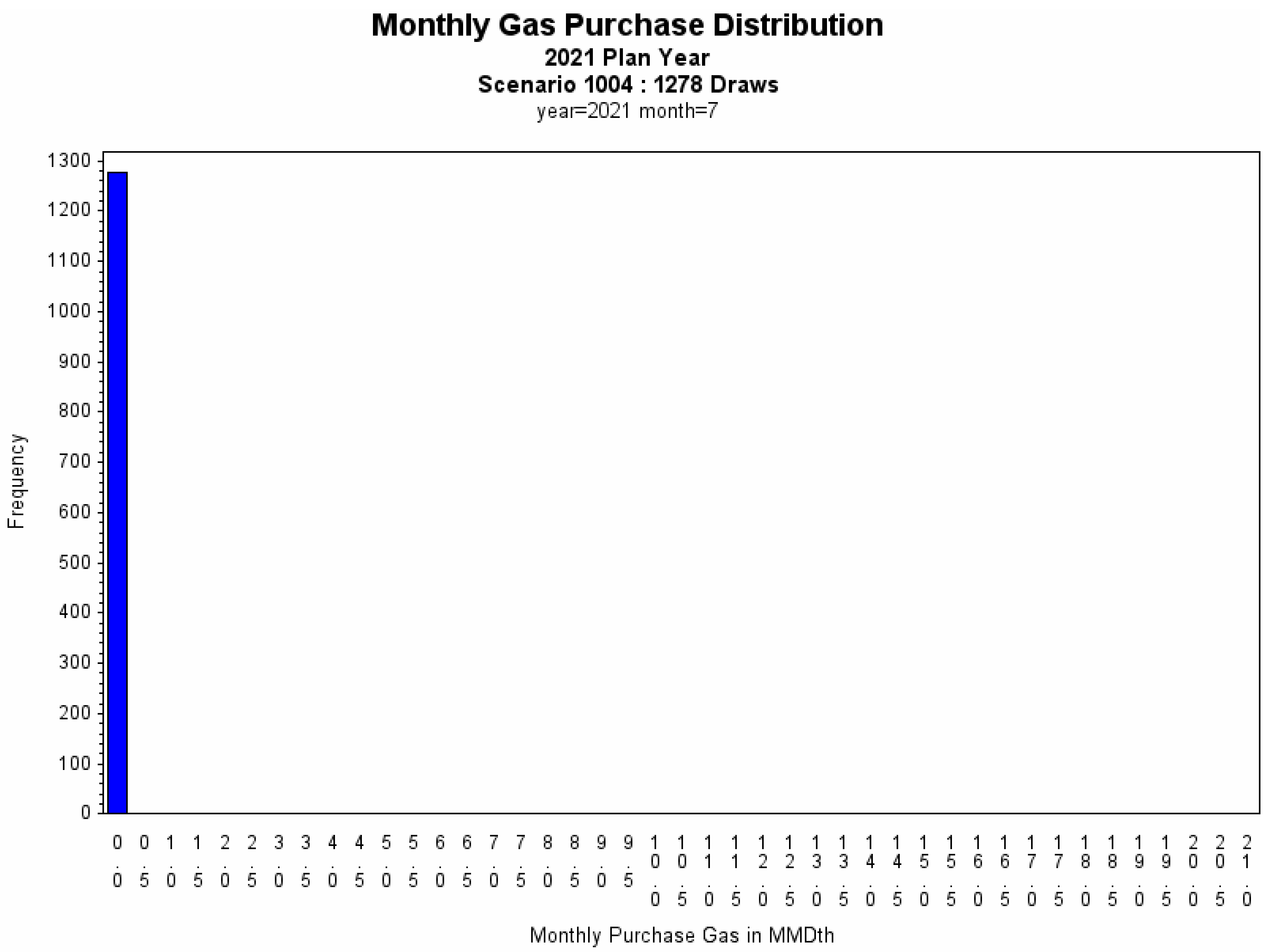

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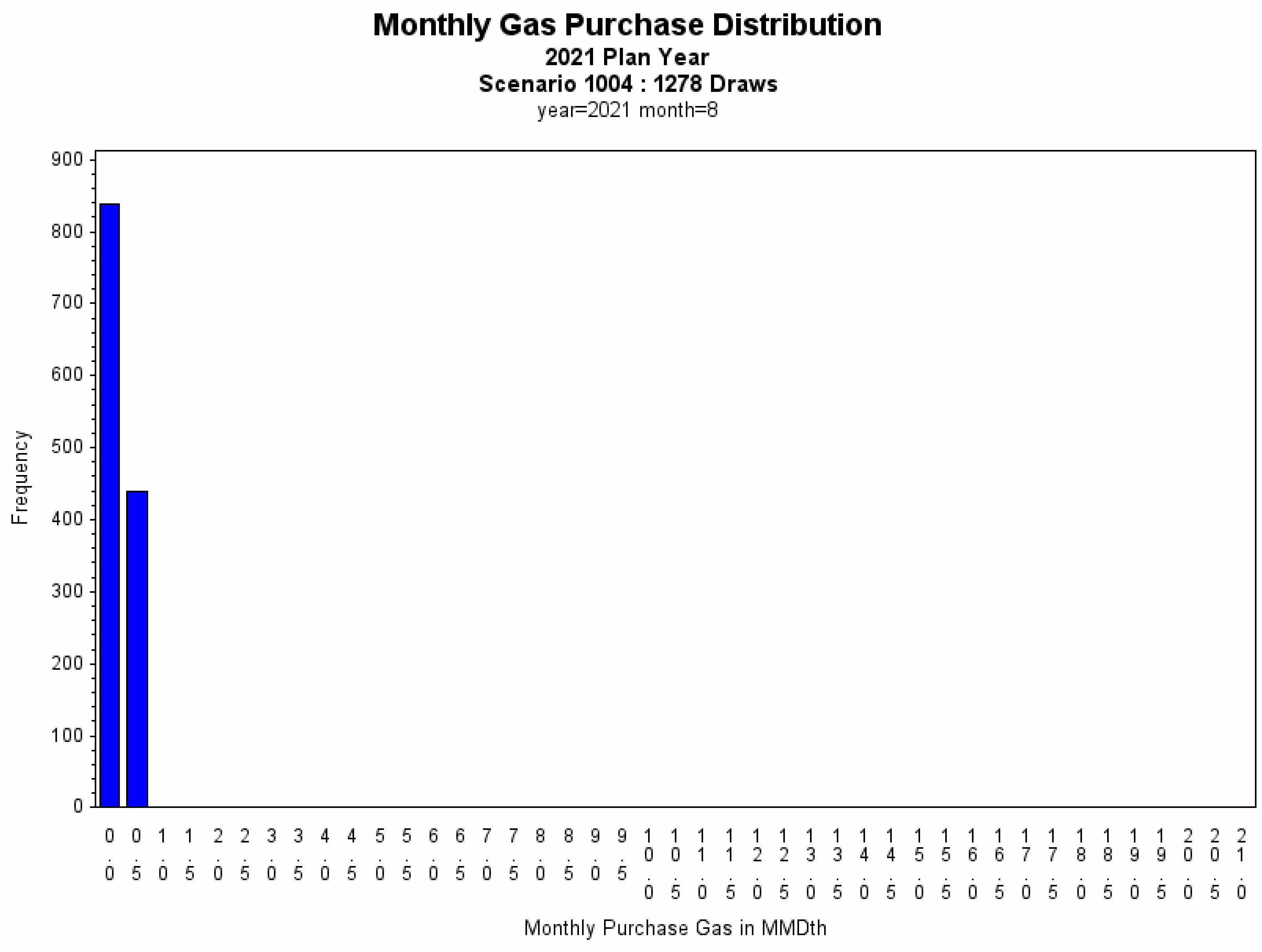

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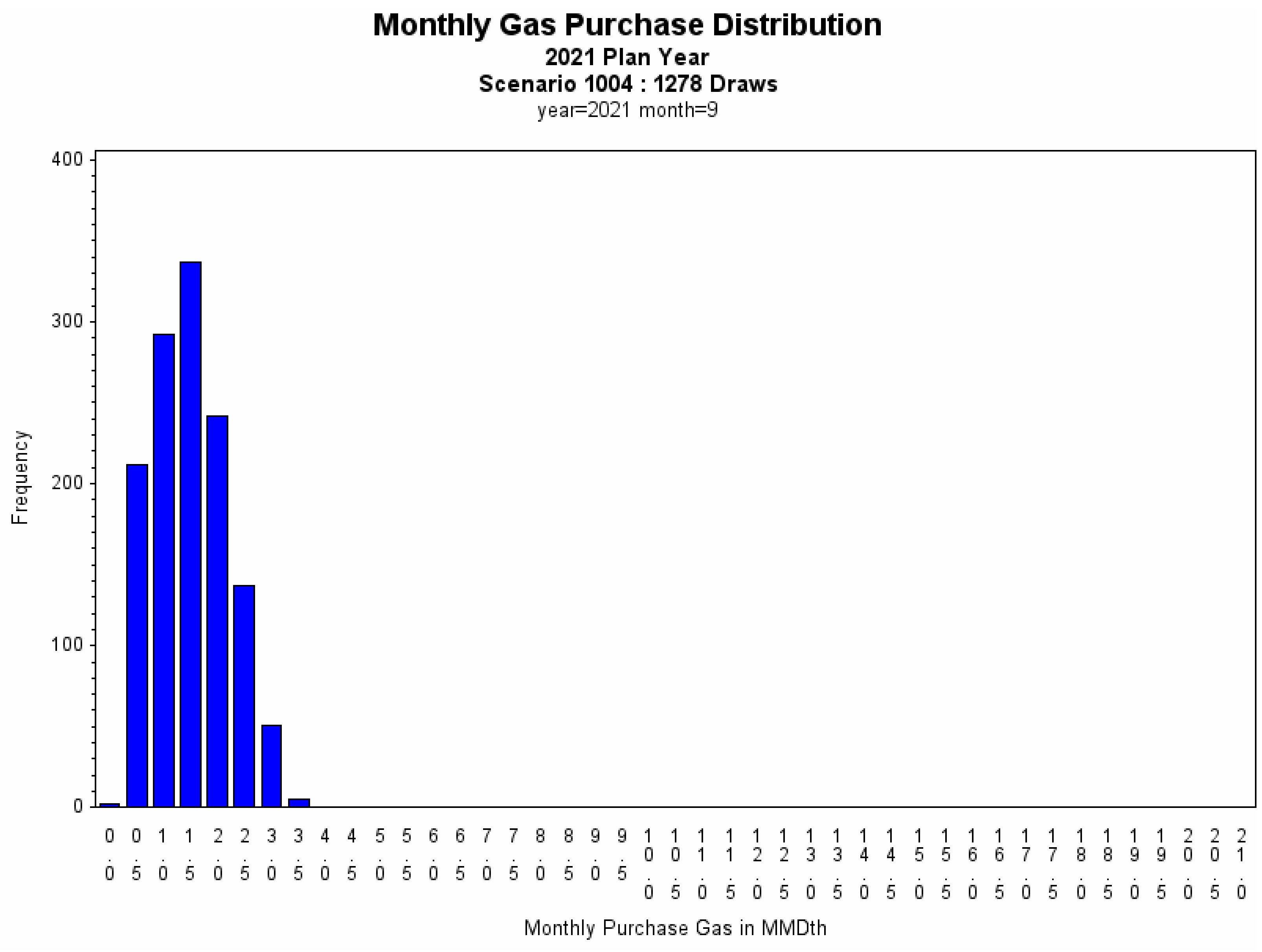

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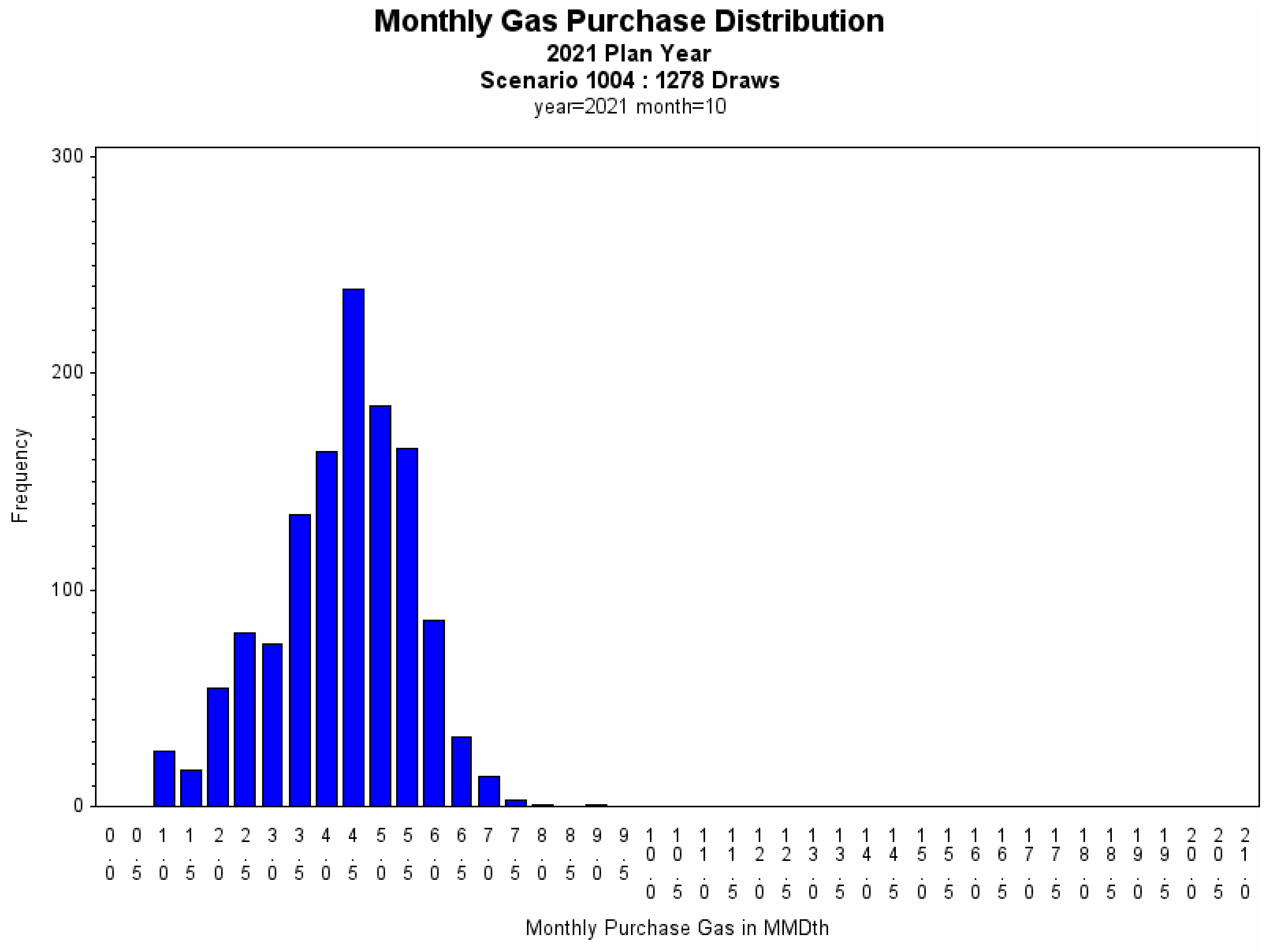

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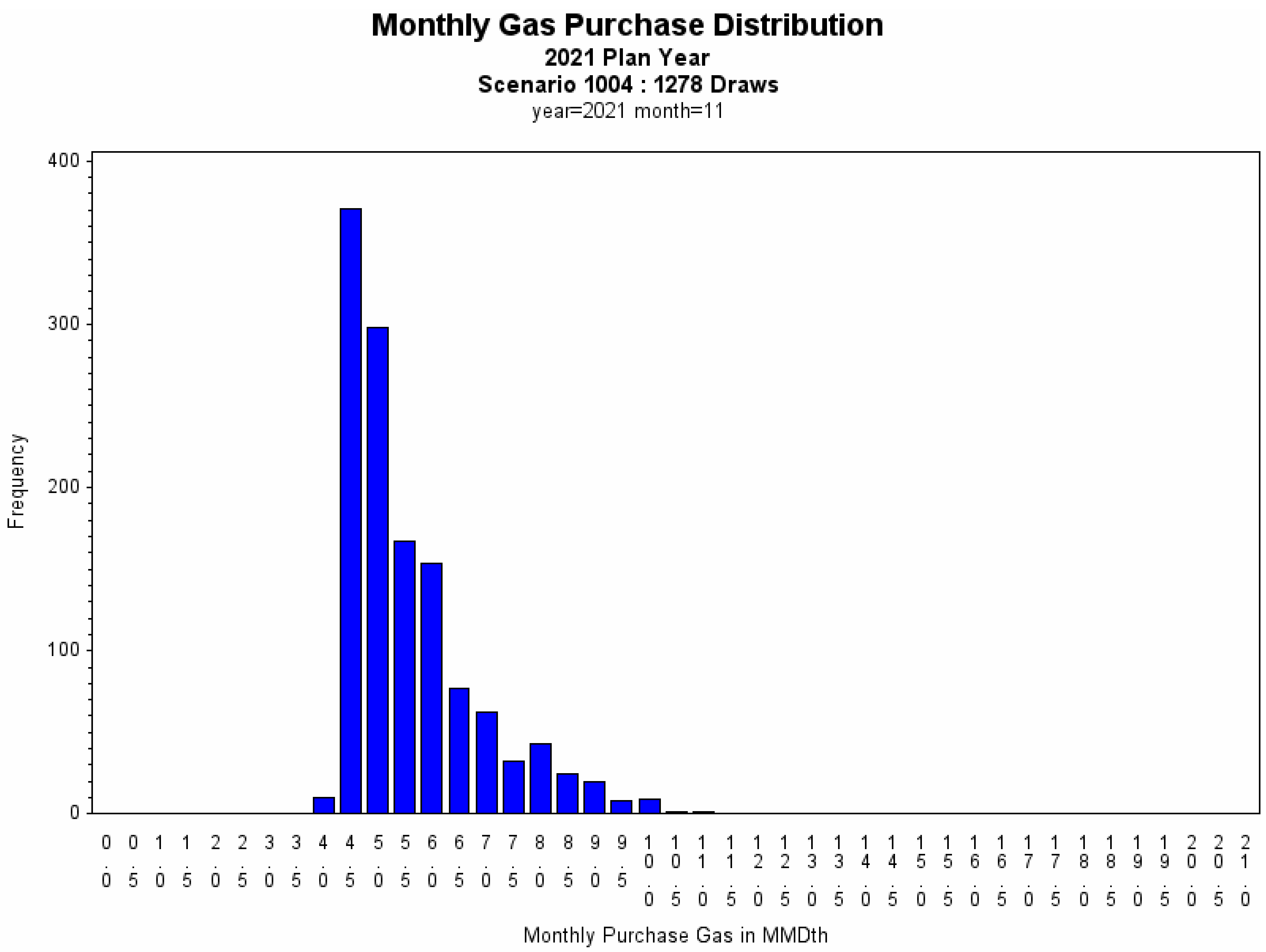

