DOMINION ENERGY UTAH / WYOMING

INTEGRATED RESOURCE PLAN

Docket 20-057-02

(Plan Year: June 1, 2020 to May 31, 2021)

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1-1

2. INDUSTRY OVERVIEW 2-1

Federal Energy Regulatory Commission Update 2-1
Clean Energy Regulation 2-1
Power Generation Impact on Natural Gas 2-2
Pricing Trends 2-3
Production Trends 2-3
Storage Trends 2-4
LNG Exports 2-4
Wyoming IRP Process 2-6
Utah IRP Process 2-6

3. CUSTOMER AND GAS DEMAND FORECAST 3-1

Impacts of COVID-19 3-1
System Total Temperature-Adjusted Dth Sales and Throughput Comparison – 2019-2020 IRP and Actual Results 3-1
Temperature-Adjusted Dth Sales and Throughput Summary – 2020-2021 IRP Year 3-1
Residential Usage and Customer Additions 3-2
Small Commercial Usage and Customer Additions 3-3
Non-GS Commercial, Industrial and Electric Generation Gas Demand 3-4
Firm Customer Design Day Gas Demand 3-4
Source Data 3-5
Alternatives to Natural Gas 3-5
Gas Lost And Unaccounted For 3-6
Forecast Exhibits 3-8
Exhibit Numbers .... 3.1 - 3.11

4. SYSTEM CAPABILITIES AND CONSTRAINTS 4-1

DEUWI System Overview 4-1
Ongoing and Future System Analysis Projects 4-2
System Modeling and Reinforcement 4-3
Model Verification 4-3
Gate Station Flows vs. Capacity 4-4
System Pressures 4-5
Long-Term Planning 4-12
System Capacity Conclusions 4-13

5. DISTRIBUTION SYSTEM ACTION PLAN 5-1

High Pressure Projects: 5-1
Plant Projects: 5-10
Intermediate High Pressure Projects: 5-10
Transponder Replacement Program 5-11
Master Meters 5-11
Rural Expansion 5-11

6. INTEGRITY MANAGEMENT 6-1

Activities and Associated Costs for Transmission Lines and Distribution Systems 6-1
Transmission Integrity Management 6-2
Distribution Integrity Management 6-5
Cost Summary 6-5
Key Performance Integrity Metrics 6-6
New Regulations 6-6

Industry and Company Best Practices 6-9
Exhibit Numbers .... 6.1 - 6.2

7. ENVIRONMENTAL REVIEW 7-1

8. PURCHASED GAS 8-1

Local Market Environment 8-1
Annual Gas Supply Request for Proposal 8-2
Price Stabilization 8-4
Exhibit Number 8.1

9. COST-OF-SERVICE GAS 9-1

Cost-of-Service Modeling Factors 9-1
Producer Imbalances 9-4
Future Resources 9-5
Production Shut-Ins 9-6
Exhibit Number 9.1

10. GATHERING, TRANSPORTATION, AND STORAGE 10-1

Gathering and Processing Services 10-1
Transportation Services 10-1
Firm Peaking Services 10-5
Storage Services 10-6
Related Issues 10-11
Exhibit Numbers .... 10.1 - 10.5

11. SUSTAINABILITY 11-1

Delivering Clean Energy 11-1
Sustainability in the West 11-2

12. ENERGY-EFFICIENCY PROGRAMS 12-1

Utah Energy-Efficiency Results 2019 12-1
Energy Efficiency Effects on Design Day & Demand Response 12-6
Wyoming Energy-Efficiency Results for 2019 12-7
Utah Energy-Efficiency Plan for 2020 12-7
Wyoming Energy-Efficiency Plan for 2020 12-12
SENDOUT Model Results for 2020 12-13
Avoided Costs Resulting From Energy Efficiency 12-14
Exhibit Number 12.1

13. FINAL MODELING RESULTS 13-1

Linear Programming Optimization Model 13-1
Constraints and Linear Programming 13-1
Model Improvements 13-2
Monte Carlo Method 13-2
Natural Gas Prices 13-3
Weather and Demand 13-3
Design Day and Baseload Purchase Contracts 13-3
Normal Temperature Case 13-4
Purchased Gas Resources 13-4
Cost-of-Service Gas 13-5
First-Year and Total System Costs 13-5
Gas Supply/Demand Balance 13-5
Shut-in Scenario Analysis 13-6
Exhibit Numbers .... 13.1 - 3.90

14. GENERAL IRP GUIDELINES 14-1
15. GLOSSARY 15-1

EXECUTIVE SUMMARY

This Integrated Resource Plan (IRP) is filed 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. 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 1.23MMDth at the city gates for the 2020-2021 heating season.

2. The Company forecasts a 2020-2021 IRP-year cost-of-service gas production level of approximately 63.0 MMDth assuming the completion of new development drilling projects (54% of forecast demand).

3. The Company forecasts a 2020-2021 IRP-year balanced portfolio of gas purchases of approximately 50.6 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. There is not a current need for any additional price stabilization, but the Company will review this on an annual basis to determine whether such measures are appropriate 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. In February 2020, Dominion Energy, announced its commitment to net zero carbon and methane emissions across its nationwide electric generation and natural gas infrastructure operations by 2050, including carbon dioxide and methane emissions, the dominant greenhouse gases, from electricity generation and gas infrastructure operations. The strengthened commitment builds on Dominion Energy, Inc.'s strong history of environmental stewardship.

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 2020-2021 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) Sustainability; 12) Energy-Efficiency Programs; 13) Final Modeling Results; 14) General IRP Guidelines/Goals, and 15) 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 March 31, 2020, James Danly was sworn in as a new member of the FERC[1]. This resulting commission now consists of four members, Chairman Neil Chatterjee, Commissioner Richard Glick, Commissioner Bernard L. McNamee, and Commissioner 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 13873 - 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] "Danly Sworn in as a FERC Commissioner," News Release, Federal Energy Regulatory Commission, March 31, 2020.

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 plats 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 April 13, 2020, the EPA released the 2020 edition of its comprehensive annual report on greenhouse gas emissions[4]. This inventory shows that since 2005, national greenhouse gas emissions have reduced by 10% and power sector emissions have reduced 27%. This occurred despite the economy growing by 25% in this time. Total U.S. energy-related emissions reduced by 12% from 2005 to 2018 compared to the global energy-related emissions increase of 24%.[5]

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 42 gigawatts (GW) of new capacity to be added in 2020. Wind is expected to account for 44% of this new generation capacity. Solar is expected to account for 32%. Natural gas is expected to account for 22% or 9.3 GW.

The 9.3 GW is projected to come from 6.7 GW of combined-cycle plants and 2.3 GW of combustion-turbine plants. More than 70% of these additions are planned for Pennsylvania, Texas, California, and Louisiana. The EIA is also projecting 3.7 GW of natural gas generation retirements in 2020, primarily consisting of the closure of 3 plants in California[6]. The majority of these retirements are older units that started operating in the 1950s or 1960s.

[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] "Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2018", U.S. Energy Information Administration, April 13, 2020.
[5] "Latest Inventory of U.S. Greenhouse Gas Emissions and Sinks Shows Long-Term Reductions, with Annual Variation", U.S. Energy Information Administration, April 13, 2020.
[6] "New electric generating capacity in 2020 will come primarily from wind and solar", U.S. Energy Information Administration, January 14, 2020.

PRICING TRENDS

In its January 2020 Short Term Energy Outlook, the EIA forecasted that U.S. natural gas prices would be 9% lower in 2020 compared to 2019. This is expected to be a result of continued production growth outpacing demand and exports. Production increases are expected to continue due to improved drilling efficiency and cost reductions, higher associated gas production from oil-directed rigs, and increased takeaway pipeline capacity from the Appalachian and Permian production regions[7].

It is important to note, this forecast was developed prior to the impacts of COVID-19 and the suspension of crude oil production reductions that had been instituted by the Organization of the Petroleum Exporting Countries (OPEC) and partner countries. The impact of these dramatic changes in the industry are still being determined and will result in greater uncertainty in forecasts.

Currently, the EIA forecasts that natural gas spot prices at Henry Hub will average $2.11/MMBtu in 2020 and then increase to $2.98/MMBtu in 2021. The EIA now expects this price increase to occur primarily due to reduced production in 2021 compared to 2020.[8]

PRODUCTION TRENDS

According to the EIA, U.S. dry natural gas production set a record in 2019 with an average of 92.2 billion cubic feet per day (Bcf/d). This dry gas production is estimated to reduce to an average of 91.7 Bcf/d in 2020 with production declining from March to December. 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 the second half of 2021 as prices begin to rise[9].

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 an all-time low of 81 rigs. By May 3, 2019, the gas-direct rig count had recovered to a level of 183. However, by April 9, 2020, the gas-directed rig count had again reduced to only 96. The gas directed rig count at this point in time is only about 16% of the total rigs in operation[10]

In January of 2020, the EIA released its annual report on natural gas proved reserves for the 2018 calendar year. On January 13, 2020, the EIA reported that U.S. proved reserves of natural gas at year-end 2018 set a new record of 504.5 Tcf. This level was a 9% increase over the previous record level of 464.4 Tcf set in 2017.

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[7] "EIA expects lower natural gas prices in 2020 as production outpaces demand," Today in Energy, Energy Information Administration, January 15, 2020.

[8] "Short-Term Energy Outlook", Energy Information Administration, January 15, 2020.

[9] "Short-Term Energy Outlook", Energy Information Administration, January 15, 2020.

[10] "North America Rig Count Current Week Data," Baker Hughes, http://www.rigcount.bakerhughes.com, April 9, 2020.

Higher prices typically increase reserve estimates because operators consider a larger portion of the natural gas economically producible. In 2018, the annual average spot price for natural gas increased 12% at Henry Hub. Texas had the largest increase in reserves in 2018. The majority of the increase in 2018 reserves was due to increased reserves in the Wolfcamp/Bone Spring in the Permian Basin. Pennsylvania and New Mexico saw the next-largest net gains.[11]

Total U.S. discoveries during 2018 totaled 79.5 Tcf. By source, the 79.5 Tcf discovered in 2018, can be broken down as 64.7 Tcf from shale formations (81%) and 14.8 Tcf from conventional and other tight formations (19%).[12]

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[13].

The 2019 storage injection season began in March with 1,117 Bcf in working gas storage. By the end of the traditional injection season at the beginning of November, national working gas storage volumes were 3,731 Bcf. The traditional 2019 injection season had net injections of 2,614 Bcf. By comparison, net injections for the 2017 traditional injection season totaled 1,846 Bcf. By the end of the 2019-2020 traditional withdrawal season, on March 27, 2020, the Lower 48 inventory level stood at 1,986 Bcf. This level was 863 Bcf higher than the same time last year and was 292 Bcf or 17.2% above the five year average.[14]

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

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.

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 January 2020, the EIA reported that net exports of LNG more than doubled in

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[11] "U.S. oil and natural gas proved reserves and production set new records in 2018," Today in Energy, Energy Information Administration, January 13,2020.

[12] "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2018," U.S. Energy Information Administration, U.S. Department of Energy, December 13, 2019. Components may not add to totals due to independent rounding.

[13] "PHMSA Issues Final Rule for Underground Natural Gas Storage Facilities," U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration, January 13, 2020

[14] "Weekly Natural Gas Storage Report," Energy Information Administration, U.S. Department of Energy, For the week ending May 15, 2020, Released May 21, 2020.

2019 compared to 2018. This trend is expected to continue with LNG exports expected to double again from 2019 totals by 2021. In 2019, growth in demand for LNG from the U.S. exceeded the demand growth from U.S. consumption in the electric power sector.

LNG exports from the U.S. averaged 5 Bcf/d in 2019. This was 2 Bcf/d increase from 2018. This increase was a result of two new facilities being placed in service in 2019. Both the Cameron LNG and the Freeport LNG facilities placed trains in service in 2019. Five moveable modular liquefaction system (MMLS) units were also placed in service at Elba Island, in Georgia.

In 2020, the Cameron LNG facility in Louisiana is scheduled to place two additional trains in service. The Freeport LNG facility, in Texas, is also scheduled to place an additional train in service this year. Elba Island is scheduled to start up five additional MMLS units in 2020. In 2021, the Corpus Christi facility, in Texas is scheduled to bring a third train online. This will bring the total U.S. liquefaction capacity to 10.2 Bcf/d of baseload capacity and 10.8 Bcf/d of peak capacity. As facilities ramp up to full production, the EIA expects capacity to average 6.5 Bcf/d in 2020 and 7.5 Bcf/d in 2021[15].

By the end of 2018, export capacity from the Lower 48 states increased to 4.9 Bcf/d.

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[16]. 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 corrections to the order. They 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[17]. 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[18].

[15] "EIA expects U.S. net natural gas exports to almost double by 2021," Energy Information Administration, U.S. Department of Energy, January 23,2020.
[16] "Statement of Chairman Neil Chatterjee", Federal Energy Regulatory Commission, March 19, 2020
[17] "Jordan Cove LNG developers seek several fixes to FERC authorizations," Platts Gas Daily, April 21, 2020.
[18] "Oregon steps up legal battle over FERC orders authorizing Jordan Cove LNG," Platts Gas Daily, April 22, 2020.

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 and file Integrated Resource Plans.[19] 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."[20] 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.[21]

The Company filed its 2019-2020 IRP on June 13, 2019, 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. No public comments were received. On December 18, 2019, Wyoming Commission Staff issued a report on its review of the 2019-2020 IRP. Wyoming Commission Staff found no areas of concern with the results and projections in the 2019-2020 IRP, and concluded, ". . . it is evident that the Company is actively identifying, evaluating, and executing projects and plans to meet its obligation to maintain Wyoming services at safe and reliable levels."[22]

The Wyoming Commission noticed the Company's 2018-2019 IRP on its Open Meeting Agendas from July 26, 2019, through December 23, 2019, and received no comments or protests. At its regularly scheduled Open Meeting on December 23, 2019, the Wyoming Commission received a presentation from representatives of the Company which provided a summary of the sections of the 2019-2020 IRP. On January 24, 2020, the Wyoming Commission issued a letter order directing the 2019-2020 IRP be placed in the Commission's files with no further action being taken and closed the matter.[23]

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.

[19] "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.

[20] 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).

[21] 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.

[22] Memorandum from Michelle Bohanan and John Burbridge to Chairman Fornstrom, Deputy Chair Throne and Commissioner Robinson; Re: Docket No. 30010-183-GA-19 (Record No. 15275) In the matter of the filing of Questar Gas Company D/B/A Dominion Energy Wyoming's Integrated Resource Plan for June 1, 2019 to May 31, 2020; December 18, 2019; Page 34.

[23] Letter Order, To: Jenniffer Nelson Clark, Corporate Counsel, Dominion Energy Wyoming, From: Dylan C. Freeman, Assistant Secretary Wyoming Public Service Commission, Re: The Matter of the Filing of Questar Gas Company d/b/a Dominion Energy Wyoming's Integrated Resource Plan For Plan Year June 1, 2019 to May 31, 2020 - Docket No. 30010-183-GA-19 (Record No. 15275), Issued: January 24, 2020.

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.[24] On March 22, 2010, the Utah Commission issued an order clarifying the requirements of the 2009 IRP Standards (Clarification Order).[25]

On June 13, 2019, the Company filed its IRP for the plan year, June 1, 2019, to May 31, 2020 (2019-2020 IRP). A technical conference was held on June 20, 2018, to discuss the 2019-2020 IRP with regulatory agencies and interested stakeholders. On September 17, 2019, the Utah Office of Consumer Services (Office) filed its IRP comments.[26] The Utah Division of Public Utilities (Division) submitted its report and recommendation on September 17, 2019.[27] On October 15, 2019, the Company and the Office filed its Reply Comments.[28]

On January 16, 2020, the Utah Commission issued its Report and Order on the 2019-2020 IRP.[29] The Utah Commission found that "the 2019 IRP as filed generally complies with the requirements of the 2009 Standards and Guidelines." The Commission adopted the Company's commitment to include an additional subsection in the "System Capacity and Constraints section, labeled "Long-Term Planning" which will "provide an outline of demand growth trends along with any known future projects beyond the scope of the DNG Action Plan." The Commission also adopted the Company's commitments to provide information related to sustainability goals, STEP initiatives, distribution expansion in rural areas. The Commission adopted the Company's commitments set forth in its reply comments and ordered the Company to "convene a stakeholder meeting as early as practicable prior to DEU's filing of the 2020 IRP to discuss concerns regarding the sufficiency of information in the IRP." On March 10, 2020, the Company met with Division and Office Staff to discuss these issues.

On February 24, 2020, the Company sent the annual request for proposals (RFP) for purchased gas to potential suppliers. The deadline for responses to the RFP was March 6, 2020.

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[24] "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.

[25] "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.

[26] Memorandum titled, "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2019 to May 31, 2020," To: The Public Service Commission of Utah, From: The Office of Consumer Services, Michele Beck, Director, Alex Ware, Utility Analyst, September 17, 2019.

[27] Action Request Docket No. 19-057-01, To: Utah Public Service Commission, From: Division of Public Utilities; Chris Parker, Director, Artie Powell, Manager, Energy Section, Doug Wheelwright, Technical Consultant, Eric Orton, Technical Consultant, , Subject: Action Request Docket No. 18-057-01, Dominion Energy Utah 2019-20 Integrated Resource Plan (IRP) Report, Division's Recommendation – Acknowledgement, Date: September 17, 2019.

[28] "In the Matter of Dominion Energy Utah's Integrated Resource Plan for Plan Year: June 1, 2019 to May 31, 2020," Before the Public Service Commission of Utah, Dominion Energy Utah's Reply Comments, Docket No. 19-057-01, October 1, 2019.

[29] "Dominion Energy Utah's Integrated Resource Plan (IRP) for Plan Year: June 1, 2019 to May 31, 2020," The Public Service Commission of Utah, Report and Order, Docket No. 19-057-01, Issued: January 16, 2020.

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 March 9, 2020, 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 2019 IRP Order
- LNG Project Update
- Sustainability Initiatives Update

The Utah Commission held another technical conference on April 23, 2020. The attendees discussed the following topics:

- Heating Season Review
- System Integrity Update
- Fuel Line Issue Review

Part of the April 23, 2020, technical conference was confidential. During the confidential part of the meeting, the following topics were discussed:

- Wexpro Matters
- RFP Recommendations

The Utah Commission held another technical conference on May 12, 2020, where the following topics were discussed:

- IRP Project Detail
- Long-Term Planning
- Future Rural Expansion
- Future STEP Projects

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 30, 2020, 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

IMPACTS OF COVID-19

At the time of this writing, recessionary effects from the COVID-19 pandemic are only beginning to materialize. Without a clear picture of how this unprecedented event will affect housing construction and demand for natural gas, it is difficult to make adjustments to a baseline forecast to account for such effects. However, an assumption of a temporary decline in the rate of customer growth through 2022 has been incorporated. It is further anticipated that the "Stay Home, Stay Safe" restrictions will be lifted around the beginning of the new IRP year in June, 2020, and that gas demand in the commercial sector will return to a normal level by the beginning of the 2020-2021 heating season. As the economic outcome of the pandemic continues to materialize, the Company will make adjustments to its forecast assumptions for internal planning and budgeting.

SYSTEM TOTAL TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT COMPARISON – 2019-2020 IRP AND ACTUAL RESULTS

On a weather-normalized basics, the Company's natural gas sales through the IRP year ending May, 2020 is estimated at 115.6 MMDth. The Company projected a total of 117.4 MMDth in last year's IRP for the same time period. Temperature-adjusted system throughput (sales and transportation) is estimated to finish the 2019-2020 IRP year at 210.6 MMDth. Last year's IRP projected 208.5 MMDth for the same period. Electric generation demand was 12% above the two-year average used for demand projection in that sector. This is the largest source of positive variance in total throughput. This estimate does include an anticipated reduction in gas demand of about 3.3 MMDth in the commercial sector through the spring months of 2020 resulting from the COVID-19 pandemic.

TEMPERATURE-ADJUSTED DTH SALES AND THROUGHPUT SUMMARY – 2020-2021 IRP YEAR

The sales demand for the 2020-2021 IRP year is forecasted to be 115.9 MMDth. Note that this total is stated using an updated normal heating degree days baseline for the Utah GS usage. The prior baseline was derived from a 30-year average ending December, 2010. The new baseline uses a 20-year average ending December, 2018. The adjustment, approved by the Utah Public Service Commission in its February 25, 2020 Report and Order in Docket No. 19-057-02, reduces usage normalized to the prior baseline by about 2.3%. The Company assumes a return to healthy economics and population growth by 2023. This leads to a sales demand projection of 125.5 Dth in the 2029-2030 IRP year (see Exhibit 3.10). Note that all normal-weather figures in Exhibits 3.1 through 3.11 are based upon the new normal heating degree days baseline.

When this forecast was developed, 43 sales customers had notified the Company of intent to shift to transportation service this year. On a weather-normalized basis, those customers account for about 540,950 Dth annually. The forecast assumes about the same number of customers and annual Dth moving to transportation service from sales classes in the next two IRP years, but no further shifting is assumed beyond that point.

The 2020-2021 IRP sales forecast of 115.9 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.

The forecast projects GS customer growth from 1.1 million customers at the end of the 2020-2021 IRP year to 1.3 million GS customers by the end of the 2029-2030 IRP year (see Exhibit 3.1). The Company forecasts annual Utah GS usage per customer at 101.2 Dth in the 2020-2021 IRP year and decline to 92.9 Dth by end of the 2029-2030 IRP year (see Exhibit 3.2. Note: these Utah averages are derived from usage adjusted to the new 20-year normal baseline). Annual Wyoming GS usage per customer is projected to be 127.3 Dth in the 2020-2021 IRP year and end the 2029-2030 IRP year at 121.6 (see Exhibit 3.5).

The Company is projecting continued customer growth throughout the service territory, albeit tempered through 2022 as the economic fallout from the COVID-19 pandemic takes hold. At this writing, the Company expects the resumption of steady growth around the 2% level beyond 2022. Higher growth is expected in Utah while more moderate growth is projected in the Company's Wyoming service territory. Non-GS commercial and industrial consumption is expected to hold steady with moderate growth over the next few years, brought about by the migration of commercial GS customers to transportation service.

The Company expects system total throughput in this year's forecast to increase from 212.5 MMDth during the 2020-2021 IRP year to 223.3 MMDth by end of the 2029-2030 IRP year (see Exhibit 3.10).

RESIDENTIAL USAGE AND CUSTOMER ADDITIONS

Utah

Utah residential GS customer additions through the twelve months ending December, 2019 totaled 25,287. Over 40% of those additions were in the multi-family sector. Strong housing growth is expected to continue over the long run. But decline in the growth rate is anticipated this year and in 2021 as the pandemic-induced recession unfolds. Growth in multi-family structures will continue to be an important element in residential construction, particularly along Utah's Wasatch Front, as the rental market remains tight and homebuyers search for a more affordable alternative to a single-family home. The Company is forecasting about 19,000 residential additions in the 2020-2021 IRP year, 18,000 in the following IRP year, and 20,000 in the year after. At this point, growth at or slightly above the 2% level is expected to resume in 2023.

Actual temperature-adjusted residential usage per customer for the twelve months ending December, 2019 was 81.2 Dth. The Company projects an average of 78.4 Dth for the 2020-2021 IRP year. About 0.4 Dth of this decline is attributable to the continued trend toward higher efficiency in housing stock and appliances and lower average square footage of living space. The remaining portion results from the adjustment to a new normal heating degree days baseline, addressed above. The overall downward trend in average consumption is expected to continue through the 2029-2030 IRP year as the appliance and shell efficiencies improve and smaller residential dwelling 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 STAT 14.1 and SAS Enterprise Time Series 14.1 are the software tools 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

During the twelve months ending December, 2019, the Wyoming residential customer base grew by 104. As with the Utah service territory, the Company is assuming a decline in residential construction brought on by the now nascent economic recession. The Company projects about 50 new additions through the 2020-2021 IRP, about 50 the following year, and around 100 the year after. At this time, an increase in the level of annual additions are indicative of a healthier economy from 2023 forward.

The average annual usage per residential customer in Wyoming was 87.1 Dth in calendar year 2019, a decrease of 0.9 Dth from the year prior. The Company forecasts an average of 86.9 Dth during the 2020-2021 IRP year and then a continuation of the long-term downward trend perpetuated by greater appliance and housing shell efficiencies. The 2029-2030 IRP year ends at 83.1 Dth (see Exhibit 3.6).

SMALL COMMERCIAL USAGE AND CUSTOMER ADDITIONS

Utah

Temperature-adjusted Utah GS commercial usage per customer for the twelve months ended December 2019 was 434.5 Dth. This year's forecast incorporates the anticipation of more GS commercial customers shifting to transportation service rate schedules over the next several IRP years. Further, at the time of this writing the Company expects that restrictions on retail patronage will be lifted around the beginning of the 2020-2021 IRP year; therefore no abnormal decline in commercial usage is woven into this forecast beyond June, 2020. An average of 424.4 Dth by the end of the 2020-2021 IRP year is projected. The resulting average at the end of the 2029-2030 IRP year is expected to be 390.1 Dth (see Exhibit 3.4). Note that these forecasted averages are derived from usage that has been adjusted to the new normal heating degree days baseline detailed in Section 3.2. This accounts for the greatest share of the difference between forecasted averages and that observed at the end of 2019.

Utah GS commercial customer additions are expected to increase along with the residential level, but at a restrained rate through 2022 as the recession plays out. The Company forecasts approximately 600 additions per year through the next two years.

Wyoming

Usage among commercial GS customers in Wyoming for the twelve months ended December 2019 averaged 463.9 Dth. With such a small base of customers and varying usage patterns, total and average usage in this sector can be volatile. But the data suggests a long-run decline in usage that leads to an average of 460.1 Dth and 440.1 Dth at the end of the 2029-2030 IRP year. At the time of this writing, the Company expects that commercial usage will return to a normal level in the Wyoming service territory around the outset of this coming IRP year and has not reduced its commercial usage forecast below the normal baseline beyond June of 2020.

There were 18 additions to the commercial GS base in 2019. Growth in this sector will likely remain moderate, particularly through the next few years. About 10 new agreements per year have been forecasted through the 2029-2030 IRP year.

NON-GS COMMERCIAL, INDUSTRIAL AND ELECTRIC GENERATION GAS DEMAND

As shown in Exhibit 3.8, annual gas demand among non-GS commercial customers and industrial customers is growing with the continued shifting of some commercial GS customers to transportation service. The Company expects demand in that sector to grow from 59.0 MMDth in the 2020-2021 IRP year to 60.0 MMDth in the 2029-2030 IRP year.

This year’s forecast of electric generation demand holds a steady level of about 41 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 2015-2016 through 2019-2020 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 2020-2021 heating season is 1.23 MMDth and grows to 1.33 MMDth in the winter of 2029-2030. 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.

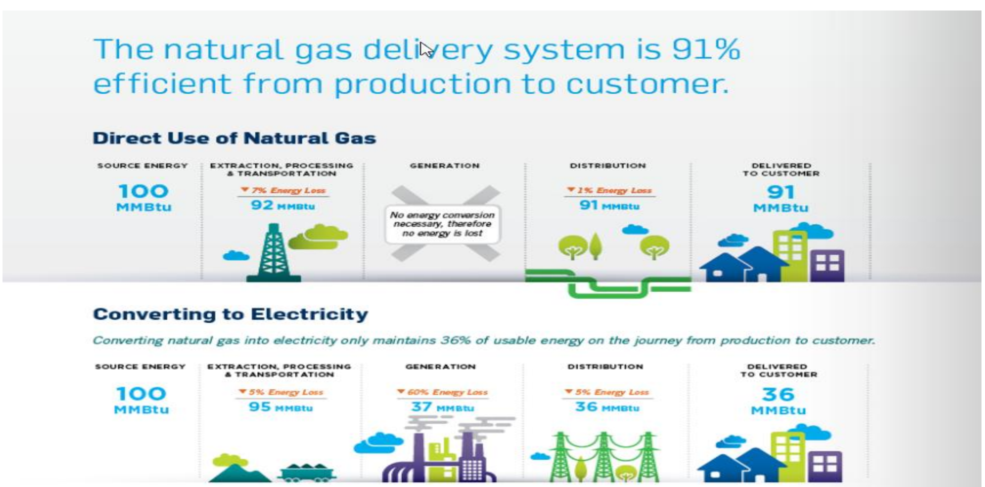


Figure 3.1: Full Fuel-Cycle Analysis
(Source American Gas Association 2020 Playbook)

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 2016-2017 IRP, the Company provided information and presented the results of a study on potential regulatory issues related to heat pumps. That study can be found in pages 9 through 16 of the Customer and Gas Demand Forecast section in Docket No. 16-057-08. The Company has seen no substantial changes in this area since the publishing of the study.

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 beginning in July of the prior year and 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 also a 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.

And 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 introduction of the 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[30].

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 0.565% 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.

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

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

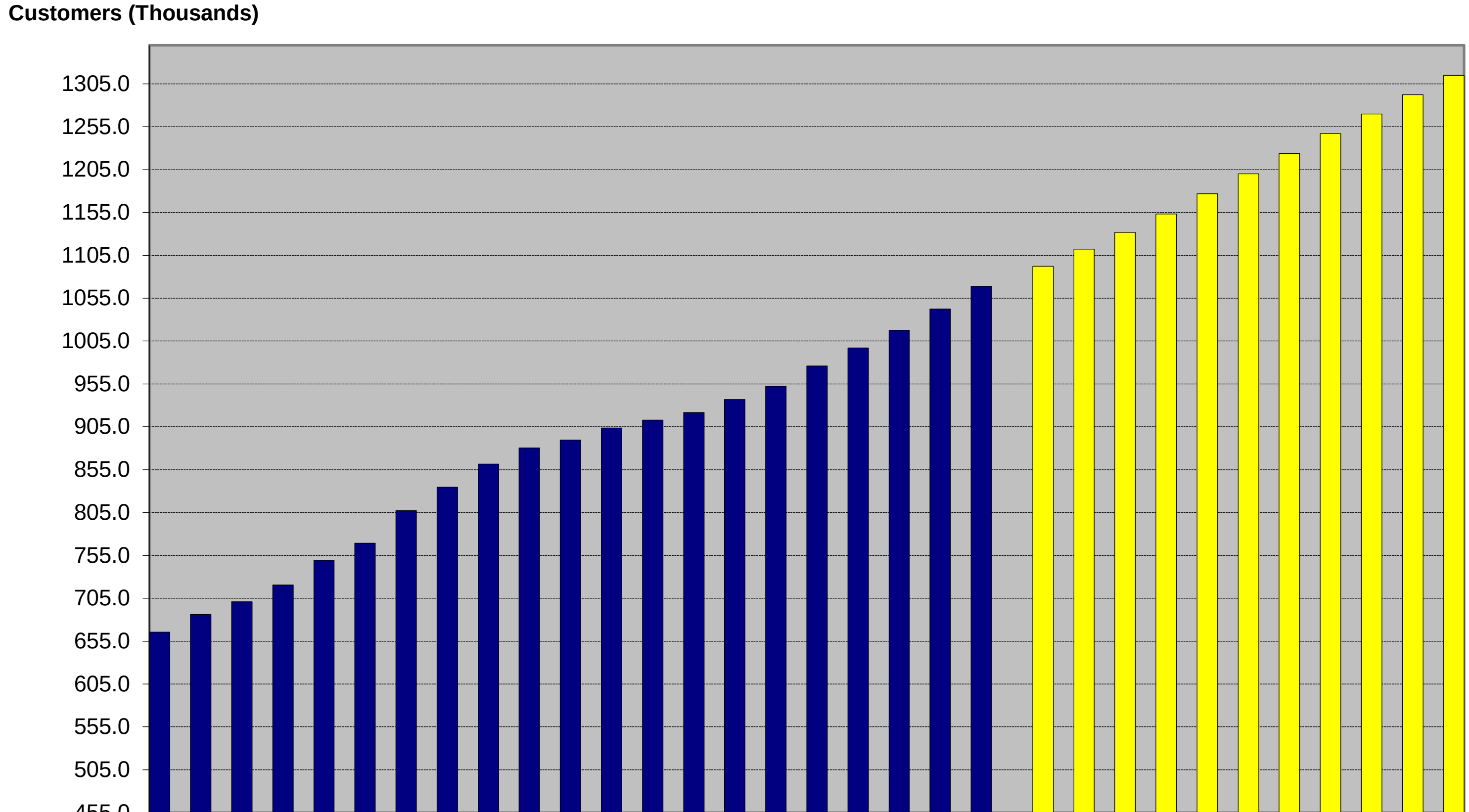
Year	DEUWI Customer Sales	DEUWI Customer Transport.	Total Receipts	DEUWI Sales & Transportation	DEUWI Use Acct. 810&812	DEUWI Loss Due to Tearouts	DEUWI Lost & Unaccounted for Gas	Total Sales, Transport, Company Usage and L&U
2016-2017	104,715,760	81,800,370	186,516,130	185,610,886	181,865	30,744	692,635	186,516,130
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
Total	**324,997,122**	**258,902,126**	**583,899,248**	**580,599,722**	**521,398**	**93,142**	**2,684,986**	**583,899,248**
	Lost-&-Unaccounted-For-Gas %		0.460%		Company Use and Lost-&-Unaccounted-For-Gas %			0.565%

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).