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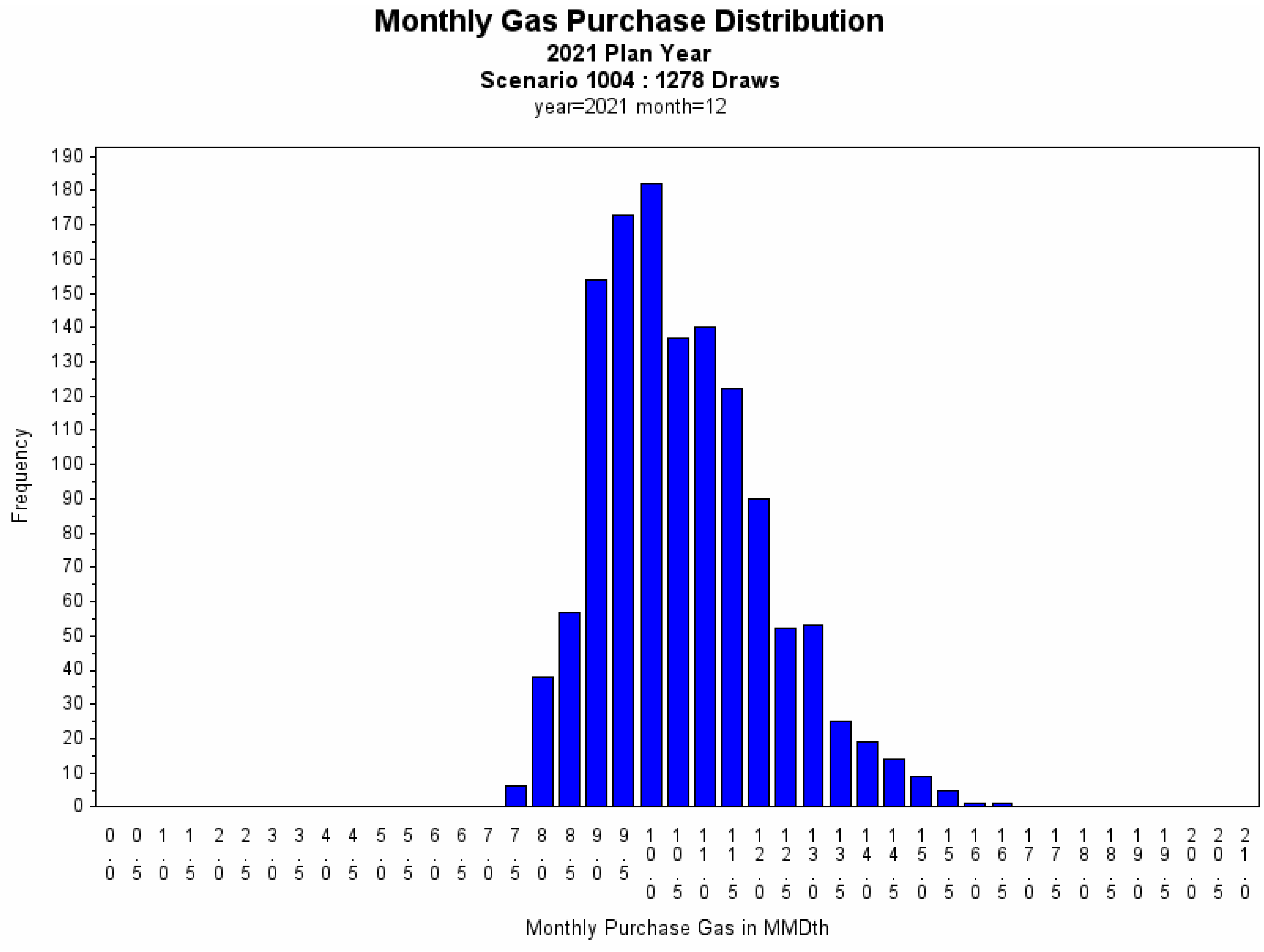


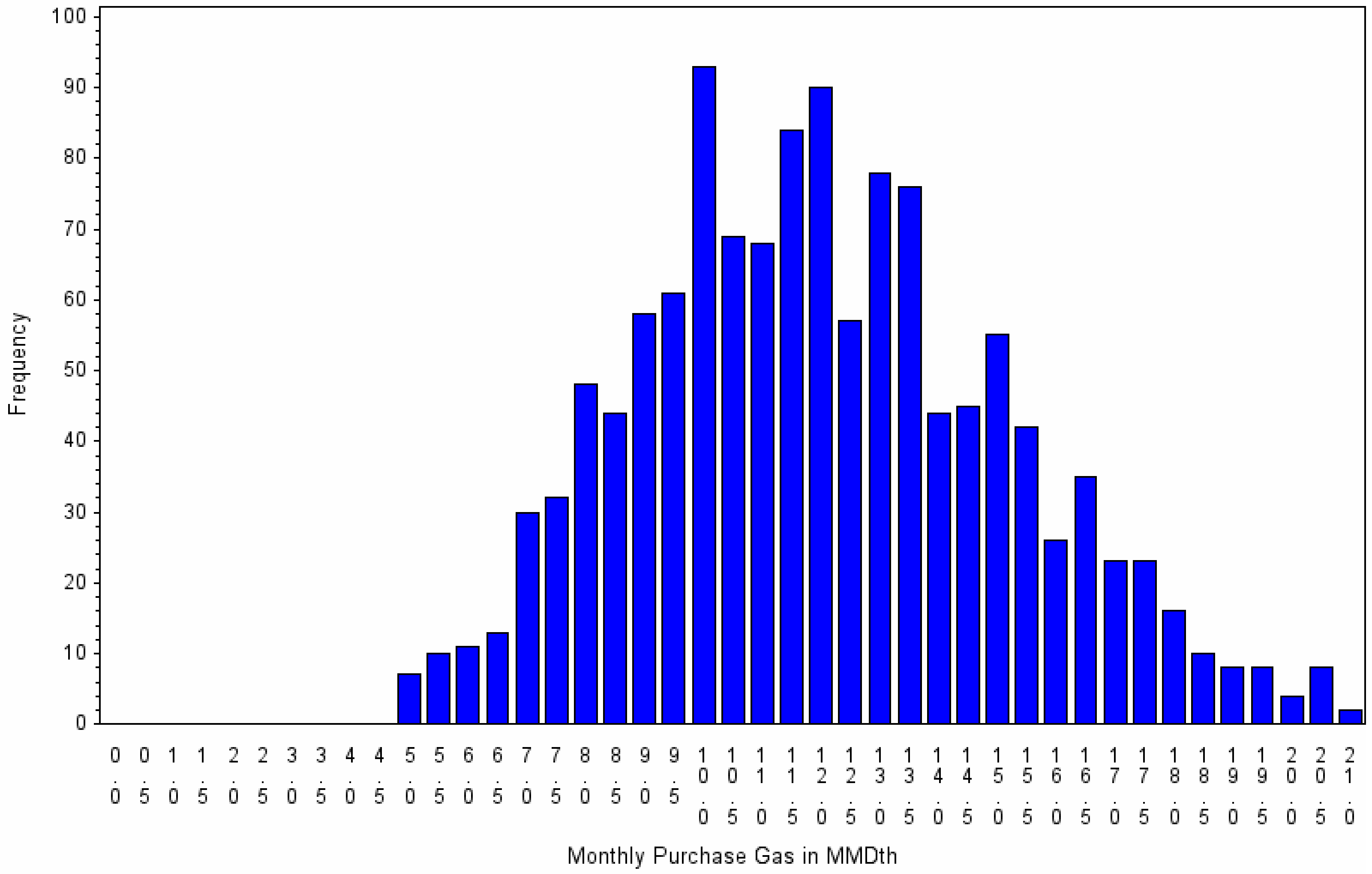
Exhibit 14.59

Monthly Gas Purchase Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2022 month=1



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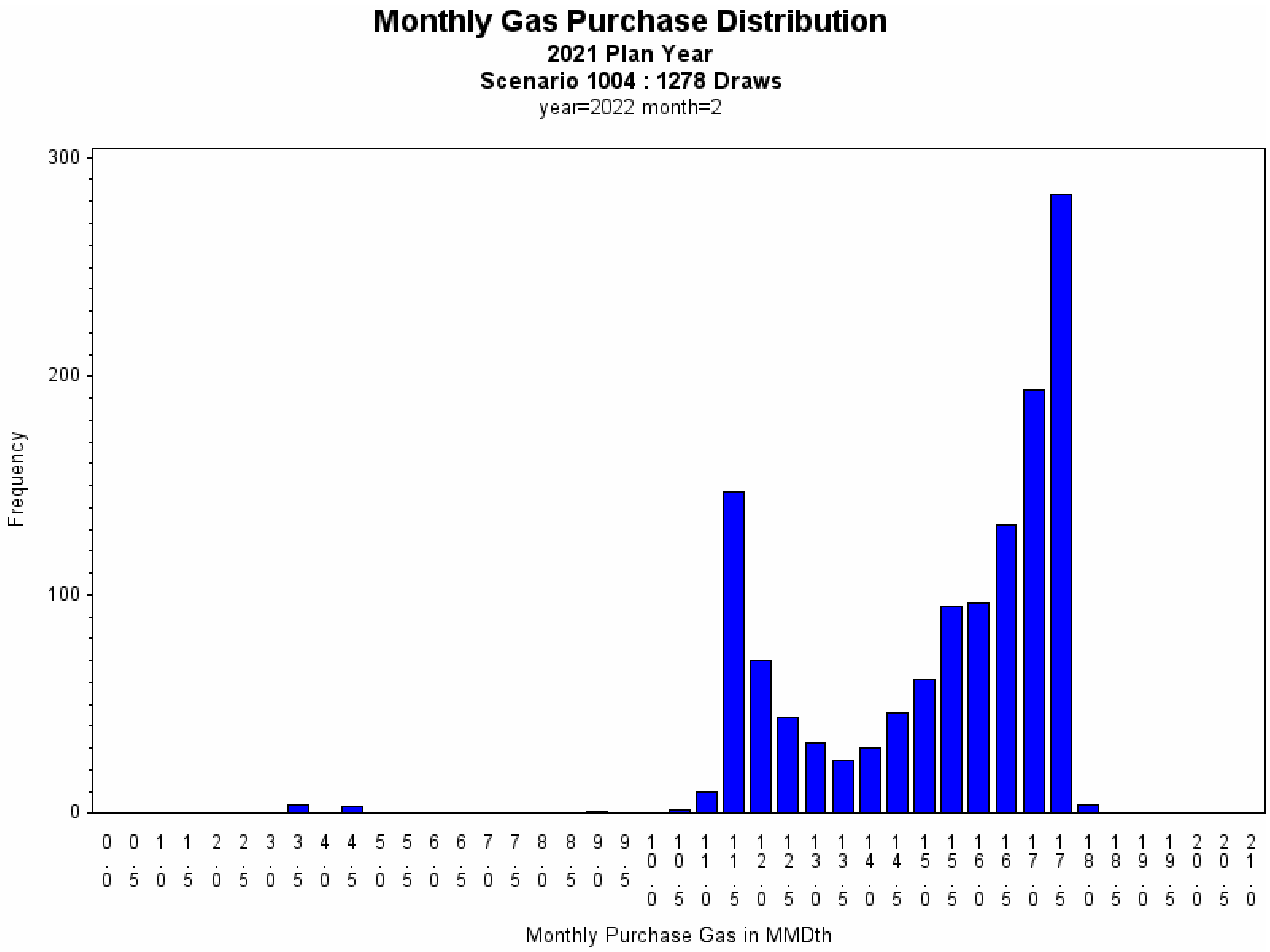

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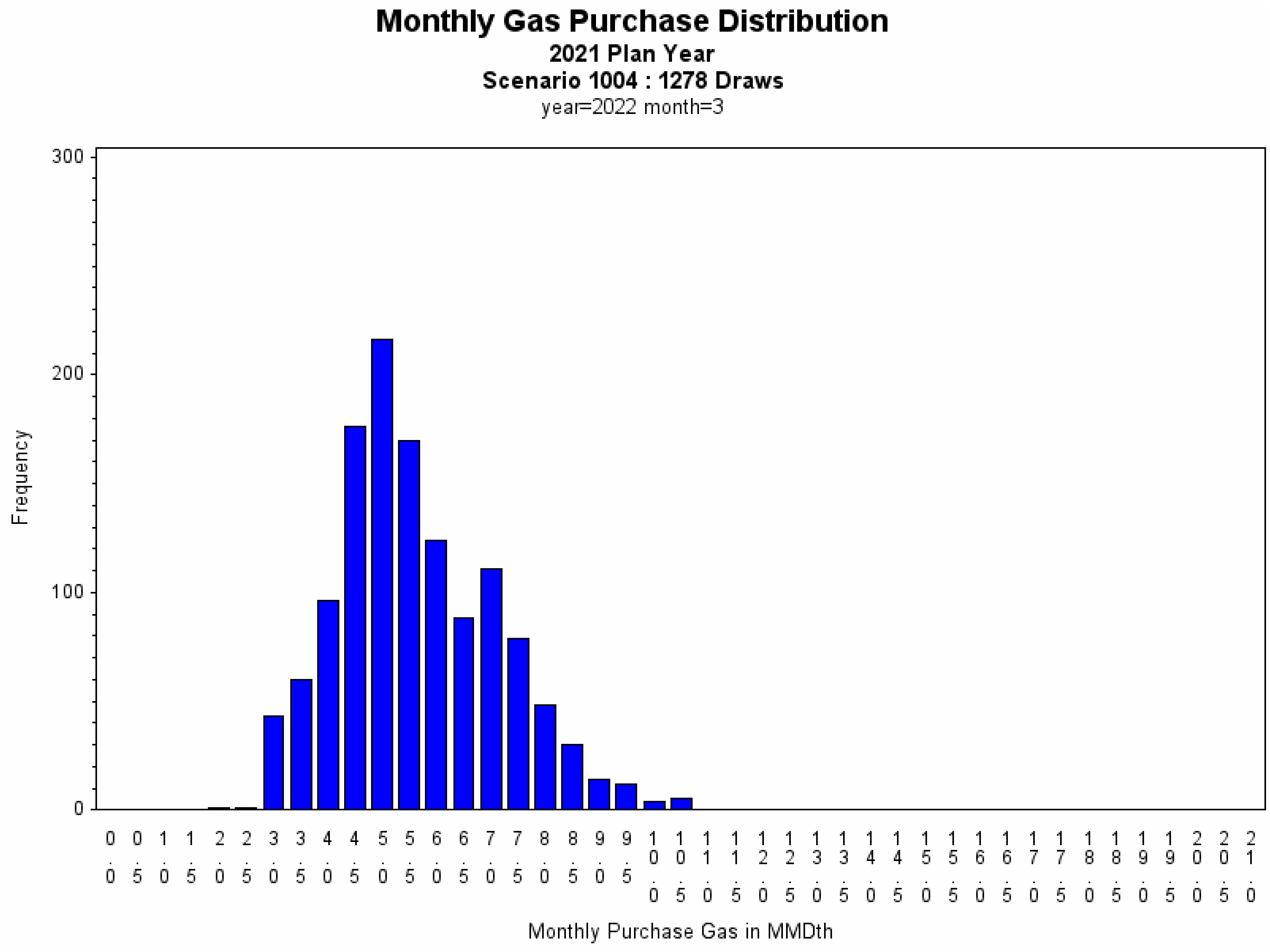

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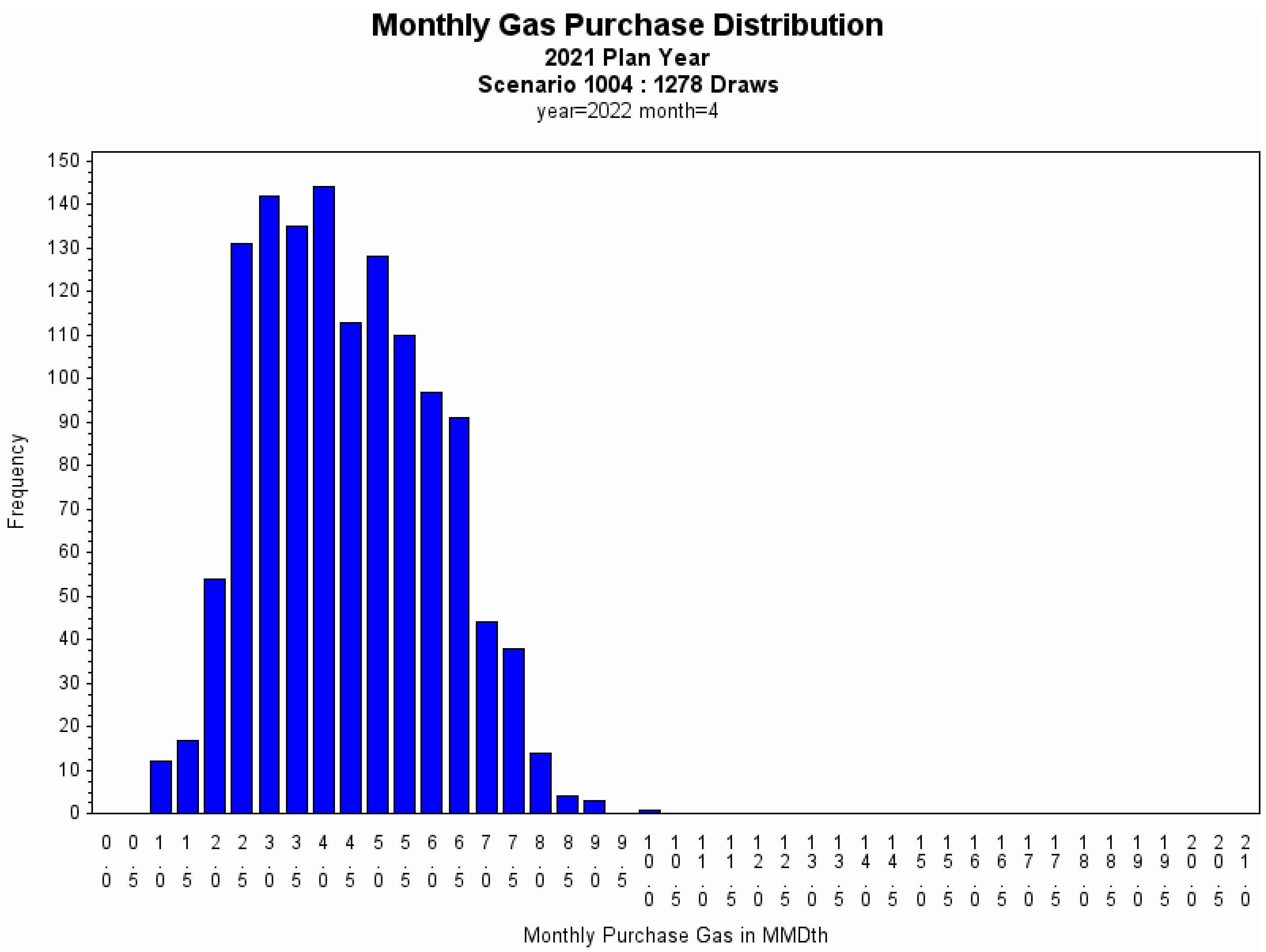

Exhibit 14.63

Monthly Gas Purchase Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

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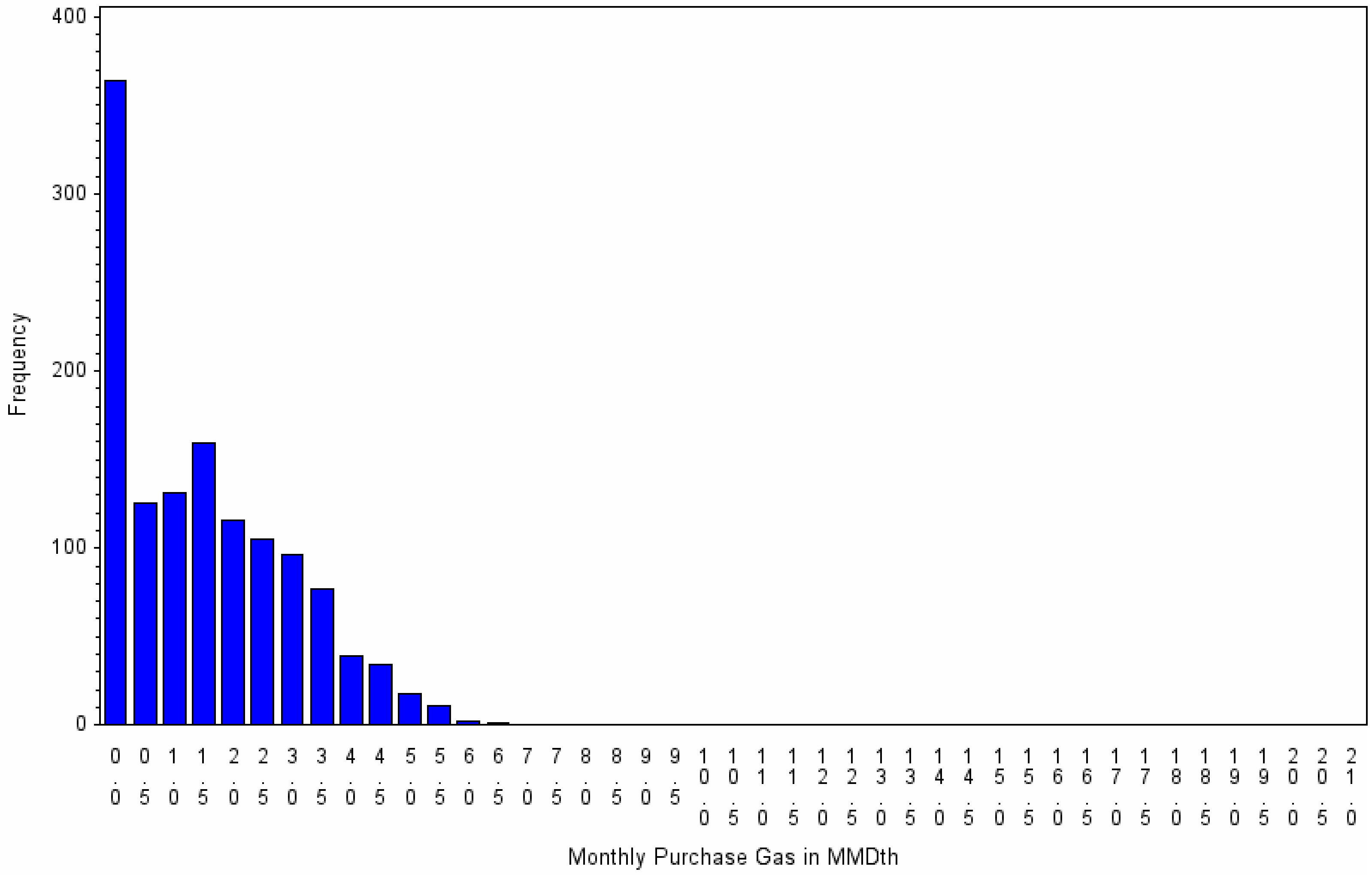

Exhibit 14.64

Mean: 61.41 MMDth
Median: 61.44 MMDth
Normal Case: 60.00 MMDth

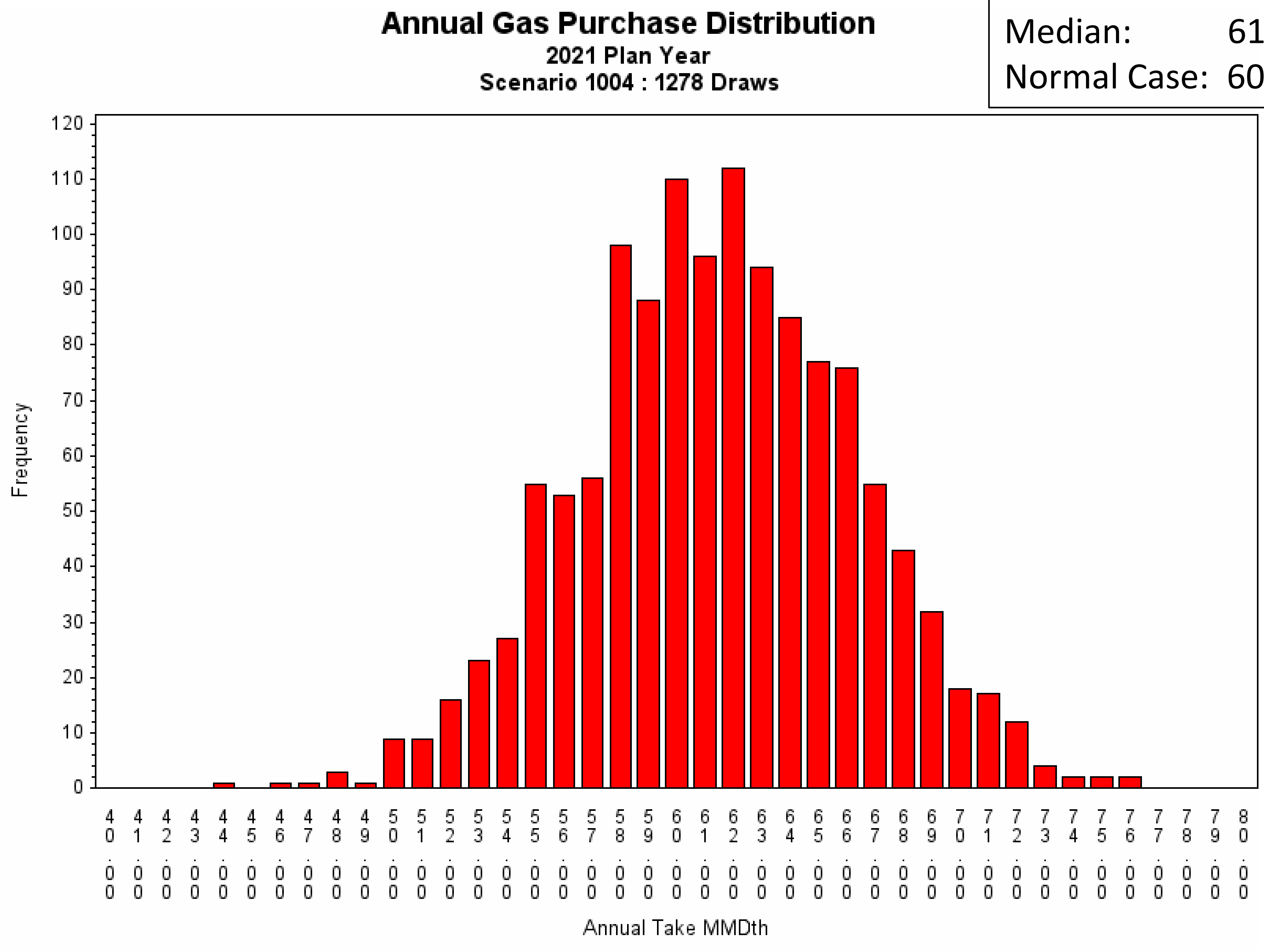

Exhibit 14.65

Monthly Purchase Gas Distribution in Mdth
2021 Plan Year
Scenario 1004 : 1278 Draws

year	month	mean	max	p95	p90	med	p10	p5	min
2020	6	0.42	1.81	1.12	0.97	0.36	0.00	0.00	0.00
2020	7	0.03	0.06	0.06	0.06	0.06	0.00	0.00	0.00
2020	8	0.19	0.51	0.35	0.32	0.22	0.00	0.00	0.00
2020	9	1.48	3.49	2.70	2.40	1.45	0.55	0.36	0.16
2020	10	4.30	8.93	6.11	5.82	4.38	2.47	2.06	0.93
2020	11	5.58	10.85	8.26	7.37	5.13	4.47	4.38	3.93
2020	12	10.59	16.67	13.46	12.74	10.34	8.87	8.45	7.48
2021	1	12.00	21.66	17.53	16.34	11.80	8.04	7.13	4.83
2021	2	15.24	17.90	17.40	17.40	16.15	11.59	11.42	3.50
2021	3	5.62	10.73	8.29	7.63	5.42	3.90	3.44	2.25
2021	4	4.42	10.12	7.23	6.65	4.27	2.40	2.17	0.91
2021	5	1.54	6.41	4.27	3.58	1.33	0.00	0.00	0.00