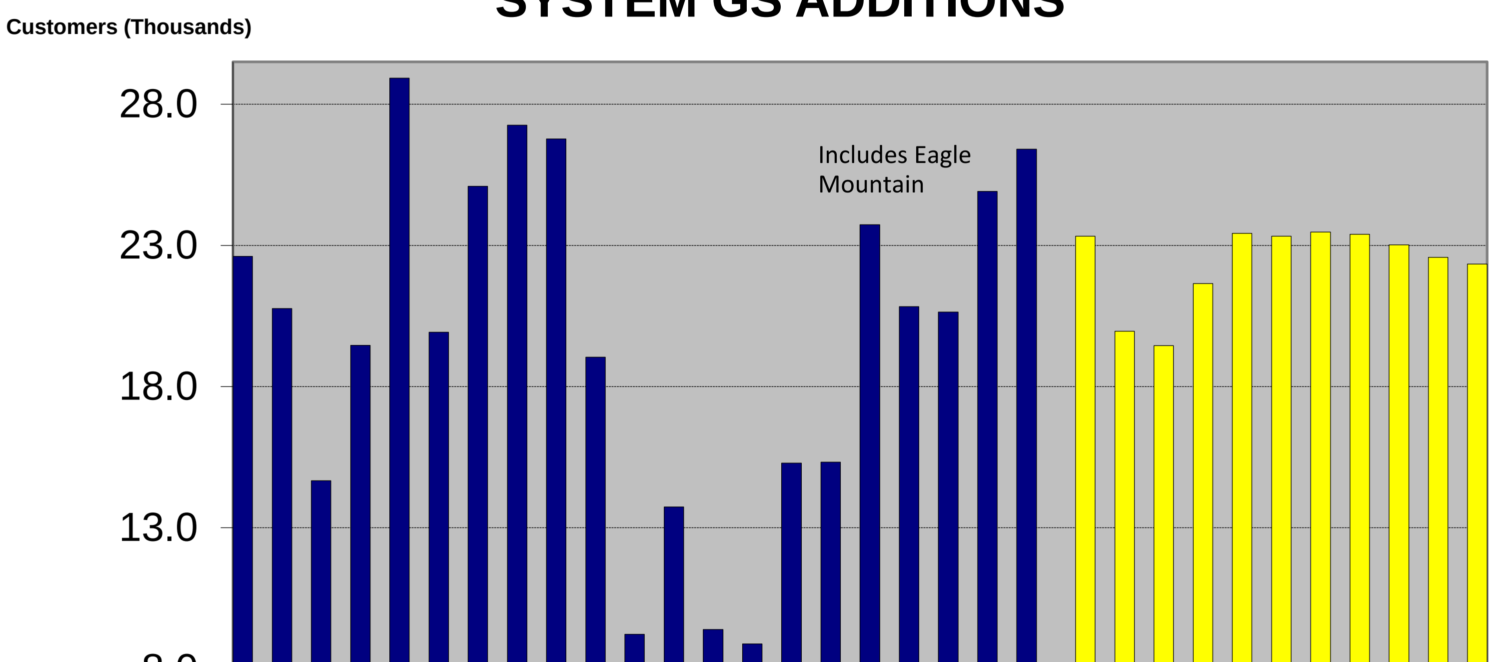
Exhibit 3.1

SYSTEM GS CUSTOMERS



	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	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	
ACTUAL	665.6	686.3	701.0	720.5	749.4	769.3	807.4	834.7	861.4	880.5	889.7	903.5	912.8	921.7	937.0	952.4	976.1	996.9	1017.6	1042.5	1068.9											
FORECAST																						1092.2	1112.2	1131.6	1153.3	1176.7	1200.0	1223.5	1246.9	1269.9	1292.5	1314.8

SYSTEM GS ADDITIONS

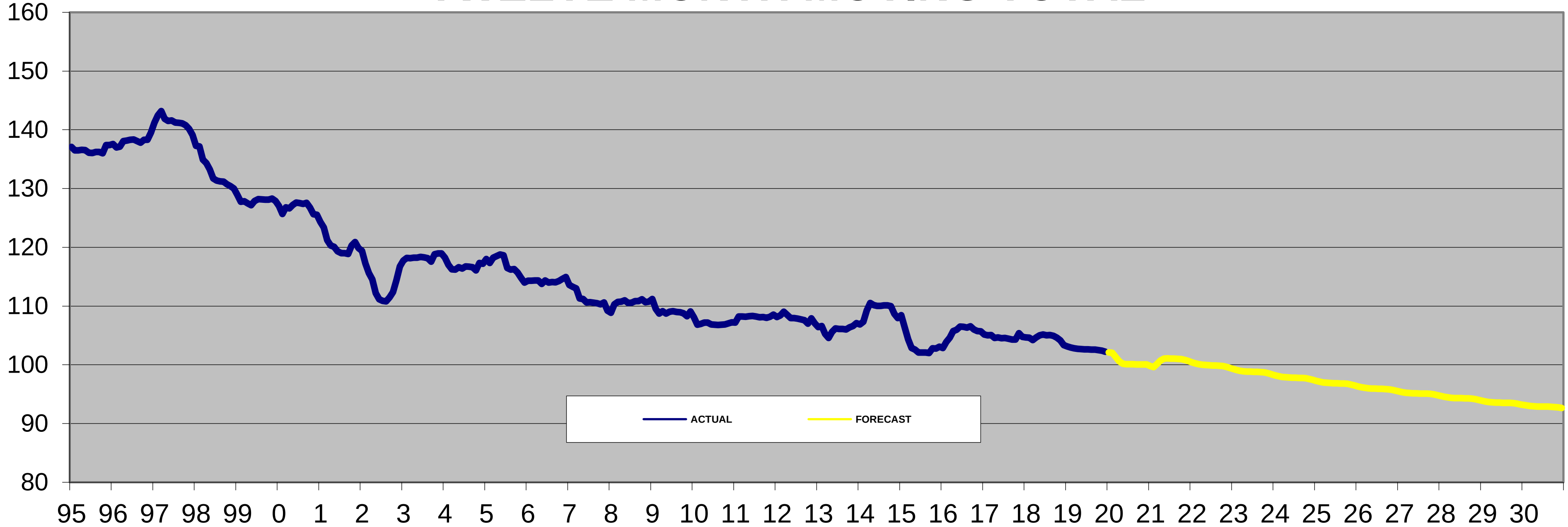


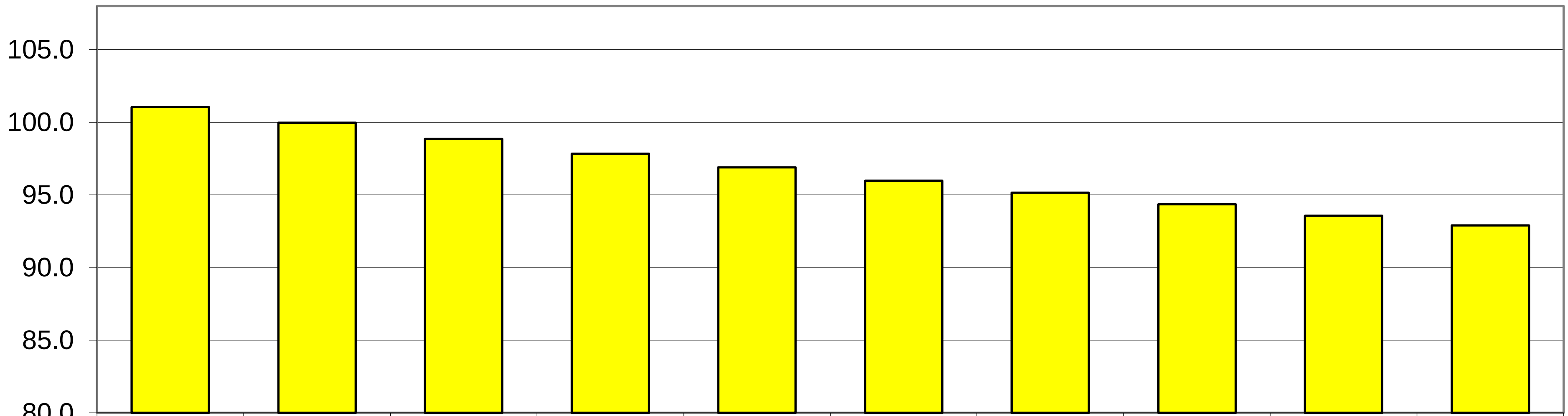
	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
ACTUAL	22.6	20.8	14.7	19.5	28.9	19.9	25.1	27.3	26.8	19.0	9.2	13.7	9.4	8.9	15.3	15.3	23.7	20.8	20.6	24.9	26.4											
FORECAST																						23.3	20.0	19.5	21.7	23.4	23.3	23.5	23.4	23.0	22.6	22.3

UTAH GS TEMP ADJ USAGE PER CUSTOMER

DTH / SA

TWELVE MONTH MOVING TOTAL



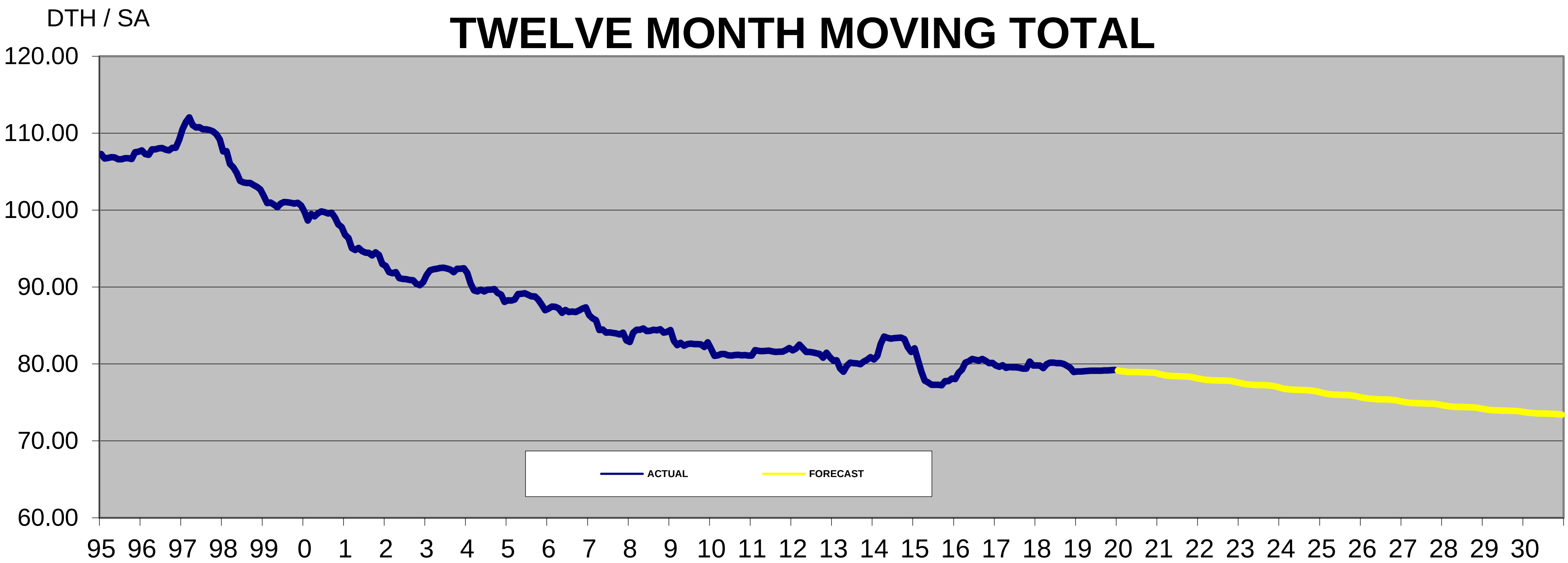


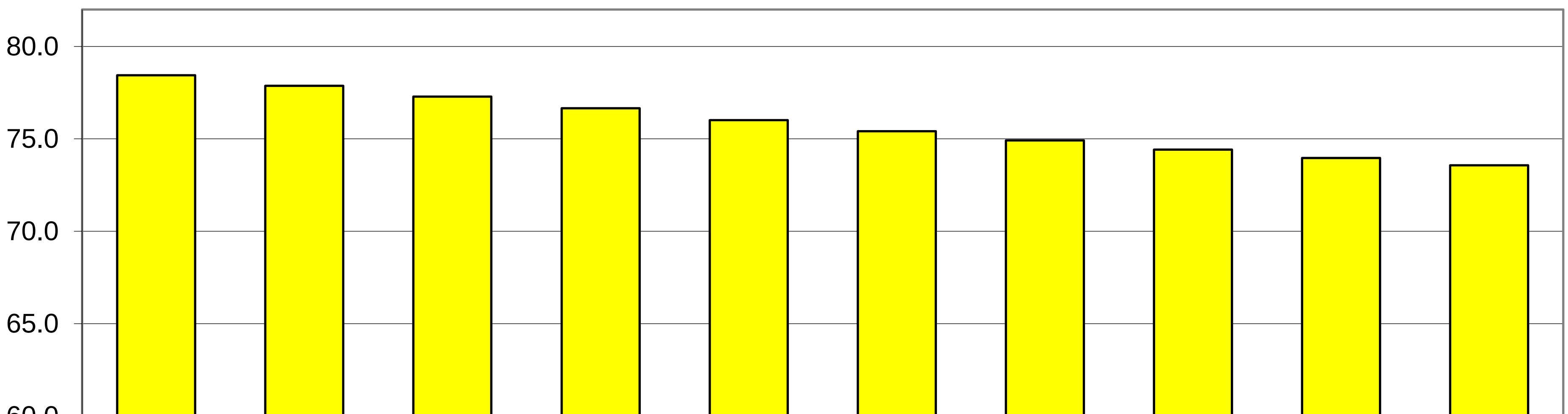
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
FORECAST	101.1	100.0	98.9	97.8	96.9	96.0	95.2	94.4	93.6	92.9

Exhibit 3.2

UTAH GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



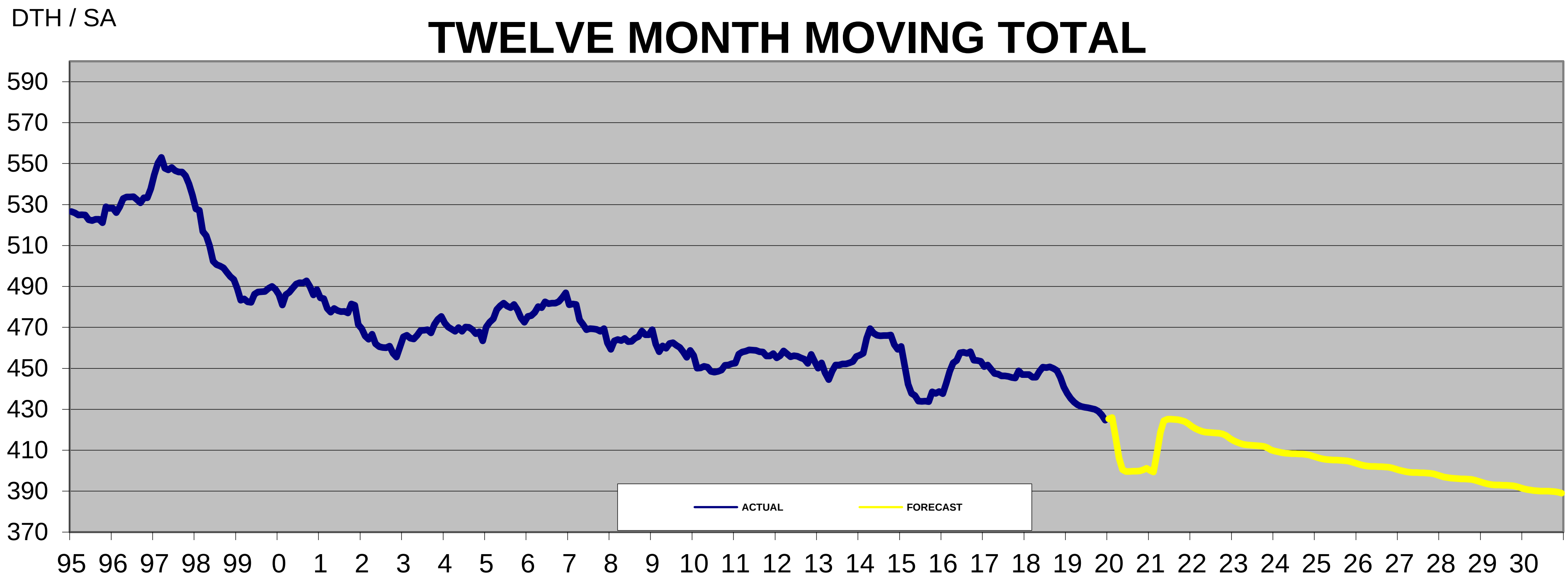


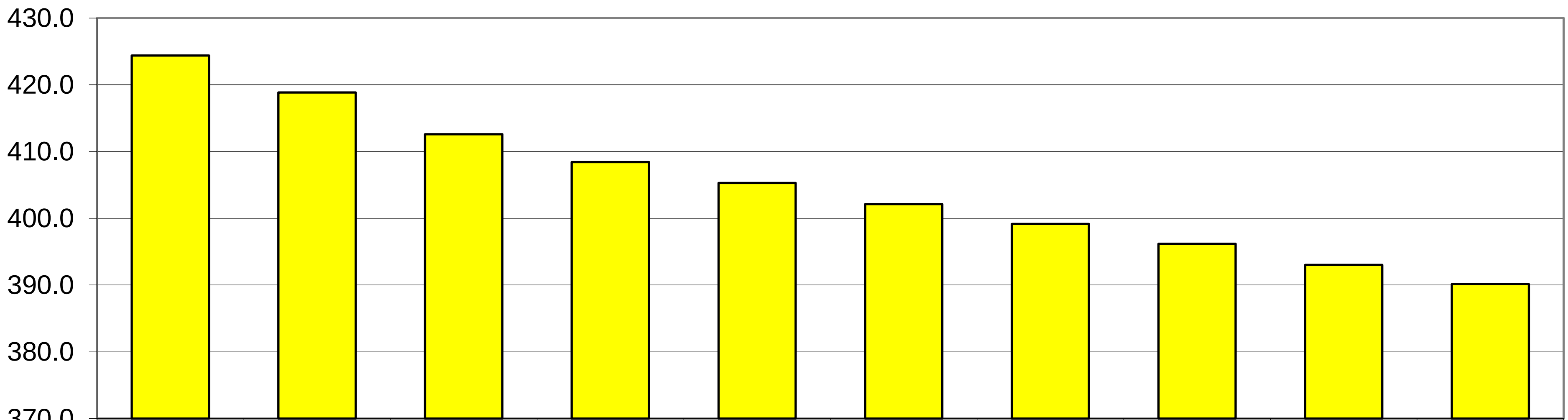
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
FORECAST	78.4	77.9	77.3	76.7	76.0	75.4	74.9	74.4	74.0	73.6

Exhibit 3.3

UTAH GS COMMERCIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



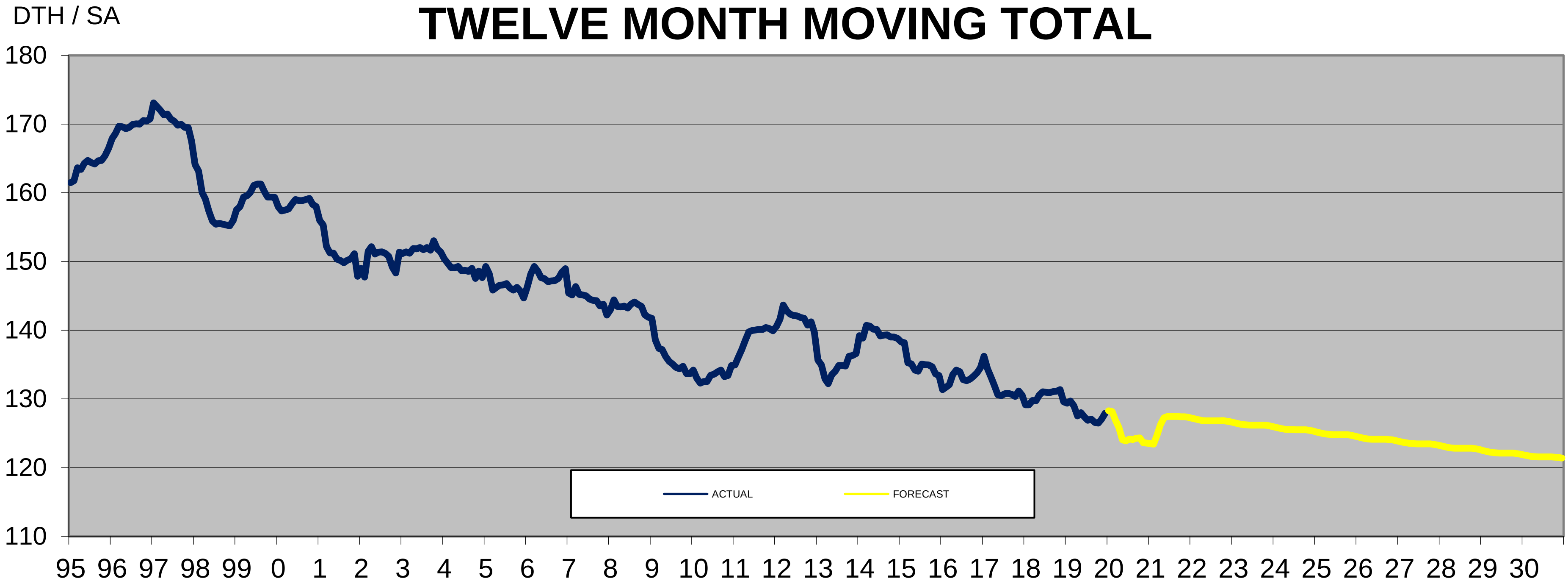


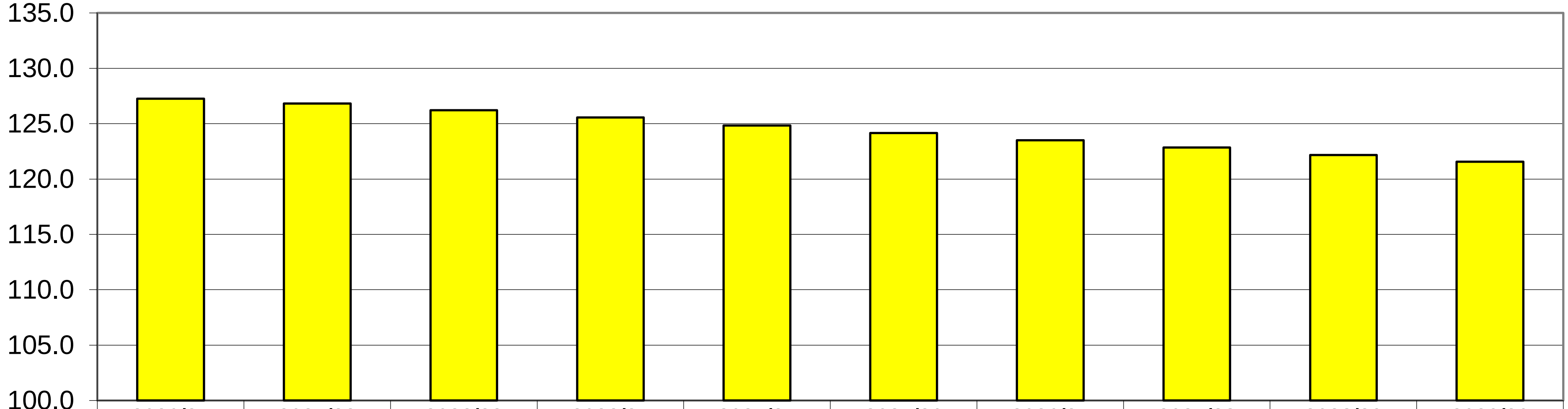
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
FORECAST	424.4	418.9	412.6	408.4	405.3	402.1	399.2	396.2	393.0	390.1

Exhibit 3.4

WYOMING GS TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL



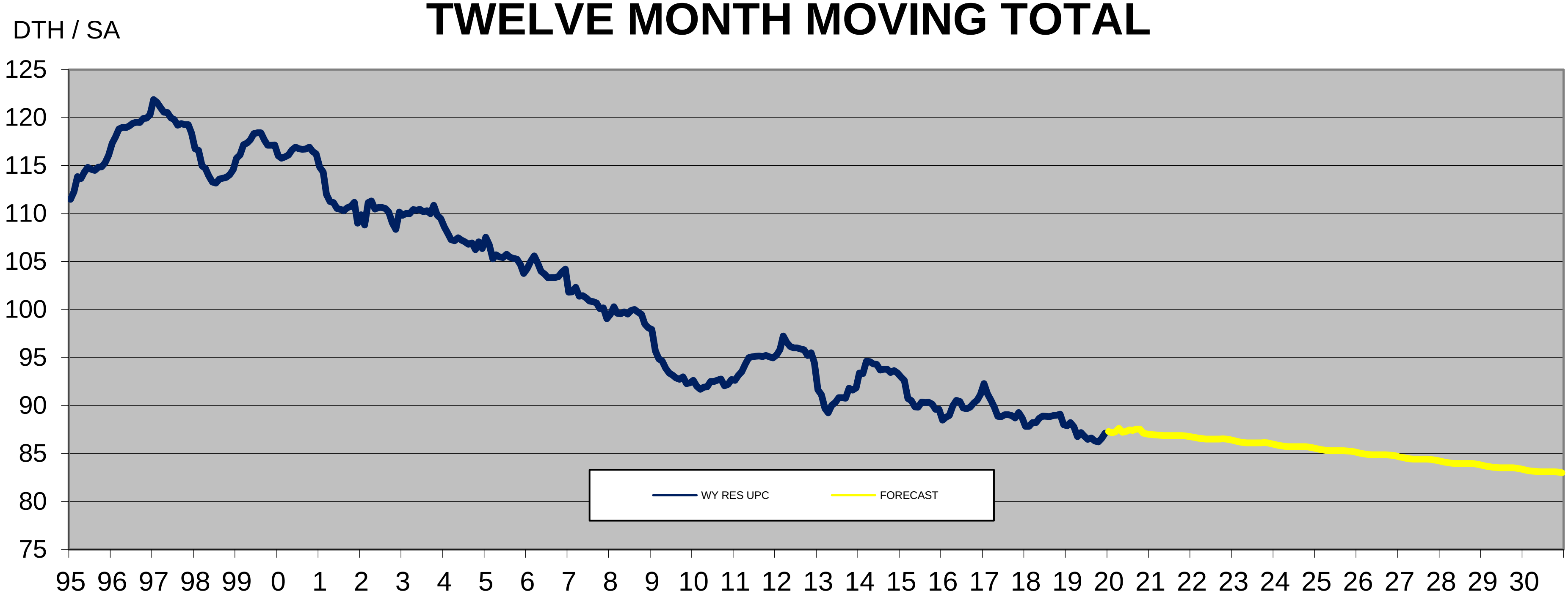


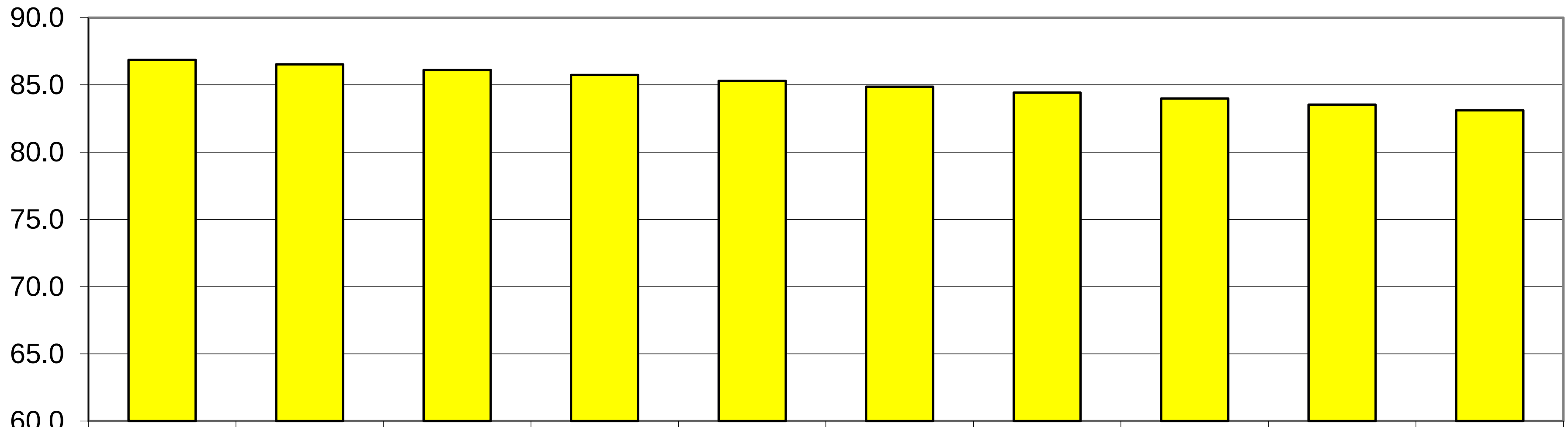
	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
WY GS	127.3	126.8	126.2	125.6	124.8	124.2	123.5	122.9	122.2	121.6

Exhibit 3.5

WYOMING GS RESIDENTIAL TEMP ADJ USAGE PER CUSTOMER

TWELVE MONTH MOVING TOTAL

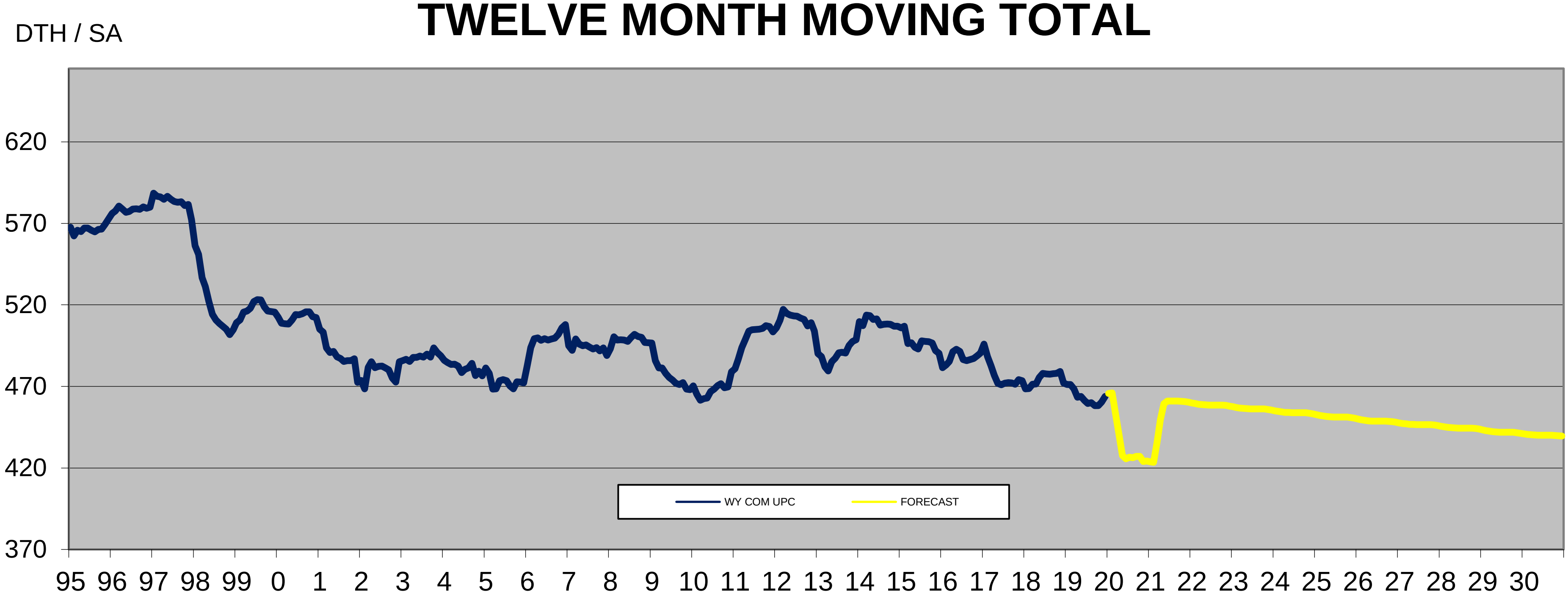


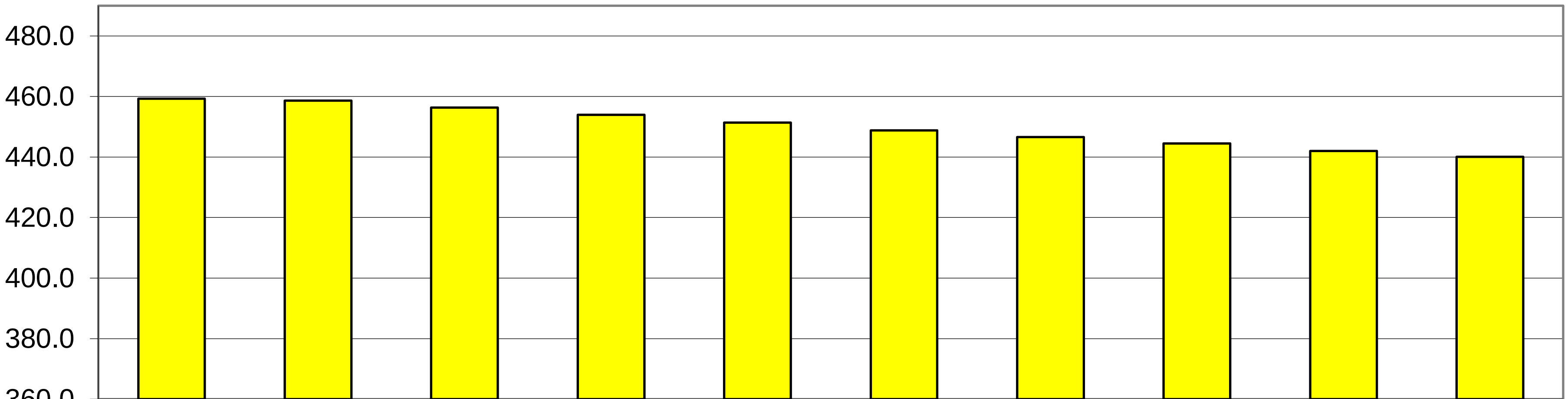


	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
WY GS RES UPC	86.9	86.5	86.1	85.7	85.3	84.9	84.4	84.0	83.5	83.1

Exibit 3.6

WYOMING GS COMMERCIALTEMP ADJ USAGE PER CUSTOMER
TWELVE MONTH MOVING TOTAL

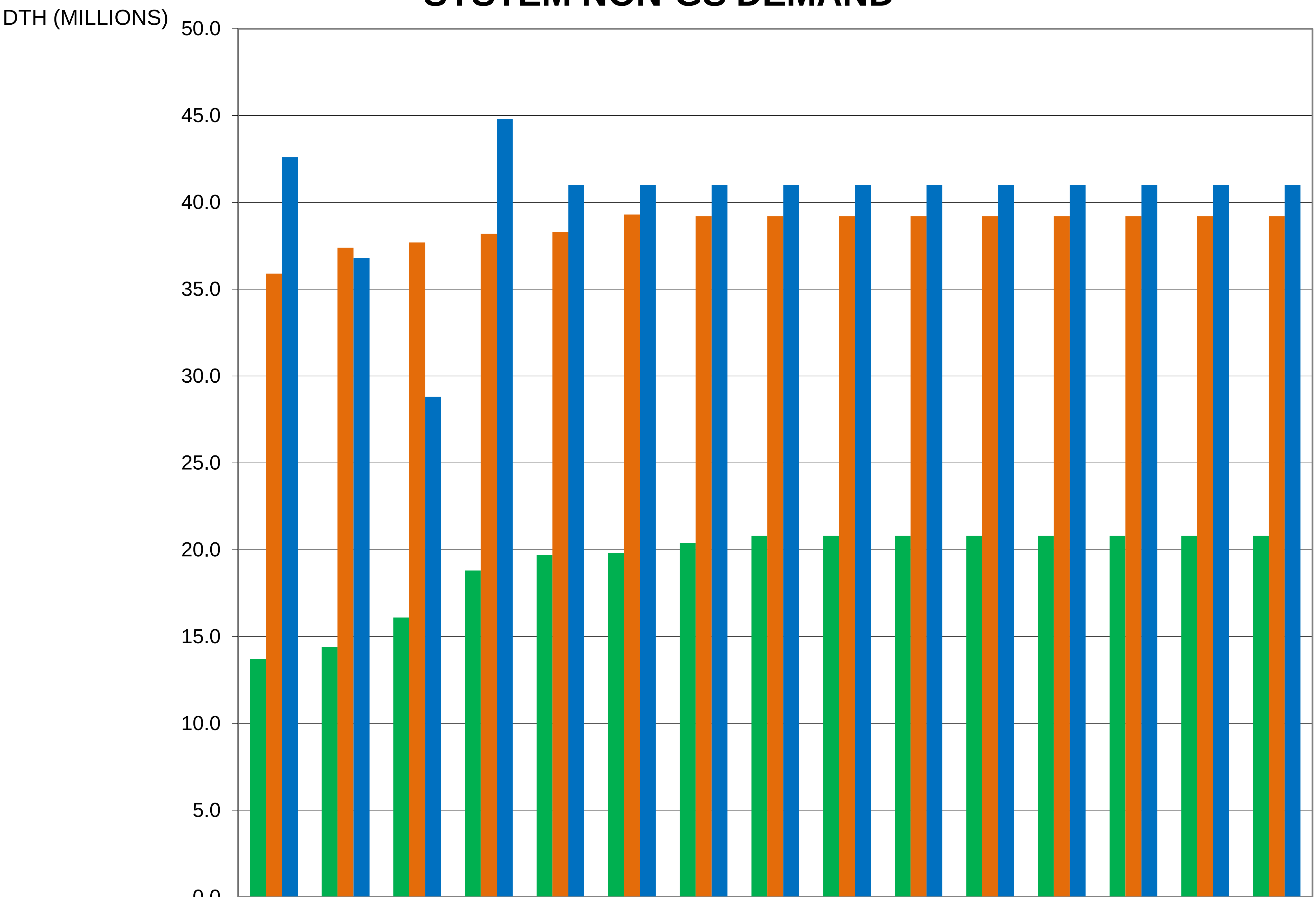




	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
WY GS COM UPC	459.3	458.7	456.3	454.0	451.4	448.8	446.6	444.5	442.0	440.1