Exhibit 14.66

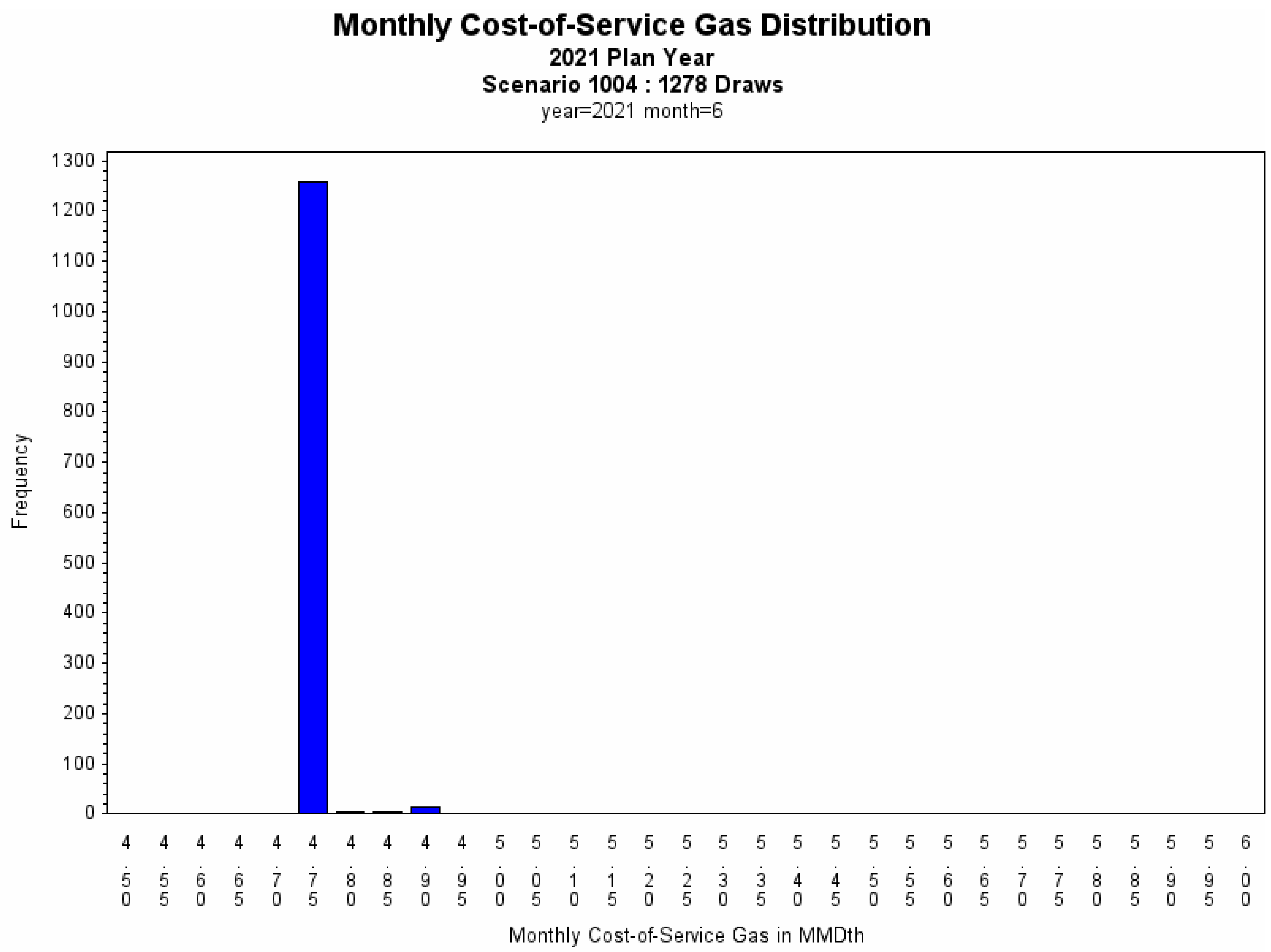

Exhibit 14.67

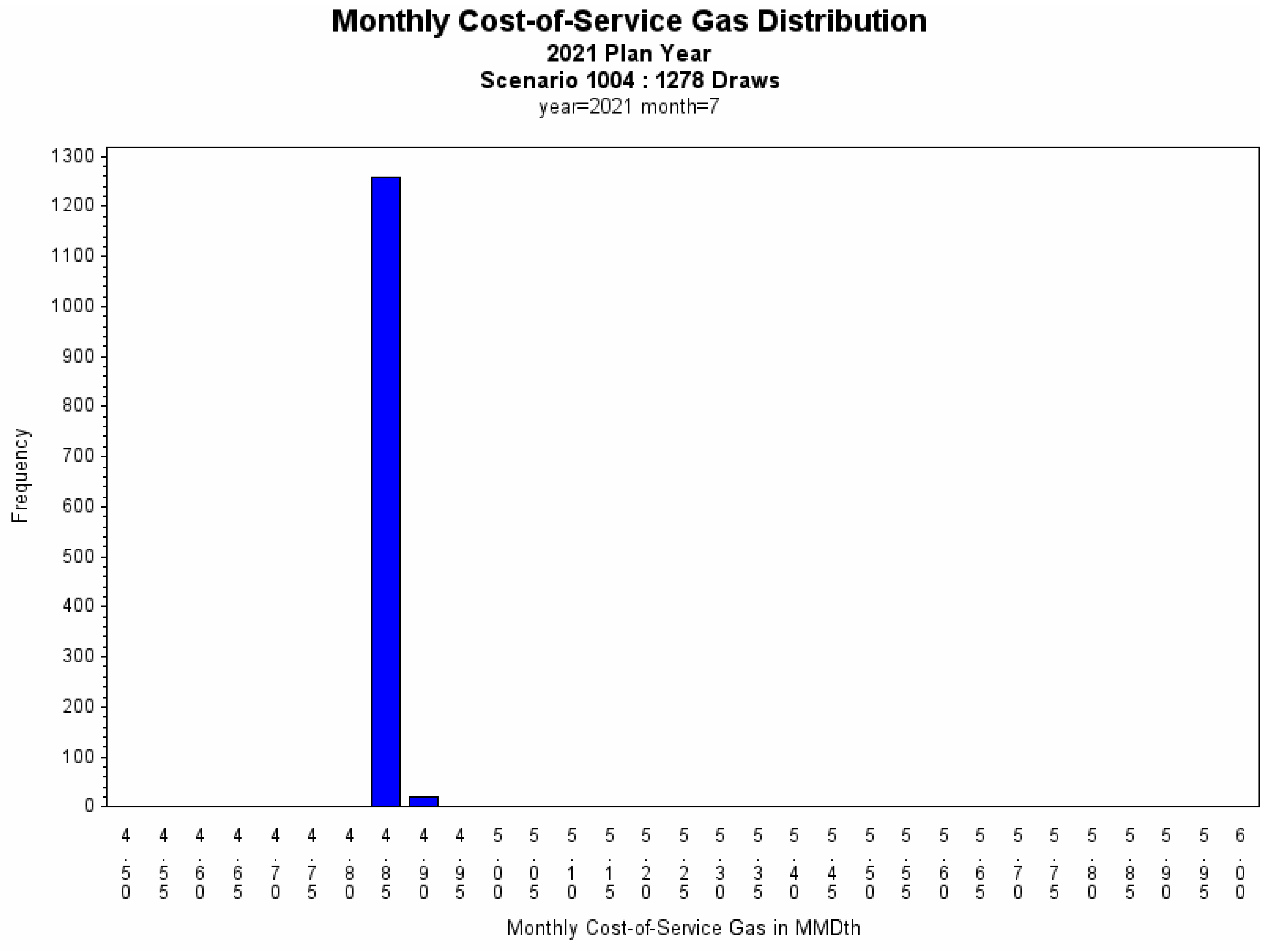

Exhibit 14.68

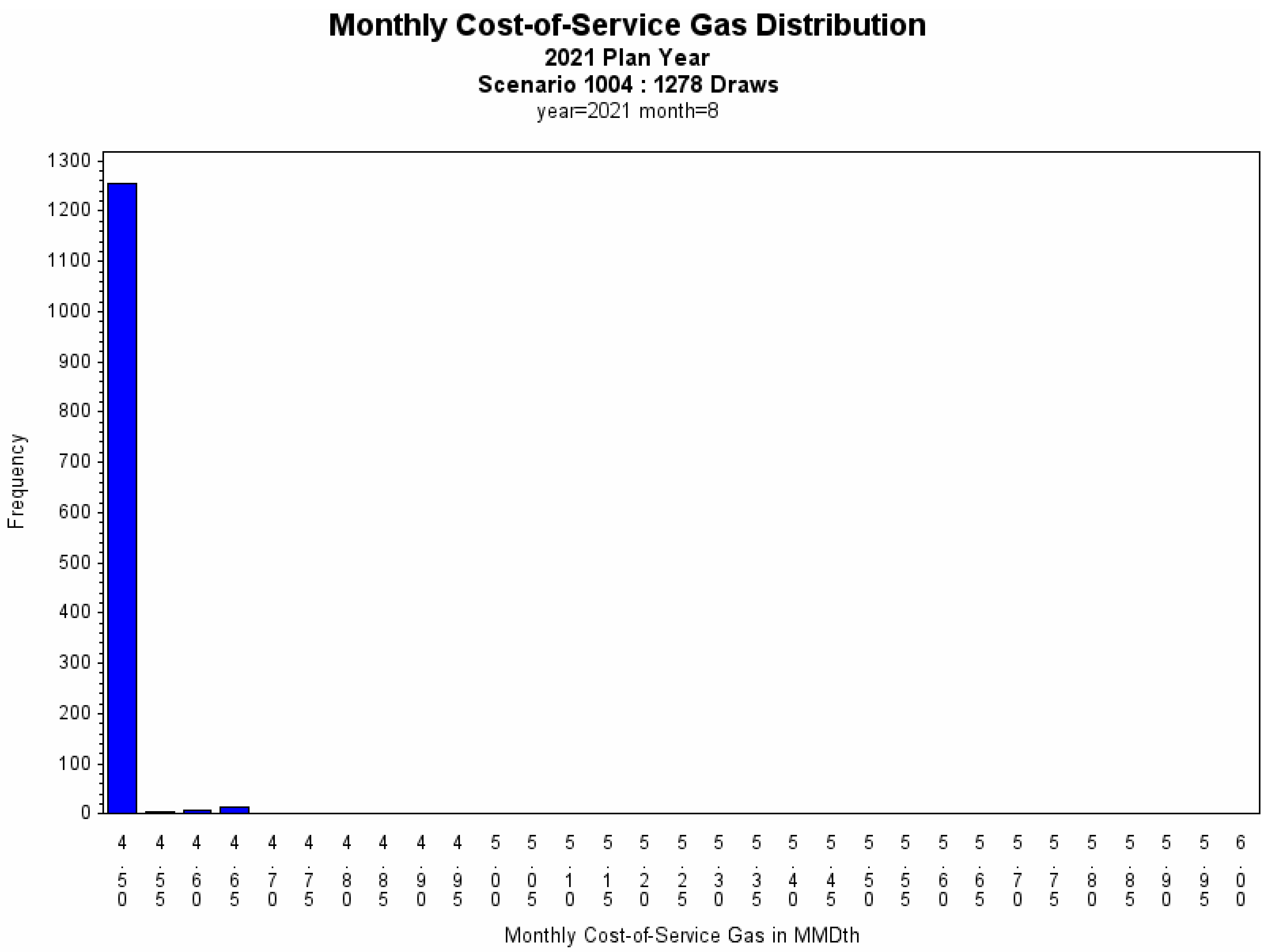

Exhibit 14.69

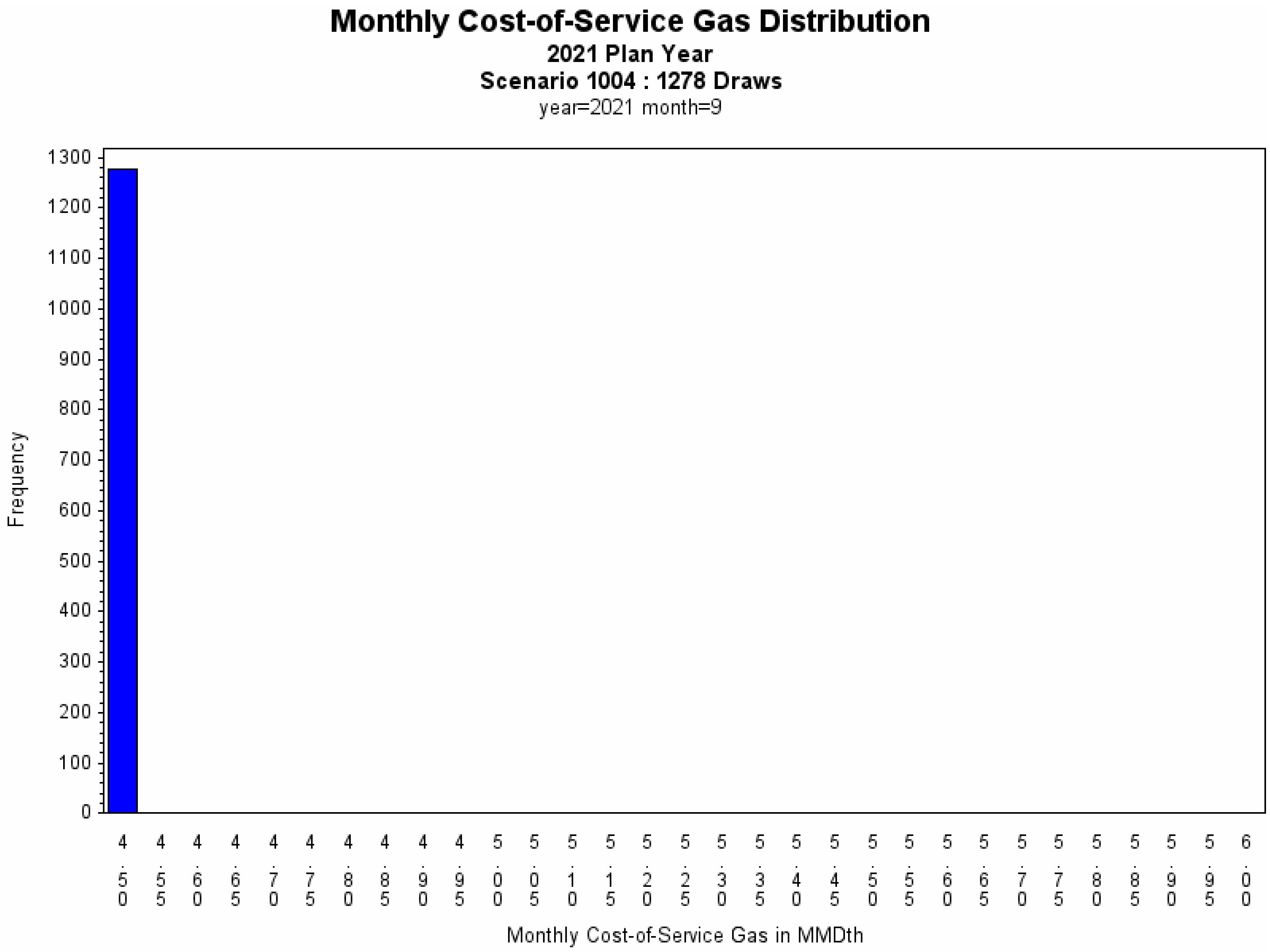

Exhibit 14.70

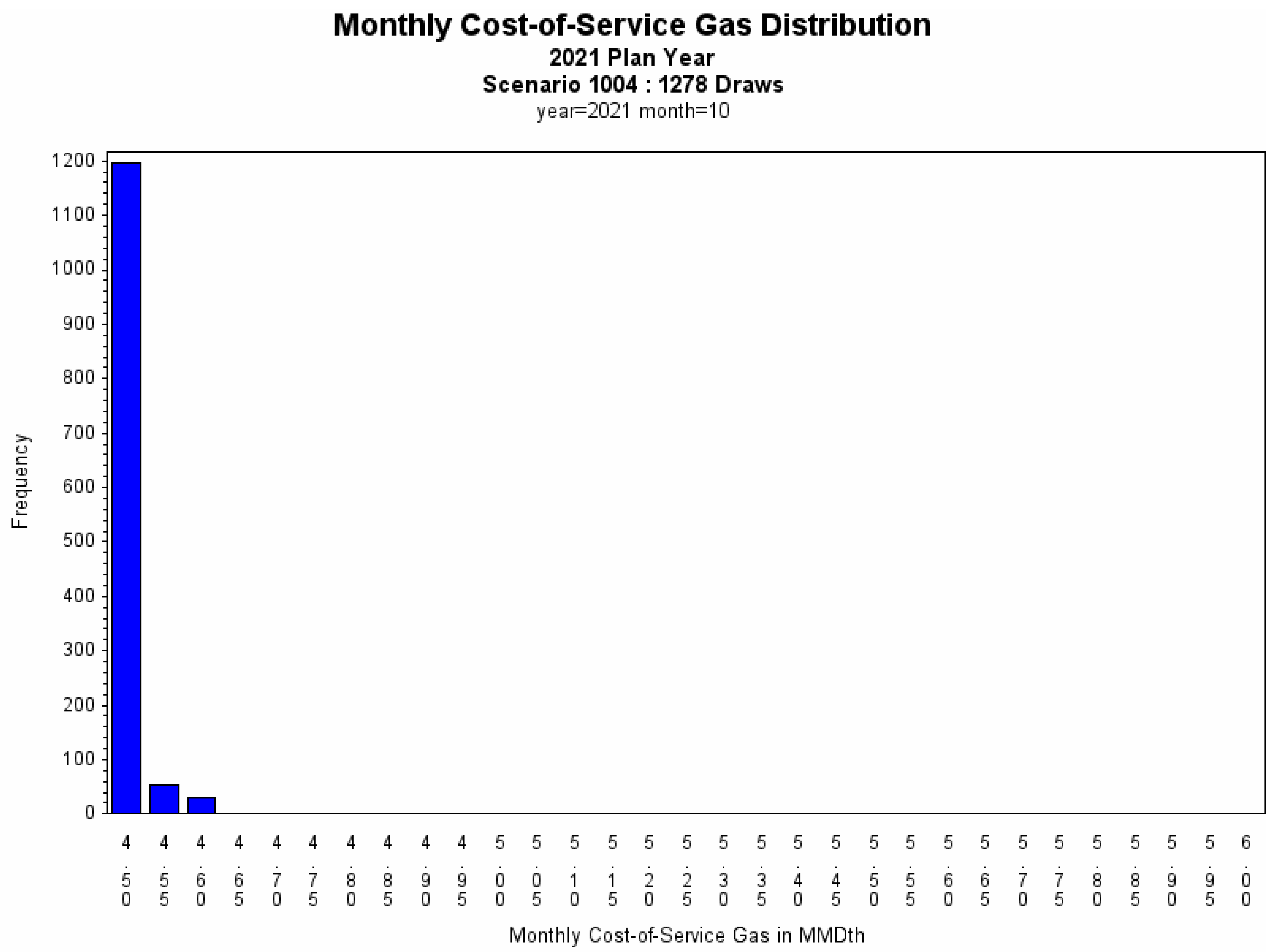

Exhibit 14.71

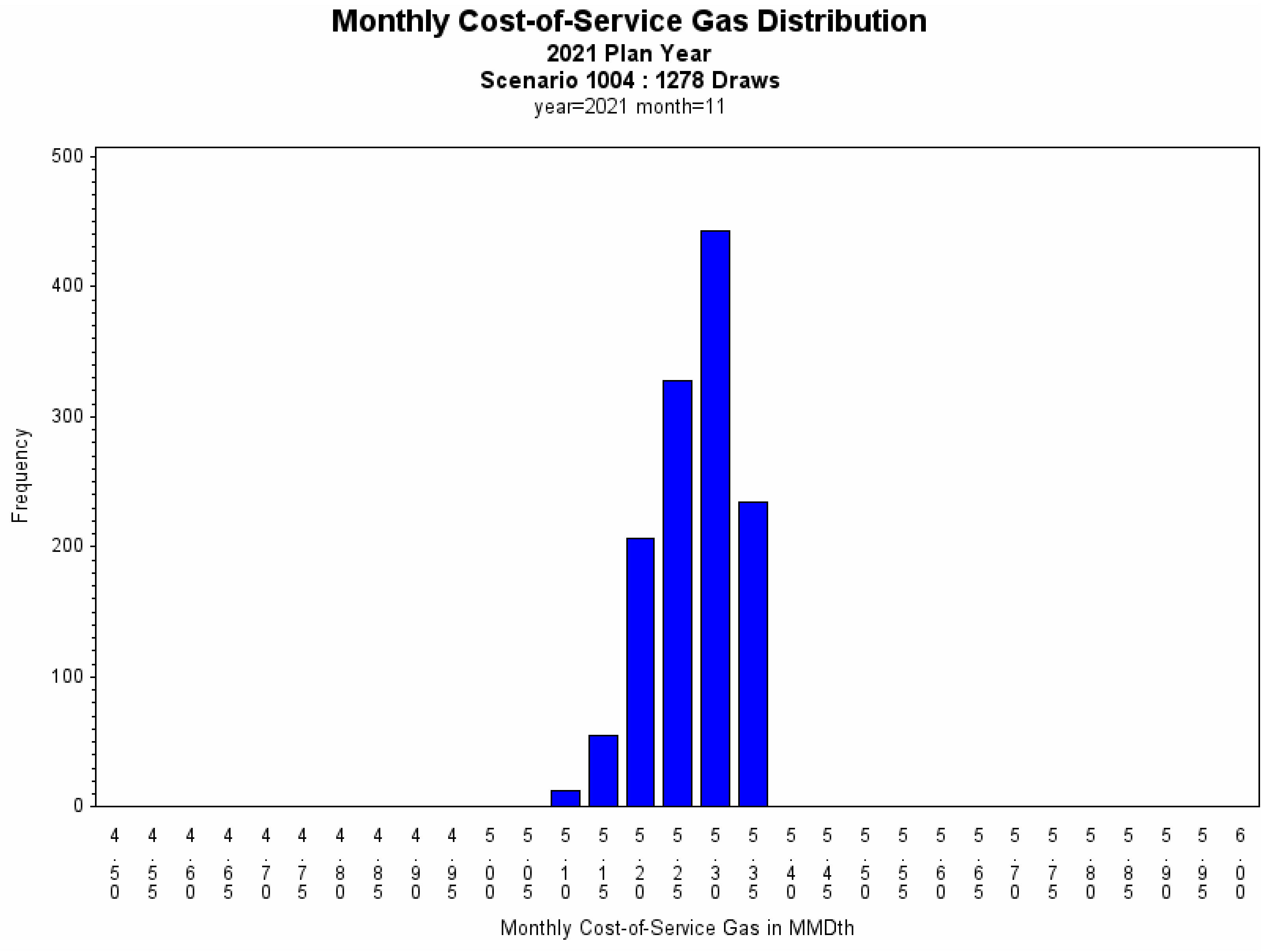

Exhibit 14.72

Monthly Cost-of-Service Gas Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year=2021 month=12

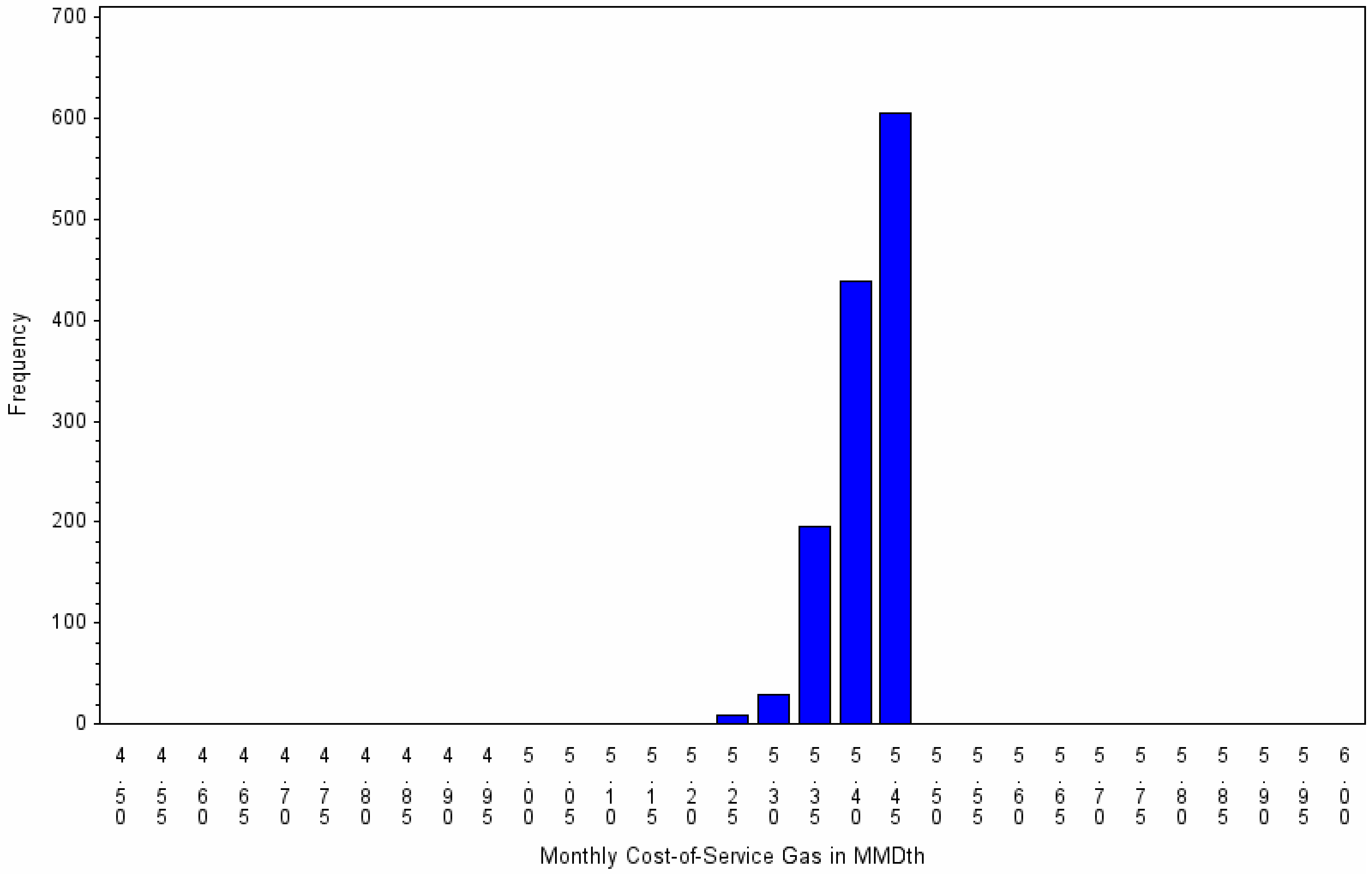

Exhibit 14.73

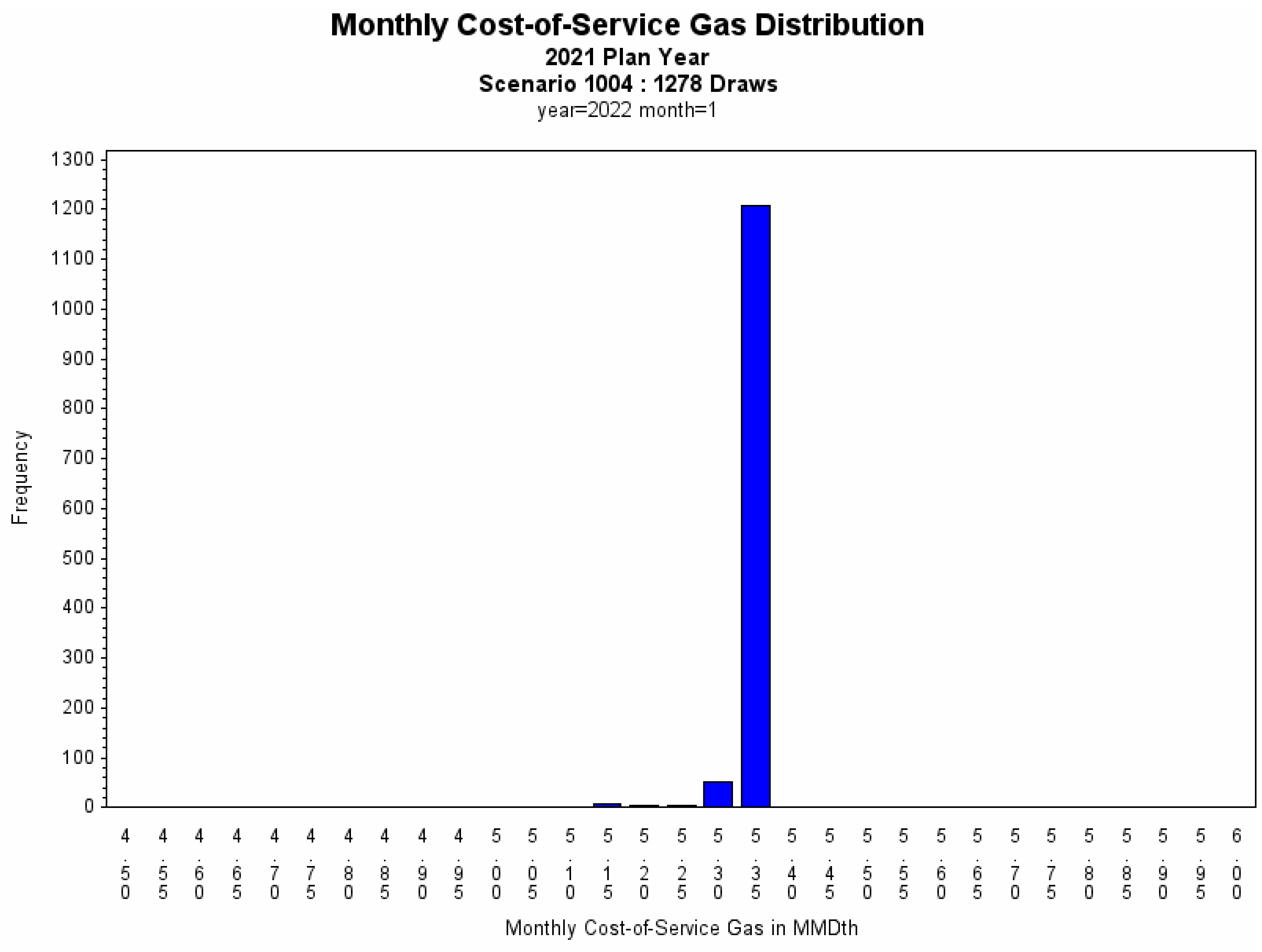

Exhibit 14.74

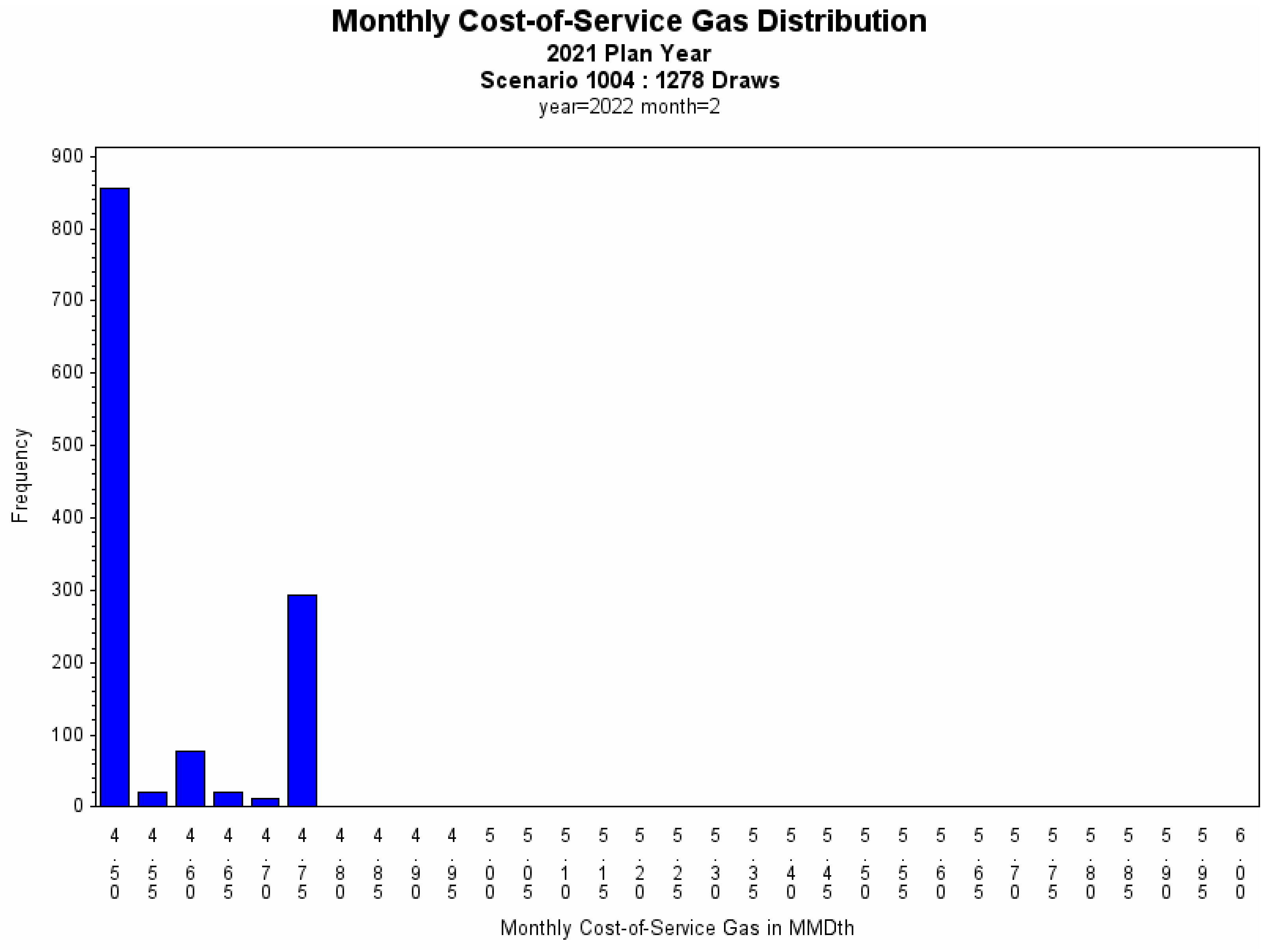

Exhibit 14.75

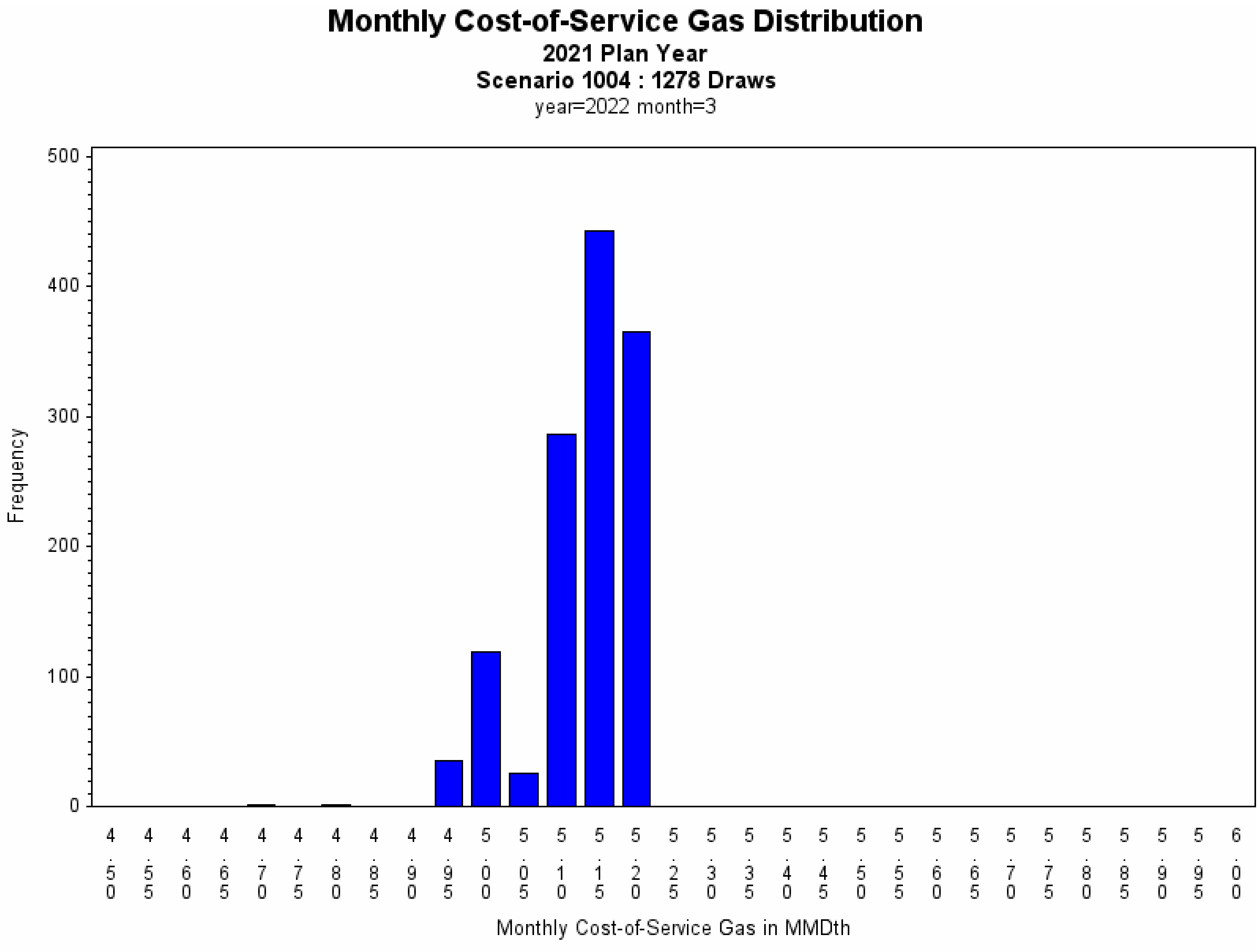

Exhibit 14.76

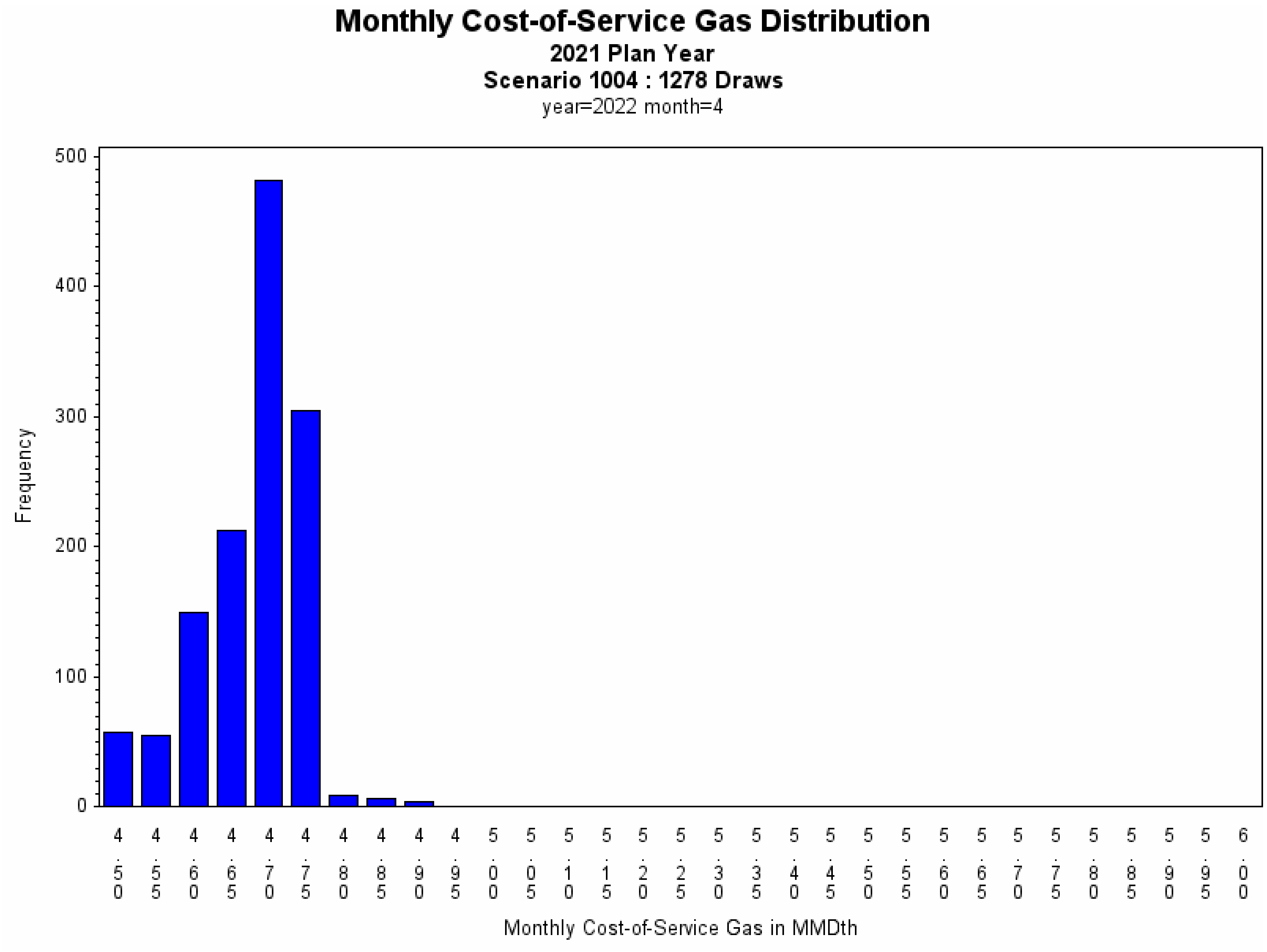

Exhibit 14.77

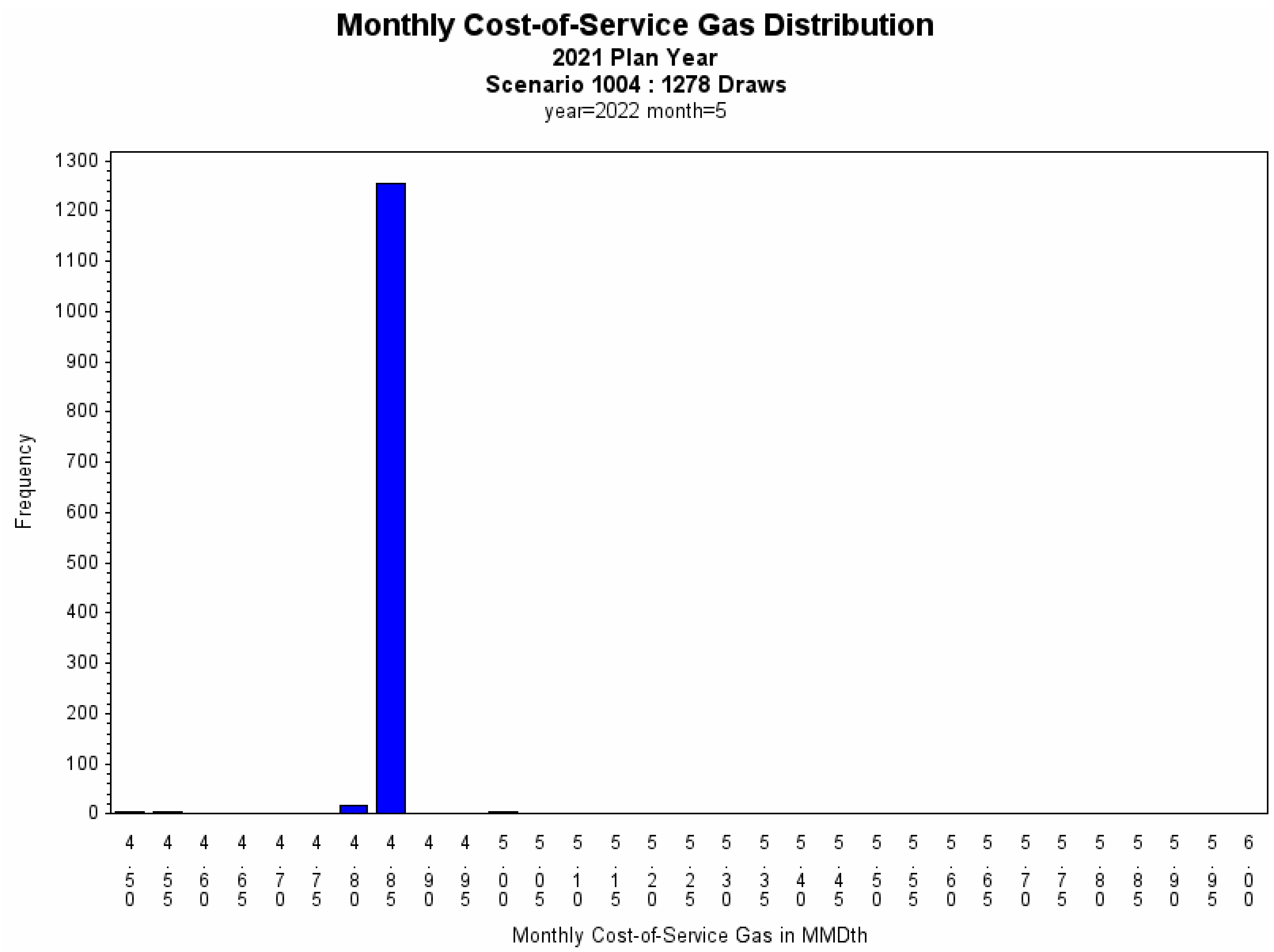

Exhibit 14.78

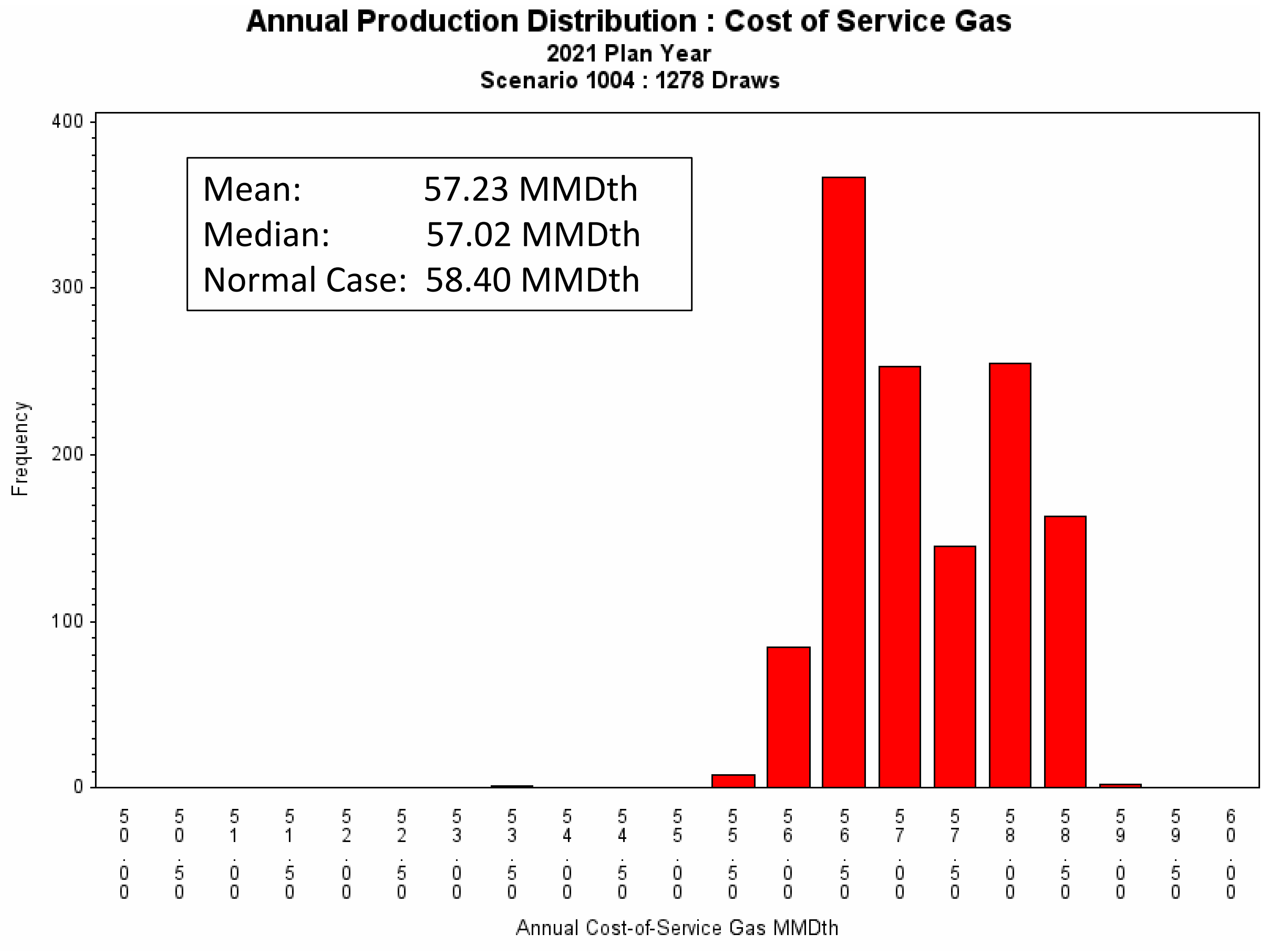

Exhibit 14.79

Monthly Cost-of-Service Gas Distribution

2021 Plan Year

Scenario 1004 : 1278 Draws

year	month	mean	max	p95	P90	med	p10	p5	min
2020	6	4.76	4.92	4.76	4.76	4.76	4.75	4.75	4.75
2020	7	4.84	4.90	4.84	4.84	4.84	4.84	4.84	4.83
2020	8	4.49	4.65	4.49	4.49	4.49	4.49	4.49	4.30
2020	9	4.33	4.41	4.34	4.34	4.33	4.33	4.33	4.22
2020	10	4.29	4.62	4.54	4.46	4.33	4.06	3.92	3.18
2020	11	5.27	5.34	5.34	5.34	5.28	5.20	5.17	5.11
2020	12	5.41	5.44	5.44	5.44	5.42	5.36	5.34	5.25
2021	1	5.35	5.36	5.36	5.36	5.36	5.34	5.32	5.15
2021	2	3.84	4.77	4.77	4.77	3.58	3.01	2.91	0.15
2021	3	5.13	5.20	5.20	5.19	5.14	5.02	5.00	4.69
2021	4	4.67	4.90	4.75	4.75	4.69	4.59	4.54	4.17
2021	5	4.83	4.98	4.83	4.83	4.83	4.83	4.83	4.35