Exhibit 3.7

SYSTEM NON-GS DEMAND

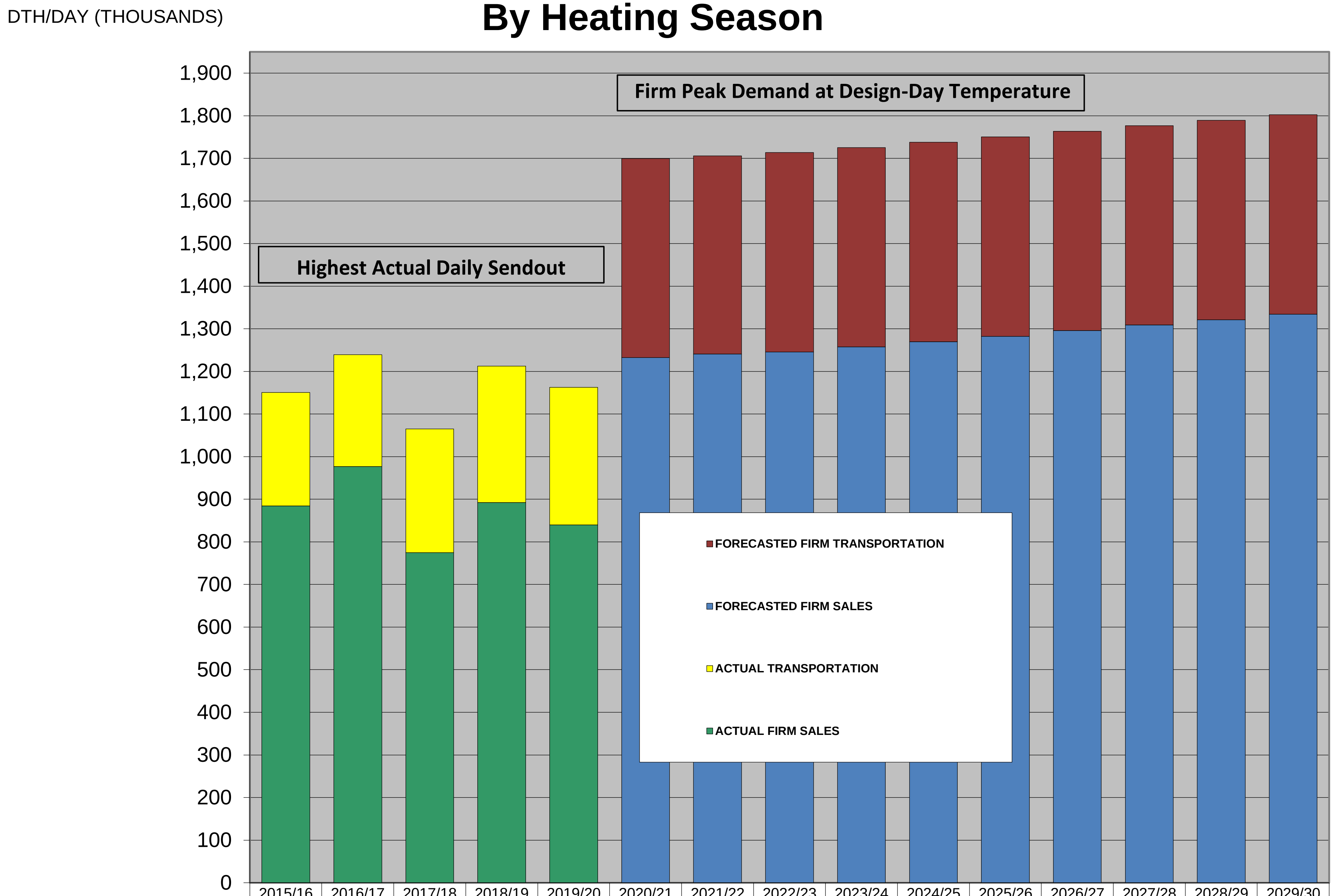


	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
LARGE COMMERCIAL DEMAND	13.7	14.4	16.1	18.8	19.7	19.8	20.4	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
INDUSTRIAL DEMAND	35.9	37.4	37.7	38.2	38.3	39.3	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2	39.2
ELECTRIC GENERATION	42.6	36.8	28.8	44.8	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0

Exhibit 3.8

DESIGN PEAK-DAY DEMAND FORECAST

By Heating Season

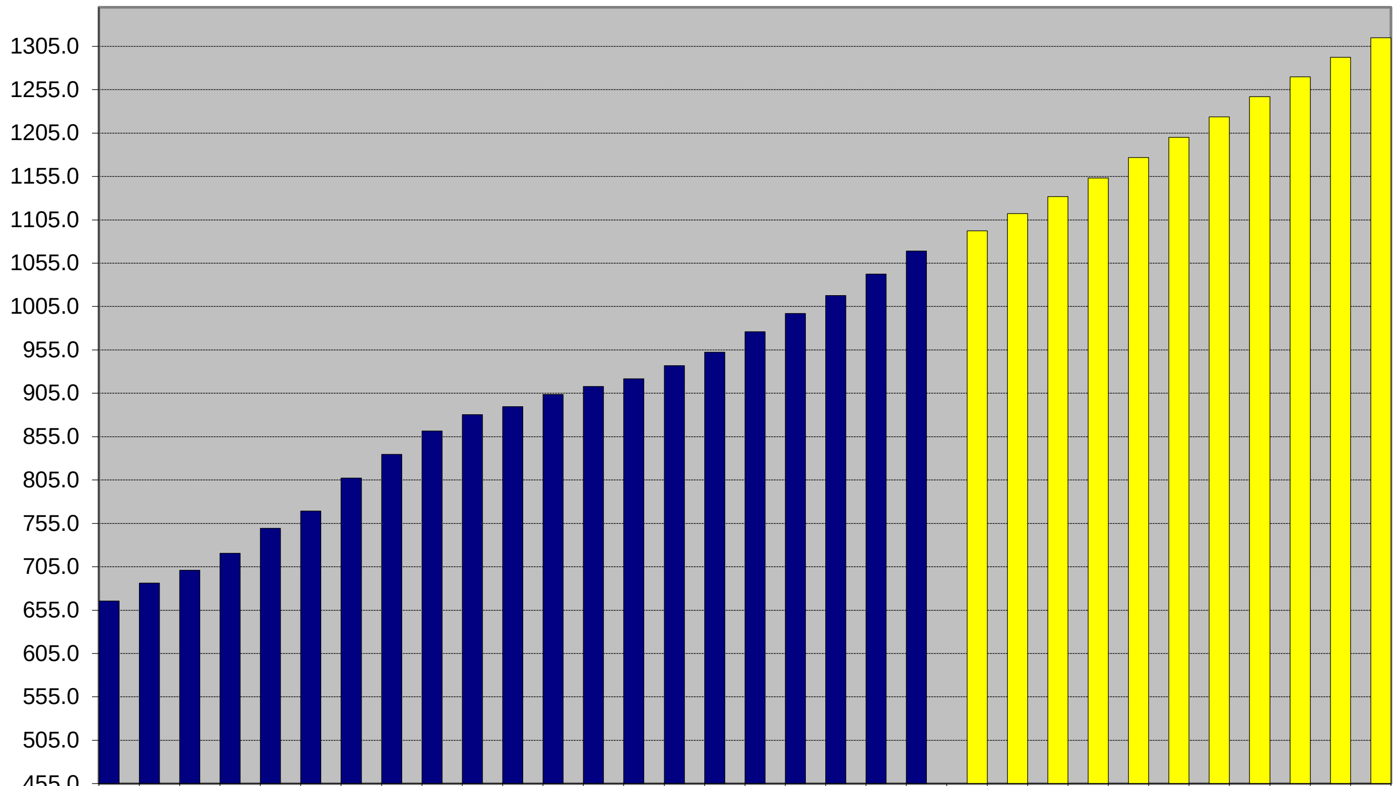


	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
FORECASTED FIRM TRANSPORTATION						467	465	468	468	468	468	468	468	468	468
FORECASTED FIRM SALES						1232	1241	1246	1257	1270	1282	1296	1309	1321	1334
ACTUAL TRANSPORTATION	266	262	290	320	323										
ACTUAL FIRM SALES	884	977	775	892	840										

Exhibit 3.9

SYSTEM GS CUSTOMERS

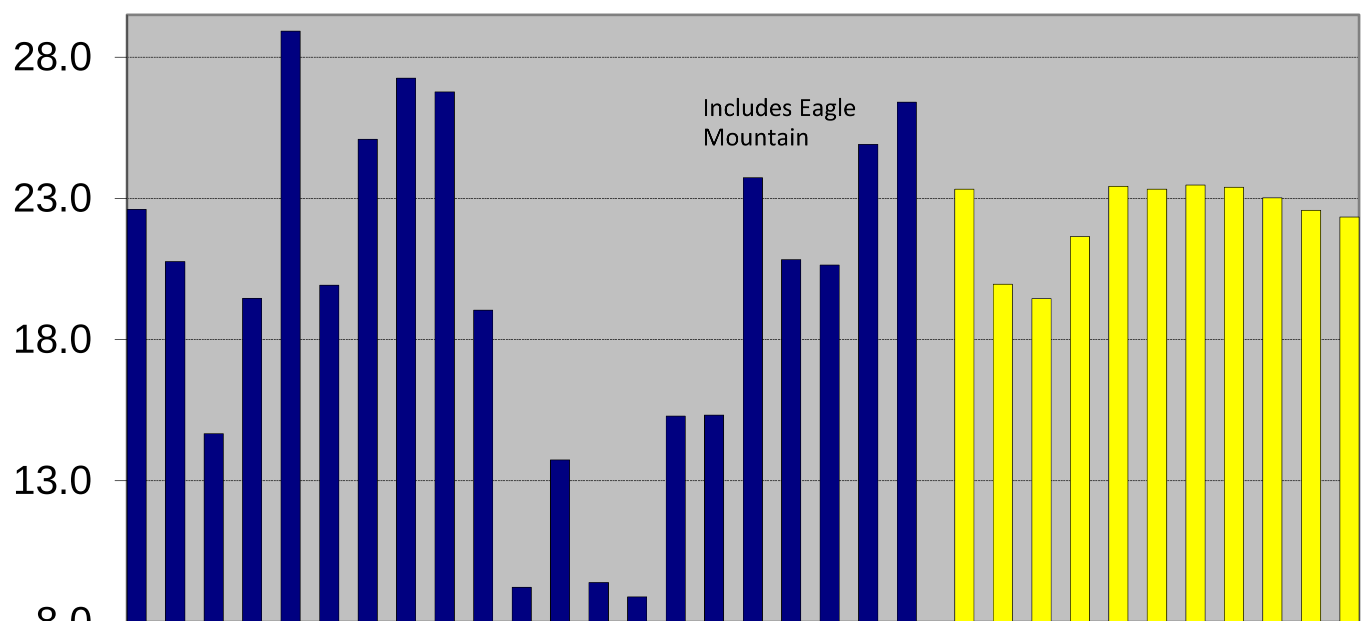
Customers (Thousands)



	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	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	
ACTUAL	665.6	686.3	701.0	720.5	749.4	769.3	807.4	834.7	861.4	880.5	889.7	903.5	912.8	921.7	937.0	952.4	976.1	996.9	1017.6	1042.5	1068.9											
FORECAST																						1092.2	1112.2	1131.6	1153.3	1176.7	1200.0	1223.5	1246.9	1269.9	1292.5	1314.8

SYSTEM GS ADDITIONS

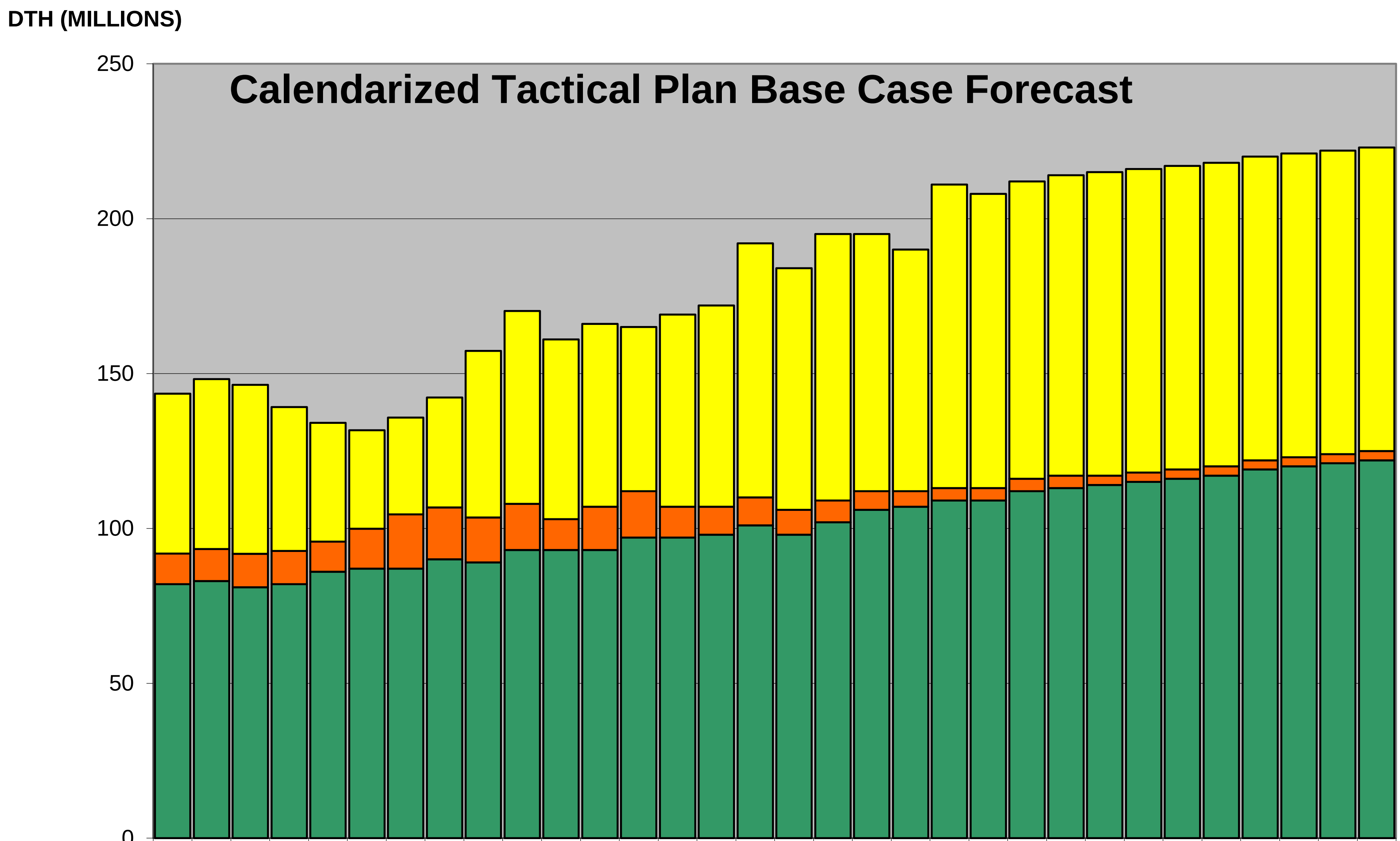
Customers (Thousands)



	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	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
ACTUAL	22.6	20.8	14.7	19.5	28.9	19.9	25.1	27.3	26.8	19.0	9.2	13.7	9.4	8.9	15.3	15.3	23.7	20.8	20.6	24.9	26.4											
FORECAST																						23.3	20.0	19.5	21.7	23.4	23.3	23.5	23.4	23.0	22.6	22.3

Exhibit 3.10

TEMP ADJUSTED THROUGHPUT



	99	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
TRANS	52	55	55	46	38	32	31	36	54	62	58	59	53	62	65	82	78	86	83	78	98	95	96	97	98	98	98	98	98	98	98	98
NON-GS SALES	10	10	11	11	10	13	18	17	15	15	10	14	15	10	9	9	8	7	6	5	4	4	4	4	3	3	3	3	3	3	3	3
SYSTEM GS	82	83	81	82	86	87	87	90	89	93	93	93	97	97	98	101	98	102	106	107	109	109	112	113	114	115	116	117	119	120	121	122

Exhibit 3.11

SYSTEM CAPABILITIES AND CONSTRAINTS

DEUWI SYSTEM OVERVIEW

The Company's system currently consists of approximately 20,189 miles of distribution and transmission mains serving more than 1,090,000 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.

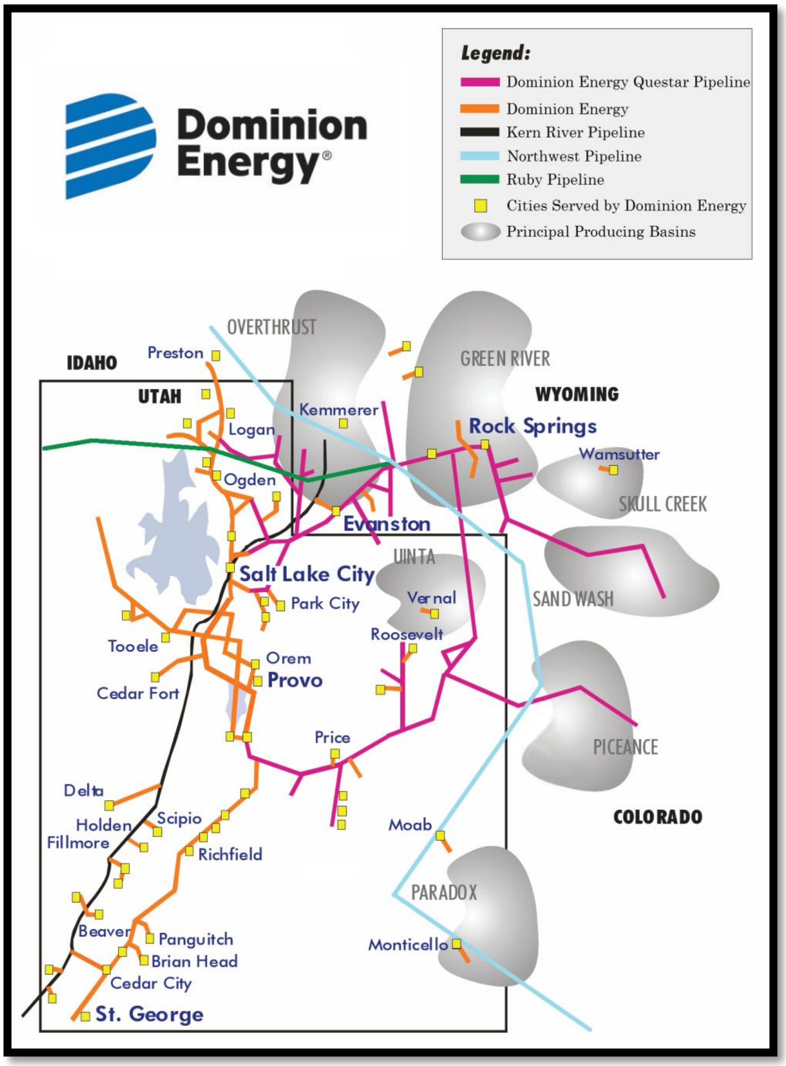


Figure 4.1: DEUWI High Pressure System

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 Tuesday, February 4, 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 248 verification points. Two hundred and forty-seven of these points were found to be within 7% of the actual pressures on that day. Two hundred and thirty-six 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 seven 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 247 verification points on that day. Two hundred and thirty-three 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 calculated 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, such as the Riverton, Central Tap, Morgan, and Rockport stations. The Dog Valley station is the sole supply for the HP system it serves and requires an upgrade this year.

Table 4.1: Gate Stations Nearing Capacity in the JOA

Station	2020-2021 (MMcfd)	Station Capacity (MMcfd)	% Utilization	Upgrade Year
Riverton	200	200	100%	-
Central Tap	47.5	47.5	100%	2024
Dog Valley	5.404	5.683	95%	2020
Morgan	1.765	1.939	91%	-
Rockport	10.039	13.958	89%	2022

In addition to these specific gate stations, the total gate station capacity[31] of the Northern HP system is approaching maximum capacity. Residential and commercial growth in Utah is increasing demand for natural gas along the Wasatch Front. In 2017, the Company determined that the system would benefit from a new gate station served by KRGT, to feed Northern Utah within the next three years. This new gate station, known as the ”Rose Park” station, will provide 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, past issues, and design inadequacies. Therefore, the Company will upgrade this station by 2021. 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, and Riverton stations.

In the steady-state model, the calculated low point in the main portion of the northern system is 202 psig, in Orem. The lowest steady-state pressure in the Summit/Wasatch system is in Woodland, which is 314 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

[31] Reflects station Capacity when combined with gas supply and upstream transportation contracts.

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	322
Endpoint of FL 36 – West Jordan	282
Endpoint of FL 48 – Stockton	307
Endpoint of FL 51 – Plain City	383
Endpoint of FL 54 – Park City	357
Endpoint of FL 62 – Alta	263
Endpoint of FL 63 – West Desert	269
Endpoint of FL 70 – Promontory	322
Endpoint of FL 74 – Preston	316
Endpoint of FL 106 – Bear River City	339
Intersection of FL 29 & FL 23 – Brigham City	415

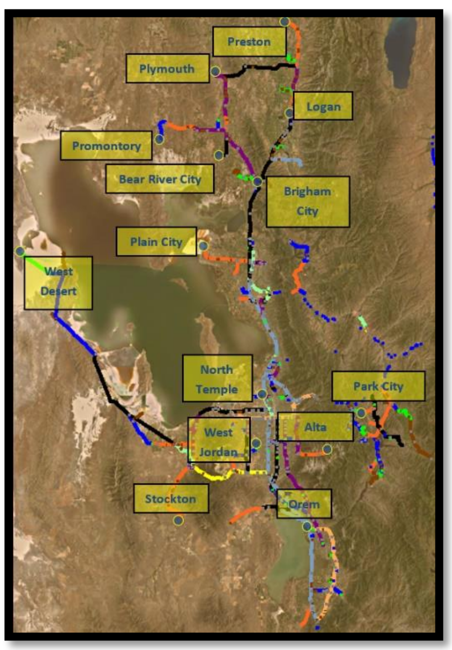


Figure 4.2: Northern Region Key Pressure Locations

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 Orem at 166 psig. The lowest predicted pressure in the Summit Wasatch subsystem is at the Woodland regulator station with 259 psig during the peak hour of Design Day.

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.

In the HP system north of the North Temple station, the minimum pressure occurs at Preston with a minimum pressure of 269 psig. While these pressures are well above operational minimums, the gate stations in the North are all expected to reach their maximum capacities on a Design Day. The planned Rose Park gate station will provide the necessary capacity required to maintain pressures in this area. The Company anticipates that the Rose Park gate station will be installed by the 2020-2021 heating season.

Hyrum gate station is the only existing station in this area that is not currently at capacity due to upstream constraints. However, Hyrum is constrained due to the size of FL23, which is scheduled for replacement as part of the Company’s Infrastructure Rate Adjustment Tracker program. Increasing the diameter of FL23 not only increases pressures in the area, it is necessary to allow more gas to flow from Hyrum Gate into the Northern system.

Feeder Line 55 is the 6-inch feeder line that currently supplies gas to the Salt Lake International Airport and is nearing capacity. In order to address this concern, the Company will install an expansion to an existing line connecting the Westport KRGT gate station to FL55. This project will be discussed in greater detail in the Distribution Action Plan section of this report.

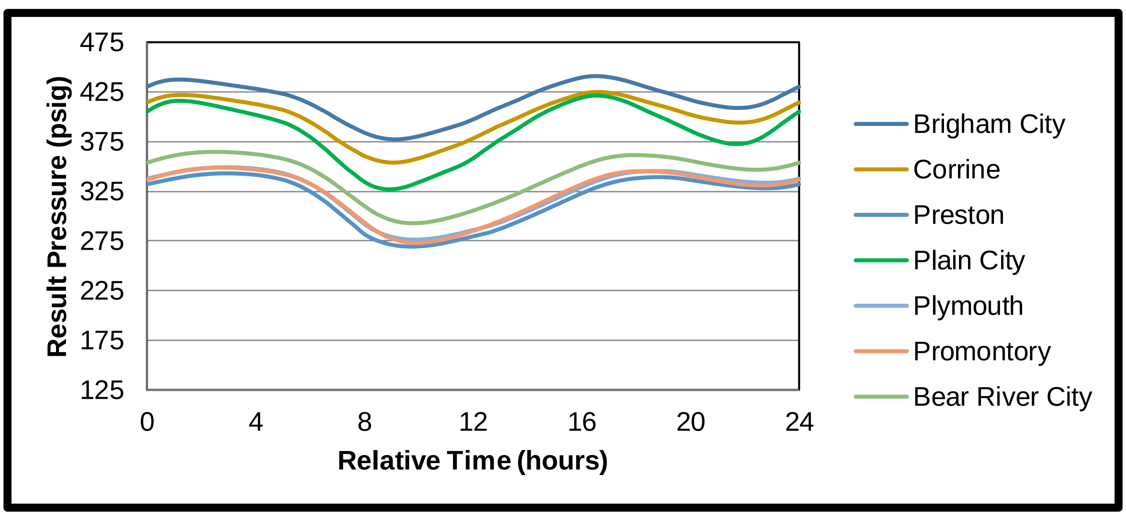


Figure 4.3: 2019-2020 Northern Unsteady-State Design Day Pressures (North of North Temple)

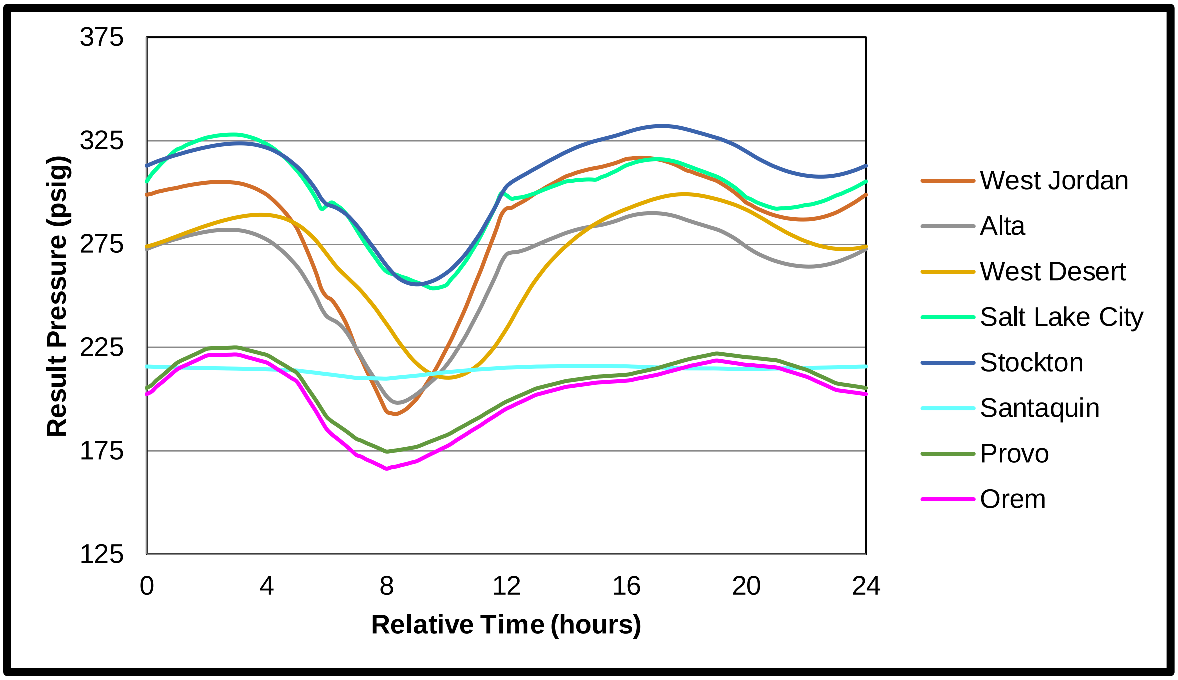


Figure 4.4: 2019-2020 Northern Unsteady-State Design Day Pressures (South of North Temple)

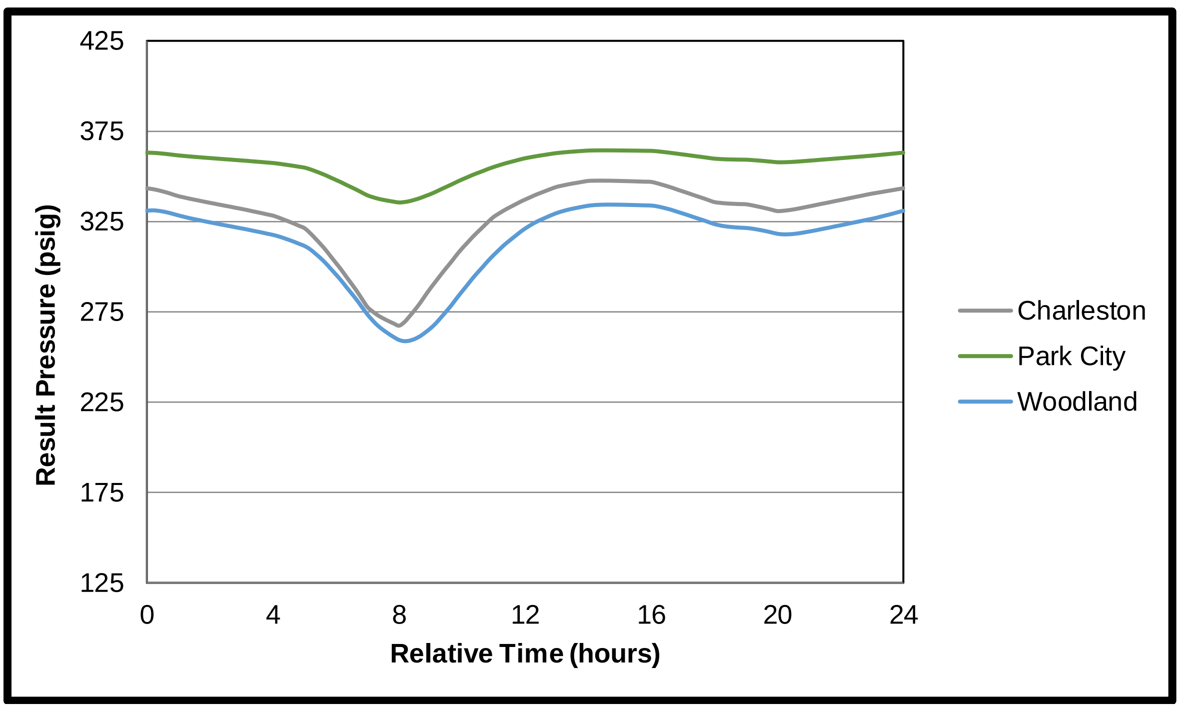


Figure 4.5: 2019-2020 Northern Unsteady-State Design Day Pressures (Summit and Wasatch Counties)

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.

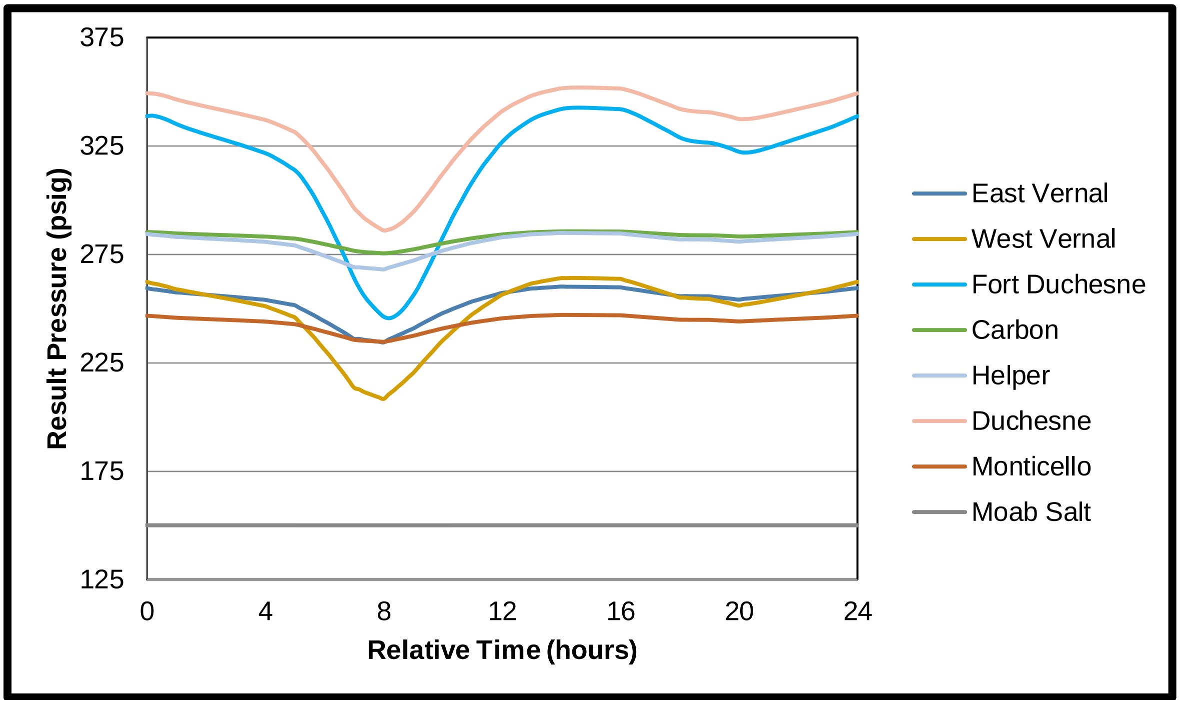


Figure 4.6: 2019-2020 Eastern (North) Unsteady-State Design-Day Pressures

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 2020-2021 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 412 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 ten years. The Company has been closely monitoring the Southern System growth since the Central Compressor station was installed. In order to maintain system growth, a new feeder line (FL133) is scheduled to be installed from the Bluff Street station east to the Washington 2 tap line prior to the 2020-2021 heating season. In the years following this tie across the system, FL81 will need to be looped 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.

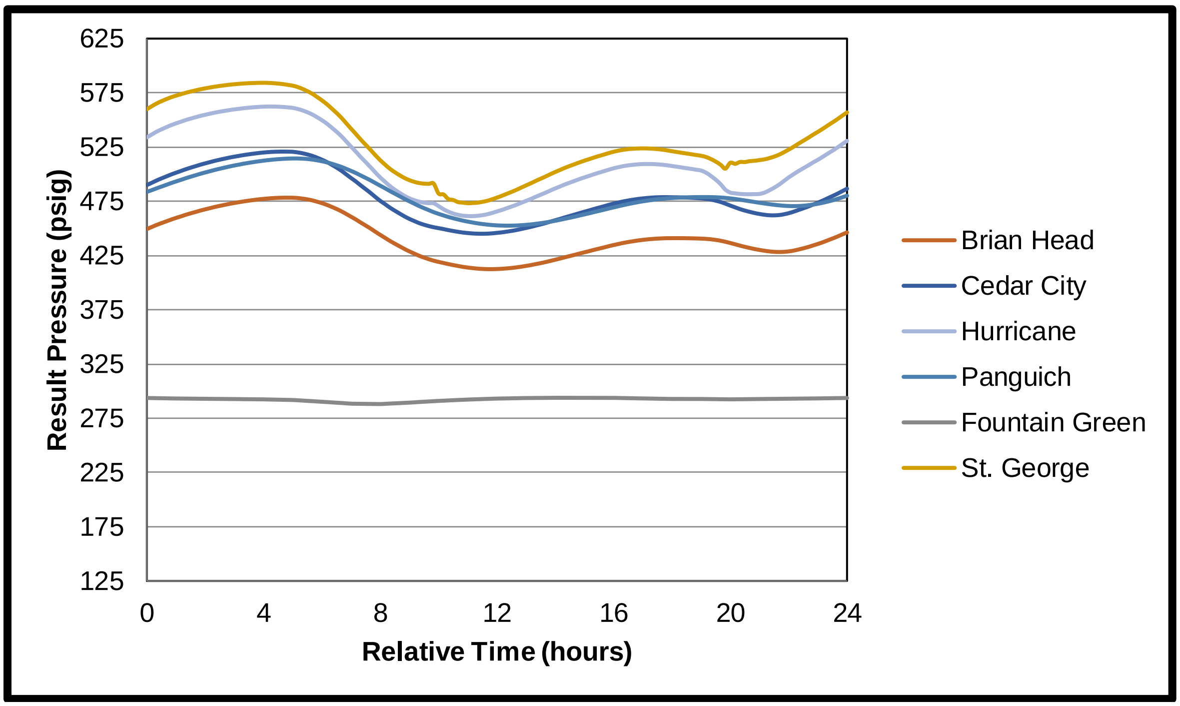


Figure 4.7: 2019-2020 Southern Unsteady-State Design Day Pressures

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.