Exhibit 14.80

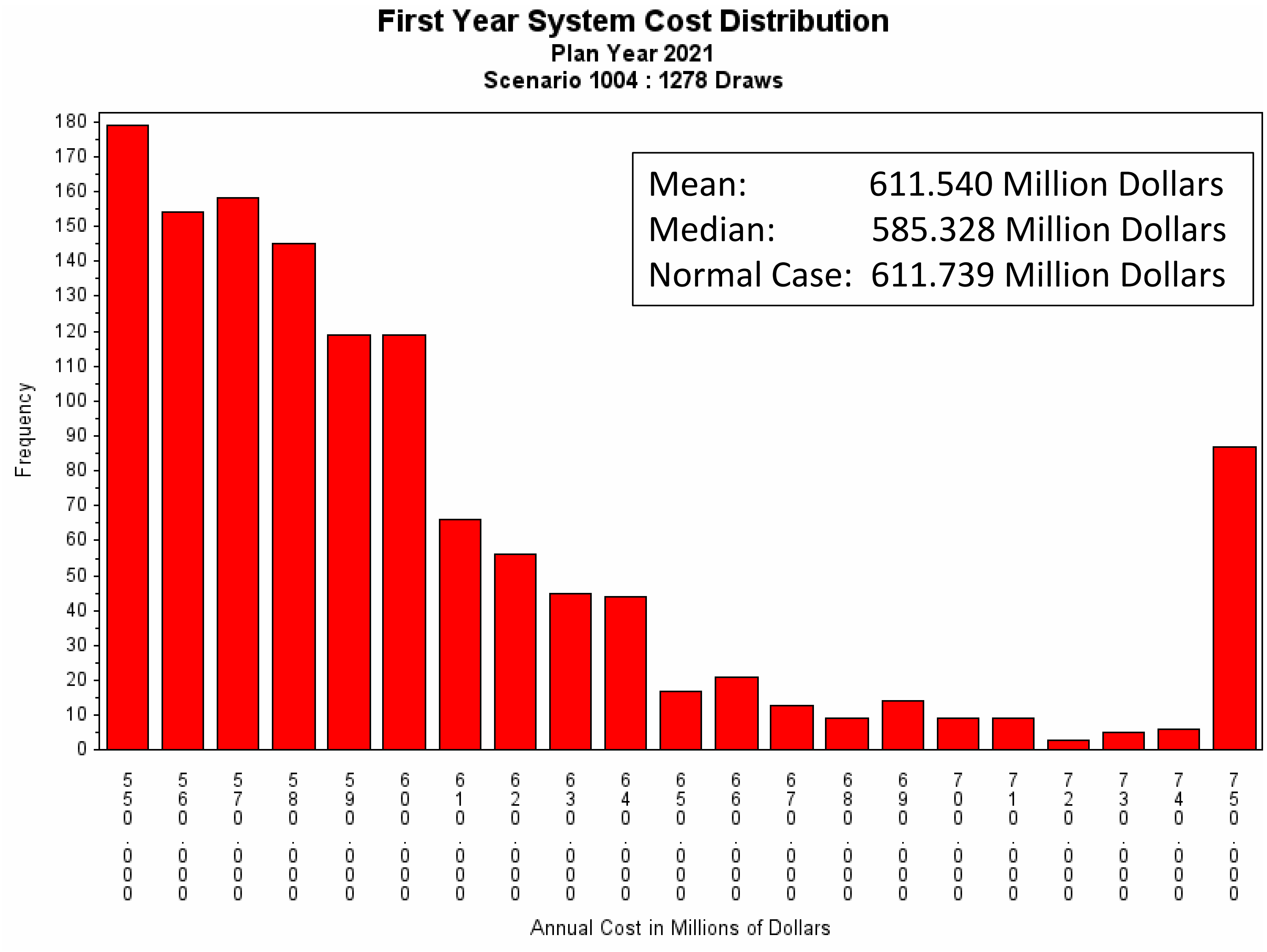

Exhibit 14.81

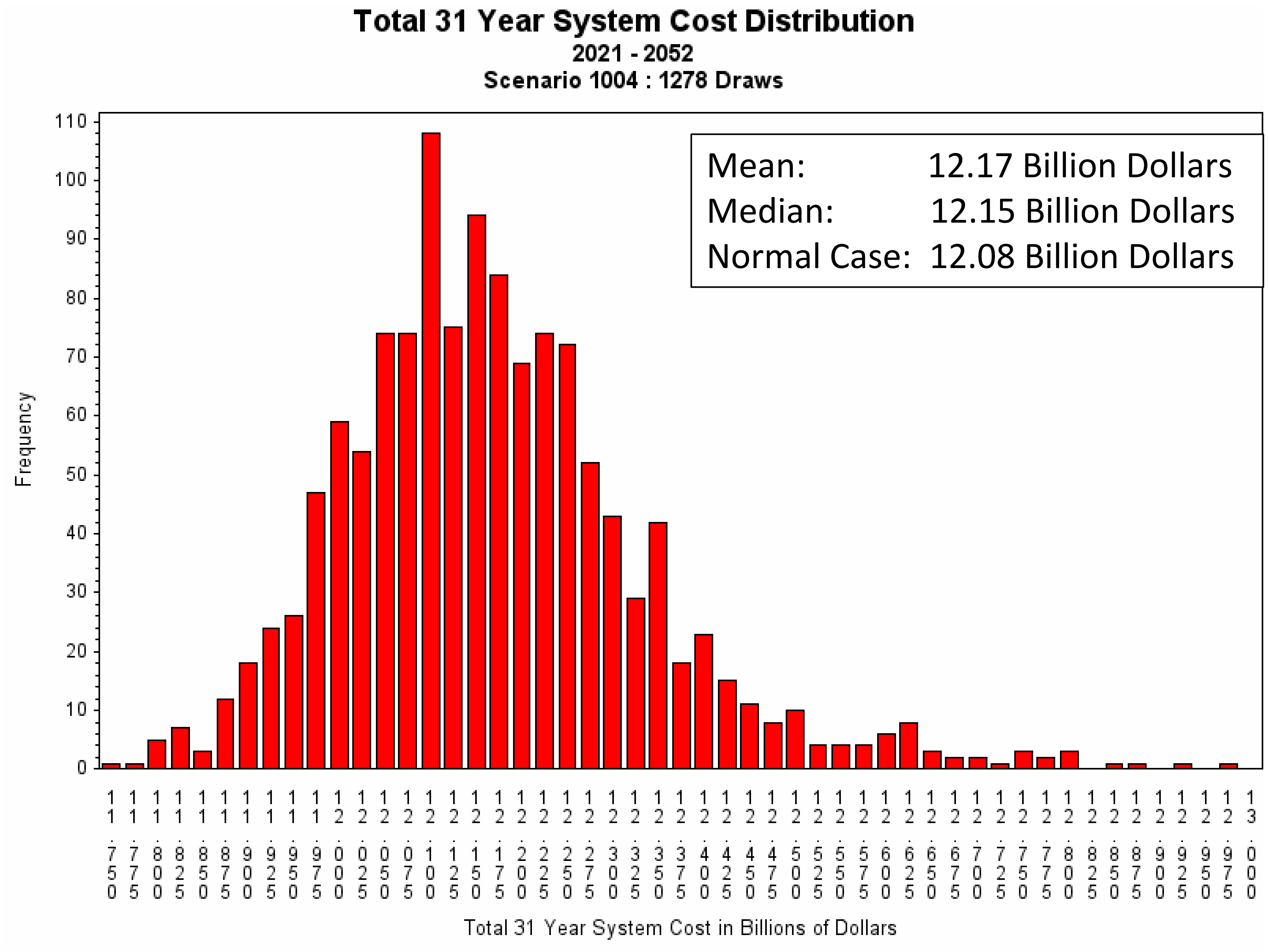

Exhibit 14.82

Exhibit 14.83

Name	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	Total
Birch Creek													
BIRCH CREEK	117.702	120.894	120.168	115.596	118.739	114.228	117.338	116.644	104.737	115.28	110.91	113.937	1386.173
Total	117.702	120.894	120.168	115.596	118.739	114.228	117.338	116.644	104.737	115.280	110.910	113.937	1386.173
D24													
ACEJDMT D24	8.613	8.832	8.764	8.418	8.634	8.289	8.5	8.435	7.563	8.308	7.98	8.184	100.520
BRFM D24	2.106	2.17	2.161	2.085	2.145	2.07	2.133	2.124	1.912	2.108	2.034	2.096	25.144
BRFQ D24	140.922	144.674	143.744	138.216	141.918	136.47	140.135	139.261	125	137.538	132.282	135.854	1656.014
BRFQMT D24	3.285	3.376	3.36	3.234	3.323	3.201	3.292	3.274	2.943	3.239	3.12	3.209	38.856
BRFW D24	56.529	58.054	57.697	55.494	56.994	54.822	56.312	55.977	50.26	55.316	53.217	54.669	665.341
CBFR D24	16.335	16.79	16.703	16.083	16.532	15.915	16.362	16.278	14.627	16.111	15.51	15.943	193.189
CCRUNIT D24	462.612	474.219	433.219	415.947	426.464	445.575	456.918	453.465	406.507	446.707	429.099	440.141	5290.873
CCRUNITMTD24	40.872	41.974	28.849	27.747	28.498	39.87	40.948	40.7	36.537	40.204	38.673	39.717	444.589
CHBT MT	15.408	15.853	15.785	15.213	15.652	15.084	15.519	15.454	13.899	15.323	14.766	15.193	183.149
CHBTBUFF D24	0.867	0.893	0.887	0.855	0.877	0.846	0.871	0.865	0.778	0.856	0.825	0.849	10.269
CHBTCAT2 D24	95.067	97.641	97.055	93.363	95.905	92.265	94.783	93.543	84	92.464	88.965	91.404	1116.455
CHBTCAT3 D24	0	0	160.878	72.276	142.082	153.273	157.557	156.739	140.837	155.118	0	0	1138.760
DRY PINY MT	5.346	5.484	5.444	5.226	5.36	5.151	5.282	5.242	4.701	5.165	4.962	5.09	62.453
DRYPINY6 D24	0.756	0.775	0.772	0.741	0.763	0.513	0.527	0.524	0.47	0.518	0.498	0.512	7.369
DRYPINYU D24	1.776	1.823	1.814	1.743	1.792	1.725	1.77	1.761	1.582	1.739	1.674	1.72	20.919
HWA DEEP D24	0.111	0.112	0.112	0.108	0.109	0.105	0.109	0.109	0.095	0.105	0.102	0.105	1.282
HWA MT	2.964	3.047	3.032	2.919	3.001	2.889	2.97	2.954	2.654	2.923	2.814	2.892	35.059
HWADEEPMTD24	13.116	13.482	13.414	12.912	13.274	12.78	13.138	13.07	11.743	12.933	12.453	12.8	155.115
HWPL1&3MTD24	7.581	7.796	7.759	7.473	7.685	7.401	7.61	7.573	6.81	7.502	7.224	7.431	89.845
HWPLT1&3 D24	76.323	78.281	77.698	74.634	76.548	73.53	75.42	74.862	67.119	73.761	70.854	72.676	891.706
HWPLT2 D24	5.682	5.791	5.716	5.46	5.571	5.325	5.434	5.372	4.796	5.248	5.022	5.134	64.551
HWPLT2MT D24	3.057	3.137	3.116	2.994	3.072	2.952	3.029	3.007	2.699	2.967	2.85	2.926	35.806
ISLAND D24	0	0	0	0	0	51.108	52.48	52.148	46.802	51.491	0	0	254.029
JNSNRDG D24	1.854	1.906	1.897	1.827	1.882	1.812	1.863	1.857	1.669	1.841	1.773	1.823	22.004
JRDG WFS D24	2.529	2.598	2.582	2.481	2.548	2.451	2.517	2.502	2.246	2.474	2.379	2.443	29.750
KNY FLD D24	11.796	12.084	11.985	11.502	11.786	11.313	11.597	11.504	10.31	11.324	10.875	11.151	137.227
MESA D24	622.455	635.956	628.835	601.773	614.95	588.564	601.524	594.974	531.572	582.18	557.355	569.78	7129.918
MOSUMT D24	1.062	1.091	1.085	1.044	1.073	1.032	1.057	1.051	0.944	1.038	0.999	1.026	12.502
PDW MT	172.995	177.37	175.996	208.389	207.356	195.168	197.234	193.561	171.973	187.596	179.094	182.736	2249.468
PDW1A1B D24	0.315	0.326	0.322	0.309	0.316	0.306	0.313	0.31	0.28	0.307	0.294	0.301	3.699
PDWCUT D24	1.245	1.28	1.274	1.227	1.262	1.215	1.249	1.243	1.117	1.234	1.188	1.221	14.755
PDWMT D24	22.326	22.903	22.735	21.84	22.404	21.525	22.078	21.917	19.653	21.601	20.751	21.288	261.021
PDWPLT2 D24	0	0	0	0	0	0	0	0	0	0	0	0	0.000
SGRLF D24	1.428	1.466	1.454	1.398	1.435	1.38	1.414	1.404	1.26	1.386	1.332	1.367	16.724
SGRLFMT D24	12.576	12.905	12.815	12.315	12.639	12.147	12.465	12.378	11.102	12.208	11.73	12.037	147.317
TRAIL D24	310.425	315.819	250.508	239.103	243.793	315.174	321.622	317.738	282.383	306.764	291.855	296.903	3492.087
TRAILMT D24	47.358	48.292	47.678	45.57	46.525	44.499	45.461	44.959	40.166	43.998	42.135	43.093	539.734
WHLA D24	31.611	32.432	32.206	30.948	31.753	30.513	31.31	31.09	27.885	30.656	29.457	30.225	370.086
WWILSON D24	3.51	3.608	3.59	3.453	3.55	3.417	3.512	3.494	3.139	3.457	3.327	3.419	41.476
PC													
ACEJDMT PC	3.471	3.568	3.553	3.42	3.519	3.39	3.484	3.469	3.119	3.438	3.312	3.404	41.147
BRFM PC	0.153	0.158	0.155	0.15	0.155	0.15	0.152	0.152	0.137	0.152	0.144	0.149	1.807
BRFQ PC	10.626	10.928	10.878	10.479	10.779	10.383	10.679	10.633	9.559	10.534	10.149	10.438	126.065
BRFQMT PC	3.3	3.391	3.376	3.252	3.345	3.219	3.311	3.295	2.962	3.264	3.144	3.23	39.089
BRFW PC	9.231	9.492	9.449	9.099	9.356	9.012	9.269	9.223	8.291	9.136	8.799	9.049	109.406
BRUFF MT	4.806	4.941	4.913	4.731	4.861	4.68	4.811	4.783	4.298	4.734	4.557	4.684	56.799
CBFR PC	59.169	60.813	60.487	58.221	59.839	57.597	59.201	58.881	52.898	58.252	56.07	57.629	699.057
CCRUNIT MT	44.337	45.167	32.349	30.879	31.487	41.877	42.712	42.172	37.615	41.137	39.33	40.161	469.223
CCRUNIT PC	48.978	50.356	50.102	48.243	49.6	47.76	49.107	48.859	43.91	48.372	46.578	47.892	579.757
CCRUNITMT PC	15.954	16.414	16.34	15.744	16.197	15.606	16.055	15.984	14.372	15.844	15.264	15.705	189.479
CHBTC1 MT PC	23.406	24.081	23.978	23.106	23.774	22.908	23.572	23.47	21.109	23.269	22.422	23.07	278.165
CHBTCAT1 PC	45.255	46.438	46.116	44.322	45.483	43.716	44.863	44.559	39.976	43.961	42.258	43.375	530.322
CHBTCAT2 PC	2.019	2.068	2.052	1.968	2.015	1.935	1.981	1.962	1.758	1.928	1.851	1.897	23.434
DRYPINY6 PC	1.05	1.079	1.076	1.035	1.066	1.026	1.057	1.051	0.946	1.042	1.005	1.035	12.468
DRYPINYU PC	10.557	10.841	10.772	10.359	10.636	10.227	10.5	10.435	9.366	10.304	9.909	10.174	124.080
FOGARTY PC	0.564	0.58	0.577	0.552	0.567	0.546	0.561	0.558	0.501	0.549	0.528	0.543	6.626
HWA DEEP PC	0.546	0.561	0.555	0.534	0.549	0.528	0.543	0.539	0.484	0.533	0.51	0.524	6.406
HWPL1&3MTPC	6.255	6.429	6.392	6.153	6.321	6.084	6.25	6.216	5.583	6.147	5.916	6.076	73.822
HWPLT1&3 PC	53.25	54.718	54.417	52.371	53.816	51.792	53.224	52.929	47.544	52.347	50.379	51.77	628.557
HWPLT2 PC	0.855	0.88	0.874	0.843	0.865	0.834	0.856	0.853	0.764	0.843	0.81	0.834	10.111
ISLAND PC	0.567	0.583	0.58	0.558	0.57	0.549	0.564	0.561	0.504	0.555	0.534	0.549	6.674
JNSNRDG PC	2.01	2.071	2.062	1.986	2.043	1.971	2.027	2.018	1.814	2.003	1.929	1.984	23.918
KNY FLD PC	3.246	3.342	3.329	3.207	3.302	3.183	3.277	3.264	2.937	3.236	3.12	3.212	38.655
MOSUMT PC	11.028	11.318	11.241	10.806	11.089	10.659	10.94	10.865	9.75	10.72	10.305	10.577	129.298
PDW1A1B PC	0.801	0.825	0.818	0.786	0.728	0.774	0.794	0.79	0.708	0.778	0.747	0.769	9.318
PDW1AB MT PC	3.315	3.407	3.391	3.267	3.36	3.234	3.326	3.311	2.976	3.28	3.159	3.249	39.275
PDWCUT PC	0.684	0.704	0.704	0.678	0.698	0.672	0.691	0.688	0.622	0.685	0.66	0.679	8.165
PDWPLT2 PC	5.124	5.27	5.245	5.052	5.196	5.004	5.146	5.121	4.606	5.075	4.887	5.028	60.754
PDWPLT3 PC	5.82	5.298	5.267	5.067	5.205	5.007	5.143	5.112	4.592	5.053	4.863	4.994	61.421
SGRLF PC	35.694	36.661	36.434	35.046	35.994	34.62	35.554	35.337	31.724	34.909	33.576	34.484	420.033
TRAIL PC	1.221	1.252	1.243	1.197	1.228	1.179	1.209	1.203	1.078	1.184	1.14	1.169	14.303
WHLA PC	9.486	9.746	9.688	9.321	9.576	9.213	9.464	9.412	8.45	9.3	8.949	9.195	111.800
WWILSON PC	10.461	10.741	10.67	10.257	10.531	10.125	10.394	10.326	9.265	10.19	9.798	10.06	122.818
Total	433.239	444.121	429.083	412.689	423.750	419.460	430.717	428.031	384.218	422.754	406.602	417.588	5052.252

Normal Temperatue Case: Plan Year 1
MDth

PW													
MOSU MT	0.492	0.505	0.502	20.499	17.853	15.159	14.093	12.893	10.786	11.163	10.173	9.957	124.075
Total	0.492	0.505	0.502	20.499	17.853	15.159	14.093	12.893	10.786	11.163	10.173	9.957	124.075
D21													
PDW1A1B D21	0.525	0.539	0.536	0.516	0.53	0.507	0.521	0.518	0.465	0.512	0.492	0.502	6.163
Total	0.525	0.539	0.536	0.516	0.530	0.507	0.521	0.518	0.465	0.512	0.492	0.502	6.163
Q50													
BRCH CRK Q50	0.918	0.927	0.905	0.855	0.865	0.819	0.828	0.809	0.717	0.778	0.738	0.747	9.906
TRAIL Q50	1.221	1.246	1.228	1.173	1.197	1.146	1.169	1.156	1.033	1.128	1.08	1.104	13.881
yTRAIL 2Q50	1.206	1.231	1.215	1.161	1.184	1.131	1.156	1.144	1.019	1.116	1.068	1.091	13.723
	3.345	3.404	3.348	3.189	3.246	3.096	3.153	3.109	2.769	3.022	2.886	2.942	37.51
Off-System													
OFF SYS D24	30.659	31.715	31.752	30.761	31.824	30.833	31.895	31.933	28.873	32.001	31.002	32.07	375.318
OFF SYS PC	7.662	7.883	7.846	7.56	7.775	7.491	7.707	7.669	6.896	7.601	7.323	7.533	90.946
OFF SYS PW	0.075	0.078	0.078	0.075	0.078	0.072	0.074	0.074	0.067	0.074	0.072	0.074	0.891
Total	38.396	39.676	39.676	38.396	39.677	38.396	39.676	39.676	35.836	39.676	38.397	39.677	467.155
Wexpro I													
CCRUNIT D8	183	185.346	181.796	172.683	175.252	166.665	169.337	166.582	148.084	161.432	153.891	156.705	2020.774
KNY FLD D8	26.991	26.992	26.158	24.564	24.664	23.214	23.358	22.766	20.059	21.681	20.499	20.714	281.661
MESA D8	518.673	519.107	503.756	473.868	476.65	510.3	516.045	504.02	445.211	482.549	457.587	463.71	5871.476
CCRUNIT MT	18.435	18.783	13.451	12.84	13.094	17.415	17.763	17.537	15.641	17.106	16.356	16.7	195.121
TRAIL D8	111.033	110.769	97.104	91.131	91.54	96.177	97.101	94.999	84.048	91.236	86.649	87.941	1139.729
Total	858.132	860.997	822.265	775.086	781.200	813.771	823.604	805.904	713.043	774.004	734.982	745.770	9508.761
Wexpro I New Drill													
z21 CCRK D8	0	0	0	0	0	55.965	57.831	57.831	52.234	50.927	43.989	41.239	360.016
z21 TRAIL D8	0	0	0	0	0	91.053	94.088	94.088	84.983	91.912	87.279	88.858	632.261
Total	0.000	0.000	0.000	0.000	0.000	147.018	151.919	151.919	137.217	142.839	131.268	130.097	992.277
Wexpro II													
CCOPA 2E	3.813	3.922	3.903	3.759	3.866	3.723	3.829	3.81	3.427	3.776	3.636	3.739	45.201
CCRUNIT 2D8	74.196	75.125	73.668	69.957	70.978	67.485	68.55	67.419	59.92	65.308	62.244	63.37	818.22
CCRUNIT 2E	253.572	259.613	228.892	219.609	225.007	256.869	262.275	259.327	231.714	253.896	243.258	248.939	2942.972
CCRUNIT2EMT	23.631	24.279	18.792	18.084	18.588	23.067	23.703	23.569	21.171	23.306	22.428	23.045	263.663
TRAIL 2D8	257.34	250.31	233.396	214.812	211.978	280.941	282.376	273.773	239.131	255.555	239.553	240.424	2979.588
TRAIL 2E	337.971	343.954	272.564	260.211	265.363	320.334	326.666	322.499	287.675	314.653	300.915	307.371	3660.177
TRAIL 2E MT	45.204	46.1	45.517	43.506	44.423	42.489	43.409	42.929	38.354	42.014	40.236	41.152	515.335
WHISKEY MT	26.685	27.196	13.513	12.906	13.166	25.47	25.984	25.662	22.898	25.048	23.958	24.471	266.958
WHISKEYC 2E	83.517	85.132	59.641	56.94	58.06	79.041	80.668	79.695	71.128	77.835	74.466	76.09	882.213
Total	1105.929	1115.631	949.886	899.784	911.429	1099.419	1117.460	1098.683	975.418	1061.391	1010.694	1028.601	12374.327
Wexpro II New Drill													
z21 CCRK 2D8	0	0	0	0	0	197.409	199.442	185.008	158.242	165.128	150.087	140.777	1196.093
z21 TRAIL2D8	0	0	0	0	0	90.027	93.028	93.028	84.025	90.877	86.295	87.857	625.137
z21 WSKY 2D8	0	0	0	0	0	35.586	35.067	29.655	23.461	23.278	20.511	19.53	187.088
Total	0.000	0.000	0.000	0.000	0.000	323.022	327.537	307.691	265.728	279.283	256.893	248.164	2008.318

Normal Temperatue Case: Plan Year 1
MDth

	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	Total
Withdraw													
Clay Bsn 935	0	0	0	0	0	384.139	1798.439	1515.578	1368.909	710.714	0	0	5777.779
Clay Bsn 988	0	0	0	0	0	229.111	1135	947.236	855.568	444.196	0	0	3611.111
Clay Bsn 997	0	0	0	0	0	229.111	1135	947.236	855.568	444.196	0	0	3611.111
Chalk Creek	0.000	0.000	0.000	0.000	0.000	0.000	0.000	307.500	13.500	0.000	0.000	0.000	321.000
Coalville	0.000	0.000	0.000	0.000	0.000	0.000	0.000	625.000	60.186	0.000	0.000	0.000	360.186
Leroy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	443.498	0.000	0.000	0.000	0.000	443.498
Total	0.000	0.000	0.000	0.000	0.000	842.361	4068.439	4786.048	3153.731	1599.106	0.000	0.000	14124.685
Inject													
Clay Bsn 935	962.747	994.838	911.927	785.228	700.816	0.000	0.000	0.000	0.000	0.000	420.168	1074.667	5850.391
Clay Bsn 988	601.717	621.774	569.966	490.747	438.019	0.000	0.000	0.000	0.000	0.000	262.416	671.667	3656.306
Clay Bsn 997	601.717	621.774	569.966	490.747	438.019	0.000	0.000	0.000	0.000	0.000	262.416	671.667	3656.306
Chalk Creek	0.000	0.000	0.000	40.000	135.000	90.000	53.892	0.000	0.000	0.000	0.000	0.000	318.892
Coalville	0.000	0.000	0.000	23.086	291.200	90.186	10.000	0.000	0.000	325.000	0.000	0.000	739.472
Leroy	0.000	0.000	0.000	49.200	45.000	300.000	76.296	0.000	0.000	0.000	0.000	0.000	470.496
Total	2166.181	2238.386	2051.859	1879.008	2048.054	480.186	140.188	0.000	0.000	325.000	945.000	2418.001	14691.863
Purchase Gas													
Spot	0	0	0	62.71	1955.937	2311.925	2026.875	3856.182	5689.432	4031.468	3258.297	1552.498	24745.324
Spot	528.775	58.162	91.244	1088.76	1523.653	1500	1550	1550	0	1550	1500	1550	12490.594
Spot	0	0	0	0	0	0	0	0	9.186	0	0	0	9.186
Spot	0	0	0	0	0	0	0	0.638	0.159	0	0	0	0.797
Base	0	0	0	0	930	900	930	930	840	930	900	0	6360
Base	0	0	0	0	0	0	310	310	280	0	0	0	900
Base	0	0	0	0	0	750	775	775	700	775	0	0	3775
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Base	0	0	0	0	0	0	775	775	700	0	0	0	2250
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Base	0	0	0	0	0	0	775	775	700	0	0	0	2250
Base	0	0	0	0	0	0	310	310	280	0	0	0	900
Peak	0	0	0	0	0	1200	1240	1240	0	0	0	0	3680
Total	528.775	58.162	91.244	1151.47	4409.59	6661.925	9621.875	11451.82	10038.777	7286.468	5658.297	3102.498	60060.901