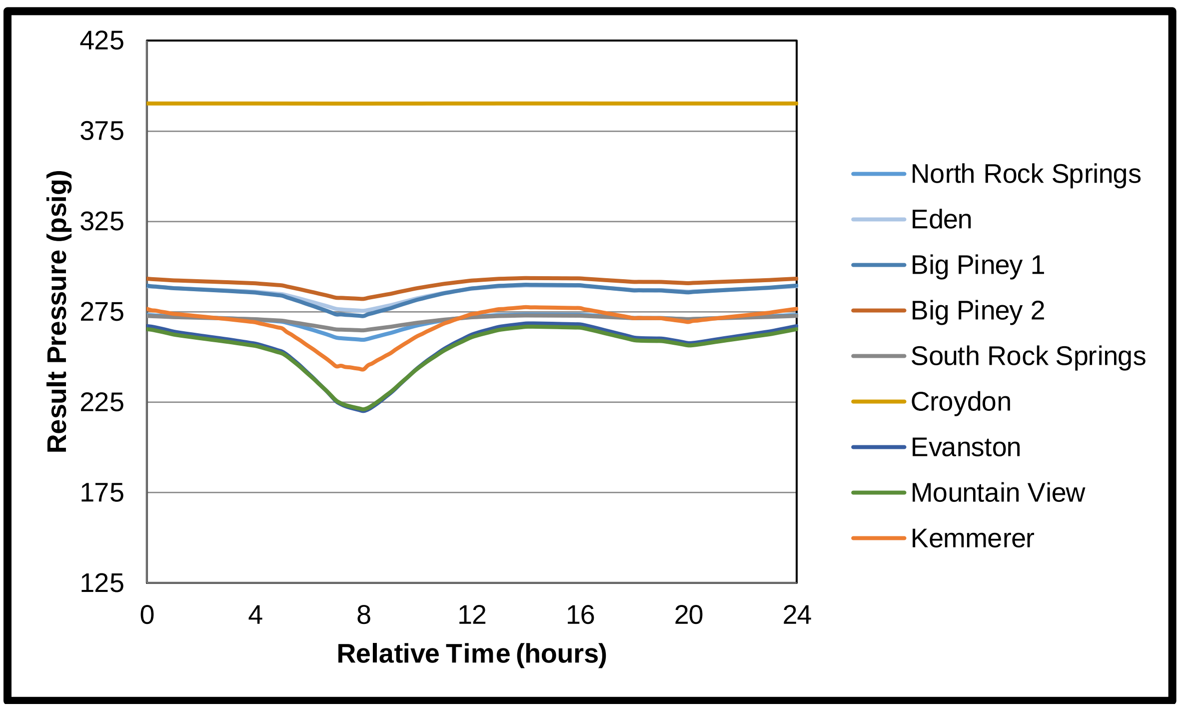


Figure 4.8: 2019-2020 Wyoming Unsteady-State Design Day Pressures

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

	2016	2017	2018	2019	2020
Peak Day Growth	2.12%	2.51%	1.83%	3.03%	0.64%
Customer Growth	2.15%	2.76%	2.28%	2.60%	2.35%

The average system growth and customer growth per year over the past 5 years have been about 2%. 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. 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 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, Goshen, Kanab, Rockville/Springdale, East Wendover, and Green River, Utah and North Rock Springs, Wyoming.

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 should 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:

- Rose Park Gate Station
- Lindon (RE0027) HP Regulator Station
- FL55 Extension
- FL133 Reinforcement Tie
- 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. TG0007 Regulator Station, Saratoga Springs, Utah: This IHP regulator station is required to meet the residential growth in Saratoga Springs. The project will extend the existing HP pipeline that serves Saratoga Springs south another 4.5 miles and will be identified as FL112. The route follows the west side of the existing development along the future Mountain View Corridor alignment. The Company considered an alternative route running down Redwood Road, but the construction costs were estimated to be $13,500,000, well above the costs for the selected project, due to required asphalt repair and traffic control. The Company first discussed this project on page 4-18 of the 2017-2018 IRP. The project is currently in the construction phase, and the Company anticipates commissioning the station in Q3 2020.

   The estimated cost for this project is $9,300,000 with a first-year revenue requirement of $1,078,800.

2. Rose Park Gate Station, Salt Lake City, Utah: This station is a new 400 MMcfd gate station receiving gas off KRGT and delivering it into DEU's FL33 in North Salt Lake. The gate station is required to meet firm sales demand growth in the area. The Company first discussed this project on page 4-17 of the 2017-2018 IRP. Additional project justification is given on page 4-4 of this IRP. The purpose of the project is to have KRGT gas brought on to the Company's 471 psig MAOP system in Davis County. There are no third-party alternatives to this project that provide the adequate volumes to DEU's North Salt Lake service area. The Company has purchased property for the station at 2700 N and 2200 W in Salt Lake City, where KRGT's pipeline crosses the Company's FL33. This location minimizes the required pipeline extension required to connect KRGT to the Company's system. The Company's facilities related to this project are currently in the construction phase, and the Company anticipates construction of those facilities in 2020.

   The estimated cost for this project is $15,800,000 with a first-year revenue requirement of $1,832,800.

3. 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 design phase, and the Company anticipates construction in 2021. The updated estimated cost for this project is $4,800,000 with a first-year revenue requirement of $556,800.

4. RE0027 FL26 HP Regulator Station, Lindon Utah: 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 it needs to be increased to 200 MMcfd. Increasing the station capacity is 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. The Company's facilities related to this project are currently in the design phase, and the Company anticipates construction of those facilities in 2021. The first-year revenue requirement is $290,000.

5. TG0005, Saratoga KRGT Gate Station, Saratoga Springs, Utah: 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 the several Utah County communities including Lehi, Eagle Mountain, and Saratoga Springs. These communities are some of the fastest growing communities in DEU's service territory. The Saratoga gate station, while not at capacity on a Design Day, requires a remodel due to operational concerns. Currently the station has a capacity of 250 MMcfd and the design capacity of the remodel project is 350 MMcfd. Other required improvements include gas measurement to allow flow control and improved overpressure protection.

   This project to remodel TG0005 in its existing location is in the early planning stages and is anticipated for construction in 2021. Total project costs are estimated at $2,000,000. 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, 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. Even assuming no feeder line extension would be required to connect the Company's system to the new station, an entirely new gate station with a design load of 100 MMcfd would have an estimated cost of approximately $6,000,000, also well above the cost of the selected option.

6. SY0002 Syracuse Regulator Station, Syracuse, Utah: This IHP regulator station is required to meet the residential growth in the west side of developed Davis County. This project is currently in the design phase. The exact station location and pipeline alignment have not yet been established. The pipeline length is anticipated to be approximately 3 miles. At this point in the design phase, it appears as though the pipeline alignment will follow the shortest route on existing roads between the beginning point and the new station location. Constructing the IHP regulator station is the only identified solution to resolving the low IHP pressures in this area. No alternative pipeline routes have been identified at this time. Once the property is purchased and the initial engineering is complete, the Company will provide updated route selection and project costs as part of the IRP Variance Report process. The Company first discussed this project on page 5-3 of the 2018-2019 IRP. The Company currently estimates that the cost will be approximately $5,200,000. The Company plans to begin construction in 2022. The first-year revenue requirement will be $603,200.

7. New FL13 West HP Regulator Station 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. This new station will separate the MAOP zones of FL13 at 720 psig MAOP from the rest of the Central HP system at 354 psig MAOP. The general location will be where FL 13 connects into the Central system in Magna (near 8000 W 2100 S). The exact station location and pipeline alignment have not yet been established.

   The project is currently in the early planning stages. Once the property is identified and initial engineering is complete, the Company will provide updated project costs as part of the IRP Variance Report process. The project's construction is anticipated in 2022.

8. New FL13 East HP Regulator Station, 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 at 354 psig MAOP. General location will be near the existing IHP regulator station SL0095 (near 900 W 2100 S, SLC, UT), where FL12 and FL13 connect. The exact station location and pipeline alignment have not yet been established.

   The project is currently in the early planning stages. Once the property is identified and initial engineering is complete, the Company will provide updated project costs as part of the IRP Variance Report process. The project's construction is anticipated in 2022.

9. Jamestown 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 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 a nearby transmission line and extending 6,300 lf of IHP main to the town. Another option would be to reinforce the area with a new supply line directly from the distribution system in Green River. The project's construction is anticipated for 2022 or 2023. The Company is in the early stages of planning. When it has completed its initial analysis, the Company will provide updated routing information and estimated project costs as part of the IRP Variance Report process or in future IRPs.

10. White Dome IHP Regulator Station, St George, Utah: 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 2022. 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 as part of the IRP Variance Report Process or in future IRPs.

11. American Fork IHP Regulator Station: The southwest side of American Fork, between I-15 and Utah Lake, is developing rapidly, and the Company needs to construct a new IHP regulator station in the area to support the growth. There will be multiple options for bringing a HP tap line to the station as FL26 is located to the north, FL85 to the northwest and FL104 to the south. The location of where the Company finds property for the station will determine in large part how the pipeline alignment is designed. The pipeline will be between 5,000 and 9,000 lf and the entire project is planned for 2022 construction. The total project estimated cost is $3,000,000. Based on this estimate, the first-year revenue requirement will be $348,000.

12. South Bluffdale IHP Regulator station, Bluffdale, Utah: 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.

Feeder Line Projects:

1. New Utah State Prison Site, Salt Lake City, Utah: The Utah State Department of Facilities and Construction Management (DFCM) is constructing a new state prison at approximately 8000 West and 1900 North, approximately 3 miles north of I-80, and expects to complete construction in late 2020. The new prison will require natural gas service in mid-2020. The Company does not currently have any facilities within this area.

   The Company's Engineering department has determined that the minimum system required to serve the new prison would be a 4-inch HP pipeline. In order to provide sufficient capacity to support future growth, the Company plans to construct an 8-inch HP pipeline. The Company estimates the cost to construct the minimum system required by the prison facilities is $7,783,000. The State of Utah will pay those minimum system costs. The total cost of the project is $10,645,000. The Company will bear the approximately $2,862,000 difference with a first-year revenue requirement of $331,992.

   The currently-proposed route leaves the new Westport gate station (approx. 5700 W 450 S) heads north along 5600 W, under I-80 to Amelia Earhart Dr, then west to John Glen Road, then north for 1/3 of a mile, then west for 1.5 miles. From there the route turns north for a mile and then west for a mile along future roads that have yet to be constructed.

   The Company considered an alternative route running from the Westport gate station north on 5600 W, running west primarily on the north side of I-80 for 2.75 miles, and then running north toward the prison for 2.5 miles. While this route is the most direct route, nearby wetlands and a landfill impair the Company's ability to complete a required bore across I-80. The proposed route has a more feasible I-80 bore than this alternative, and most of the alignment is either in existing roads or future roads. Pipeline footage is comparable on either route. The estimated cost for this alternative route is approximately $13,000,000, above the estimated cost of the selected option. The Company received payment from the state for the estimated costs in 2018. Additionally, it carried with it significant risk to budget, schedule and overall feasibility with the wetland permits and soil quality risks.

   Approximately 1200 lf of this project and the bore under I-80 were constructed in 2018. Another 2.1 miles were completed in 2019. The Company commenced construction on the final 4.5 mile section in October 2019, and will complete that section in June 2020. The Company first discussed this project on page 5-4 of the 2018-2019 IRP

2. FL55 extension, Salt Lake City, UT: Currently the Company's FL55 is a 6-inch HP pipeline extending from 2200 W past the Salt Lake International Airport to 5000 W, serving multiple IHP regulator stations along the way. Industrial growth is strong in

this area, and modeling shows that on a Design Day, pressures on the pipeline would drop. The 2018 construction of the Westport KRGT Gate Station provided an opportunity to extend FL55 and to provide a two-way feed to the International Center as well as the Salt Lake City International Airport, thereby boosting the pressures to accommodate the area's growing gas needs. Additionally, the new Utah State Prison HP pipeline (FL131) will reduce the length required for this extension.

The current design for the pipeline alignment is a 5600 lf route that begins at the current FL55 termination point at SL0118, 5000 W and Douglas Corrigan Way. From there it will run north to Amelia Earhart Drive, and then west to 5600 W where it will connect to the FL131 Utah State Prison pipeline.

The Company considered two other routes: The first would follow Wiley Post Way from the west until it intersects with Admiral Byrd Rd, and then continue west through 1,000 ft of private property. This option would have reduced the pipeline footage by about 1,800 lf, but property owners were not willing to sell property to the Company. Instead of pursuing condemnation, the Company abandoned this option.

The second alternate route ran along Amelia Earhart Drive, Wiley Post Way and Admiral Byrd Road. This route would have been the same length, but it would have avoided the heavy vehicle traffic of Amelia Earhart Drive. The Company abandoned this option after Salt Lake City Planning and Engineering departments opposed the route. Salt Lake City personnel were concerned that this route would have a heavy impact to nearby businesses and that the chosen alternative would result in a reduced traffic disruption on Amelia Earhart Drive. Total cost for this option was estimated at $2,400,000.

The selected project is currently in the design phase and construction is planned for 2021. Additional project justification is given on page 4-9 of the System Capabilities and Constraints section of this report. The total estimated cost for the project is $2,400,000. Based on this estimate, the first-year revenue requirement will be $278,400.

3. <u>Feeder Line Replacement Program:</u> 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 southern system is fed from three gate stations which include Indianola, Central and Wecco (Cedar City). Both Central and Wecco are fed from KRGT. The bottleneck in bringing gas to St. George is the 8-inch HP pipelines. The Company considered several options. The three most viable options were:

1) Tie FL81 to FL71 with a 12-inch pipe across St. George.
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:

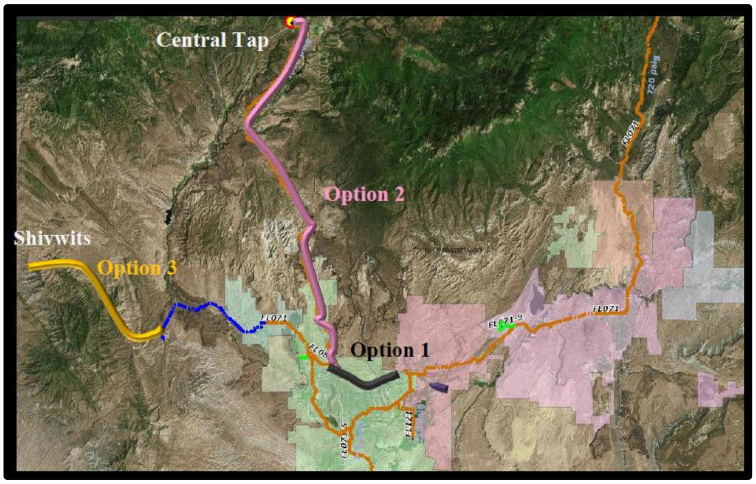


Figure 5.1: Southern System Options

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.

1. FL133, St. George Reinforcement tie, St. George, Utah: In order to reinforce its HP system to meet the growing demands of St George and the surrounding area, the Company has determined it necessary to construct a 12-inch pipeline through the north end of the city. The pipeline will begin at the HP regulator station WH0030 on Bluff Street and Snow Canyon Drive, will terminate at 3050 E and 450 N, and will be approximately 6.7 miles long. After leaving the WH0030 station, the route will run east on Red Hills Parkway until 1680 E, where it will then bore under I-15 and run south to 280 N, then to Mall Drive and then along 450 North heading east to 3050 E. The Company has acquired property where a pig receiver and interconnect valves with FL71 will be constructed. The total project cost is currently estimated at $21,000,000.

   The Company considered an alternative route that begins at the WH0030 station and runs south on Bluff Street for approximately 1.5 miles. It then turns east on 100 S until River Road, then travels northeast until Mall Drive, then south to 450 N, then east to 3050 E. This alternative route had an approximate cost of $24,000,000, well above the cost of the selected option. Costs are increased for this alternative due to extensive traffic control requirements and asphalt replacement along the entire alignment. Additionally, UDOT and the City of St. George discouraged this route because it adversely impacted traffic on roads with high traffic volume.

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 project is currently in the construction phase. The Company started construction in December of 2019 and plans on completing the project in the fall of 2020. The first-year revenue requirement will be $2,436,000.

2. FL135, Central 20-inch loop, St. George, Utah: 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
2020	TG0007 District Regulator Station	$9,300,000	$1,078,800
	Rose Park Gate Station	$15,800,000	$1,832,800
	St George Reinforcement Tie (FL133)	$21,000,000	$2,436,000
	Utah State Prison Site Extension	$2,862,000	$331,992
2021	TG0005 Saratoga KRGT Gate Station	$2,000,000	$232,000
	RE0027 FL 26 HP Regulator Station	$2,500,000	$290,000
	LG0012 Logan District Regulator Station	$4,800,000	$556,800
	FL55 Extension	$2,400,000	$278,400
2022	Central 20-inch Loop (Phase 1)	$32,813,000	$3,806,308
	White Dome District Regulator Station	TBD	TBD
	American Fork District Regulator Station	$3,000,000	$348,000
	SY0002 Syracuse District Regulator Station	$5,200,000	$603,200
	FL13 West HP Station, Magna, UT	TBD	TBD
	FL13 East HP Station, Salt Lake City, UT	TBD	TBD
2022/2023	Jamestown, WY Regulator Station	TBD	TBD
2023	Bluffdale District Regulator Station	TBD	TBD
2025	Central 20-inch Loop (Phase 2)	TBD	TBD
2028	Central 20-inch Loop (Phase 3)	TBD	TBD

PLANT PROJECTS:

1. On-System LNG Facility: As discussed in greater detail 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 proposed the construction of an on-system LNG facility. This facility would provide a reliable supply source that the Company could call upon in the event of unanticipated supply disruption, line damage, or events caused by forces of nature.

   The Company has 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. In an effort to avoid inclusion of Highly Confidential information in this IRP, the Company incorporates that analysis by reference.

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

   The proposed facility would 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 2020. 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 2016 there was approximately 4,300 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.

TRANSPONDER REPLACEMENT PROGRAM

On January 6, 2018, the Company provided information to the Commission and interested parties relating to its transponder replacement program. Beginning in 2012, the Company began to experience challenges related to non-responsive transponders. Battery degradation in Elster transponders was resulting in an unacceptably high failure rate, and an increase in estimated customer bills. In order to address the matter, the Company determined that it should replace the Elster transponders with Itron transponders. The only alternatives would be to either continue to replace the Elster transponders as they fail, or to increase manual meter reading. Because neither option would fully address the problem, the Company opted to replace all of the transponders proactively.

The Company began installing Itron transponders in November of 2015. To date the Company has completed replacements for about 95% of its customers, including customers located in Bluffdale, Tooele, St. George, Park City, Moab, Wyoming, Richfield, Cedar City, Ogden, Logan, and Springville. Eagle Mountain customers had a prior version of the Itron transponders when the Company purchased the Portions of the Salt Lake, Vernal, and Price systems remain to be installed. The Company anticipates completing the project by end of the 3rd Quarter 2020 with a total cost of approximately $70 million. Spending on this project was about $6,000,000 in 2018, $10,000,000 in 2019 and is anticipated to be approximately $3,000,000 in 2020 with first-year revenue requirements of $348,000 in 2020.

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.

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. This Docket is scheduled for a hearing with the Commission on July 16, 2020.

The Company is continuing the feasibility evaluation of expanding to several other interested communities including Green River, Kanab, 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.

Wyoming

The Company is also working to identify communities in Wyoming that are geographically proximate to the Company’s existing system and may be candidates for natural gas service. To date, the Company has identified North Rock Springs, Bear River, and Almy as communities that may be candidates for expansion. The Company is conducting preliminary analysis including engineering work, evaluation of numbers of potential customers in each area, customer interest, and possible cost savings over propane to those customers in order to identify the best expansion candidate. The Company will provide updates to stakeholders in Wyoming with more detailed information when it becomes available, and to discuss regulatory and legal requirements for proceeding for such an expansion.

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.[32]

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.[33] 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.

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[32] 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)).
[33] 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 a 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 196.6 miles of transmission piping (25% 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

	2020	2021	2022
Transmission Integrity Management Program	8,960	9,560	8,480
Distribution Integrity Management Program	1,719	1,734	1,689
Total Integrity Management Cost ($ Thousands)	10,929	10,794	10,419

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
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; and
- 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; and

- 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; and
- 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. However, to date the NPRM has not been published. This rule is expected to cover rupture detection and response time metrics including the integration of automatic shutoff valves and remote-control valves on transmission pipelines with an objective to improve overall incident response.

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. As a result of this initiative, the indirect inspection costs are expected to increase in 2019 and 2020.

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

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 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 our knowledge of these pipelines. Testing is scheduled to be completed by year end 2021.

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	2020	2021	2022
ECDA			
Pre-Assessment			
2020 (FL19, 23, 28, 40, 71, 73, 74, 125) (9.85 HCA miles; 12.06 CA miles @ $4 K/FL)	32		
2021 (FL64, 65, 66, 68, 69, 78, 83, 84, 99, 104) (1.94 HCA miles; 8.16 CA miles @ $4 K/FL)		44	
2022 (FL10, 14, 41, 42, 48, 52, 88) (12.67 HCA miles; 14.8 CA miles @ $4K/FL)			28
Indirect Inspections			
2020 (FL19, 23, 28, 40, 71, 73, 74, 125) (9.85 HCA miles; 12.06 CA miles @ $16 K/mile)	350		
2021 (FL64, 65, 66, 68, 69, 78, 83, 84, 99, 104) (1.94 HCA miles; 7.00 CA miles @ $16 K/mile)		143	
2022 (FL10, 14, 41, 42, 48, 52, 88) (12.67 HCA miles; 14.8 CA miles @ $16 K/mile)			436
Direct Examinations			
2019 (FL18, 21, 29, 70) (6 excavations @ $34.5 K ea.)	207		
2019 (FL18, 21, 29, 70) (Pipetel 1 sites, 1 casings @ $150K/site)	150		
2020 (FL19, 23, 28, 40, 71, 73, 74, 125) (6 excavations @ $34.5 K ea.)		207	
2020 (FL19, 23, 28, 40, 71, 73, 74, 125) (Pipetel 2 sites, 2 casings @ $150K/site)		300	
2021 (FL64, 65, 66, 68, 69, 78, 83, 84, 99, 104) (6 excavations @ $34.5 K ea.)			207
2021 (FL64, 65, 66, 68, 69, 78, 83, 84, 99, 104) (Pipetel 2 sites, 2 casings @ $150 K/mile)			300
Post Assessment			
2019 (FL18, 21, 29, 70) (14.12 HCA miles; 29.42 CA miles @ $1.5 K/FL)	6		
2020 (FL19, 23, 28, 40, 71, 74, 125) (9.85 HCA miles; 12.06 CA miles @ $1.5 K/FL)		12	
2021 (FL64, 65, 66, 68, 69, 78, 83, 84, 99, 104) (1.94 HCA miles; 7.00 CA miles @ $1.5K/FL)			15
CIS			
Indirect Inspections			
2020 (FL19, 23, 28, 28-6, 40, 64, 65, 71, 74, 85, 125) (166 miles @ $6.5K/mile)	1079		
2021 (FL10, 35, 39, 49, 64, 65, 69, 78, 83, 84, 99, 104) (139 miles @ $6.5K/mile)		904	
2022 (FL10, 14, 23, 26, 41, 42, 48, 52, 66, 67, 68, 88) (145.6 miles @ $6.5 K/mile)			946
Reports			
No additional cost under current contract			
ACCDA			
Pre-Assessment			
2020 (FL19, 23, 28, 71, 74, 125) (6.69 HCA miles; Fixed)	12		
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; Fixed)		13	
2022 (FL10, 14, 41, 42, 48, 52, 88) (12.67 HCA miles; Fixed)			12
Indirect Inspections			
2020 (FL19, 23, 26, 28, 71, 74, 125) (7.66 HCA miles; @ $18.4 K/mile)	141		
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; @ $18.4k/mile)		36	
2022 (FL10, 14, 41, 42, 48, 52, 88) (12.67 HCA miles; @ $18.4 K/mile)			233
Direct Examinations			
2019 (FL21, 51, 29, 70) (2 excavations @ $34.5 K ea.)	69		
2020 (FL19, 23, 28, 71, 74, 125) (2 excavations @ $34.5 K ea.)		69	
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (2 excavations @ 34.5 K ea.)			69
Post Assessment			
2019 (FL21, 51, 29, 70) (14.2 HCA Miles; 2.2 Distribution IM Miles; 1.2 Additional; Fixed)	9		
2020 (FL19, 23, 28, 71, 74, 125) (6.69 HCA miles; Fixed)		11	
2021 (FL64, 65, 66, 68, 69, 83, 84, 99) (1.94 HCA miles; Fixed)			13
ICDA			
ICDA is complete, no longer required (refer to the on-going DEU Internal Corrosion Plan).			
Inline Inspection			
2018 Excavations/ Validations Digs/ Remediation (6 excavations @ 34.5 K ea)	207		
2019 Excavations/ Validations Digs/ Remediation (7 excavations @ 34.5 K ea)	241.5		
2020 (FL064/FL065)	500		
2020 (FL065)	500		
2020 (FL071)	250		
2020 (FL026)	250		
2020 Excavations/ Validations Digs/ Remediation (16 excavations @ 34.5 K ea)		552	
2021 (FL064)		500	
2021 (FL065/FL066)		500	
2021 (FL028-6)		500	
2021 Excavations/ Validations Digs/ Remediation (8 excavations @ 34.5 K ea)		138	138
2022 (FL066, FL067, FL068)			500
2022 (FL023)			500
2022 (FL010)			500
2022 Excavations/ Validations Digs/ Remediation (16 excavations @ 33 K ea)			276
Direct Examination (Spans and Vaults)			
2020 - Vaults (7 @ 3.5 K/ vault)	31.5		
2020 - Spans (2 @ 75 K/ span)	75		
2020 - Spans Reassessment (5 @ 10 K/ span)	10		
2021 - Vaults (3 @ 3.5 K/ vault)		10.5	
2021 - Spans (4 @ 75 K/ span)		300	
2021 - Spans Reassessment (3 @ 10 K/ span)		30	
2022 - Vaults (12 @ 3.5 K/ vault)			42
2022 - Spans (2 @ 75 K/ span)			150

Transmission Integrity Management Costs

Activity	2020	2021	2022
Pressure Test Assessment			
2020 - 0 pipeline segments @ $150,000/segment			
2021 - 2 pipeline segments @ $150,000/segment		300	
2022 - 2 pipeline segments @ $150,000/segment			300
Material Verification			
2020 - (FL014)	45		
2021 - (FL021)		15	
MAOP Verification MAOP, for MAOP established in accordance with §192.619(c)			
2020 - HYDRO Test (FL011, 13, 21, 35, 46, 50)	450		
2020 - Nitrogen Test (FL011, 13, 21, 35, 46, 50)	550		
2021 - HYDRO Test (FL004, 21)		600	
2021 - Nitrogen Test (FL021)		500	
Excavation Standby			
5 employees (2080 hrs x 5 x $100.00/hr * 90% standby work)	728	728	728
3 contractors (312 days * 3 * $580/day * 60% standby work)	543	543	543
Additional Leak Survey			
3 employees (2,080 hrs x 3 x $45/hr)	281	281	281
Additional Cathodic Protection Survey			
2 employees (2,080 hrs x 3 x $60/hr)	250	250	250
Administration			
Project Coordination (5 employees (2080 hrs x 5 x $60.00/hr))	624	624	624
Data Integration Specialists (2 employees (2080 hrs x 2 x $60/hr))	250	250	250
Construstion Records Tech (2080 x $45/hr)	94	94	94
Supervisor (2080 hrs x $65/hr)	135	135	135
4 x Engineer (2080 hrs x $60/hr)	500	500	500
IM Engineer - Engineer Tech (1 employee (2080 hrs @ $ 40/hr))	94	94	94
Damage Prevention Tech (3 employees 2080 hrs x $45/hr)	281	281	281
Training (IM and Engineering personnel)	15	35	35
Consultant - 3rd Party Review Plan		60	
Transmission Integrity Management Total ($ Thousands)	8,960	9,560	8,480

Distribution Integrity Management Costs

Activity	2020	2021	2022
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
Additional Leak Survey (Performed internal in 2018)	0	0	0
Damage Prevention (IHP Standby)	1,323	1,323	1,323
Meter Paints	281	281	281
2020 (FL110, 98) (6 excavations @ 5 K ea.) (Internal Crews Utilized)	30		
Administration			
Consultant - 3rd Party Plan Review		45	
Distribution Integrity Management Total ($ Thousands)	1,719	1,734	1,689

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.

In 2010, the EPA adopted Greenhouse Gas (GHG) Reporting Regulations requiring the measurement and reporting of carbon dioxide equivalent (CO2e) emissions emitted from combustion at large facilities (emitting more than 25,000 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 2019, the Company reported a total of 6.9 million metric tons of CO2e emissions in Utah and 255 thousand metric tons of CO2e emissions in Wyoming. The Company also reported approximately 3,500 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 five years.

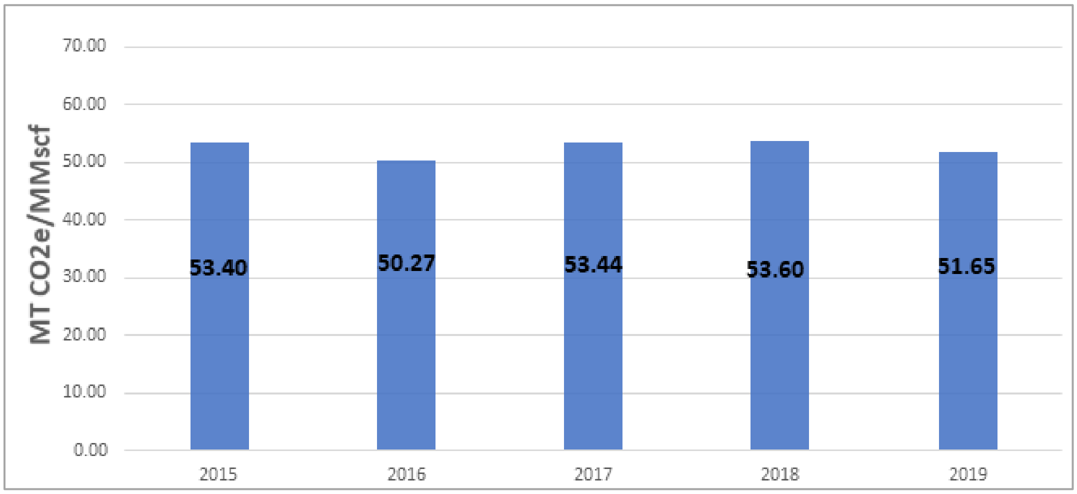


Figure 7.1: Greenhouse Gas Intensity

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 more than 1.4 MMDth of natural gas in 2019 through the ThermWise program. The savings represents the equivalent of about 74,074 metric tons of CO2e or 16,003 passenger vehicles each driven for one year (calculated using EPA's GHG equivalencies calculator). Lifetime savings attributable to the ThermWise® program totals more than 423,280 metric tons of CO2e or the equivalent of about 91,447 passenger vehicles each driven for one year.

Additionally, in 2020, Dominion Energy announced that by 2050, it will achieve net zero greenhouse gas emissions across all of its electric and natural gas operations in all states where Dominion Energy and its subsidiaries do business. As discussed in the Sustainability section of this report, the Company is taking immediate action to reduce emissions and exploring new technologies to accelerate future emissions reductions.

PURCHASED GAS

LOCAL MARKET ENVIRONMENT

Local prices during the 2019 calendar year averaged $2.59 per Dth. This was lower than the 2018 average price of $2.63 per Dth, a decrease of $0.04 per Dth or about 1.5%. The 2018 and 2019 monthly index prices are provided in Table 8.1 below.

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

Month	2018	2019	Difference
Jan	$2.50	$4.22	$1.72
Feb	$2.80	$3.38	$0.58
Mar	$2.17	$3.77	$1.60
Apr	$1.85	$2.48	$0.63
May	$1.90	$1.88	($0.02)
Jun	$2.09	$1.89	($0.20)
Jul	$2.24	$1.92	($0.32)
Aug	$2.41	$2.01	($0.40)
Sep	$2.32	$1.81	($0.51)
Oct	$2.32	$2.01	($0.31)
Nov	$3.23	$2.32	($0.91)
Dec	$5.70	$3.44	($2.26)
Average	$2.63	$2.59	($0.04)

The local market price for natural gas during the 2019-2020 heating season (November-March) averaged $2.48 per Dth compared to an average price of $4.06 per Dth during the 2018-2019 heating season, a decrease of $1.49 or about 39%. 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	2018-2019	2019-2020	Difference
Nov	$3.23	$2.32	($0.91)
Dec	$5.70	$3.44	($2.26)
Jan	$4.22	$3.16	($1.06)
Feb	$3.38	$1.95	($1.43)
Mar	$3.77	$1.54	($2.23)
Average	$4.06	$2.48	($1.58)

April 2020 PIRA Energy Group (PIRA) and IHS Energy (IHS) forecasts of Rockies indices reflect an average price of approximately $1.42 per Dth through October 2020. Prices for the 2020-2021 heating season are forecasted to be approximately $2.14 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 (approximately 55-65%) 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 24, 2020, the Company sent its RFP to 60 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 required all proposals to have language ensuring creditworthiness and language specifying the minimum advance notice before nomination deadlines for gas flow.

Responses to the purchased-gas RFP were due on March 6, 2020. The Company received proposals for 111 gas supply packages from 11 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 373,000 Dth/D, down from the 380,000 Dth/D offered last year. Peaking supplies offered on the DEQP system totaled 165,000 Dth/D, up from the 130,000 Dth/D offered last year. Peaking supplies offered on KRGT totaled 180,000 Dth/D, down from last year's level of 390,000 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.[34] The Company must identify the pricing mechanisms utilized for each package and 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 111 supply packages.

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

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 2019 - March 2020 time period, the Company did not hedge the price of any of its baseload purchased gas supplies because of the forecasted level of cost-of-service gas in the supply portfolio. Given the current forecast for cost-of-service production, the Company does not plan to enter into any fixed-price agreements designed to hedge the price of its baseload purchased gas supplies during the next IRP year, but may do so in the future.

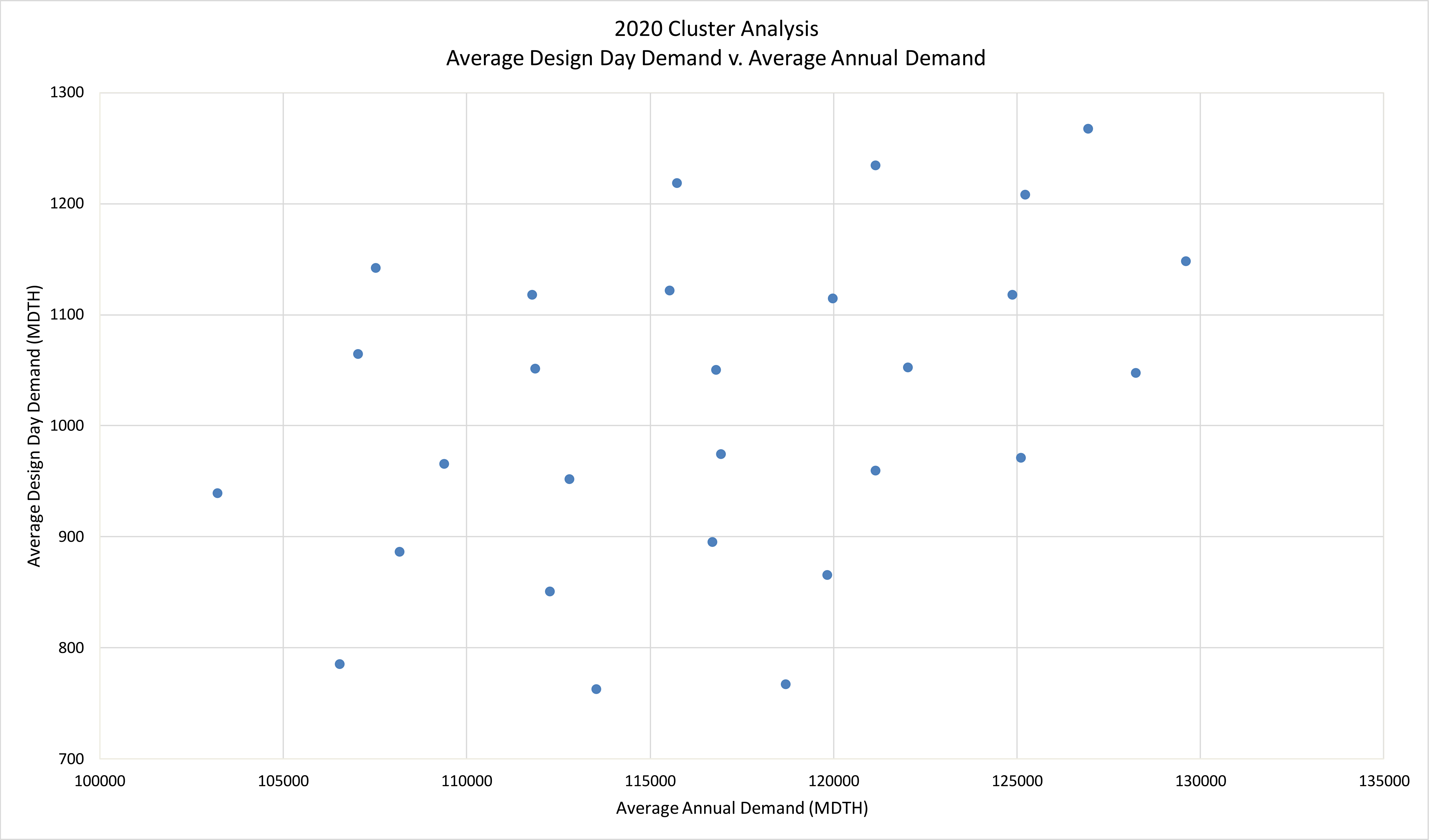

2020 Cluster Analysis
Average Design Day Demand v. Average Annual Demand
1300
1200
1100
1000
900
800
700
Average Design Day Demand (MDTH)
100000
105000
110000
115000
120000
125000
130000
135000
Average Annual Demand (MDTH)

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, which historically has been lower-priced than market-based sources. 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 this 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 7.64% until August 1st, 2020, when the rate will be changed to 7.19% due to a change in 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 2019, Wexpro produced 71.8 MMDth of cost-of-service supplies measured at the wellhead, down from the 73.3MMDth level produced during calendar year 2017. 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 2017 to 2018, the total costs, net of credits and overriding royalties, for cost-of-service production declined by approximately 7.6% (the fifth consecutive year of declining net costs). This decrease was caused primarily by a 12.6% reduction in the Wexpro operating service fee. This was partially offset by two cost components. First, the cumulative credits decreased by 40%. Second, Wexpro's royalty costs increased by approximately 15.6%. 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 116 categories of cost-of-service production. Last year, it modeled 123 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.[35] 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 1,635 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

[35] 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.