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.86

Name	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	
Birch Creek													
BIRCH CREEK	108.312	111.237	110.558	106.329	109.201	105.033	107.874	107.214	96.247	105.908	101.868	104.622	1274.403
Total	108.312	111.237	110.558	106.329	109.201	105.033	107.874	107.214	96.247	105.908	101.868	104.622	1274.403
D24													
ACEJDMT D24	7.86	8.06	7.998	7.683	7.877	7.566	7.759	7.7	6.902	7.586	7.284	7.471	91.747
BRFM D24	2.019	2.08	2.074	2.001	2.058	1.986	2.046	2.037	1.834	2.024	1.953	2.009	24.121
BRFQ D24	130.671	134.205	133.393	128.31	131.077	126.09	129.512	128.74	115.587	127.212	122.382	125.714	1532.893
BRFQMT D24	3.087	3.174	3.159	3.042	3.128	3.009	3.094	3.078	2.766	3.047	2.934	3.016	36.535
BRFW D24	52.452	53.887	53.481	51.459	52.871	50.871	52.269	51.972	46.676	51.386	49.449	50.809	617.581
CBFR D24	15.351	15.779	15.698	15.114	15.537	14.958	15.376	15.295	13.745	15.14	14.574	14.982	181.551
CCRUNIT D24	422.832	433.752	430.621	413.736	424.474	407.856	418.469	415.518	372.669	409.711	393.735	404.035	4947.408
CCRUNITMTD24	38.205	39.24	39.001	37.515	38.533	37.065	38.068	37.839	33.972	37.386	35.964	36.94	449.727
CHBT MT	14.64	15.063	14.998	25.173	24.168	22.194	22.029	21.325	18.746	20.277	19.227	19.511	237.35
CHBTBUFF D24	0.816	0.84	0.834	0.804	0.828	0.795	0.818	0.815	0.731	0.806	0.777	0.8	9.664
CHBTCAT2 D24	87.951	90.368	89.857	86.466	88.846	85.497	87.854	87.364	78.47	86.394	83.145	85.439	1037.651
CHBTCAT3 D24	0	0	0	0	0	93.454	4.649	143.366	128.825	4.569	0	0	374.862
DRY PINY MT	4.89	5.016	4.982	4.785	4.91	4.716	4.839	4.805	4.309	4.737	4.554	4.672	57.215
DRYPINY6 D24	0.492	0.505	0.502	0.486	0.499	0.48	0.493	0.49	0.44	0.484	0.465	0.481	5.816
DRYPINYU D24	1.656	1.699	1.69	1.626	1.671	1.608	1.652	1.643	1.473	1.621	1.56	1.603	19.501
HWA DEEP D24	0.099	0.102	0.102	0.099	0.099	0.096	0.099	0.099	0.087	0.096	0.093	0.096	1.168
HWA MT	2.784	2.861	2.846	2.742	2.818	2.712	2.787	2.774	2.492	2.744	2.643	2.716	32.919
HWADEEPMTD24	12.324	12.67	12.602	12.132	12.471	12.009	12.344	12.279	11.035	12.152	11.7	12.028	145.746
HWPL1&3MTD24	7.158	7.359	7.325	7.053	7.254	6.987	7.186	7.152	6.429	7.084	6.822	7.015	84.824
HWPLT1&3 D24	69.813	71.61	71.083	68.286	70.045	67.287	69.022	68.516	61.435	67.521	64.866	66.538	816.022
HWPLT2 D24	4.914	5.025	4.976	4.764	4.873	4.671	4.78	4.737	4.236	4.65	3.819	3.909	55.354
HWPLT2MT D24	2.811	2.886	2.864	2.754	2.824	2.715	2.787	2.765	2.481	2.728	2.622	2.691	32.928
ISLAND D24	0	0	0	0	0	0	0	0	1.54	0	0	0	1.54
JNSNRDG D24	1.758	1.807	1.801	1.734	1.786	1.719	1.77	1.761	1.585	1.745	1.683	1.73	20.879
JRDG WFS D24	2.349	2.412	2.396	2.307	2.368	2.277	2.341	2.325	2.089	2.297	2.211	2.269	27.641
KNY FLD D24	10.71	10.983	10.9	10.47	10.742	10.317	10.583	10.509	9.425	10.36	9.954	10.215	125.167
MESA D24	545.535	557.752	551.868	528.453	539.326	516.483	528.15	522.675	467.216	511.943	490.338	501.49	6261.23
MOSUMT D24	0.987	1.014	1.008	0.969	0.995	0.957	0.983	0.977	0.876	0.964	0.927	0.952	11.608
PDW MT	174.747	178.222	176.3	168.843	172.72	165.519	169.412	167.837	150.217	164.827	158.109	161.963	2008.716
PDW1A1B D24	0.291	0.298	0.295	0.285	0.291	0.282	0.288	0.285	0.258	0.282	0.27	0.279	3.404
PDWCUT D24	1.176	1.209	1.203	1.161	1.193	1.149	1.181	1.178	1.058	1.166	1.122	1.156	13.953
PDWMT D24	20.451	20.978	20.826	20.007	20.525	19.719	20.227	20.082	18.007	19.79	19.014	19.505	239.131
PDWPLT2 D24	0	0	0	0	0	0	0	0	0	0	0	0	0
SGRLF D24	1.314	1.348	1.339	1.287	1.321	1.269	1.302	1.293	1.159	1.274	1.224	1.259	15.389
SGRLFMT D24	11.568	11.873	11.789	11.331	11.628	11.175	11.467	11.386	10.214	11.231	10.794	11.076	135.534
TRAIL D24	283.152	288.576	284.8	272.16	277.837	265.737	271.489	268.5	239.918	262.843	251.763	257.551	3224.326
TRAILMT D24	41.286	42.238	41.828	40.089	41.112	39.489	40.511	40.219	36.072	39.665	38.124	39.134	479.768
WHLA D24	29.046	29.803	29.593	28.437	29.18	28.041	28.771	28.57	25.623	28.17	27.069	27.776	340.079
WWILSON D24	3.291	3.382	3.367	3.24	3.329	3.204	3.295	3.277	2.943	3.243	3.12	3.209	38.899
Total	2010.486	2058.076	2039.399	1966.803	2011.214	2021.959	1979.702	2101.183	1883.540	1929.155	1846.290	1892.039	23739.846
PC													
ACEJDMT PC	3.279	3.373	3.357	3.234	3.326	3.204	3.295	3.28	2.948	3.249	3.129	3.218	38.893
BRFM PC	0.144	0.149	0.146	0.141	0.146	0.141	0.143	0.143	0.129	0.143	0.138	0.139	1.7
BRFQ PC	10.056	10.342	10.295	9.918	10.202	9.828	10.109	10.063	9.047	9.97	9.606	9.88	119.315
BRFQMT PC	3.111	3.199	3.184	3.066	3.156	3.039	3.125	3.109	2.794	3.078	2.964	3.05	36.876
BRFW PC	8.715	8.962	8.919	8.589	8.835	8.508	8.748	8.708	7.826	8.624	8.307	8.541	103.282
BRUFF MT	4.509	4.634	4.61	4.437	4.56	4.389	4.51	4.486	4.032	4.439	4.272	4.393	53.271
CBFR PC	55.47	57.012	56.708	54.585	56.101	54	55.502	55.205	49.594	54.613	52.569	54.03	655.388
CCRUNIT MT	38.415	39.243	38.8	37.134	37.953	36.333	37.147	36.76	32.864	36.016	34.503	35.303	440.47
CCRUNIT PC	46.116	47.415	47.179	45.429	46.711	68.232	65.667	62.57	54.516	58.655	55.437	56.141	654.068
CCRUNITMT PC	15.129	15.565	15.497	14.931	15.361	14.799	15.224	15.159	13.63	15.026	14.475	14.892	179.688
CHBTC1 MT PC	22.23	22.875	22.776	21.948	22.58	21.759	22.388	22.292	20.048	22.103	21.297	21.914	264.21
CHBTCAT1 PC	41.697	42.802	42.52	40.878	41.965	40.347	41.419	41.152	36.929	40.622	39.063	40.105	489.499
CHBTCAT2 PC	1.818	1.863	1.848	1.773	1.817	1.743	1.786	1.77	1.585	1.739	1.668	1.708	21.117
DRYPINY6 PC	0.996	1.026	1.02	0.984	1.011	0.975	1.004	0.998	0.899	0.992	0.954	0.983	11.842
DRYPINYU PC	9.783	10.044	9.982	9.6	9.858	9.48	9.734	9.672	8.68	9.551	9.183	9.43	114.997
FOGARTY PC	0.522	0.536	0.533	0.513	0.527	0.507	0.518	0.515	0.462	0.508	0.489	0.502	6.132
HWA DEEP PC	0.504	0.518	0.515	0.495	0.508	0.489	0.502	0.499	0.448	0.493	0.474	0.487	5.932
HWPL1&3MTPC	5.847	6.011	5.977	5.751	5.909	5.685	5.844	5.809	5.219	5.744	5.529	5.682	69.007
HWPLT1&3 PC	49.824	51.2	50.918	49.005	50.359	48.465	49.805	49.532	44.492	48.986	47.145	48.45	588.18
HWPLT2 PC	0.804	0.825	0.822	0.789	0.812	0.783	0.803	0.8	0.72	0.79	0.762	0.784	9.493
ISLAND PC	0.525	0.539	0.536	0.516	0.53	0.51	0.524	0.521	0.468	0.515	0.495	0.508	6.187
JNSNRDG PC	1.914	1.969	1.959	1.89	1.944	1.875	1.928	1.922	1.728	1.903	1.836	1.888	22.755
KNY FLD PC	3.096	3.187	3.174	3.06	3.15	3.036	3.125	3.112	2.8	3.088	2.976	3.063	36.866
MOSUMT PC	10.167	10.435	10.363	9.963	10.227	9.831	10.09	10.022	8.991	9.889	9.504	9.756	119.238
PDW1A1B PC	0.453	0.756	0.753	0.337	0	0.714	0.732	0.725	0.652	0.722	0	0	5.846
PDW1AB MT PC	3.129	3.218	3.202	3.084	3.171	3.054	3.14	3.125	2.808	3.094	2.979	3.066	37.071
PDWCUT PC	0.654	0.676	0.673	0.648	0.666	0.642	0.663	0.66	0.594	0.654	0.63	0.651	7.811
PDWPLT2 PC	4.842	4.979	4.957	4.773	4.91	4.731	4.864	4.842	4.351	4.796	4.62	4.752	57.417
PDWPLT3 PC	4.806	4.938	4.907	4.722	4.851	4.668	4.796	4.768	4.281	4.712	4.533	4.659	56.642
SGRLF PC	33.171	34.066	33.858	32.568	33.449	32.172	33.043	32.845	29.484	32.445	31.209	32.054	390.363
TRAIL PC	1.125	1.153	1.144	1.101	1.128	1.086	1.113	1.107	0.991	1.091	1.047	1.076	13.162

Normal Temperature Case : Plan Year 2
MDth

Exhibit 14.87

PW

MOSU MT	9.174	0	0	0	0	0	0	0	0	0	0	0	9.174
Total	9.174	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9.174

Q50

BRCH CRK Q50	0.711	0.719	0.707	0.672	0.682	0.651	0.66	0.651	0.577	0.629	0.6	0.611	7.87
TRAIL Q50	1.059	1.082	1.07	1.026	1.051	1.005	1.029	1.02	0.913	1.001	0.96	0.983	12.198
TRAIL 2Q50	1.047	1.07	1.057	1.014	1.039	0.993	1.017	1.008	0.902	0.989	0.948	0.973	12.055
Total	2.817	2.871	2.834	2.712	2.772	2.649	2.706	2.679	2.392	2.619	2.508	2.567	32.126

Off-System

OFF SYS D24	31.068	32.138	32.172	31.167	32.244	31.237	32.309	32.343	29.244	32.408	31.396	32.474	380.200
OFF SYS PC	7.257	7.465	7.431	7.158	7.362	7.092	7.297	7.263	6.53	7.198	6.933	7.133	86.119
OFF SYS PW	0.072	0.074	0.074	0.072	0.071	0.069	0.071	0.071	0.064	0.071	0.069	0.071	0.849
Total	38.397	39.677	39.677	38.397	39.677	38.398	39.677	39.677	35.838	39.677	38.398	39.678	467.168

Wexpro I

CCRUNIT D8	149.496	152.340	150.282	143.514	146.382	139.872	142.749	141.022	125.866	137.733	131.772	134.642	1695.670
KNY FLD D8	19.614	19.843	19.440	18.441	18.690	17.748	18.005	17.686	15.697	17.084	16.257	16.529	215.033
MESA D8	440.418	446.955	439.230	417.960	423.581	402.552	408.766	401.921	357.143	387.897	368.766	374.570	4869.758
TRAIL D8	83.643	85.008	83.654	79.713	81.146	77.394	78.858	77.785	69.328	75.767	72.405	73.904	938.604
CCRUNIT MT	15.975	16.318	16.135	15.441	15.782	24.777	23.523	22.168	19.135	20.42	19.155	19.263	228.093
Total	709.146	720.464	708.741	675.069	685.581	662.343	671.901	660.582	587.169	638.901	608.355	618.908	7947.160

Wexpro I New Drill

z21 CCRK D8	36.651	35.114	32.801	29.835	29.128	26.748	26.328	25.157	21.776	23.160	21.579	21.511	329.787
z21 TRAIL D8	84.966	86.927	83.074	74.559	71.994	65.505	63.972	60.717	52.245	55.285	51.279	50.911	801.434
z22 CCRK D8	0.000	0.000	0.000	0.000	0.000	195.879	202.408	202.408	182.820	178.244	153.963	144.336	1260.059
z22 TRAIL D8	0.000	0.000	0.000	0.000	0.000	128.469	132.751	132.751	119.904	132.751	126.486	123.179	896.292
Total	121.617	122.041	115.875	104.394	101.122	416.601	425.459	421.033	376.745	389.440	353.307	339.937	3287.571

Wexpro II

CCOPA 2E	3.603	3.705	3.686	3.552	3.652	3.519	3.618	3.602	3.237	3.568	3.438	3.534	42.713
CCRUNIT 2D8	60.444	61.585	60.741	57.996	59.145	56.505	57.657	56.953	50.823	55.608	53.193	54.346	684.996
CCRUNIT 2E	238.647	244.339	242.150	232.281	237.953	228.324	233.966	232.041	207.886	228.315	219.204	224.738	2769.844
CCRUNIT2EMT	22.179	22.788	22.661	21.810	22.410	21.567	22.162	22.038	19.796	21.793	20.973	21.554	261.731
TRAIL 2D8	226.473	228.206	222.884	210.951	212.136	200.304	202.210	197.774	174.896	188.474	178.011	179.722	2422.042
TRAIL 2E	294.117	300.585	297.355	284.733	291.189	278.946	285.380	282.596	252.798	277.239	265.803	272.149	3382.891
TRAIL 2E MT	39.426	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	39.426
WHISKEY MT	23.418	23.929	23.672	22.665	23.176	22.197	22.708	22.481	20.107	22.050	21.138	21.638	269.178
WHISKEYC 2E	72.825	74.440	73.653	70.533	72.137	69.105	70.702	70.010	62.625	68.677	65.841	67.410	837.958
Total	981.132	959.577	946.802	904.521	921.798	880.467	898.403	887.495	792.168	865.724	827.601	845.091	10710.779

Wexpro II New Drill

z21 CCRK 2D8	125.220	120.078	112.285	102.240	99.913	91.839	90.474	86.530	74.959	79.791	74.403	74.226	1131.959
z21 TRAIL2D8	84.006	85.948	82.138	73.719	71.182	64.767	63.249	60.032	51.657	54.662	50.700	50.338	792.397
z21 WSKY 2D8	17.577	17.016	16.036	14.700	14.446	13.347	13.206	12.679	11.024	11.771	11.007	11.011	163.820
z22 CCRK 2D8	0.000	0.000	0.000	0.000	0.000	81.453	84.168	84.168	76.023	74.118	64.023	60.019	523.972
z22 TRAIL2D8	0.000	0.000	0.000	0.000	0.000	124.209	128.349	128.349	115.928	128.349	122.322	119.251	866.758
z22 WSKY 2D8	0.000	0.000	0.000	0.000	0.000	142.347	140.269	118.621	93.850	93.108	82.047	78.126	748.369
Total	226.803	223.042	210.459	190.659	185.541	517.962	519.715	490.379	423.441	441.799	404.502	392.971	4227.273

Exhibit 14.88

Normal Temperatue Case: Plan Year 2
MDth

Withdraw

	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Clay Bsn 935	962.7470	944.9550	911.9270	762.4990	700.8160	0.0000	0.0000	0.0000	0.0000	0.0000	420.1680	1074.6670	5777.778
Clay Bsn 988	601.7170	515.7470	569.9660	551.5800	438.0190	0.0000	0.0000	0.0000	0.0000	0.0000	262.4160	671.6670	3611.111
Clay Bsn 997	601.7170	515.7740	569.9660	551.5530	438.0190	0.0000	0.0000	0.0000	0.0000	0.0000	262.4160	671.6670	3611.111
Chalk Creek	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	262.4960	13.5000	0.0000	0.0000	0.0000	288.900
Coalville	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	719.4450	0.9270	0.0000	0.0000	0.0000	360.186
Leroy	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	364.5550	0.0000	0.0000	0.0000	0.0000	443.498
Total	2166.1810	1976.4760	2051.8590	1865.6320	1576.8540	0.0000	0.0000	1346.4960	14.4270	0.0000	945.0000	2418.0010	14360.926

Inject

	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Clay Bsn 935	0.000	0.000	0.000	0.000	0.000	1574.397	1318.895	1515.578	1368.909	0.000	0.000	0.000	5777.779
Clay Bsn 988	0.000	0.000	0.000	0.000	0.000	1131.631	676.676	947.236	855.568	0.000	0.000	0.000	3611.111
Clay Bsn 997	0.000	0.000	0.000	0.000	0.000	1131.631	676.676	947.236	855.568	0.000	0.000	0.000	3611.111
Chalk Creek	0.000	0.000	0.000	40.000	135.000	10.996	90.000	0.000	0.000	0.000	0.000	0.000	275.996
Coalville	0.000	0.000	0.000	42.000	280.800	0.000	37.386	0.000	0.000	360.186	0.000	0.000	720.372
Leroy	0.000	0.000	0.000	47.500	45.000	0.000	272.055	0.000	0.000	0.000	0.000	0.000	364.555
Total	0.000	0.000	0.000	129.500	460.800	3848.655	3071.688	3410.050	3080.045	360.186	0.000	0.000	14360.924

Purchase Gas

	6/1/2022	7/1/2022	8/1/2022	9/1/2022	10/1/2022	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	Total
Spot	0	0	0	251.463	3028.141	181.907	6780.382	6885.368	7000	7072.043	4412.225	1805.633	37417.161
Spot	704.763	0	174.593	1079.504	1550	1500	1550	1550	100	1550	1500	1550	12808.86
Spot	0	0	0	0	0	0	15.393	0	1325.821	75	0	0	1416.214
Spot	0	0	0	0	0	0	0	0	0	0	55.165	0	55.165
Spot	0	0	0	0	0	0	0	0	8.998	6.295	0	0	15.293
Peak	0	0	0	0	0	1200	1240	1240	0	0	0	0	3680
Base	0	0	0	0	0	0	310	310	280	0	0	0	900
Base	0	0	0	0	0	750	775	775	700	775	0	0	3775
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Base	0	0	0	0	0	0	775	775	700	0	0	0	2250
Total	704.763	0	174.593	1330.967	4578.141	3631.907	11910.775	12000.368	10534.82	9478.338	5967.39	3355.633	63667.693

Required vs. Supply

Area	Class	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	11/1/2021	12/1/2021	1/1/2022	2/1/2022	3/1/2022	4/1/2022	5/1/2022	Total
Ut/Id	FS_COM	108.884	101.931	102.195	110.840	168.884	149.877	189.807	209.833	196.910	173.633	153.346	136.474	1802.615
Wy QGC	FS_COM	7.216	6.469	6.509	7.779	20.187	12.683	22.757	19.770	19.731	19.117	16.468	15.738	174.424
Ut/Id	FS_IND	35.579	34.012	34.066	35.895	56.353	50.012	63.335	70.028	65.726	57.973	51.213	45.631	599.823
Ut Geo	GS_COM	41.921	34.772	35.165	49.467	92.939	167.392	258.240	293.299	244.404	186.731	127.730	73.276	1605.336
Ut KRGT	GS_COM	4.675	3.877	3.918	5.515	10.362	18.678	28.799	32.717	27.270	20.819	14.248	8.167	179.046
UT NPC	GS_COM	3.228	2.674	2.708	3.800	7.140	12.899	19.862	22.528	18.800	14.352	9.824	5.644	123.462
Ut/Id	GS_COM	680.360	568.043	574.870	822.059	1551.604	2852.385	4426.939	5042.165	4183.197	3180.345	2158.299	1214.368	27254.633
Wy QGC	GS_COM	29.857	20.720	21.029	29.909	77.801	147.214	209.649	224.355	200.263	160.484	114.329	71.795	1307.406
Ut Geo	GS_RES	113.137	95.065	96.409	106.711	255.017	459.499	706.747	803.915	668.611	511.861	351.169	202.233	4370.375
Ut KRGT	GS_RES	12.620	10.603	10.754	11.902	28.446	51.249	78.829	89.667	74.571	57.094	39.168	22.556	487.460
UT NPC	GS_RES	8.704	7.313	7.415	8.210	19.618	35.340	54.364	61.848	51.432	39.373	27.012	15.553	336.182
Ut/Id	GS_RES	1836.305	1553.116	1576.194	2250.236	4256.303	7824.618	12119.061	13816.436	11449.032	8714.261	5934.615	3351.048	74681.222
Wy QGC	GS_RES	46.829	32.557	33.069	47.188	122.905	231.517	329.493	351.150	312.265	250.845	179.000	112.773	2049.589
Ut/Id	IS_COM	5.372	5.495	5.513	6.101	10.641	17.478	26.527	28.595	24.519	19.099	15.203	7.641	172.185
Wy QGC	IS_COM	3.969	3.974	3.975	4.020	6.703	12.752	16.104	18.417	17.871	15.584	12.672	7.745	123.786
Ut/Id	IS_IND	5.478	4.669	4.677	4.846	4.998	6.308	9.856	10.218	9.187	8.508	6.308	6.585	81.638
Wy QGC	IS_IND	0.038	0.000	0.002	0.061	0.342	0.712	1.055	0.000	0.000	0.000	0.000	0.000	2.209
Ut Geo	L_and_U	0.840	0.704	0.713	0.846	1.886	3.398	5.230	5.947	4.949	3.786	2.596	1.493	32.388
Ut KRGT	L_and_U	0.094	0.078	0.080	0.094	0.210	0.379	0.583	0.663	0.552	0.422	0.290	0.167	3.612
UT NPC	L_and_U	0.065	0.054	0.055	0.065	0.145	0.261	0.402	0.457	0.381	0.291	0.200	0.115	2.491
Ut/Id	L_and_U	14.482	12.289	12.453	17.506	32.784	59.082	91.249	103.941	86.333	65.874	45.089	25.809	566.889
Wy QGC	L_and_U	0.476	0.345	0.350	0.482	1.235	2.194	3.138	3.326	2.982	2.417	1.748	1.128	19.823
Off-Sys Dmd	Off_Sys	36.389	37.601	37.601	36.389	37.601	36.389	37.601	37.601	33.963	37.601	36.389	37.601	442.727
Total		2996.517	2536.363	2569.718	3559.923	6764.108	12152.318	18699.627	21246.878	17692.948	13540.470	9296.913	5363.539	116419.322
Fuel	Transport	96.644	92.413	89.649	97.995	125.576	194.722	281.132	310.081	261.516	208.752	156.058	122.056	2036.594
Fuel	Injection	30.007	31.008	28.424	26.621	27.741	11.004	2.967	0	0	3.548	13.091	33.496	207.906
Fuel	Withdrawl	0	0	0	0	0	1.809	8.735	38.694	8.3	3.433	0	0	60.971
	Total Fuel	126.651	123.421	118.073	124.616	153.317	207.535	292.834	348.775	269.816	215.733	169.149	155.552	2305.471
Inject	Clay Basin	2166.18	2238.386	2051.859	1766.721	1576.854	0	0	0	0	0	945	2418	13163
Inject	Aquafer	0	0	0	112.286	471.2	480.186	140.188	0	0	325	0	0	1528.86
	Total Inject	2166.180	2238.386	2051.859	1879.007	2048.054	480.186	140.188	0.000	0.000	325.000	945.000	2418.000	14691.860
Total Required		5289.348	4898.170	4739.650	5563.546	8965.479	12840.039	19132.649	21595.653	17962.764	14081.203	10411.062	7937.091	133416.654

Exhibit 14.89

Required vs. Supply

Supply	Spot	528.775	58.162	91.244	1151.47	3479.59	3811.925	3576.875	5406.82	5698.777	5581.468	4758.297	3102.498	37245.902
Supply	Peak	0	0	0	0	0	1200	1240	1240	0	0	0	0	3680
Supply	Base	0	0	0	0	930	1650	4805	4805	4340	1705	900	0	19135
	Total	528.775	58.162	91.244	1151.47	4409.59	6661.925	9621.875	11451.82	10038.777	7286.468	5658.297	3102.498	60060.901

Withdraw	Clay Basin	0	0	0	0	0	842.361	4068.439	3410.05	3080.045	1599.106	0	0	13000.001
Withdraw	Aquafers	0	0	0	0	0	0	0	1375.998	73.686	0	0	0	1449.684
Production	Company	2758.116	2823.703	2836.576	2698.809	2823.585	2914.125	2982.139	2953.913	2643.013	2898.439	2580.531	2642.282	33555.231
Production	Wexpro I	839.697	842.214	808.815	762.246	768.106	943.374	957.761	940.286	834.618	899.738	849.894	859.168	10305.917
Production	Wexpro II	1124.364	1134.414	963.337	912.624	924.522	1439.856	1462.76	1423.911	1256.788	1357.778	1283.943	1293.466	14577.763
	Total	4722.177	4800.331	4608.728	4373.679	4516.213	6139.716	9471.099	10104.158	7888.150	6755.061	4714.368	4794.916	72888.596

Off-System	Off System	38.396	39.676	39.676	38.396	39.676	38.396	39.676	39.677	35.837	39.677	38.397	39.677	467.157
	Total	38.396	39.676	39.676	38.396	39.676	38.396	39.676	39.677	35.837	39.677	38.397	39.677	467.157

Total Supply	5289.348	4898.169	4739.648	5563.545	8965.479	12840.037	19132.650	21595.655	17962.764	14081.206	10411.062	7937.091	133416.654

Exhibit 14.90

GENERAL IRP GUIDELINES/GOALS FOR GAS SUPPLY AND ENERGY EFFICIENCY RESOURCES

The Company has compiled a list of general guidelines to help direct the Company's daily decision-making processes with regard to gas supply and energy-efficiency resources. While some of these guidelines incorporate specific numeric targets from the SENDOUT modeling process this year, all are general and flexible in nature to accommodate the potential for variability in weather, markets, and operating conditions. Many are similar to those of previous years and have evolved from years of operating experience. When substantial changes in operating and/or market conditions occur, the Company uses the SENDOUT model to help assess the appropriate mix of market resources. The guidelines for the 2021-2022 gas-supply year are as follows:

- Produce approximately 58.4MMDth of cost-of-service gas, recognizing the uncertainties associated with demand, operating conditions, and gas well productivity.
- Execute Distribution System Action Plan to ensure distribution system is adequate to serve firm customers.
- Produce the categories of cost-of-service gas as determined this year in the modeling exercise as contained in Exhibits 15.83 and 15.84, and also, subject to demand, operating conditions, gas well productivity, and the terms of the Trail Unit, Canyon Creek, and Vermillion Settlement Stipulations.
- Purchase a balanced portfolio of gas of approximately 60 MMDth.
- Continue to monitor and manage producer imbalances.
- Override the SENDOUT model utilization profiles when producer-imbalance considerations dictate.
- Maintain flexibility in purchase decisions since actual conditions will vary from the normal-case conditions in the modeling simulation.
- Review options for additional price stabilization to determine whether such measures are appropriate.
- Continue to promote cost-effective energy-efficiency measures in Utah and Wyoming.
- Contract to resolve peak-hour issues and to secure needed storage and transportation capacity.
- Continue construction of an on-system LNG facility to help ensure system reliability for sales customers.
- Work to contribute to Dominion Energy's commitment to achieve net zero carbon and methane emissions across Dominion Energy's nationwide electric generation and natural gas infrastructure operations by 2050.

GLOSSARY

This Glossary is intended for convenience and reference use only. The operational provisions of the Tariff are controlling in any case where there is an inconsistency.

A

Aquifers

The three DEQP aquifer storage facilities at which the Company has Peaking Storage (PKS) contracts. The facilities are Leroy, Coalville, and Chalk Creek.

AFUE

Annual fuel utilization efficiency is the ratio of annual heat output of a furnace or boiler compared to the total energy consumed by a furnace or boiler. An AFUE of 90% means that 90% of the energy in the fuel becomes heat for the home or business.

ARC

Advanced rooftop controls are digital system that allow remote monitoring, and enables control of fan speed, economizer functions, and a thermostat, making it easier to maintain occupant comfort and system efficiency in commercial buildings.

B

base load

Gas required for non-seasonal purposes, such as water heating and cooking.

Bcf

One billion cubic feet

Bcf/D

One billion cubic feet per day

blowdown

The process of reducing pressure in a pipeline.

Btu

A British thermal unit, equivalent to the amount of heat required to raise the temperature of one pound of water one-degree Fahrenheit.

C

cf

Cubic feet

CIG

Colorado Interstate Gas, an interstate pipeline serving the Company.

Close Interval Survey (CIS)

An inspection technique that includes a series of above ground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e. 2-100 feet) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

Company

Questar Gas Company dba Dominion Energy Utah.

Compressed Natural Gas (CNG)

Natural gas that has been compressed to a high-pressure to increase the amount of gas that can be stored and transported in a vessel. Typical pressures are between 2,900-3,600 psig. CNG is generally used to describe the fuel that takes the place of gasoline or diesel fuel in a vehicle.

cost-of-service production

Production managed by Wexpro that is provided to the Company on cost-based rates.

D

degree-day (heating)

Heating degree day is a term that refers to a measurement of how far the average temperature extends below the base temperature of 65º Fahrenheit. The time period measured is normally a 24-hour day. It is a measurement that is used to calculate weather normalized usage. The heating degree day measurement is calculated by taking the difference between 65º Fahrenheit and average temperature for the period. Any positive difference means that the average temperature was below the base, and this difference is the heating degree days measurement for the period. Any negative difference means that the average temperature was above the base; in this case, the heating degree days measurement is zero.

dekatherm (Dth)

A unit of heat equal to 1,000,000 British thermal units (Btu).

Design Day

A day with a daily mean temperature of -5 degrees Fahrenheit or lower in the Salt Lake valley.

DEU

Dominion Energy Utah, the Utah region of the Company.

DEUWI

Dominion Energy Utah, Wyoming, and Idaho, also known as the Company.

DEQP

Dominion Energy Questar Pipeline. An interstate pipeline serving the DEUWI system.

DNG

Distribution Non-Gas

dry hole well

A well that is determined to not be productive based on a commercial test.

dry natural gas

Natural gas production not associated with any other liquid hydrocarbons.

Dth

Dekatherm

Dth/D

Dekatherms per day

E

ECM

Electrically commutated motors are ultra-high efficiency, programmable, brushless direct current motors typically in heating, ventilation, and cooling applications.

end devices

Electronic devices such as pressure transmitters on the tubing or casing. These can be temperature transmitters, pressure switches, high level switches, etc.

ERV

Energy Recovery Ventilation are devices which are used to recover energy contained in normally-exhausted building or space air and is then used to treat (or precondition) the incoming outdoor ventilation air in residential and commercial heating, ventilation, and cooling systems.

External Corrosion Direct Assessment (ECDA)

A four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline [§192.925 and NACE SP 0502-2008 Pipeline External Corrosion Direct Assessment Methodology].

Excess Flow Valve (EFV)

A small valve that automatically reduces the flow of gas if a customer or contractor accidentally breaks the service line while digging on the property.

F

Fitness for Service (FFS)

The pipeline's ability to operate in a manner that ensures the safety of the people that live and work near pipelines, protects the environment, while dependably transporting natural gas from sources to markets. INGAA designed their FFS program to address previously untested pre-regulation pipeline, or pipelines built prior to federal regulations established March 12, 1970. The FFS program establishes a starting point for evaluation and remediation of pre-regulation pipeline in High Consequence Areas (HCAs) that lack traceable, verifiable and complete test records. Further, the FFS process defines a priority-based process, and includes a timeline for analysis, implementation and completion of the program.

firm

Firm service. The is priority distribution service from the utility that will not be curtailed in the event of a supply shortfall until all interruptible service has been curtailed.

FL

Feeder Line

fugitive methane emissions

Emissions of methane that are not captured and therefore are released to the atmosphere.

FOM

First of month as it refers to pricing indexes for gas supply purchasing.

G

Global Positioning System (GPS)

A system used to identify the latitude and longitude of locations using GPS satellites.

GNA

Gas Network Analysis, which refers to the types of engineering models used by the Company's System Planning department to model pressures and flows throughout the entire system.

Gas Pipeline Advisory Committee (GPAC)

A committee of government, industry, and public representatives appointed by the Secretary of Transportation to advise PHMSA on rulemaking.

GS

The General Service rate schedule.

GW

Gigawatt

H

High Consequence Area (HCA)

An area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area

extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy.

HP

High Pressure. The distribution system that is connected to Gate Stations and moves gas to District Regulator Stations and High-Pressure customers. This system operates at or above 125 psig and the material mainly used for pipe is steel.

hydrostatic test

A method of pressure testing a pipe or fitting using water.

I

Internal Corrosion Direct Assessment (ICDA)

A process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas [§192.927].

IHP

Intermediate-High Pressure. This system is downstream of District Regulator stations and operates between 15 psig and 45 psig with an MAOP of 60 psig. The majority of DEUWI customers are connected to the IHP system by a network of steel and plastic pipe.

Integrity Management Continuous Improvement (IMCI)

A systematic process developed by INGAA and its members to improve the integrity of the interstate natural gas transmission system. The overall goal of the IMCI process is zero incidents. To achieve that goal, INGAA and its members have instituted a system for reassessing individual processes, ranking them in priority, and applying management system methodologies to improve performance. In general, IMCI extends IM processes and FFS to transmission pipelines outside of HCAs.

Interstate Natural Gas Association of America (INGAA)

A trade organization that advocates regulatory and legislative positions of importance to the natural gas pipeline industry in North America. INGAA is comprised of 27 members, representing the vast majority of the interstate natural gas transmission pipeline companies in the U.S. and Canada. INGAA members operate almost 200,000 miles of pipeline.

interruption

Period when gas service is unavailable to interruptible customers; or period when emergency sales restrictions apply to customers because of a major disaster or pipeline break.

J

JOA

Joint Operations Agreement, which refers to the document outlining maintenance responsibilities and operating conditions on a peak day at interconnect points (gate stations) between the Company and DEQP.

K

Kern River Gas Transmission (KRGT)

Interstate pipeline serving the DEUWI system.

L

lf

linear feet.

liquefaction

The process of changing a substance, such as natural gas, to a liquid state.

LAUF

Gas volume that is lost and unaccounted for.

LNG

Liquified Natural Gas

loop

Any pipe that is meant to reinforce an existing area without replacing older or smaller pipelines.

M

MAOP

Maximum Allowable Operating Pressure, the maximum rated pressure at which a given Feeder Line is allowed to operate.

MAP

Meter Allocation Point. A receipt or delivery point on a pipeline.

MBCx

Monitoring-based commissioning is an evolution of the energy efficiency industry standard measure, known as retrocommissioning, whereby major building components and equipment are tuned up after a period of time in order to achieve efficiency gains. The difference between retrocommissioning and MBCx is that MBCx introduces software and analytics into the process to provide actionable information that can be used to optimize facility operations.

meter purge

Removing any air from the meter after any work has been performed (i.e. new meter, service replacement)

Mcf

One thousand cubic feet

Mcfd

One thousand cubic feet per day

Mcfh

One thousand cubic feet per hour

MDth

One thousand dekatherms

MDth/D

One thousand dekatherms per day

Mega Rule

Industry name given to PHMSA's Rule making, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments".

MMBtu

One million British thermal units

MMcf

One million cubic feet

MMCfd

One million cubic feet per day

MMDth

One million dekatherms.

MW

Megawatt

N

non-GS

Includes all rate schedules other than GS (General Service).

NOx

Oxides of nitrogen, especially as atmospheric pollutants

NTSB

National Transportation Safety Board

O

operator service fee

The fees charged by Wexpro under the Wexpro under the Wexpro I and Wexpro II Agreements

P

pad drilling

The process of drilling multiple, directional wells from a single site of disturbance. Each well that is drilled from the pad is drilled during the time that the rig is at the pad location. Pad drilling drastically cuts down on the amount of land that would have to be disturbed as well as reduces the number of drill rigs needed for an operation. A typical multi-well pad can have 2 to more than 20 wells depending on various factors.

pigging

A pipeline inspection technique that uses devices known in the industry as smart pigs. These devices run inside the pipe and provide indications of metal loss, deformation and other defects. Also referred to as In-line inspection (ILI).

pneumatic device

Any tool or instrument that uses pneumatic power (either compressed air, or natural gas from the wellhead) to open/close a valve or controller.

psi

Pounds per square inch

psia

Pounds per square inch absolute

psig

Pounds per square inch gauge

PHMSA

The Pipeline Hazardous Materials Safety Administration

purge procedure

The procedures that must be followed to remove air from the existing pipeline facilities.

Q

R

Remote Methane Leak Detection (RMLD)

A methane detection device that can detect methane and identify leaks up to 100 feet away from the gas source.

receipt point

The point at which measured gas enters the Company's distribution system.

Reserved Daily Capacity (RDC)

The quantity of Natural Gas in Dth per day that Dominion Energy Questar Pipeline is obligated to receive, transport and deliver to Shipper on a firm basis.

RNG

Renewable Natural Gas, which refers to recovered methane that is injected and blended into the Company's system.

RSG

Responsibly Sourced Natural Gas, which refers to natural gas produced from wells that have undergone certification to verify the operator has utilized best practices in the operation of the wells.

S

Sales

Demand by customers receiving firm or interruptible sales service from the utility.

scraper facility

A vessel at a predetermined location that traps contaminates from the pipeline that have been removed by a pig (i.e. scraper). Contaminated fluids are then pumped from this vessel to a tanker truck for shipment to a treatment facility.

sphere facilities

Storage tanks for compressed natural gas or liquefied natural gas, that are spherical.

sendout

The volume of gas that enters the distribution system.

segmentation rights

The rights of a shipper to be able to utilize separate sections of a pipeline under a single contract.

span

A section of pipe that crosses an obstruction, such as a river, above ground.

stack-tested

When the exhaust stack on any burner or engine undergoes testing to verify its emissions are within the permitted limit.

steady-state models

These are gas network analysis models that are indicative of conditions at a particular moment in time due to conditions.

SWGA

System Wide Gathering Agreement. A gathering contract between Marathon Petroleum Corp and Dominion Energy Utah to for Marathon Petroleum Corp to perform gathering and processing services for cost-of-service production.

T

tapline

A high pressure line extending from a feeder line to specifically serve a district regulator station or industrial customer. No other district regulator station or customer will be on this line.

Tariff

The published volume of rate schedules, conditions of service and billing provisions under which natural gas will be supplied to customers by the Company.

Tcf

One trillion cubic feet

temperature-adjusted

Gas demand that has been adjusted to a baseline of long-run average heating degree days.

token relief valve

A low capacity relief valve intended to provide limited overpressure protection while reducing gas released to the atmosphere and providing an audible alert to an increase in downstream pressure beyond the regulator set point.

throughput

The total demand across the distribution system by customers of all service classes.

transportation

Demand by customer receiving transportation service from the utility.

U

unsteady-state models

These are gas network analysis models that are indicative of conditions over a period due to conditions.

upstream

This references the location on a pipeline based on the direction of flow. Gas flows from upstream to downstream.

UT Commission

Public Service Commission of Utah

V

W

well pads

A temporary site that is constructed for the use of a drilling rig during drilling operations. Well pads are generally constructed of local materials, such as gravel, and are reclaimed almost entirely after drilling operations. Depending on the number of wells to be drilled from a pad, they can range in size from less than an acre to over 5 acres.

Wexpro

Dominion Energy Wexpro

WFS

Williams Field Services, an interstate pipeline serving the Company's system.

X

Y

Z