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 multiplicity 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 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 2019 and for the first two months of 2020. The Company has been taking recoupment in the Canyon Creek, Pinedale and Moxa Arch areas for the entire January 2019 through February 2020 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, 2019, 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 0.5 Bcf.[36] By way of comparison, the total net producer imbalance level for December 31, 2018, was a negative 0.7 Bcf. The Wexpro Agreement Hydrocarbon Monitor reviews producer imbalances as part of its responsibilities. In a recent audit report, the Hydrocarbon Monitor did not express any concerns about the total producer imbalance levels.[37]

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

[36] A positive imbalance means volumes are owed to other parties.
[37] Wexpro Hydrocarbon Auditor Review, Evans Consulting Company, May 2019.

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.[38]

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 are required to "stay on a well pad until the well pad is completely drilled out".[39] 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 2020, Wexpro plans on completing to production, approximately 13.2 net wells with a capital budget for those wells of approximately $19 million.[40] Assuming market prices don't deviate dramatically from current expectations for the years 2020 through 2024, the total planned net wells are approximately 14, 18, 18, 18, and 17 respectively, with total annual investments in the range of $18 to $25 million. Given the uncertainties in the financial and natural gas markets, these longer-term estimates could vary. Drilling activity through the end of 2020 will focus on the Trail Field in the Vermillion Basin.

Wexpro II drilling plans for 2020 through 2024, broken out from the total net wells stated above, are approximately 9, 8, 8, 9, and 7 net wells respectively to be drilled with total annual capital costs ranging from approximately $10 million to $15 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.

Based on the 2019 forecast for production provided by Wexpro and normal weather, the model determined that there should be approximately 430 MDth of cost-of-service production shut-in for June 2019 through October 2019. As shown in Table 9.1, the Company did not shut in any gas June 2019 to October 2019. The Company was able to avoid shut ins to the

[38] 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.
[39] Ibid., Summary, Page 20.
[40] "Net wells" are the summation of working interests (total and partial ownership).

availability of a short-term storage contract which the SENDOUT model determined to be more cost effective then shutting in the production.

Table 9.1: 2019 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	0 Dth	0 Dth	430,170 Dth	0 Dth	0 Dth	**430,170 Dth**
Actual Shut-in Production	0 Dth	0Dth	0Dth	0 Dth	0Dth	**0 Dth**

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.

Table 9.2: 2020 Production Shut-ins

	June	July	August	September	October	Total
Forecasted Shut-in Production	184,608 Dth (6,153 Dth/day)	189,367 Dth (6,108 Dth/day)	187,993 Dth (6,064 Dth/day)	180,603Dth (6,020 Dth/day)	185,268Dth (5,976 Dth/day)	**927,839 Dth (6,064 Dth/day)**

Exhibit 9.1

Recoupment Nominations (Dth per month by Field) Dominion Energy					
	Moxa	Butcherknife	Church Buttes	Canyon Creek	Pinedale
Jan-19	3,816	0	0	16,419	4,574
Feb-19	1,115	0	0	14,286	3,821
Mar-19	4,223	0	0	14,238	2,202
Apr-19	3,478	0	0	13,918	2,154
May-19	3,948	0	0	14,637	2,676
Jun-19	4,076	0	0	13,751	2,593
Jul-19	4,147	0	0	14,000	2,534
Aug-19	4,512	0	0	13,797	2,526
Sep-19	4,293	0	0	13,508	2,714
Oct-19	4,058	0	0	8,610	3,097
Nov-19	4,305	0	0	14,244	3,030
Dec-19	3,743	0	0	15,014	3,664
Jan-20	3,552	0	0	13,876	3,542
Feb-20	2,876	0	0	12,275	3,583
Total	52,142	0	0	192,572	42,710

Recoupment Nominations (Dth per month by Field) Other Parties				
	Canyon Creek	Hiawatha Deep	Moxa	Pinedale
Jan-19	0	0	3,223	13,576
Feb-19	0	0	3,231	13,461
Mar-19	0	0	2,992	14,860
Apr-19	0	0	3,481	14,709
May-19	0	1,736	8,325	14,320
Jun-19	0	0	13,199	13,912
Jul-19	0	244	13,272	13,953
Aug-19	0	726	13,334	13,228
Sep-19	0	702	14,772	12,975
Oct-19	0	726	14,799	12,583
Nov-19	0	702	3,664	12,138
Dec-19	0	726	3,694	11,282
Jan-20	0	726	3,513	10,875
Feb-20	0	712	3,319	10,660
Total	0	7,000	104,817	182,533

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 include the #163 contract, commonly known as the System Wide Gathering Agreement (SWGA), the #4485 contract, the #2091 contract, and the #163 contract.

In 2020, Wexpro negotiated the purchase of a portion of the gathering facilities from Marathon. The sale of these facilities closed on March 1, 2020. As a result of this transaction, Wexpro will take over operations for a portion of the gathering and processing services. The cost for these services will be included in the operator service fee. The transfer of assets will also result in a reduction of costs under the SWGA. The Company expects that overall costs to customers will decrease.

The Company includes cost data for the gathering and processing functions each year in the SENDOUT modeling process. The Company used the rates from the amended SWGA in this year's 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).

Dominion Energy Questar Pipeline

The Company has three 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), and (3) Contract #2361 for 30,000 Dth/D. The Company contracted for an additional 100,000 Dth/D under Contract #241 as part of the Hyrum expansion project, bringing the total permitted volumes under Contract #241 to 898,902 Dth/D. This additional 100,000 Dth/D will continue to be included in Contract #241 through June 30, 2027. This contract provides capacity from multiple receipt points, including Clay Basin, Vermillion Plant, Blacks Fork Plant, Emigrant Trail Plant, Kanda, and interconnects with Northwest Pipeline, Overthrust Pipeline, and White River Hub.

Contract #2945 entered into year-to-year evergreen on March 31, 2018, and renewed for another year under this evergreen provision again in March 2019. This contract provides seasonal capacity with valuable receipt points. It also provides the summertime capacity necessary to transport supplies to the Spire Storage West (formerly Ryckman Creek) storage facility for injections. The Company is currently negotiating to extend this contract for a 5-10 year term.

Contract #2361 expires on November 1, 2021. This contract provides capacity to serve the Company’s southern HP system.

No-Notice Transportation Service

DEQP provides No-Notice Transportation (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 357 days during the 2019-2020 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 217 days during the 2019-2020 IRP year to reduce nominations to the city gate by reducing withdrawals or increasing injection into storage. The Company used NNT 140 days to provide for additional storage withdrawal or reduce injections. The maximum daily use of NNT to reduce supply to the city gate was 115.511 Dth with an average daily supply reduction to the city gate of 28,560 Dth. The maximum daily supply increase to the city gates was 202,140 Dth with an average daily increase to the city gate of 40,948 Dth. The NNT usage for the 2019-2020 IRP year is shown in Figure 10.1 below.

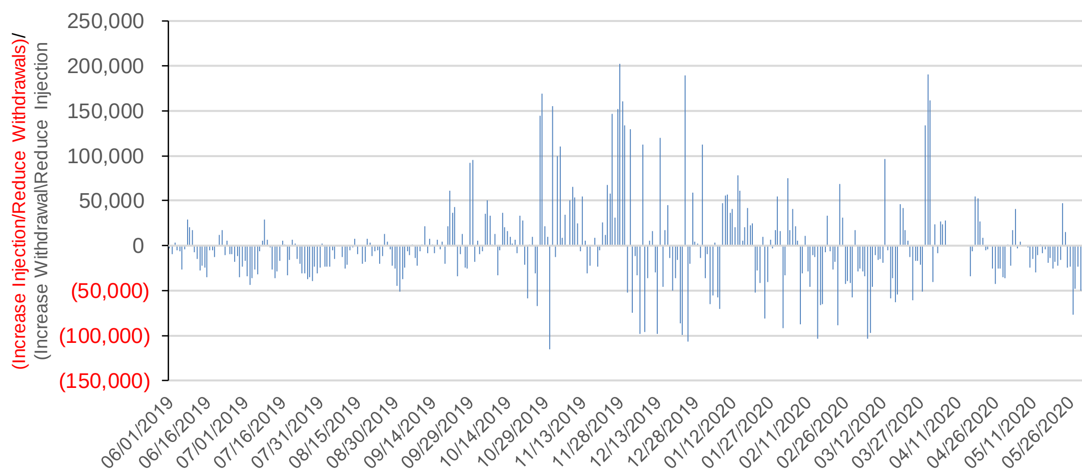


Figure 10.1: NNT Usage – 2019-2020 IRP Year

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.

Kern River Gas Transmission

The Company has two existing transportation contracts with KRGT: (1) Contract #20029 for 83,000 Dth/D, and (2) Contract #1829 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.

The current term expiration for Contract #1829 is November 1, 2020. That contract required the Company to provide notice of intent to renew to KRGT one year prior to expiration. Prior to the October 31, 2019, the Company notified KRGT that it would be renewing this contract for 10 years at the Alternate Period 2 rates.

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, 2025. 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.

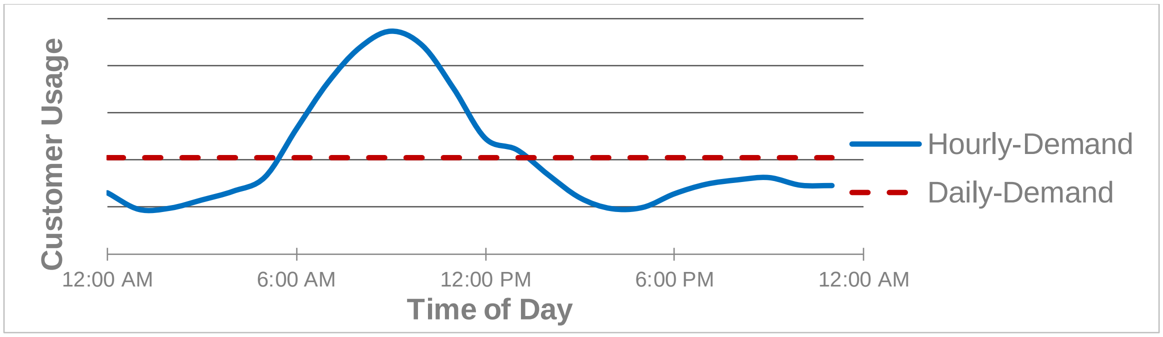


Figure 10.2: Hourly vs. Daily Demand

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 318,068 Dth/day during the 2020-2021 heating season to 344,438 Dth/day during the 2029-2030 heating season.

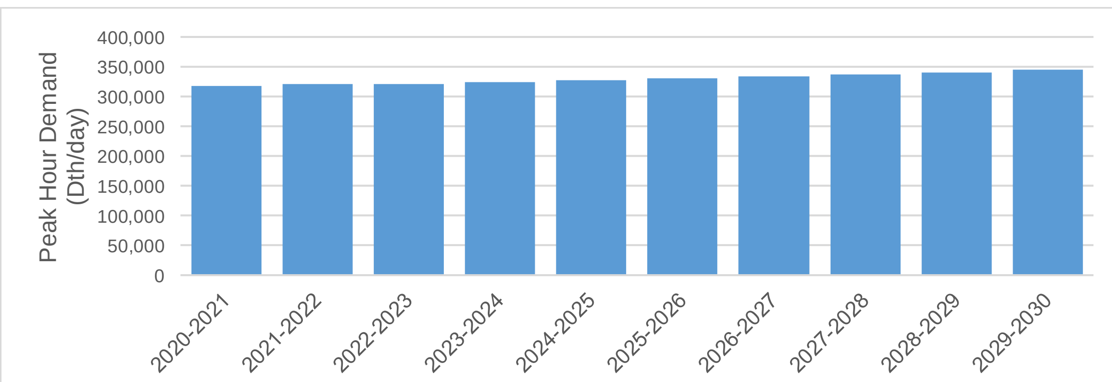


Figure 10.3: Peak-Hour Demand Requirements above Firm Capacity

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 again review available options for meeting peak-hour demand requirements in order to determine the most cost-effective and reliable solution for the 2020-2021 heating season

Kern River Gas Transmission

The Company had a contract with KRGT for 25,002 Dth of Firm Peaking Service for November 15, 2018, to February 14, 2019, and 28,752 Dth of Firm Peaking Service from November 15, 2019, to February 14, 2020. The KRGT Firm Peaking Service for 25,002 Dth allows the Company to flow 4,167 Dth/hr during the 6 peak hours (25,000/6 = 4,167). In order to get the same 4,167 Dth/hr flow on a standard transportation capacity contract, the contract would need to be for 100,008 Dth/day (4,167 x 24 = 100,008). 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. The Company will work with KRGT to determine if a contract with similar terms will be available going forward prior to the upcoming heating season.

Dominion Energy Questar Pipeline

The Company had Peak Hour contracts in place with DEQP for the 2017-2018 heating season which provided 250,000 Dth/day of maximum flow rate during peak hours. Specifically, these contracts allowed for 190,000 Dth/day of maximum flow rate with delivery to MAP 164 and 60,000 Dth/day of maximum flow rate to other DEUWI delivery points on the DEQP system. In November 2018, the Company renewed the contract with DEQP for Firm Peaking Service for November 15, 2018, to February 14, 2019, and November 15, 2019, to February 14, 2020, respectively. The extensions were 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 the 2018-2019 heating season, and for 142,000 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 the 2019-2020 heating season. The Company will work with DEQP to determine if a contract with similar terms will be available going forward prior to the upcoming heating season..

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. The Company will evaluate Contract #988 prior to its expiration to determine if it is cost effective and/or operationally necessary to extend the contract.

In 2019, the Company also contracted for 775,000 Dth of Park and Load (PAL-1) capacity at Clay Basin for July 1, 2019, through January 31, 2020. This provided additional injection capacity for the summer of 2019. The Company used the SENDOUT model to determine it was cost effective to store this extra gas until the winter rather than to shut in production. The 775,000 Dth of capacity was transferred into the FSS contracts in December of 2019.

Between October 1, 2019, and April 30, 2020, the Company utilized the Clay Basin storage facility to provide more than 12,133 MDth of supply to meet customer demand. This included 56 days with withdrawals that exceeded 100 MDth and 19 days with withdrawals that exceeded 150 MDth. Clay Basin also provided operational flexibility by providing 61 days of injection during this period.

Leroy and Coalville Storage

The Company as 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. Both of these contracts have a current term expiration of August 31, 2023. Since 2000, the operation of the Leroy and Coalville storage facilities have been modified to provide more flexibility and enhance storage efficiency. 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. This contract also has a current term expiration of August 31, 2023.

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.

2019-2020 Aquifer Usage

The Company used the Aquifers to provide supply during periods of cold temperatures in 2019-2020 heating season in October, December, January, and February. All of the Aquifer's deliverability will be required to provide 135 MDth of supply on a Design Day.

In order to continue to provide operational flexibility during the Clay Basin testing period in April 2020, the Company withdrew inventory from the Aquifers in March. The Company adjusted the inventory in the Aquifers in order to provide maximum flexibility during the Clay Basin test in April.

The Company was able to utilize the Aquifers for both injection and withdrawal during this time period as shown in Figure 10.4 below. This flexibility is critical to operations when Clay Basin is not available.

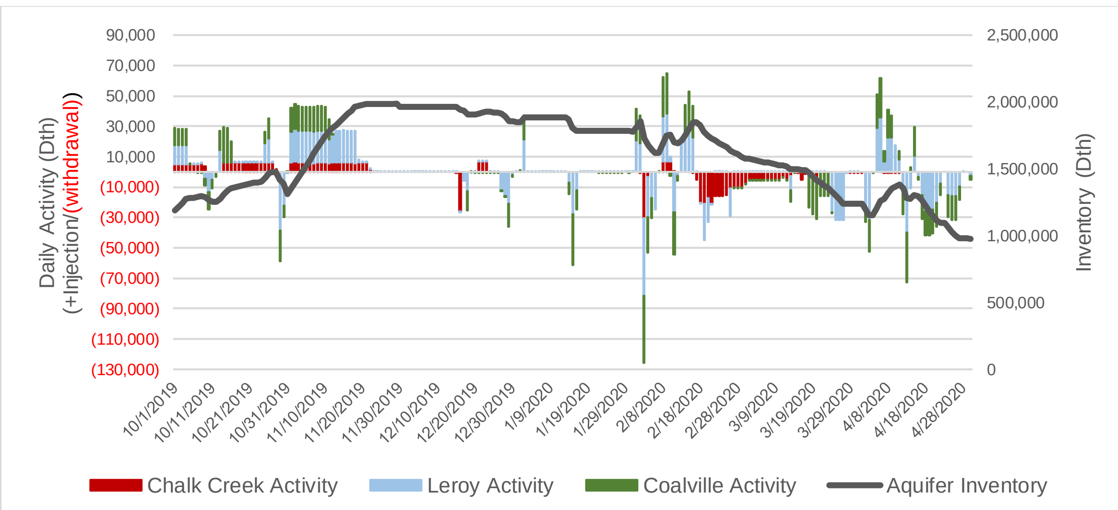


Figure 10.4: Aquifer Usage 2019-2020 Heating Season (Oct 2019 through April 2020)

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. This contract has a current term expiration of March 31, 2021.

On December 27, 2017, Belle Butte LLC, an indirect, wholly-owned subsidiary of Spire Inc., acquired a controlling interest in Ryckman Creek Resources, LLC ("Ryckman Creek"). Ryckman Creek subsequently changed its name to Spire Storage West LLC (Spire Storage West). Since taking ownership of the facility, management of Spire Storage West has made a number of changes. One significant change is that the former management of the facility reported the total working gas capacity at 35 Bcf. Management of Spire Storage West will report the working gas capacity as 19 Bcf until it can confirm additional working gas capacity is available. [41]

Another significant change occurred in May, 2018, when Belle Butte II, LLC, another indirect, wholly owned subsidiary of Spire, acquired all of the membership interests in Clear Creek, resulting in Spire Storage West and Clear Creek becoming affiliates. Clear Creek owns and operates interstate natural gas storage facilities located in Uinta County, Wyoming. Since these two facilities are only about 6 miles apart, and they serve the same markets, Spire Storage West has combined the two companies and operate the storage facilities as one integrated facility called Spire Storage West. The combined working gas capacity of the facility is 39 Bcf with 385 MMcf/D of maximum injection capability and 530 MMcf/D of maximum withdrawal capacity. [42]

Between October 1, 2019, and April 30, 2020, the Company utilized the Spire Storage West storage facility to provide 2,128,625 MDth of supply to meet customer demand. This included 127 days of withdrawals, usually at the contract maximum withdrawal rate of 16.6 MDth. Spire Storage West also supplied operational flexibility by providing 42 days of injection during this period. During this period there were no operational issues at the facility that resulted in an inability to perform.

The Company will evaluate the Spire Storage West contract prior to its expiration to determine if it is cost effective and/or operationally necessary to extend the contract.

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 3.7 Bcf.

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

[41] Letter from Spire Storage West to FERC Spire Storage West LLC – Notice Regarding Storage Capacity Development, dated July 26, 2018, Docket No. CP11-24-000.
[42] Spire Storage West 166 FERC ¶ 62,038 FEDERAL ENERGY REGULATORY COMMISSION

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.[43] 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 2019. The daily averages for 2019 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 the a biomethane supplier to take deliveries into the DEUWI system.

[43] 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.

System Diagram 2020

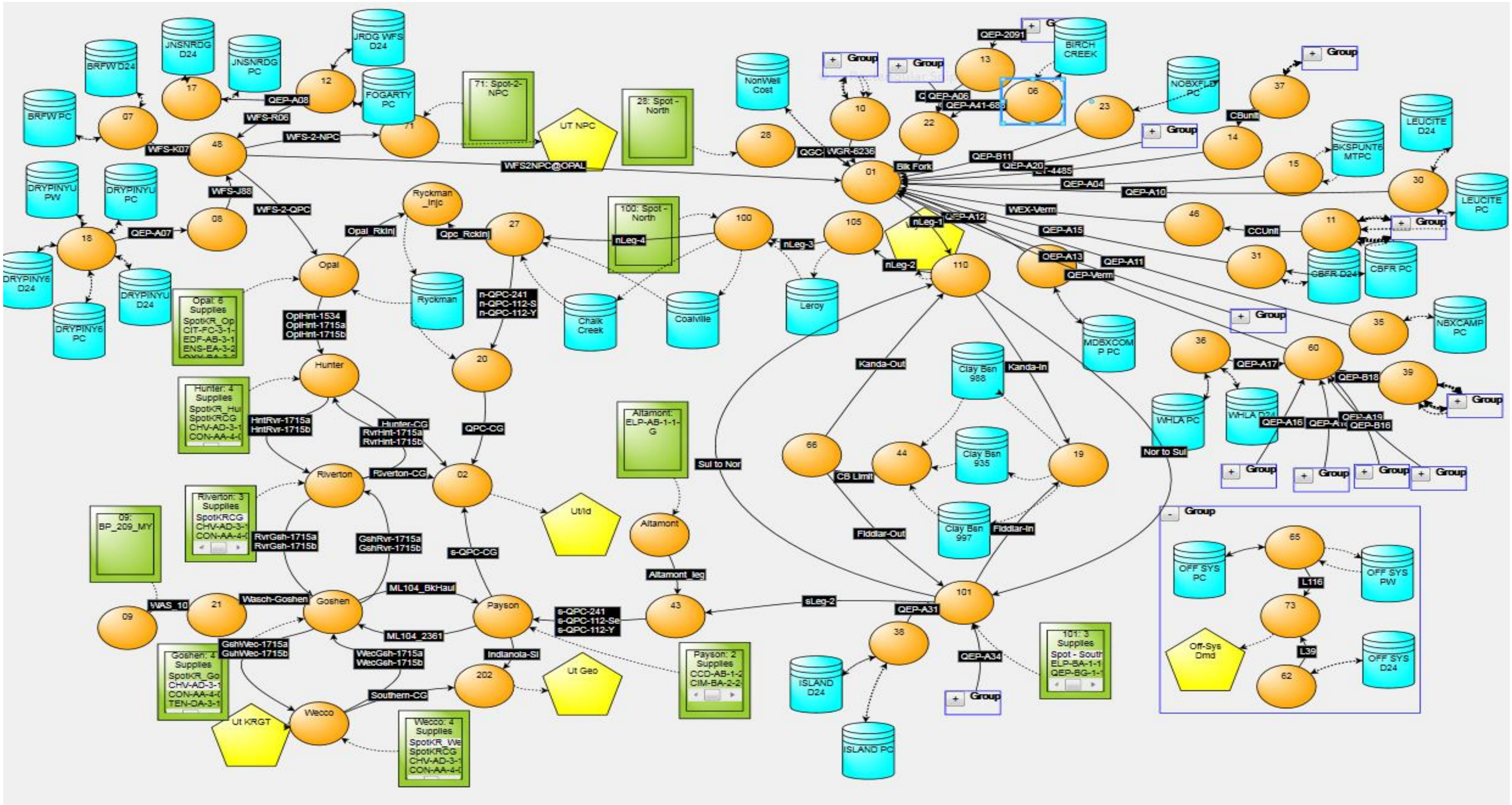


Exhibit 10.1

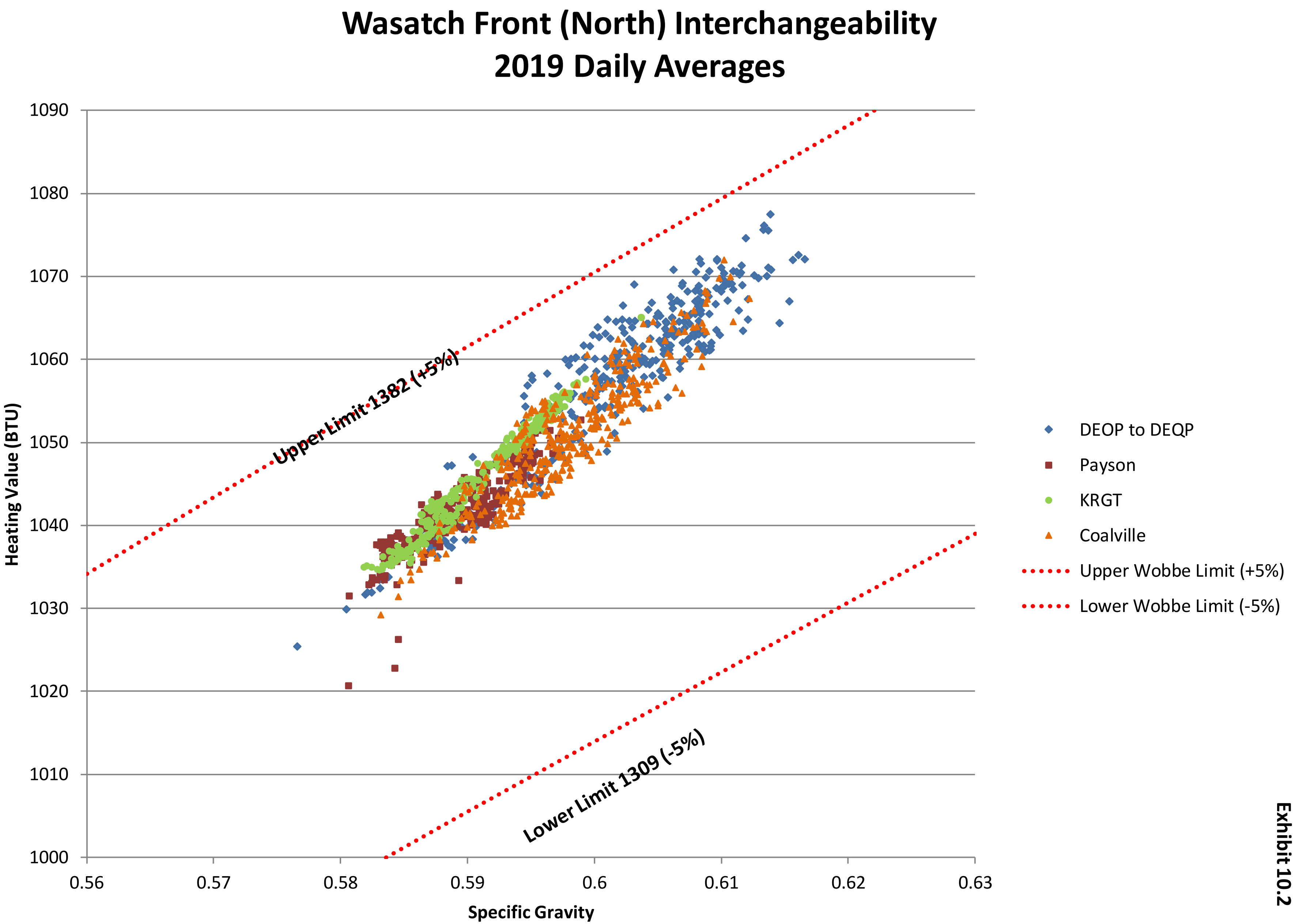

Wasatch Front (North) Interchangeability
2019 Daily Averages
Heating Value (BTU)
Specific Gravity
1090
1080
1070
1060
1050
1040
1030
1020
1010
1000
0.56
0.57
0.58
0.59
0.6
0.61
0.62
0.63
Upper Limit 1382 (+5%)
Lower Limit 1309 (-5%)
DEOP to DEQP
Payson
KRGT
Coalville
Upper Wobbe Limit (+5%)
Lower Wobbe Limit (-5%)

Exhibit 10.2

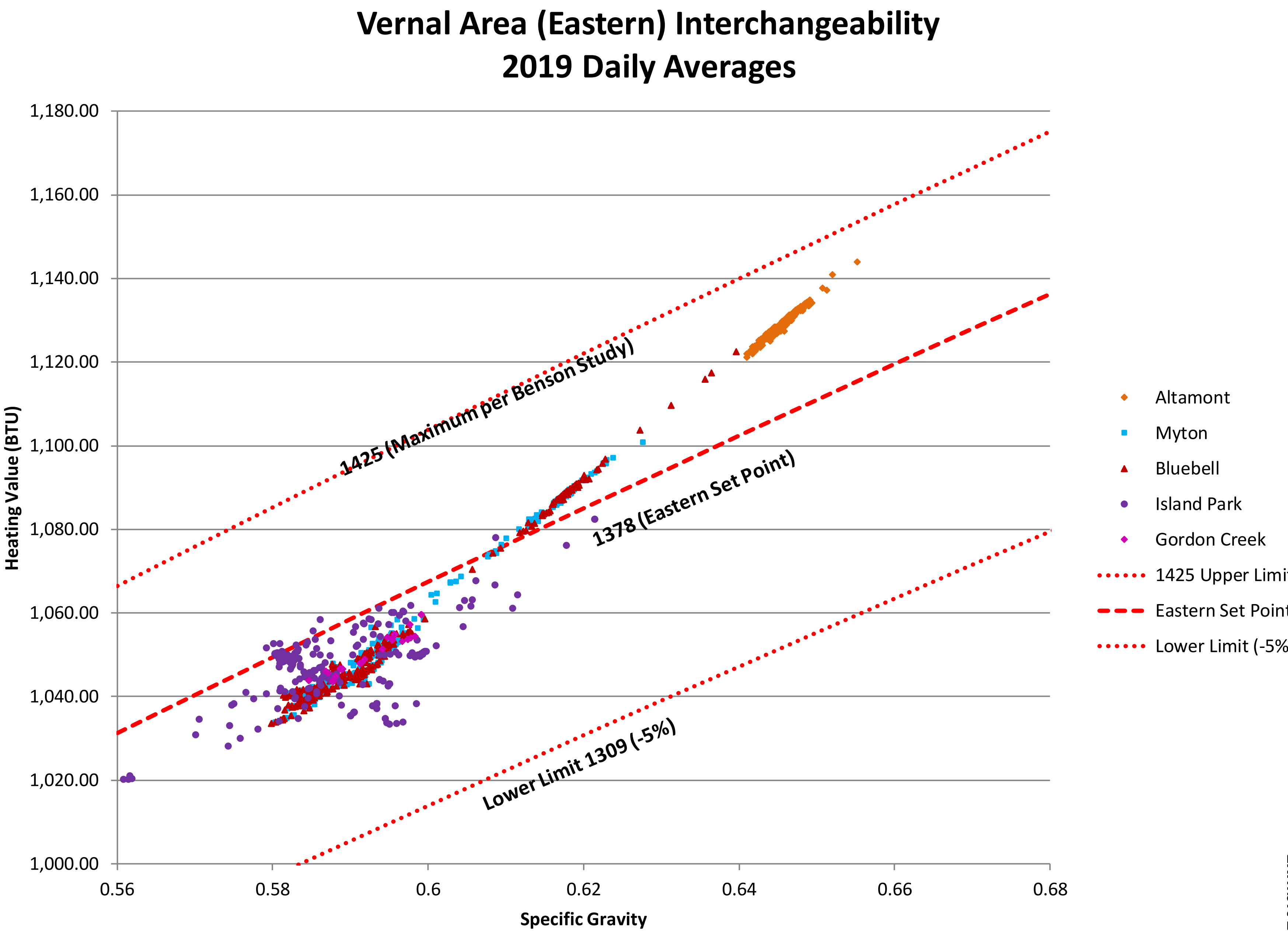
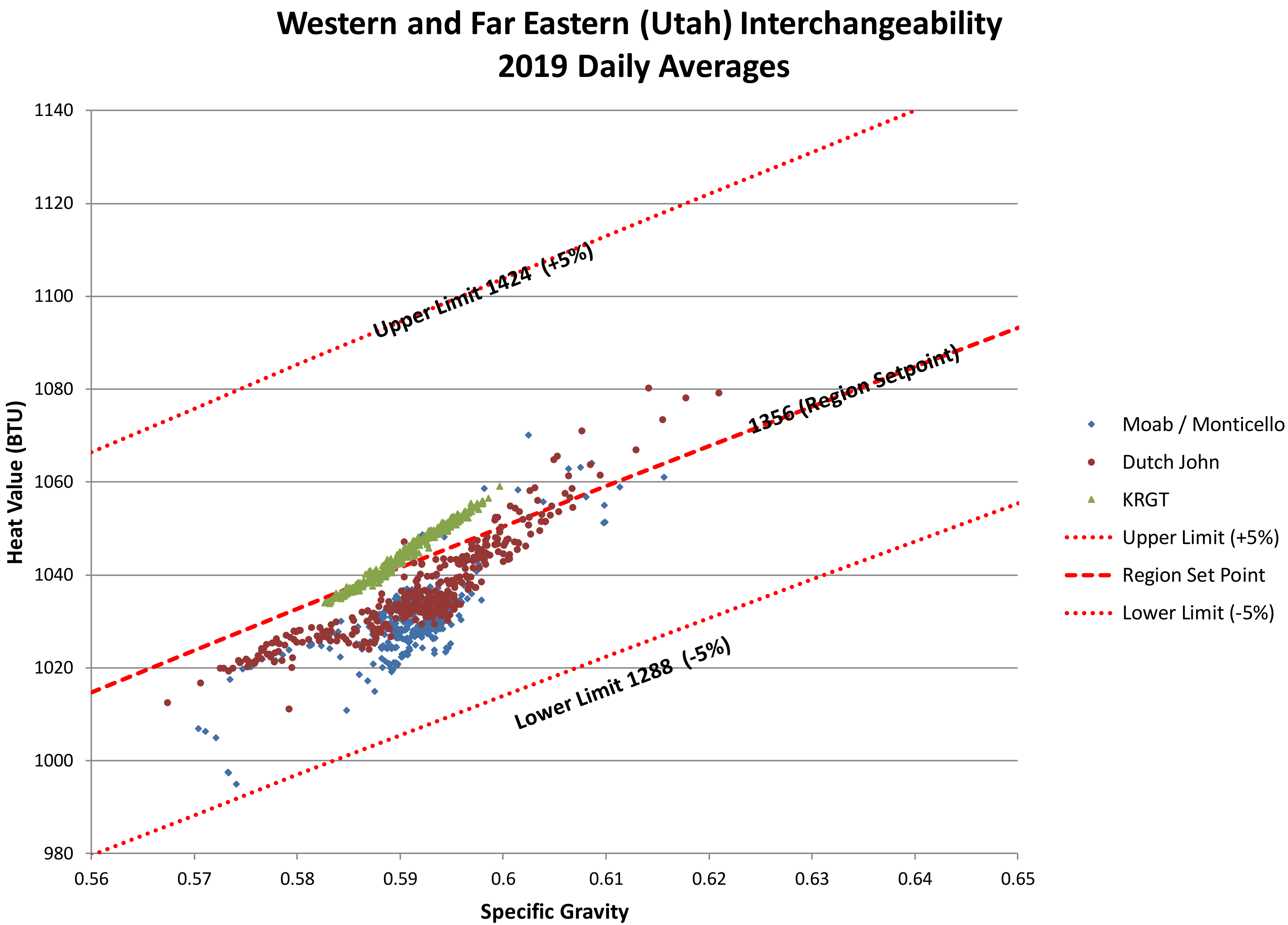

Vernal Area (Eastern) Interchangeability
2019 Daily Averages
Heating Value (BTU)
1,180.00
1,160.00
1,140.00
1,120.00
1,100.00
1,080.00
1,060.00
1,040.00
1,020.00
1,000.00
0.56
0.58
0.6
0.62
0.64
0.66
0.68
Specific Gravity
1425 (Maximum per Benson Study)
1378 (Eastern Set Point)
Lower Limit 1309 (-5%)
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
2019 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 2020

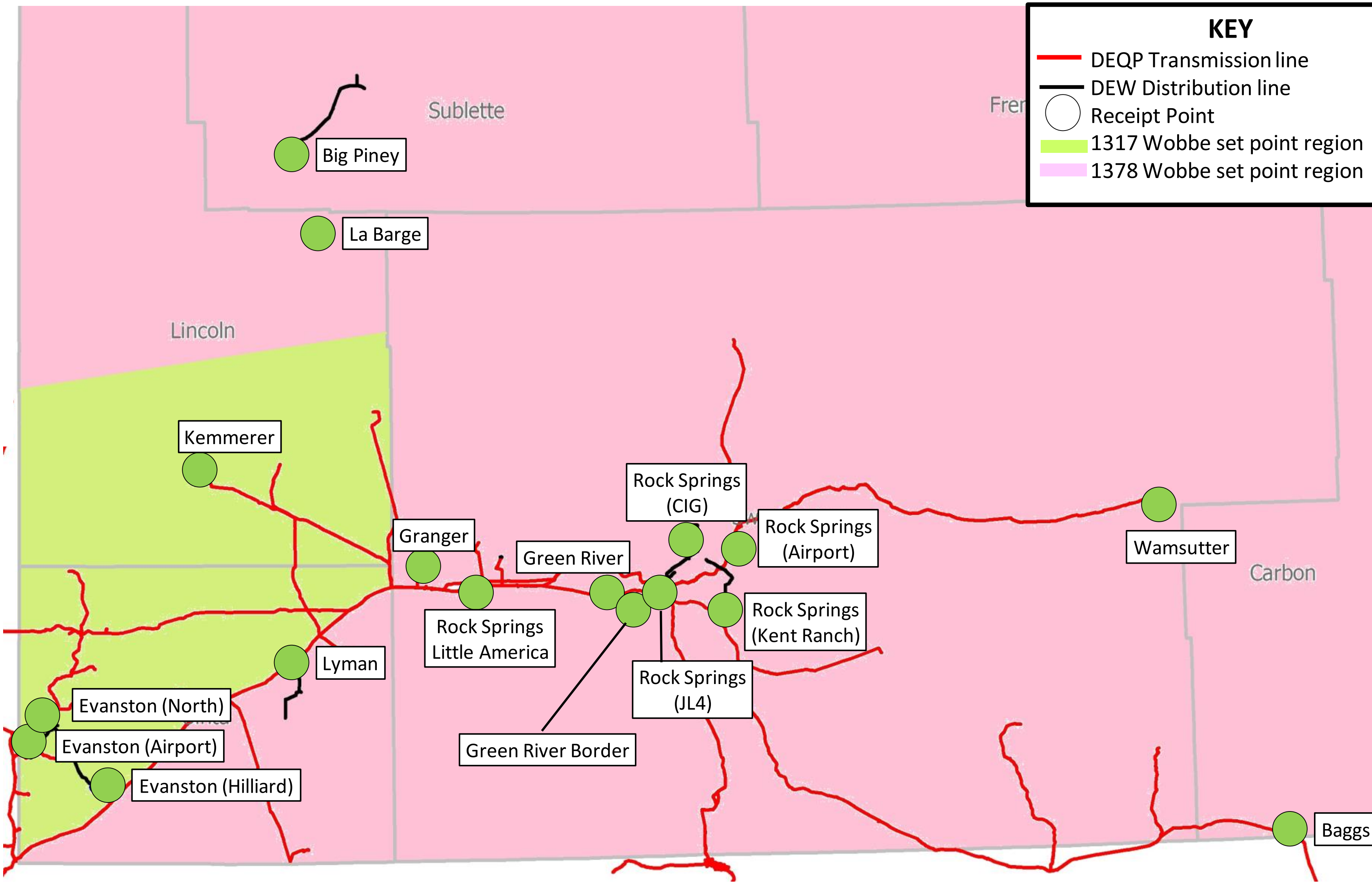


Exhibit 10.5

SUSTAINABILITY

> ***"Dominion Energy already has made important progress on emissions. This new commitment sets an even higher bar that I am confident we can - and will - reach. Net zero emissions will be good for all of our stakeholders - for our customers, communities, employees and investors."***
>
> ***-Thomas F. Farrell, II***
> ***Chief Executive Officer***

DELIVERING CLEAN ENERGY

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 new 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 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[44]. Dominion Energy in Utah, Wyoming, and Idaho will play a key role in meeting these goals.

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

SUSTAINABILITY IN THE WEST

Methane Reduction Program

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

- Replacing Aging Infrastructure – continuing the ongoing program of replacing parts of Dominion Energy'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.

- Reducing Emissions from Pigging Projects utilizing Zero Emission Vacuum & Compressor (ZEVAC) that will significantly reduce emissions from pigging operations.

- Reducing Pressure During Maintenance Prior to Blow Down – continuing the practice of reducing pressure in gas mains to the lowest possible pressure before completely blowing a line down in anticipation of scheduled maintenance work. This minimizes the amount of gas that is blown down to the atmosphere. The Company records or estimates the pressure in order to calculate the amount of gas that it blows down. Additionally, the Company is testing portable compressors that may be used to remove gas from the pipe prior to maintenance, and thereby further reduce the need for blowdowns.

- Meter Purge Procedure – utilizing a modified purge procedure used during meter turn on that reduces the amount of methane released to the atmosphere.

- Leak Detection and Repair Program – utilizing a leak detection and repair program focused on regulator stations, with more than 100 stations surveyed annually.

- Pressure Monitoring at Regulator Stations – adding remote pressure monitoring at district regulator stations that takes the place of token relief valves and eliminates the potential release of gas.

- 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. as the Company has also supported the institution of civil penalties for excavators who use unsafe excavation practices, as allowed under the current 811 laws.

- Excess Flow Valves – installing Excess Flow Valves (EFVs). Beginning in 2006, the Company proactively began installing EFVs on all new and replaced service lines to single family residences and continues to do so today. In 2008, the PHMSA promulgated a rule requiring installation on all new and replaced service lines to single family residences. Beginning in 2013, the Company proactively began installing EFVs on service lines 2-inches and smaller with usage of 5,000 cfh and under. In 2017, PHMSA enacted a rule requiring, among other things, the installation of EFVs on all services 1,000 cfh and smaller. (49 CFR 192.383 and 49 CFR 192.385). PHMSA regulations also require operators like Dominion Energy to notify all customers in writing or electronically of the availability of EFVS. On April 6, 2017, the Company issued a letter to the Utah and Wyoming Commissions explaining its compliance with the new PHMSA rule related for excess flow valves. On April 7, 2017, the Company began publishing such notice on its website and it included further notice in its Gaslight News in the May, 2017 issue.

- Leak Survey 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.

- Response Time to Leak Calls – continuing to evaluate ways to reduce the response time to gas leak calls through efficiencies in how employees are dispatched to these gas leaks. The Company has implemented a Global Positioning System (GPS) to allow dispatchers the ability to dispatch personnel based on their geographic location with respect to the leak.

- Leak Detection Equipment - utilizing advanced technologies for locating and identifying leaks. Examples include the remote methane leak detection (RMLD) and the Rover and SENSIT gas detector.

- 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. The Company 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 Dominion Energy 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. This funding would allow 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 work with the IIAC to identify projects that it could then propose under the STEP legislation.

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 Dominion Energy’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 will facilitate and support 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.

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. The Company expects to sell 3,000 Dth of RNG to GreenTherm™ customers in 2020.

Inclusion of RNG in Dominion Energy’s Natural Gas Supply Portfolio

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

Wexpro Sustainability Initiatives

Air Quality Initiatives

Beginning in 2019, all Wexpro-operated production unit burners, as well as tank burners, were lowered in BTU output to better match the demand of the declined production. Also, they are currently in the process of being 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.

ENERGY-EFFICIENCY PROGRAMS

UTAH ENERGY-EFFICIENCY RESULTS 2019

The Company's 2019 Commission-approved ThermWise® energy-efficiency programs and measures were similar to programs in 2018, but also included new measures, minor changes to qualifying equipment, and changes to rebate levels. ThermWise® results for 2019 were strong with participation for all of the programs exceeding 89% of original projections. Spending for the 2019 program year totaled $23.6 million or 92% of the $25.5 million Commission-approved ThermWise® budget. In total, rebate dollars accounted for nearly 76% of the total ThermWise® spending in 2019 (73% in 2019 budget) and resulted in annual natural gas savings of more than 900,000 Dth. Actual natural gas savings were nearly 92% of the amount projected in the Company's 2019 budget filing.

Utah ThermWise® Appliance Rebates

The Company continued this program in 2019 with the elimination of the 92% annual fuel utilization efficiency (AFUE) furnace as a rebate-eligible measure. The Company first began to offer a rebate for 92% AFUE furnaces in the 2011 program year (Docket No. 10-057-15). Prior to that time, rebates for furnaces had been set at an efficiency level of 90% AFUE or above. In the 2013 ThermWise® budget filing (Docket No. 12-057-14), the Company proposed eliminating the 92% AFUE furnace as a rebate-eligible measure and setting the minimum efficiency at 95% AFUE for future program years. This change was proposed by the Company in anticipation of a United States Department of Energy (DOE) promulgated rule requiring national minimum efficiency standards for furnaces to be set at 90% AFUE. However, DOE's proposed rule was never implemented, and the Company sought Commission approval to reintroduce the 92% AFUE furnace and establish a four-tiered furnace rebate structure (>92<95%, >95%, >95% with electrically commutated motor (ECM), and >98% with ECM) in the 2014 ThermWise® budget filing (Docket No. 13-057-14). In an effort to continue pushing efficiency standards forward, the Company permanently eliminated the 92% AFUE furnace as a rebate-eligible measure in 2019.

The Company also reduced the rebate for tankless water heaters by $50 and made minor changes to Tariff language by setting the definition for rebate-qualifying single-family residences at three or fewer, and multifamily at four or more residences. The reduction in the tankless water heater rebate from $350 to $300 is a result of the Company's 2018 market research that found a significant reduction in the incremental cost between the base level storage water heater and the high-efficient tankless models. These changes in Tariff language align the ThermWise® programs with the Company's internal definitions of single and multifamily properties and also with Rocky Mountain Power's (RMP) Wattsmart® programs.

The Company continued to perform outreach and marketing work in-house in 2019. Nexant provided technical assistance and continued to perform rebate processing work for this program in 2019.

Utah ThermWise® Builder Rebates

In 2019, the Company added Tariff language to the Builder Program to set the definition for rebate-qualifying single-family residences at three or fewer, and multifamily at four or more residences. Additionally, the Company eliminated the 92% AFUE furnace as a rebate-eligible measure from the Builder Program and reduced the rebate amount for the tankless rebate measure by $50 in 2019.

The Company also added Tariff language to the Builder Program in 2019 which defines the version of efficiency rating software that must be used by home energy raters (HERS) and also excludes solar energy as part of the calculation for whole-home single-family rebate measures. These changes were made to ensure consistency across the community of HERS raters and establish a baseline for modeling natural gas savings.

Another 2019 Builder Program change was the addition of a pay-for-performance rebate measure for new multifamily properties. The Multifamily Performance measure compares the energy usage of new multifamily properties against a software-designed reference property. The reference property is based on existing Utah building codes. Incentives for this measure are based on the software's calculation of the difference between the natural gas usage of the reference and above-code multifamily properties. The Multifamily Performance measure is similar to the Commission approved HERS rebates for single family properties offered by the Company beginning in the 2017 ThermWise® program year. The Company added this measure in an effort to be responsive to market conditions and to increase natural gas savings.

The Company continued to perform outreach and marketing work in-house in 2019. Nexant provided technical assistance and continued to perform rebate processing work for this program in 2019.

Utah ThermWise® Business Rebates

The Company continued this program in 2019 with the elimination of the 92% AFUE furnace as a rebate-eligible measure. The Company also increased the incentives for tier 2 and tier 3 boiler tune-ups by $50 in 2019. Under this scenario, tier 2 tune-ups increased to $200 and tier 3 tune-ups to $300. This change was made based on feedback from commercial customers, including several of the State's school districts, that the 2018 incentive amounts were not set at a level that would motivate them to take action triennially. For 2019, the Company also removed previous Tariff language which set a size limitation (<300 kBtu) on the tier 1 boiler tune-up measure. This limitation was erroneously included in the 2015 ThermWise® budget filing (Docket No. 14-057-25).

The Company additionally added six types of used food service equipment (char broilers, combination ovens, commercial fryers, convection ovens, conveyor ovens, and steam cookers) to the list of rebate-eligible measures in 2019. Used food service equipment accounts for a large percentage of annual sales in the kitchen and restaurant equipment industry. Since used equipment had not historically been rebate-eligible through the Business Rebates Program, the Company believed that a large portion of the restaurant industry was not benefitting from this program and the resulting natural gas savings. The rebate for used food service equipment was made in an effort to encourage kitchens and restaurants to select the efficient models when purchasing used equipment. The rebate amount for each type of used food service equipment is half of the rebate for corresponding new equipment.

Additionally, the Company added the following equipment as rebate-eligible measures in 2019: 1) combined heat and power; 2) direct-fired heaters; 3) prescriptive energy recovery ventilators (ERV); 4) green certified new buildings; 5) boiler O2 trim controls; 6) boiler linkageless controls; 7) commercial find-and-fix $RC_{x;}$ and 8) commercial high performance building envelope.

Nexant continued to perform rebate processing and assisted with design, outreach, marketing, and technical assistance for this program in 2019.

Utah ThermWise® Weatherization Rebates

The Company continued this program in 2019 with changes to the Tariff to align the definition of single and multifamily residences outlined in the 2019 Appliance Program discussion. Additionally, the Company changed the structure of the air sealing rebate measure and created a rebate based on building performance in the Pilot Multifamily Program.

The 2018 air sealing rebate measure, originally proposed in Docket No. 11-057-12, was intended to incent customers to seal penetrations in residential structures, thereby reducing the number of air changes per hour and the corresponding heat losses. The incentive for this measure was previously structured to provide a base incentive of $100 per home with an additional $0.18 per square foot of area sealed. The measure is capped at a maximum rebate of $850 per single family residence. The 2018 market feedback indicated that weatherization contractors were avoiding smaller square footage homes because of the incentive structure at the time. In order to address this issue, the Company changed the structure in 2019 by increasing the base incentive to $200, reduced the per square foot portion of the incentive to $0.12, and maintained the maximum rebate limitation at $850 per home. The Company believes these changes will give an incentive to weatherization contractors to promote this measure to all homes, regardless of size, while also ensuring positive cost-effectiveness results.

In 2018, the Company launched a three-year pilot initiative, through the Weatherization Program, designed to achieve natural gas savings in both low-income and market rate multifamily properties. This initiative, called the Pilot Multifamily Program, aims to entice multifamily property owners to implement comprehensive energy efficiency retrofits and replace energy systems across the entire property instead of waiting to replace equipment at the point of failure. The Company selected the ICAST to administer the three-year pilot initiative. The Pilot Multifamily Program has seen good participation and market uptake since introduction in 2018. However, the Company recognized in 2018 that the existing Tariff limited payment for natural gas savings to the prescriptive rebate measures in the Appliance, Builder, and Weatherization programs. Based on feedback from ICAST, the Company believed that additional natural gas savings could be achieved with a second rebate path. Therefore, the Company added an incentive method that is paid based on the overall performance of existing multifamily properties in 2019. This path is structured, and natural gas savings modeled, similarly to the pay-for-performance measure detailed in the 2019 Builder Program discussion.

Nexant continued to perform rebate processing and assisted with technical assistance for this program in 2019.

Utah ThermWise® Home Energy Plan

The Company continued this program in 2019 with no major changes.

Utah Low-Income Efficiency Program

The Company continued funding the Low-Income Efficiency Program in 2019 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 eliminated the 92% AFUE furnace as a rebate-eligible measure, for the reasons outlined in the 2019 Appliance Program discussion. The Company also added the smart thermostat as a rebate-eligible measure in the Low-Income Efficiency Program for 2019. Throughout 2018, the Utah Weatherization Assistance Program (Utah WAP), the administrator of the Low-Income assistance funds provided by the Company, studied and tracked the performance of smart thermostats in other areas of the country. Particularly, data from a pilot program in the Colorado Weatherization Assistance Program (Colorado WAP) showed significant natural gas savings had been achieved in low income homes where a smart thermostat had been installed. Utah WAP began installing ThermWise® qualifying smart thermostats in late 2019. These installations were focused on Home Energy Assistance Target (HEAT) qualified customers in order to achieve maximum natural gas savings impact. An additional benefit of this measure is that rebate funds provided by the Company were rolled back into Utah WAP's budget, thereby allowing Utah WAP to complete additional statewide low-income work.

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 2019 the Company sent the ECR to more than 224,000 of its customers. As of the end of September 2019, the Comparison Report had been generated over 305,000 times online by nearly 120,000 unique customers.

The Company decreased delivery of the Comparison Report to 224,000 in 2019. The Company realized this total number by pausing Groups B and D beginning August and December 2018 respectively, and adding Group G which will be delivered to 25,000 additional customers in 2019.

While program participants decreased in 2018, natural gas savings increased by 34% in 2019. Natural gas savings increased because of the expansion of the Comparison Report in 2019, and because of savings persistence. The Company conducted a study in 2018 that focused its analysis on the current recipients of the report (Groups B, C, D, and E). The study showed weather-normalized usage reductions per participant of 1.62 Dth/year. As a result, the Company updated the natural gas savings number from 1.22 Dth/year in the 2018 Model, to 1.62 Dth/year in the 2019 Model.

A summary of the cost-effectiveness used in the energy-efficiency model for each ThermWise® program as provided with the 2019 budget filing is shown in Table 12.1.

Table 12.1 - Utah 2019 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	
	2019 Projected B/C	2019 Actual B/C	2019 Projected B/C	2019 Actual B/C	2019 Projected B/C	2019 Actual B/C	2019 Projected B/C	2019 Actual B/C
ThermWise® Appliance Rebate	1.72	1.30	4.25	3.23	1.96	1.58	0.93	0.83
ThermWise® Builder Rebates	1.17	0.84	2.72	1.86	1.49	1.54	0.83	0.85
ThermWise® Business Rebates	1.35	1.63	3.60	4.18	2.13	2.65	1.10	1.23
ThermWise® Weatherization Rebates	1.39	1.16	3.08	2.83	1.47	1.17	0.85	0.73
ThermWise® Home Energy Plan	1.42	2.23	54.58	94.99	1.40	2.19	0.75	0.93
Low Income Efficiency Program	1.55	0.89	5.89	2.29	1.69	1.02	0.87	0.65
Energy Comparison Report	1.27	1.82	5.42	6.57	1.27	1.82	0.61	0.72
Market Transformation Initiative	0	0	N/A	N/A	0	0	0	0
Totals	**1.35**	**1.10**	**3.56**	**2.75**	**1.60**	**1.49**	**0.87**	**0.84**

Actual benefit/cost results for 2019 mirrored corresponding budget projections. The ThermWise® programs as a whole passed the Total Resource, Participant, and Utility Cost tests. Actual cost-effectiveness results were lower than projected primarily due to higher than expected participation in lower-savings energy-efficiency measures and lower than forecasted avoided natural gas costs than were used in cost-effectiveness modeling for the 2019 ThermWise® budget filing (Docket No. 18-057-20).

Customer participation in the ThermWise® programs remained high in 2019 (79,418 actual rebates paid) finishing the year at 89% of the Company's original 2019 estimate (89,496). Actual participation surpassed estimated participation in the Builder (30,486) and Business (2,217) programs. The Builder program had the highest total number of participants and finished at 174% of the 2019 goal.

The DSM Advisory Group continued to meet to discuss the Company's energy-efficiency initiative. Three meetings were held on the following dates: March 28, 2019, August 28, 2019, and September 24, 2019.

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." The evaluation concluded with the idea that, "traditional energy efficiency and behavioral conservation-based programs, most notably Seasonal Energy Update energy reports, may yield greater savings over longer periods of supply shortage."[45]

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

The Company has continued to monitor developments in 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 ThermWise® programs. The Company expects to discuss the recent demand response program proposals in a 2020 meeting with the Advisory Group. This discussion may result in the Company seeking funding for a demand response pilot initiative as part of the 2021 ThermWise® programs.

The Company reviewed the proposals and ultimately determined that the estimated natural gas savings did not justify proposing inclusion in the 2020 ThermWise® programs.

WYOMING ENERGY-EFFICIENCY RESULTS FOR 2019

The Company filed for approval (Docket No. 30010-179-GT-18) of the tenth-year of the Wyoming ThermWise® programs on October 31, 2018. The tenth-year Wyoming programs were modified to closely align with the 2019 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 tenth-year programs (December 31, 2019, Order) and ordered the changes be effective January 1, 2019.

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 tenth full program year (January through December 2019) the Wyoming ThermWise® programs had 403 participants or 1.6% of the Company's December 31, 2019, Wyoming GS customer base.

UTAH ENERGY-EFFICIENCY PLAN FOR 2020

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 2020 as well as the ThermWise® Market Transformation initiative. The ThermWise® energy-efficiency programs continuing in 2020 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 2020 with the elimination of 95% and 98% annual fuel utilization efficiency (AFUE) furnaces which currently include an additional $50 rebate for electrically commutated motors (ECM) as rebate-eligible measures. 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, 2019, 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, 2020. Because of the elimination of the ECM, the Company proposes to rebate >95% and >98% AFUE furnaces at $300 and $350 respectively in 2020.

The Company will also add 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 will continue to perform outreach and marketing work in-house in 2020. Nexant will provide technical assistance and continue to perform rebate processing work for this program in 2020.

Utah ThermWise® Builder Rebates

The Company will continue this program in 2020 by eliminating the $50 ECM rebate and establish the tiered rebate amounts for ≥95% and ≥98% AFUE furnaces at $300 and $350 respectively in 2020 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 2020 Appliance Program discussion.

Additionally, the Company continued this program in 2020 by restructuring the pre-2019 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, a builder 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 would need to achieve modeled natural gas savings of 47 Dth or greater and multifamily units would need savings of 27 Dth or greater. The Company anticipates that the average Pay-for-Performance 2020 participant single and multifamily homes will 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 2019 HERS tiers) in place for Pay-for-Performance homes which seek and 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 will continue to perform outreach and marketing work in-house in 2020. Nexant will provide technical assistance and continue 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 >95% and >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 also increased the rebate for 95% TE boilers ($3.50 per kBtu/hour versus the 2019 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 2020. 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 will pay 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) will be 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 will continue to perform rebate processing and assist with design, outreach, marketing, and technical assistance for this program in 2020.

Utah ThermWise® Weatherization Rebates

The Company continues 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 2020, 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 will update the Advisory Group on the savings values achieved by direct-install participant homes throughout 2020. The Company will also 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 will continue to perform rebate processing and assist with technical assistance for this program in 2020.

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. This program includes two primary components: an in-home energy plan performed by trained and experienced Company auditors and a "do-it-yourself" mail-in plan with on-line data input availability. This program will continue to be available to customers in the Company's Utah service territory in 2020.

Utah Low-Income Efficiency Program

The Company will continue 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 will also continue this program with the elimination of the $50 ECM rebate and to establish 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

In 2020 the Company will send the ECR to more than 266,000 of its customers. As of the end of September 2019, the Comparison Report had been generated over 330,000 times online by nearly 130,000 unique customers.

The Company will increase delivery of the Comparison Report to 266,000 in 2020. The Company realizes this total number by restarting Group D beginning November 2019 and adding Group I which will be delivered to 25,000 additional customers in 2020.

While proposed program participants increase from 2019, natural gas savings are projected to decrease by 11% in 2020. The Company expects savings to decrease because of the Company-conducted study in 2019 that focused savings analysis on all current 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 decatherm 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 12.2 below.

Table 12.2 - Utah 2020 projected NPV & BC ratios by program and California Standard Practice Test

2020 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	$4.23	1.65	$27.55	4.97	$4.60	1.75	-$3.06	0.78
ThermWise® Builder Rebates	$2.04	1.29	$18.39	3.27	$3.28	1.56	-$2.28	0.80
ThermWise® Business Rebates	$0.20	1.04	$10.73	3.39	$1.96	1.63	-$1.59	0.76
ThermWise® Weatherization Rebates	$1.26	1.15	$18.10	2.90	$1.65	1.21	-$3.73	0.72
ThermWise® Home Energy Plan	$0.09	1.17	$2.07	50.46	$0.09	1.15	-$0.43	0.61
Low Income Efficiency Program	$0.39	1.42	$2.96	6.96	$0.45	1.52	-$0.45	0.75
Energy Comparison Report	$0.06	1.11	$2.25	5.25	$0.06	1.11	-$0.67	0.49
Market Transformation Initiative	-$1.32	0	$0	N/A	-$1.32	0	-$1.32	0
Totals	**$6.96**	**1.23**	**$82.05**	**3.72**	**$10.77**	**1.41**	**-$13.53**	**0.73**

*Shown in millions

Table 12.3 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 12.3 - Utah 2020 NPV & B/C ratios using gas cost forward curve from SENDOUT model

2020 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	$4.57	1.70	$28.64	5.13	$4.94	1.80	-$3.01	0.79
ThermWise® Builder Rebates	$2.45	1.35	$19.49	3.40	$3.70	1.63	-$2.15	0.82
ThermWise® Business Rebates	$0.34	1.07	$11.21	3.49	$2.11	1.68	-$1.57	0.77
ThermWise® Weatherization Rebates	$1.82	1.22	$19.43	3.04	$2.20	1.28	-$3.53	0.74
ThermWise® Home Energy Plan	$0.11	1.20	$2.11	51.46	$0.10	1.18	-$0.42	0.62
Low Income Efficiency Program	$0.44	1.48	$3.09	7.22	$0.50	1.58	-$0.44	0.76
Energy Comparison Report	$0.13	1.23	$2.25	5.25	$0.13	1.23	-$0.60	0.54
Market Transformation Initiative	-$1.32	0.00	$0	N/A	-$1.32	0.00	-$1.32	0
Totals	**$8.55**	**1.28**	**$86.22**	**3.86**	**$12.36**	**1.47**	**-$13.04**	**0.75**

*Shown in millions

WYOMING ENERGY-EFFICIENCY PLAN FOR 2020

The Company expects eleventh-year participation in the portfolio of Wyoming ThermWise® programs to reach 760 customers which would be a decrease of 11% from the 2019 budget participation levels.

SENDOUT MODEL RESULTS FOR 2020

The Company entered projections from the approved 20202020 energy-efficiency budget into the SENDOUT model in response to the Utah Commission's request. Data entries for the 20202020 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 2020 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 2020 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 2020 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 12.1 for the SENDOUT results in a table format.

The model accepted the 2020 ThermWise® Appliance, Builder, Business, Weatherization, Home Energy Plan, and Low Income programs at 25% of 2020 projected participation if administration costs were increased to 200% of the 2020 budget projection. The model accepted the Energy Comparison Report 100% of participation and 150% of the 2020 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 20202020 projection. In this scenario, the administration costs for the Appliance, Builder, Business, Weatherization, Home Energy Plan, and Low Income programs could increase by eight times the 20202020 budget projection and still be accepted. The Energy Comparison Report could increase projected administration costs by fifty 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 2020 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 2020 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 1,139,452 Dth in 2020. This analysis resulted in a projected potential total energy-efficiency spending limit of $37.2 million per year using the Utility Cost Test. The currently-approved $26.4 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 2019, the avoided gas cost attributable to energy-efficiency was calculated to be $36.23 million. For 2020, the avoided gas cost attributable to energy-efficiency was calculated to be $37.2 million. This gas is valued at the same price that is used for purchased gas in the IRP modeling.

2020 Energy-Efficiency Modeling Results from SENDOUT

Program @ <u>100%</u> of 2020 Budget $	% of 2020 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThemWise 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 2020 Budget $	% of 2020 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThemWise 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 2020 Budget $	% of 2020 Budget Participation				
	25%	50%	75%	100%	150%
ThermWise Appliance Program					
ThermWise Builder Program					
ThermWise Business Program					
ThemWise 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.

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 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.

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 3.88% to reflect the Carrying Charge stated in the Tariff. The Company also updated the normal heating degree days used in the weather forecast to 20-years ending 2018.

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 1,292 draws.

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 13.01 through 13.36 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.

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 1,292 draws. 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 13.37 through 13.49 show the annual and the monthly demand distribution curve for the first year of the base simulation. Exhibit 13.50 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 2020-2021 heating season is approximately 1.23 MMDth per day at the city gates. The most likely day for a Design Day to occur is on January 2, 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.[46] 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 1,199 draws generated in this process, four draws would exceed the Design Day requirement of 1.2320 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 13.51 shows the resources utilized to meet the Design Day. Exhibit 13.52 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 13.83 through 13.88. 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 13.53 through 13.64 show the probability distributions for purchased gas for each month of the first plan year from the base simulation. Exhibit 13.65 shows the annual distribution from the simulation. Exhibit 13.66 shows the numerical monthly data with confidence limits. Gas purchased for the first plan year under the normal case is approximately 50.6 MMDth. The Company is confident that, for a colder-than-normal year, 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.

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

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 13.67 through 13.78 show the distributions for cost-of-service gas for each month of the first plan year from the base simulation. Exhibit 13.79 shows the annual distribution from the simulation. Exhibit 13.80 shows the numerical monthly data with confidence limits. Cost-of-service production for the first plan year from the normal case is approximately 63.0 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 13.81. The first year total cost from the normal case is approximately $602 million. A similar curve for the total 31-year modeling time horizon is shown in Exhibit 13.82. The normal case cost for this time period is approximately $10.8 billion.

GAS SUPPLY/DEMAND BALANCE

Exhibits 13.89 and 13.90 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.[47] 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 13.89 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 130 MMDth for the normal case. Exhibit 13.90 shows sources of supply which include purchased gas categories, cost-of-service gas, Clay Basin and the Aquifers. The total supply meets the 130 MMDth demand for the normal case.

[47] 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).[48]

The tables below illustrate different scenarios that may occur with differing levels of cost-of-service gas and demand. Table 13.1 shows the estimated annual volume of cost-of-service gas that would be shut in under different scenarios. Table 13.2 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 13.1: Annual Shut-In Production

		Demand (Thousands of Dths)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	1421.9	984.962	984.8
	IRP Forecast	2571.2	1097.5	1097.5
	High 10%	6210.0	1724.5	1646.7

Table 13.2: Total Annual System Costs

		Demand (Millions of Dollars)		
		One Standard Deviation Warmer	Normal Temperatures	One Standard Deviation Colder
Cost-of-service gas	Low 10%	533.3	604.4	680.8
	IRP Forecast	532.8	602.4	679.5
	High 10%	532.3	601.4	678.0

[48] 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.

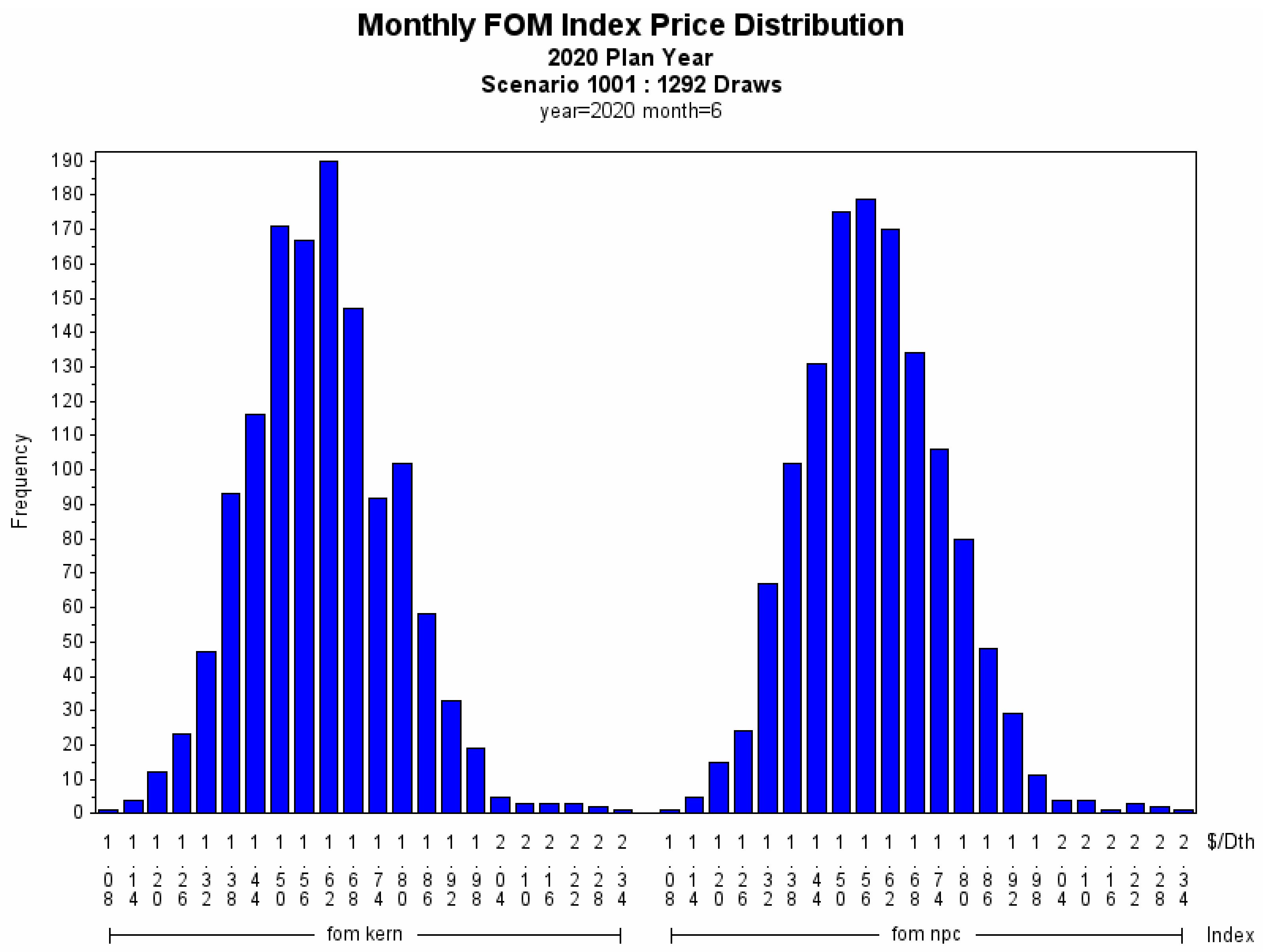


Exhibit 13.01

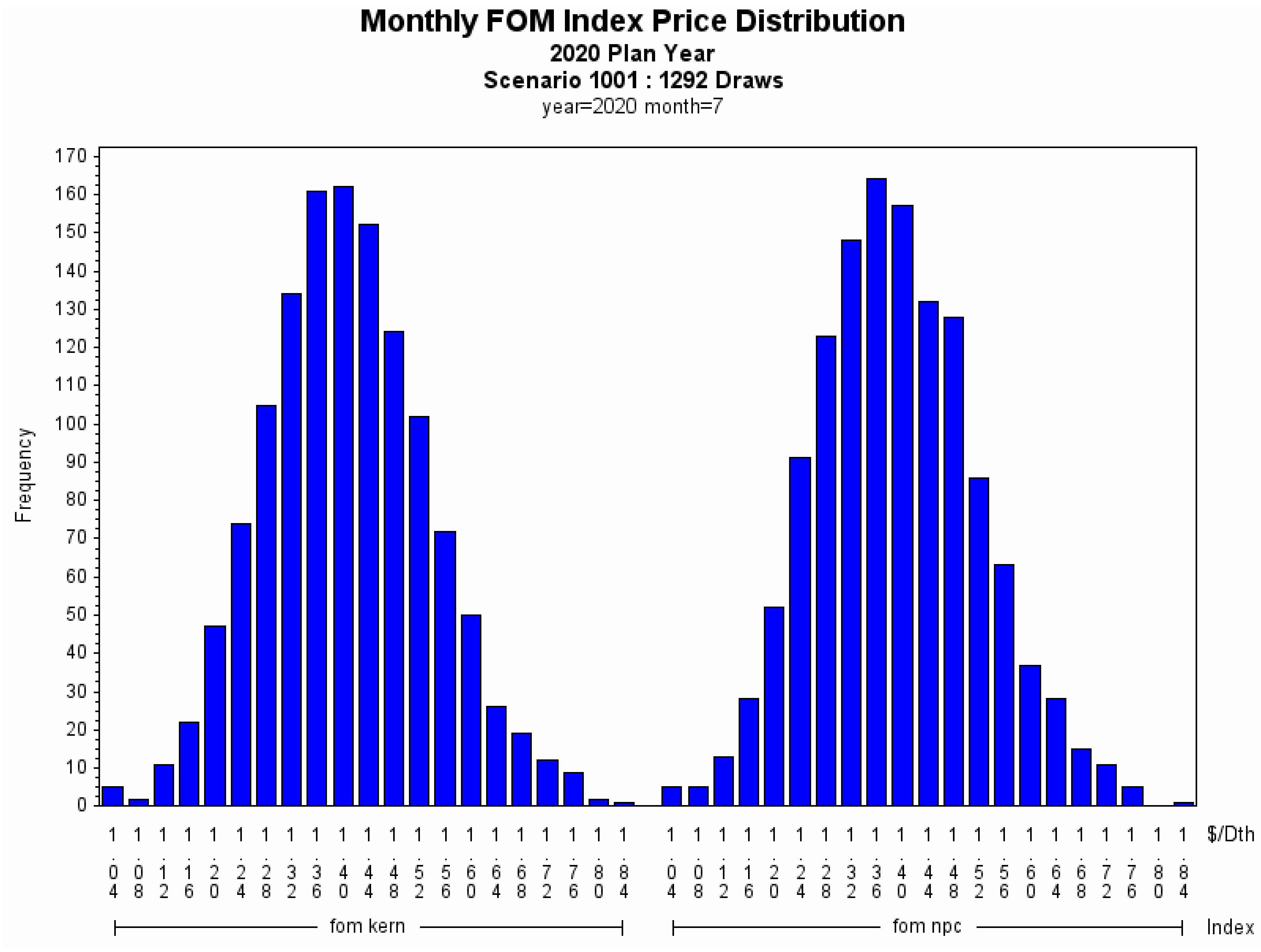


Exhibit 13.02

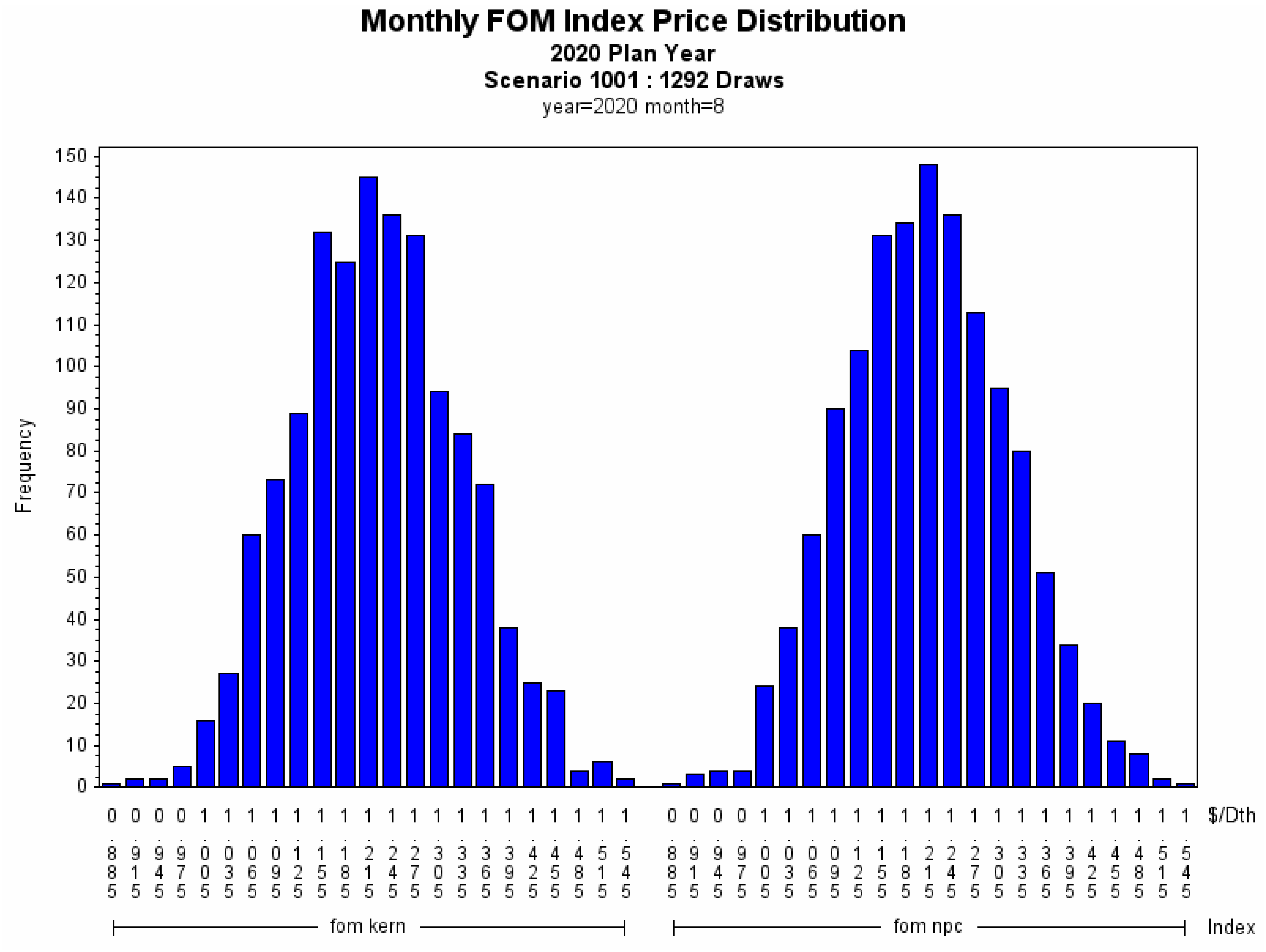


Exhibit 13.03

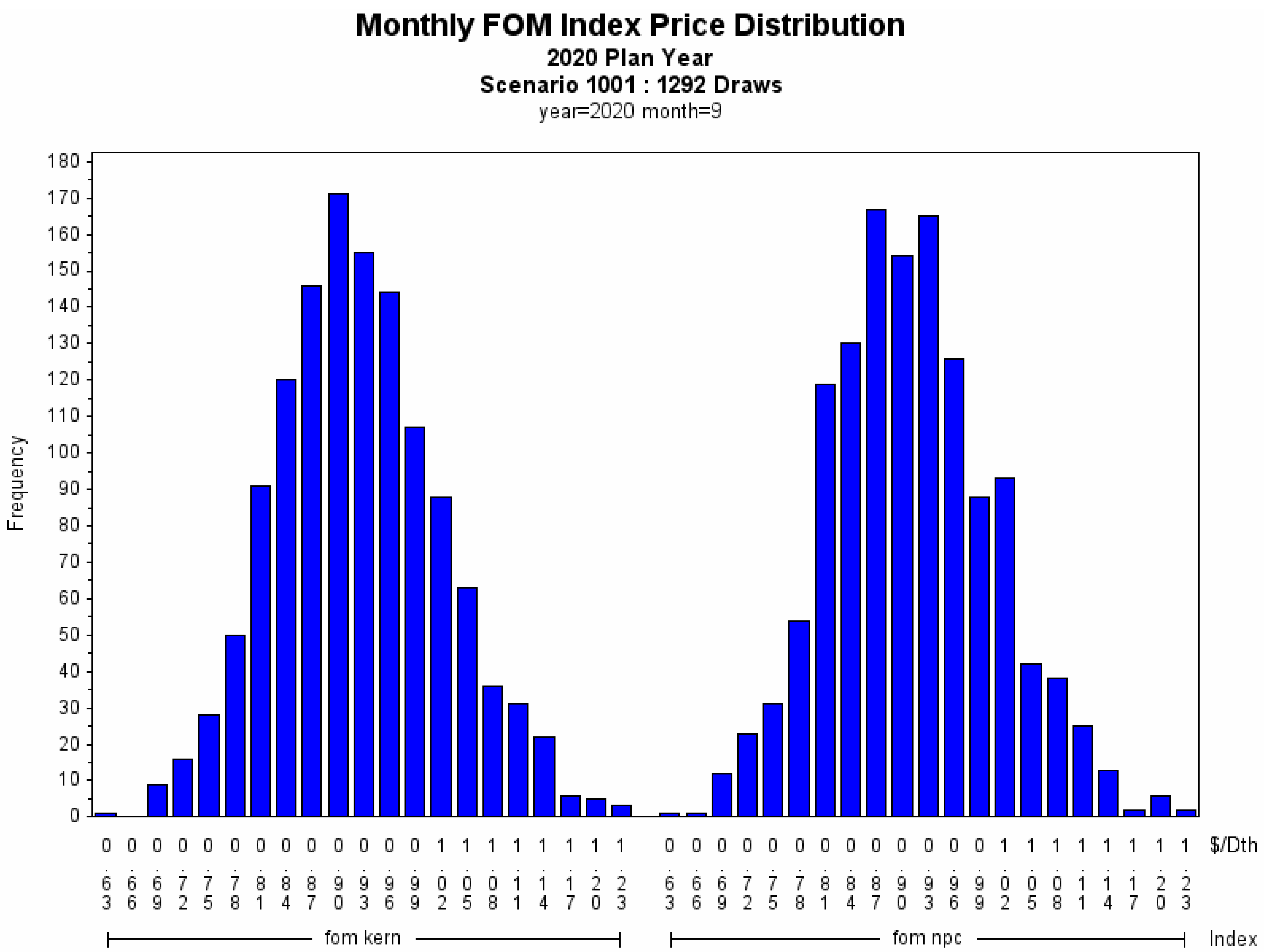


Exhibit 13.04

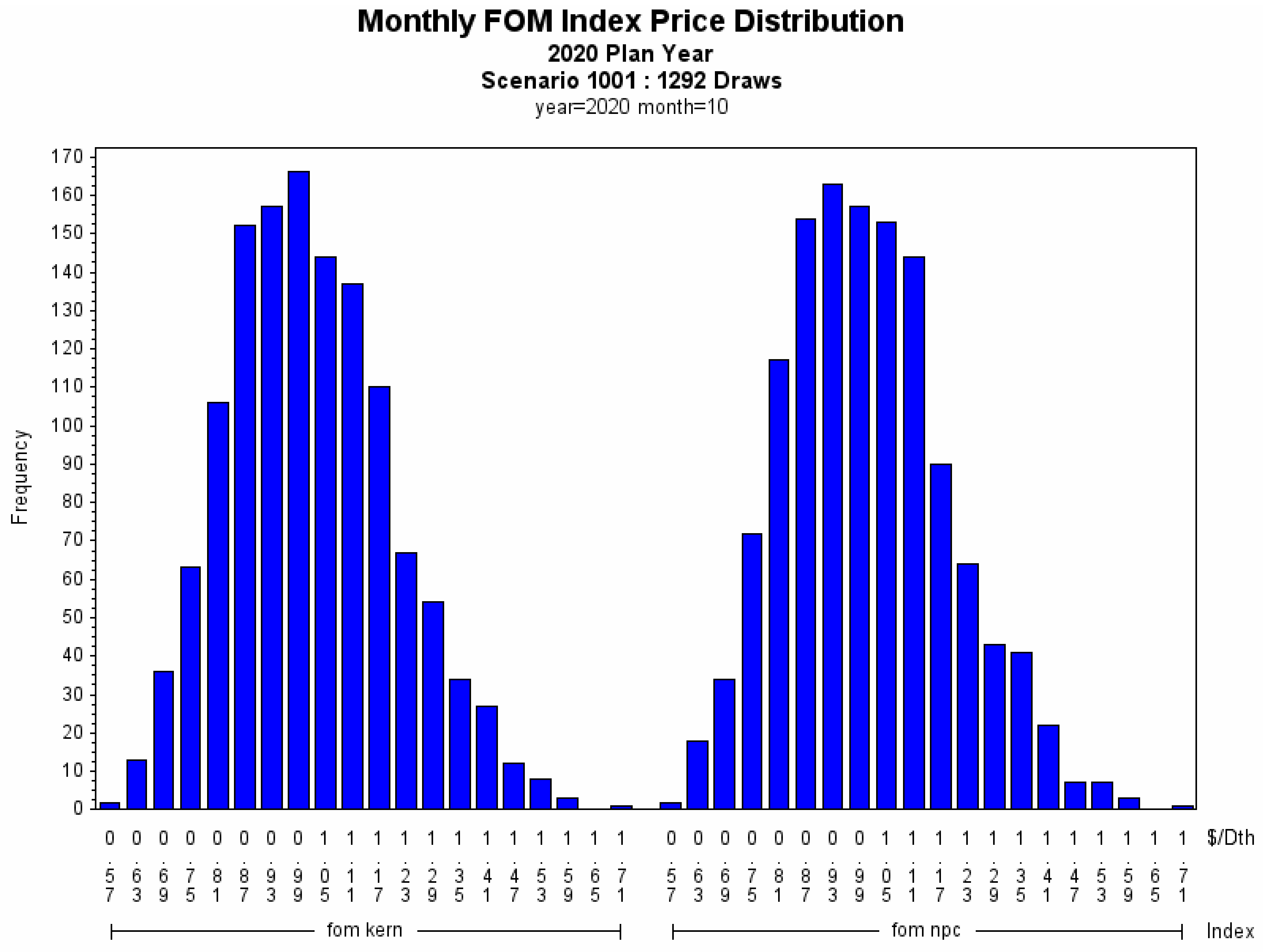


Exhibit 13.05

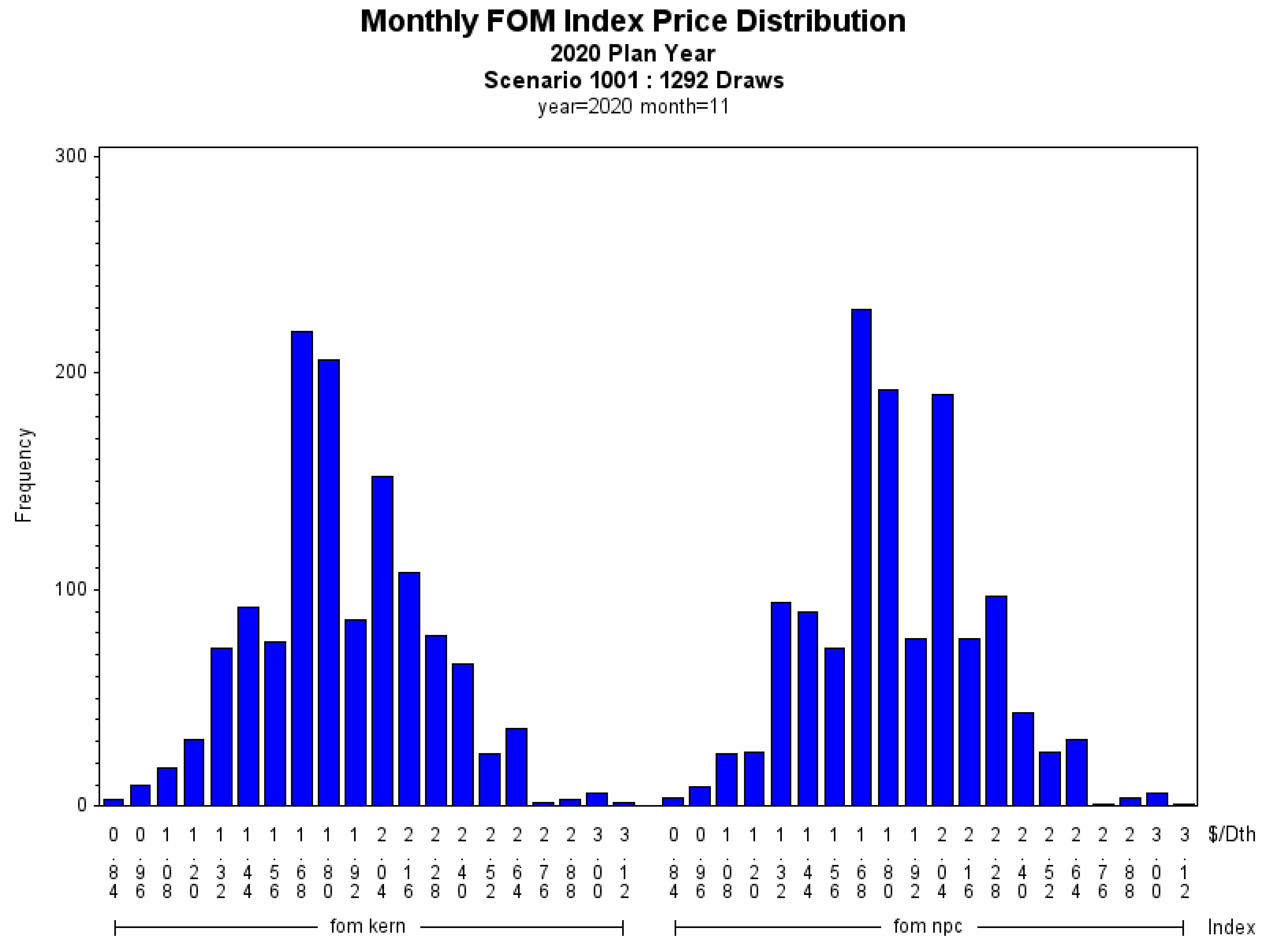


Exhibit 13.06

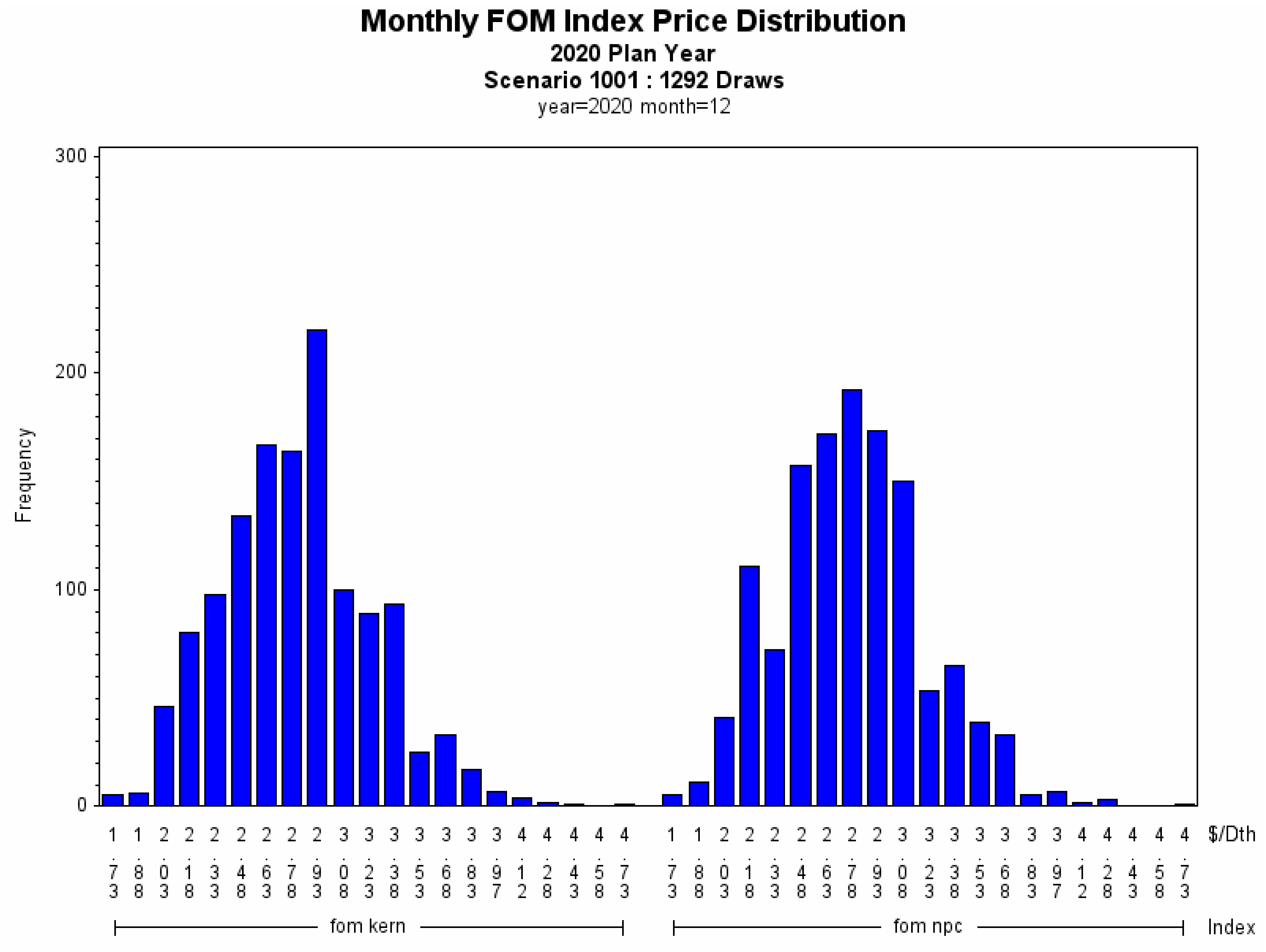


Exhibit 13.07

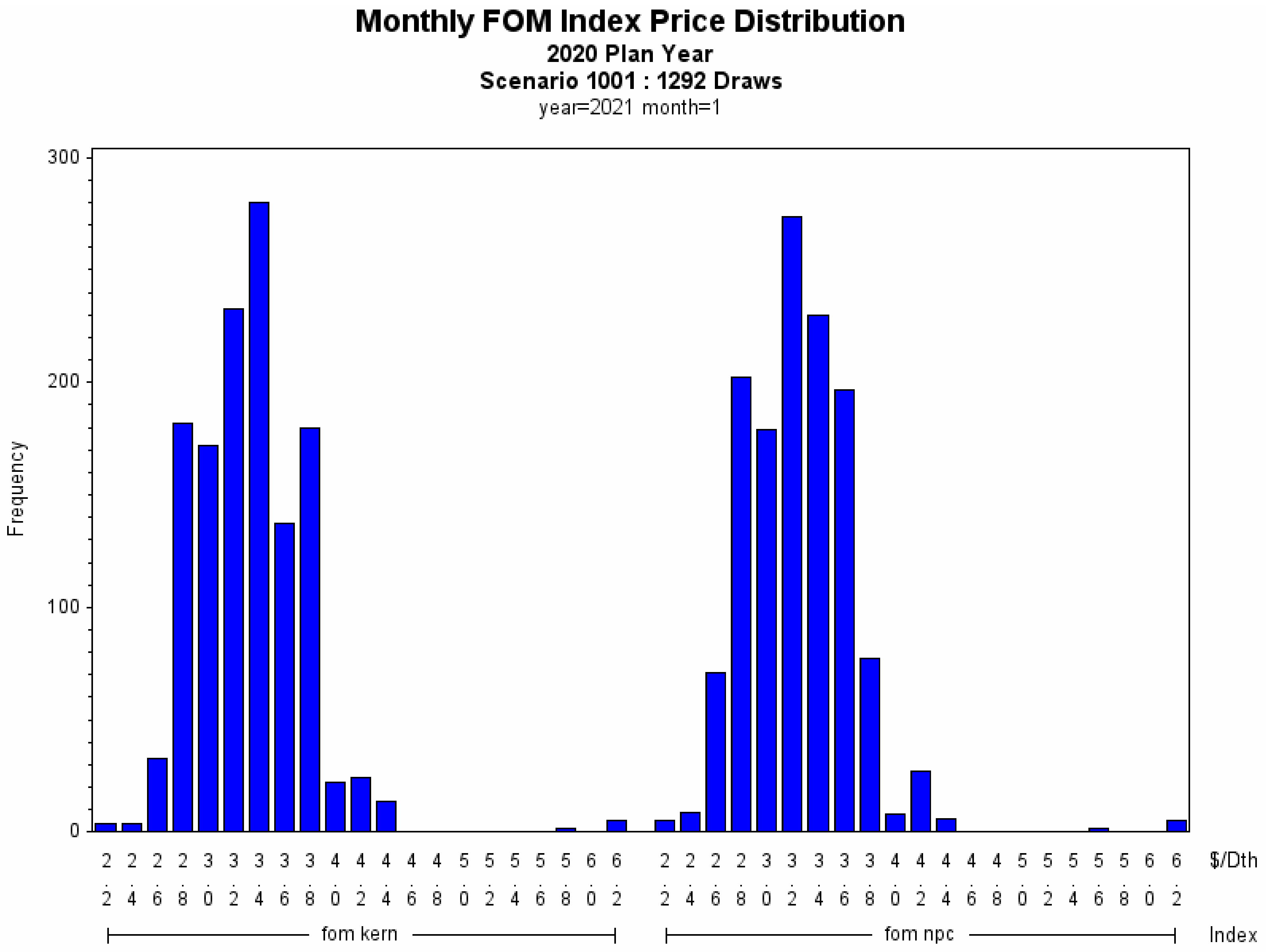
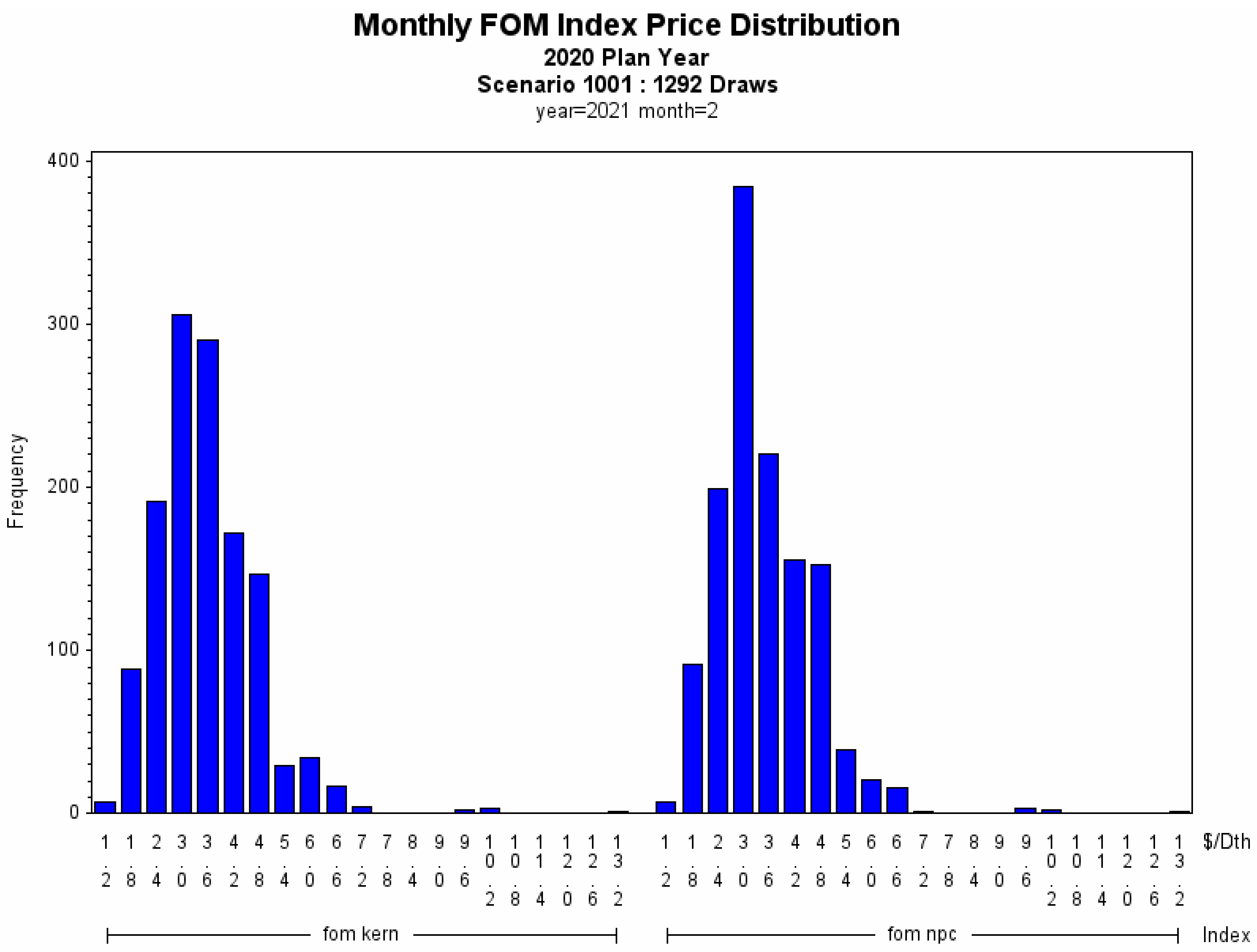


Exhibit 13.08


Monthly FOM Index Price Distribution
2020 Plan Year
Scenario 1001 : 1292 Draws
year=2021 month=2
Frequency
400
300
200
100
0
1.2 1.8 2.4 3.0 3.6 4.2 4.8 5.4 6.0 6.6 7.2 7.8 8.4 9.0 9.6 10.2 10.8 11.4 12.0 12.6 13.2
$/Dth
fom kern
fom npc
Index

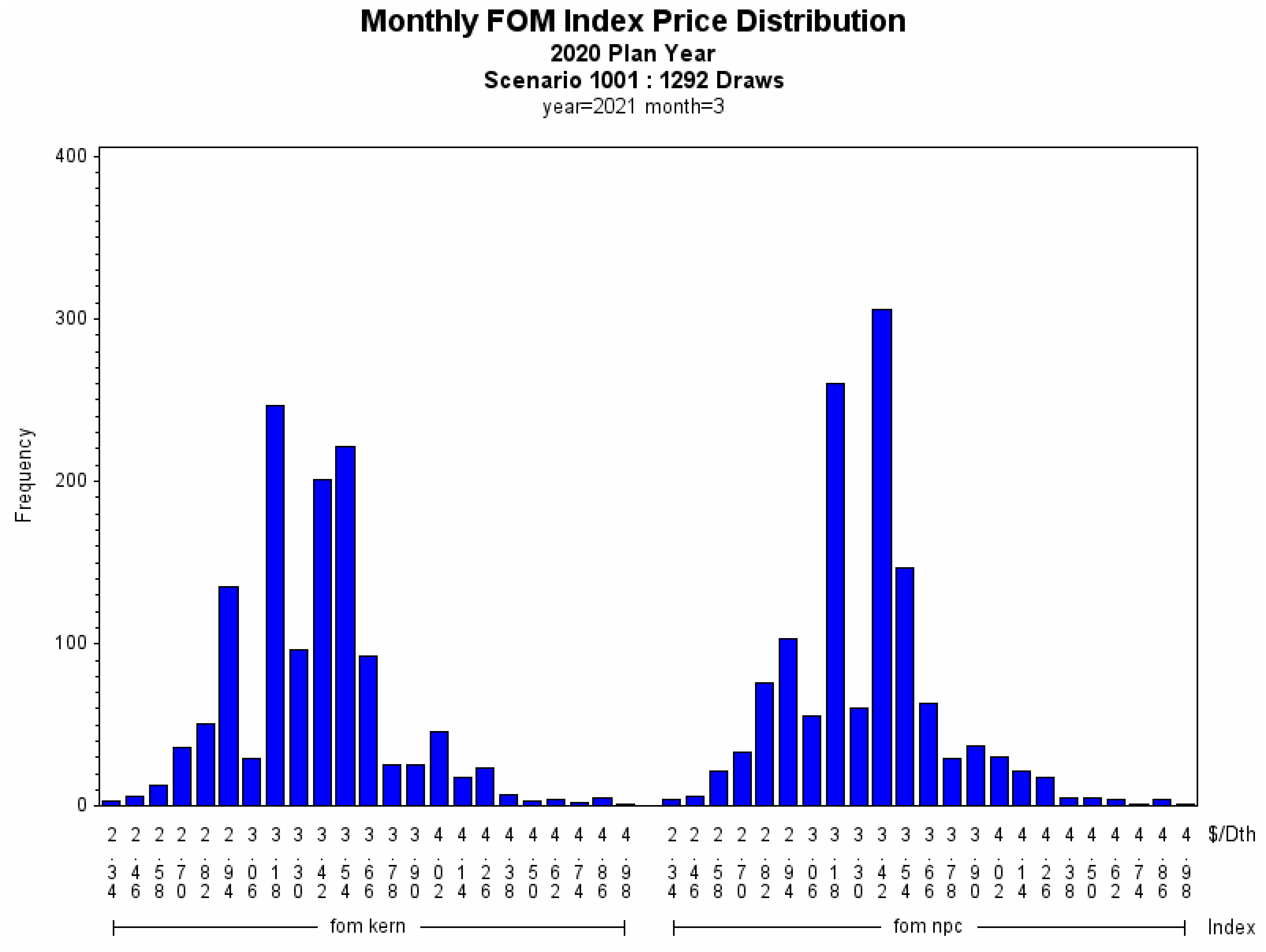
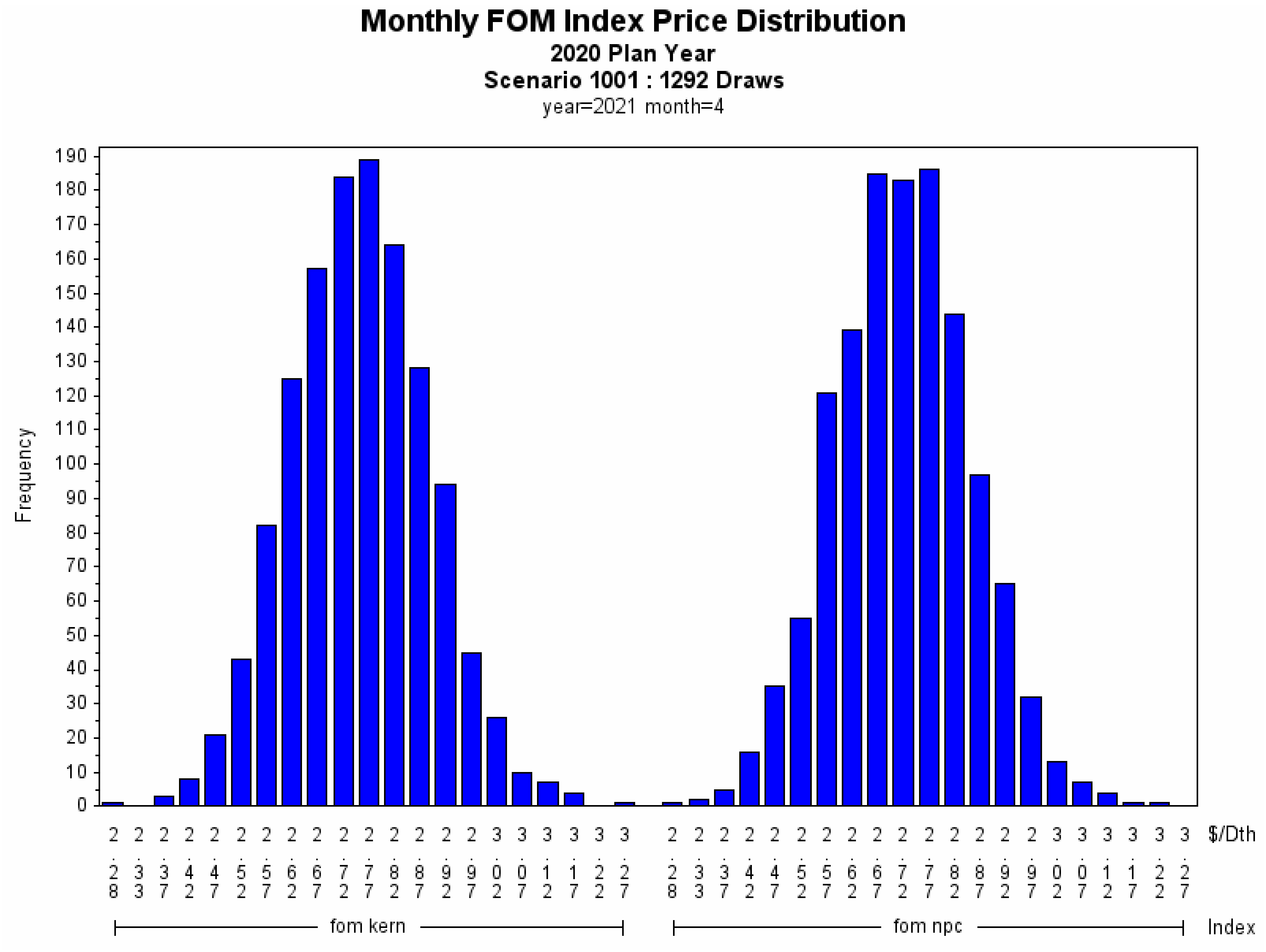


Exhibit 13.10



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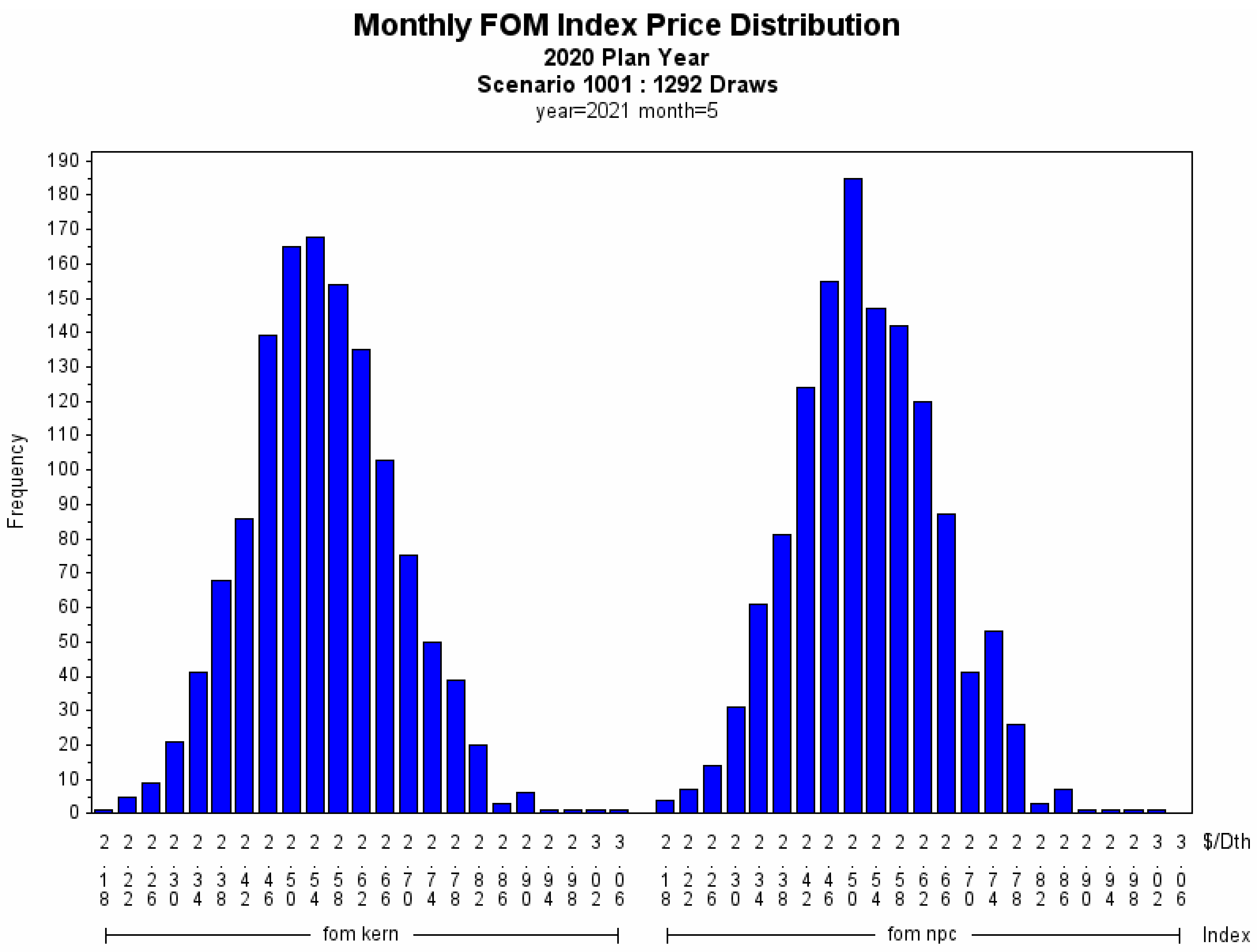

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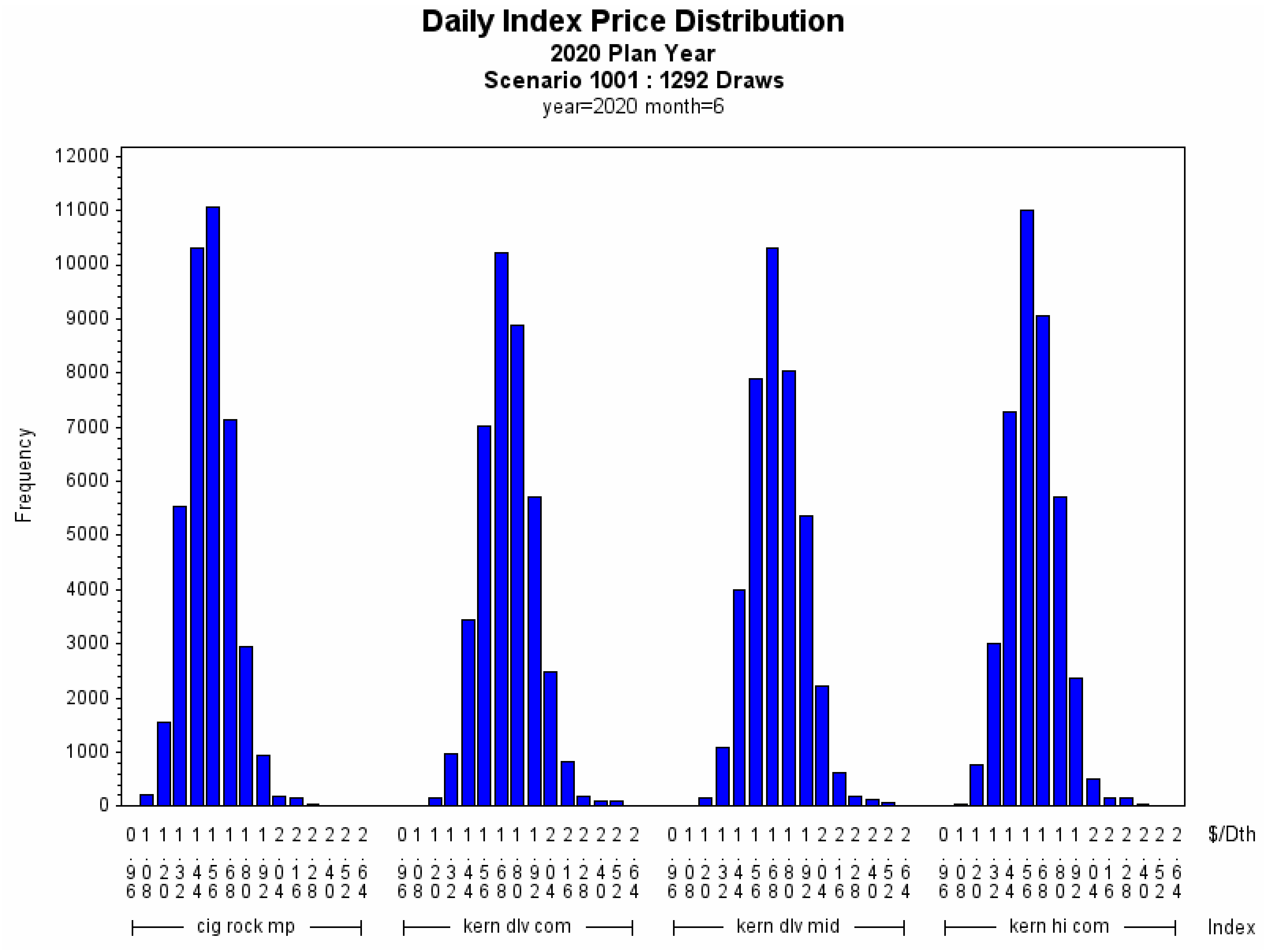


Exhibit 13.13

Daily Index Price Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2020 month=6

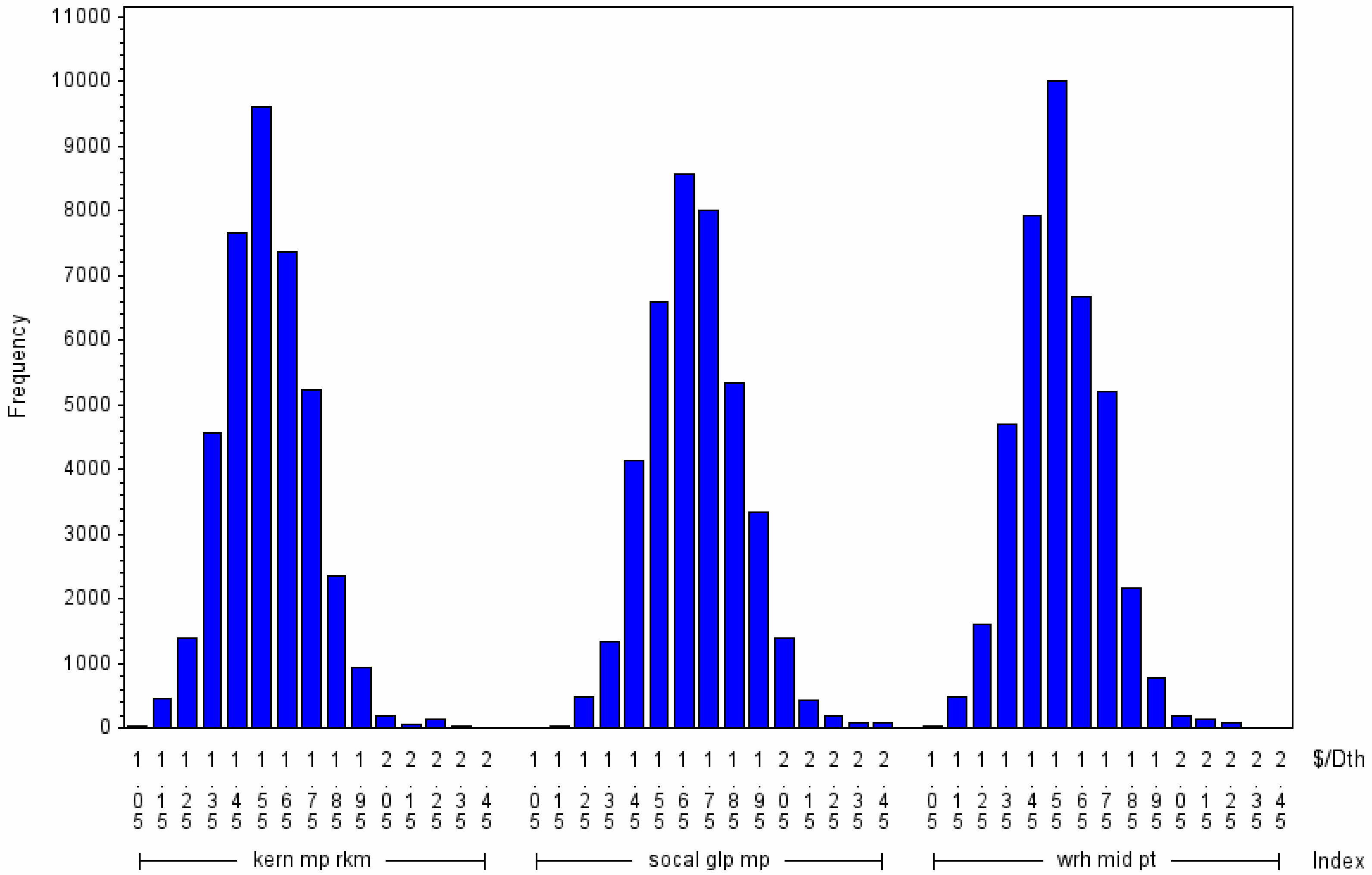


Exhibit 13.14

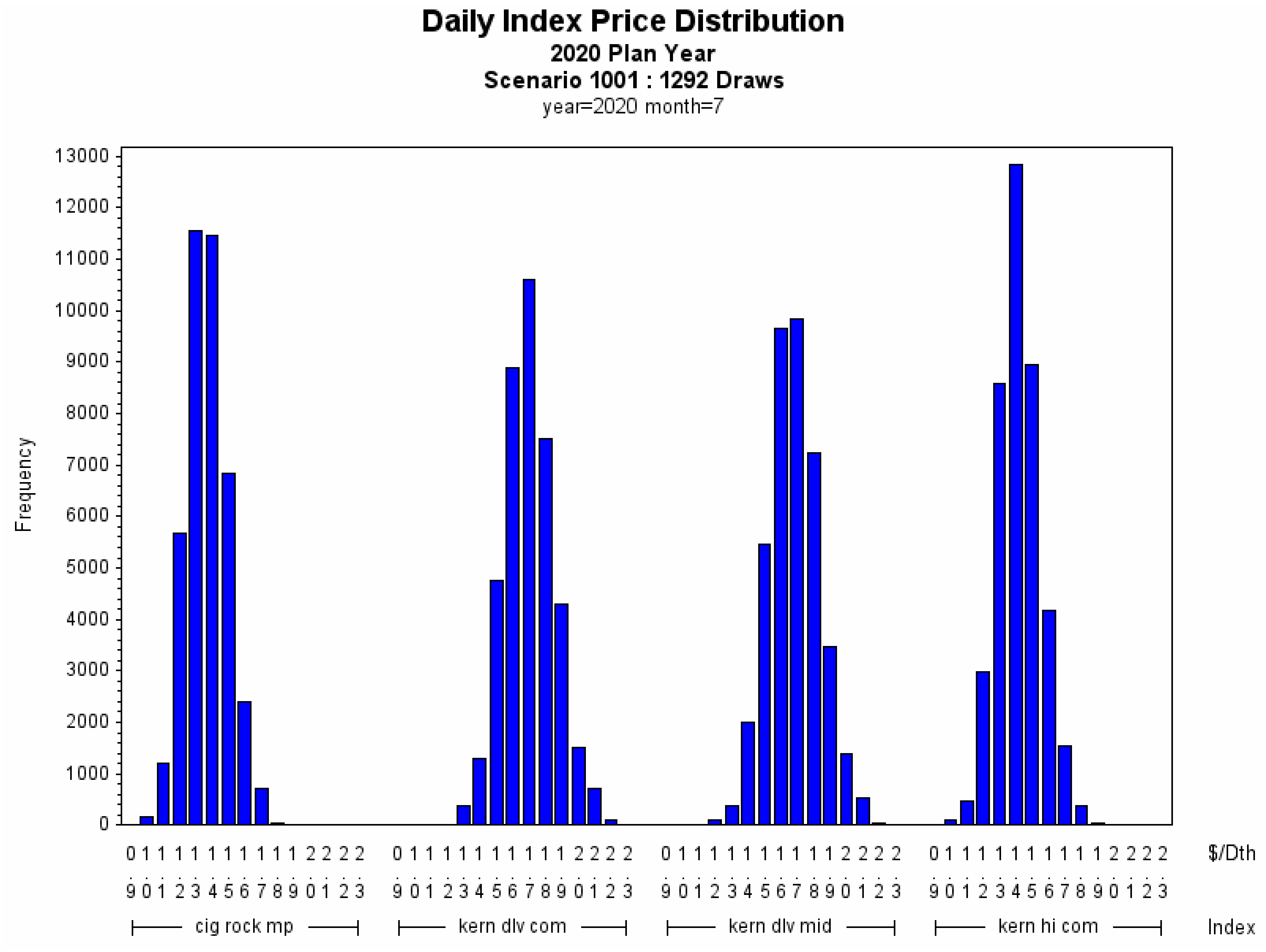


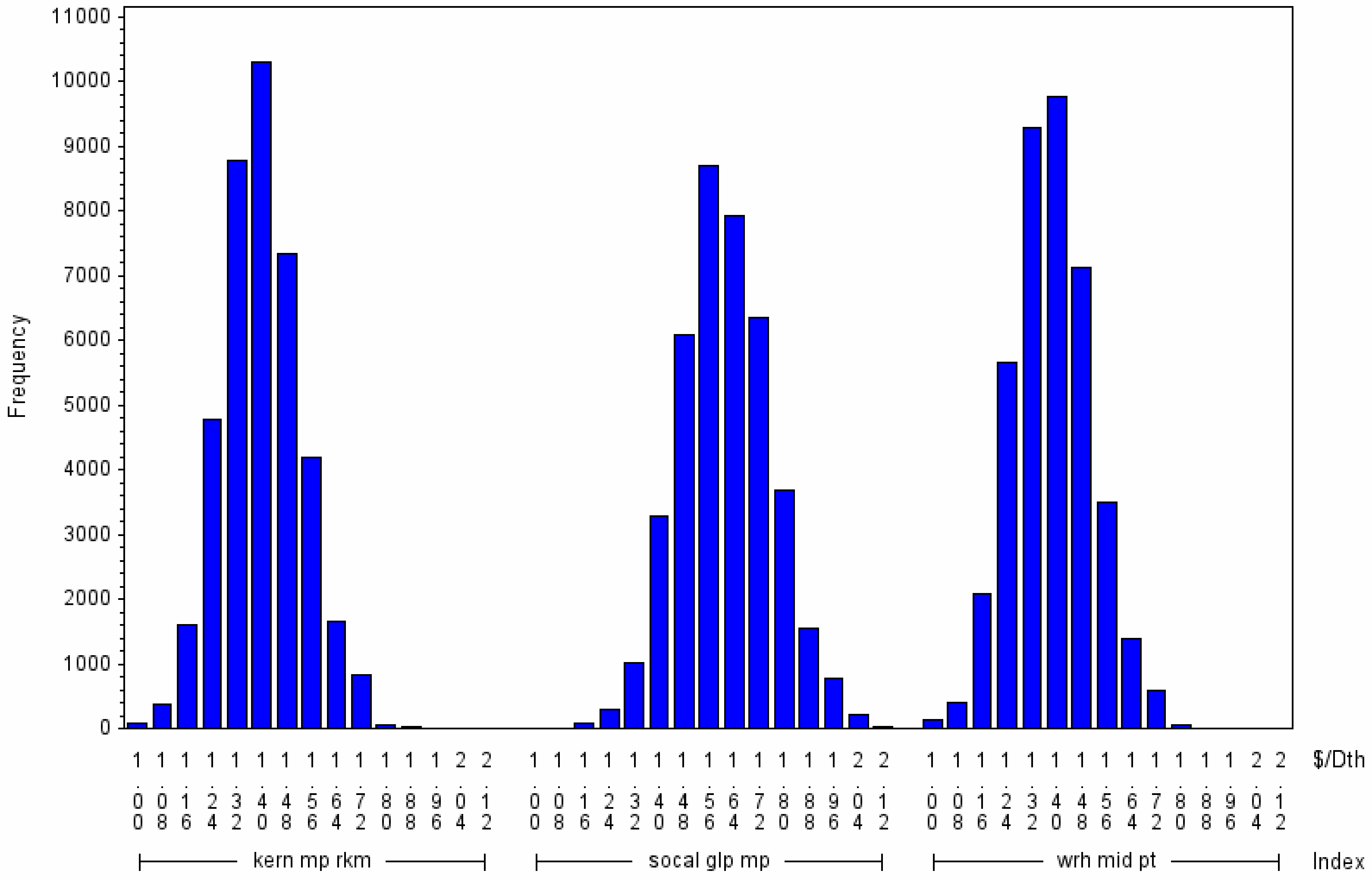
Exhibit 13.15

Daily Index Price Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2020 month=7



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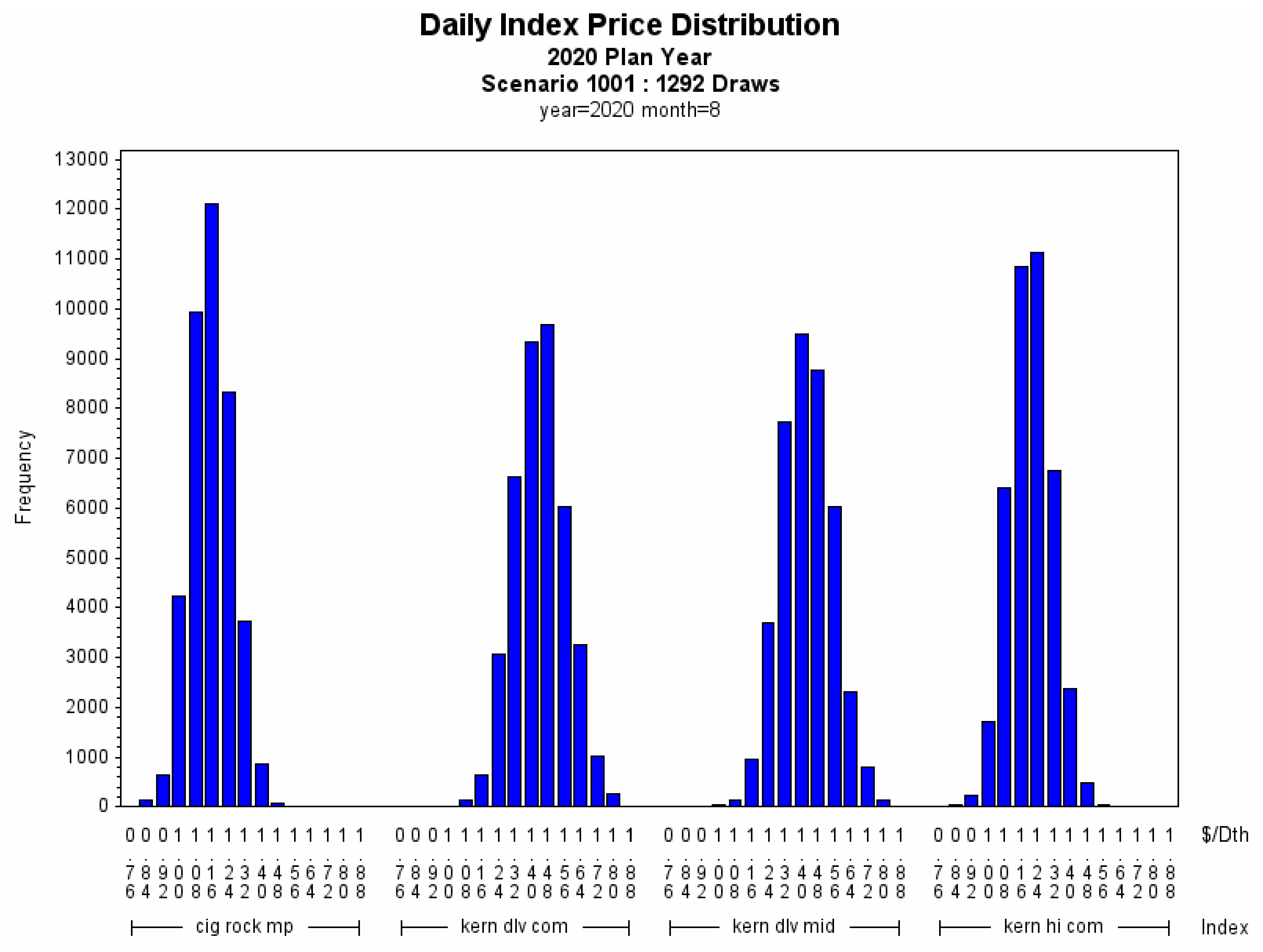

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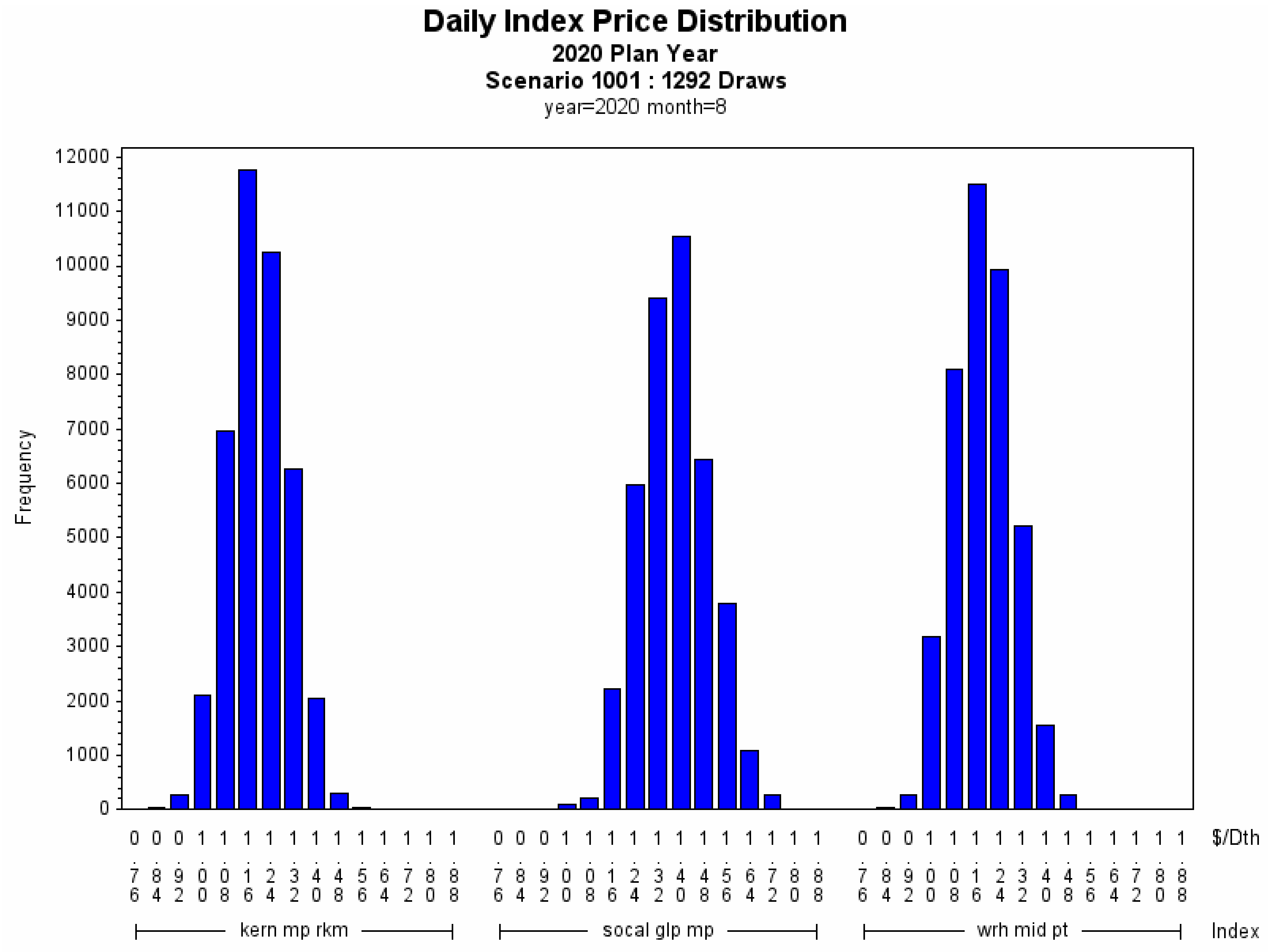

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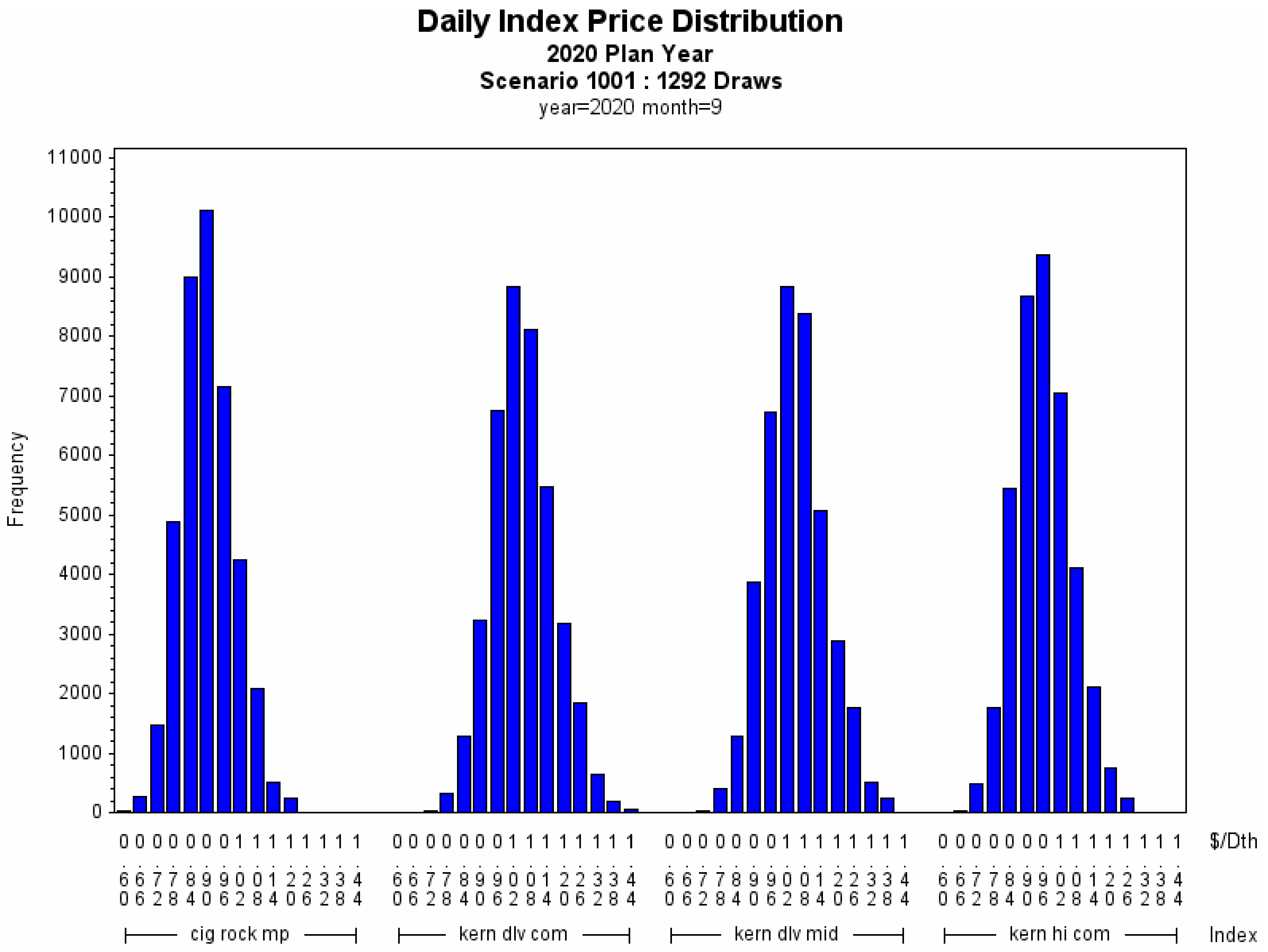

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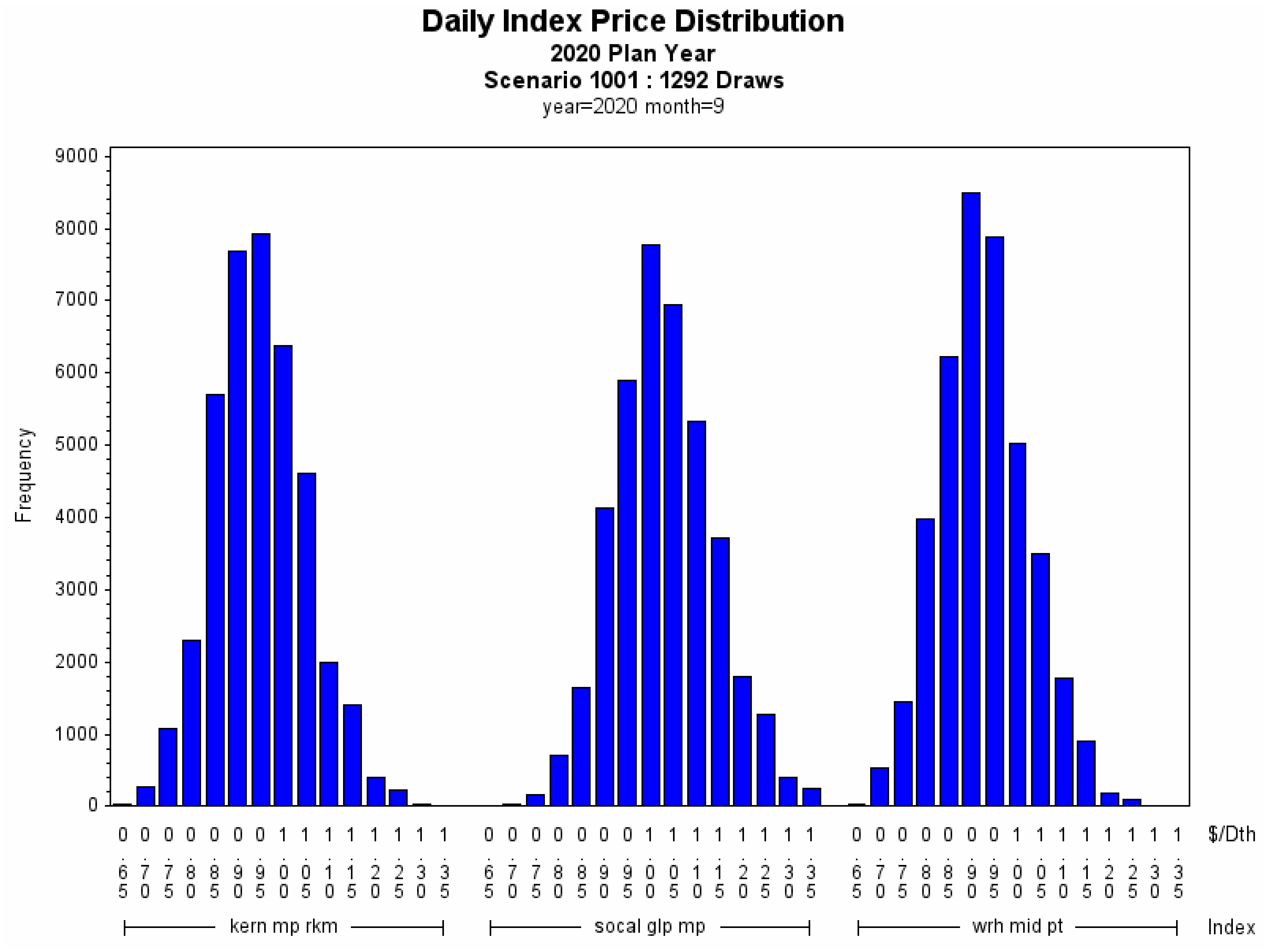

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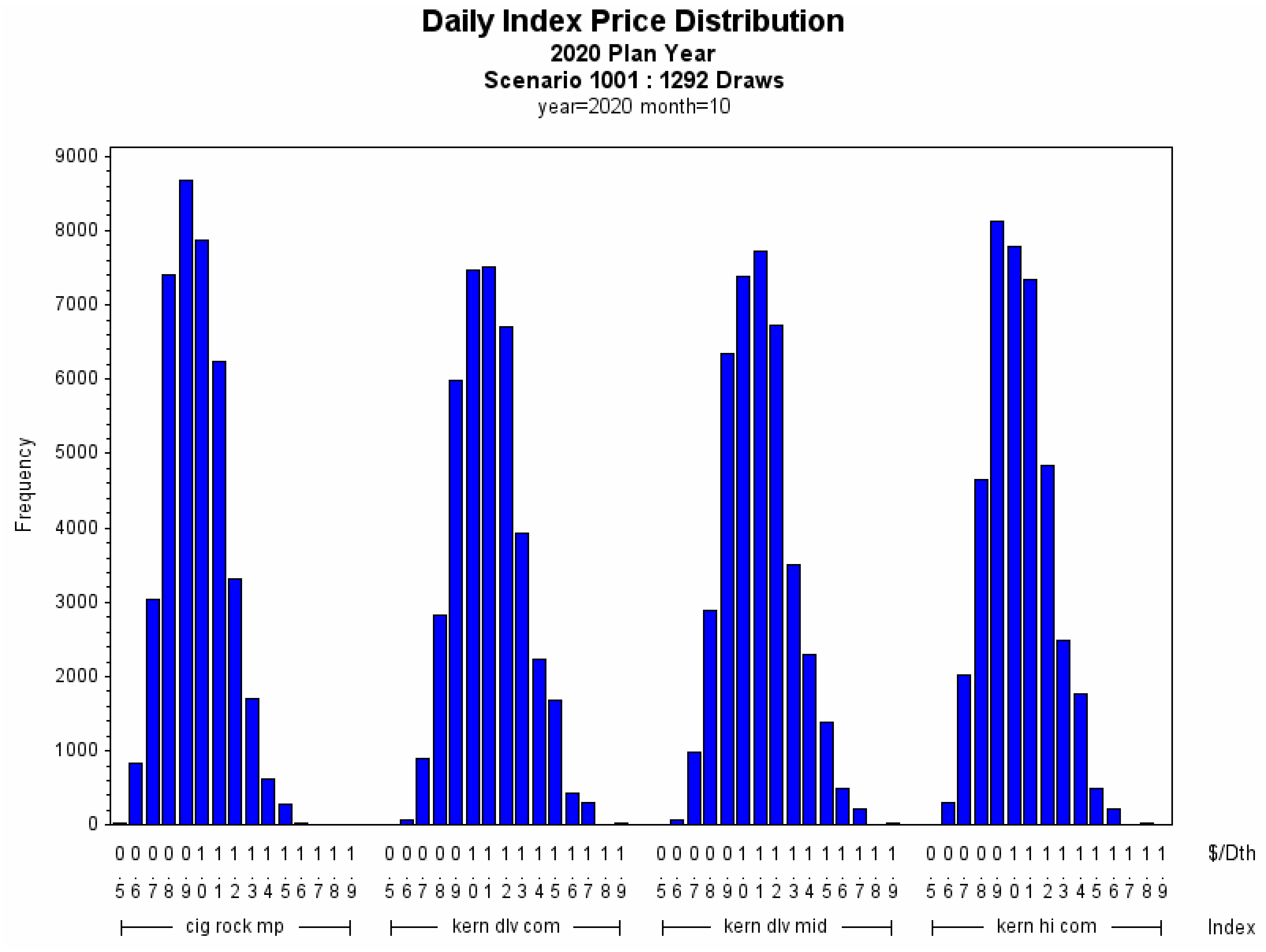

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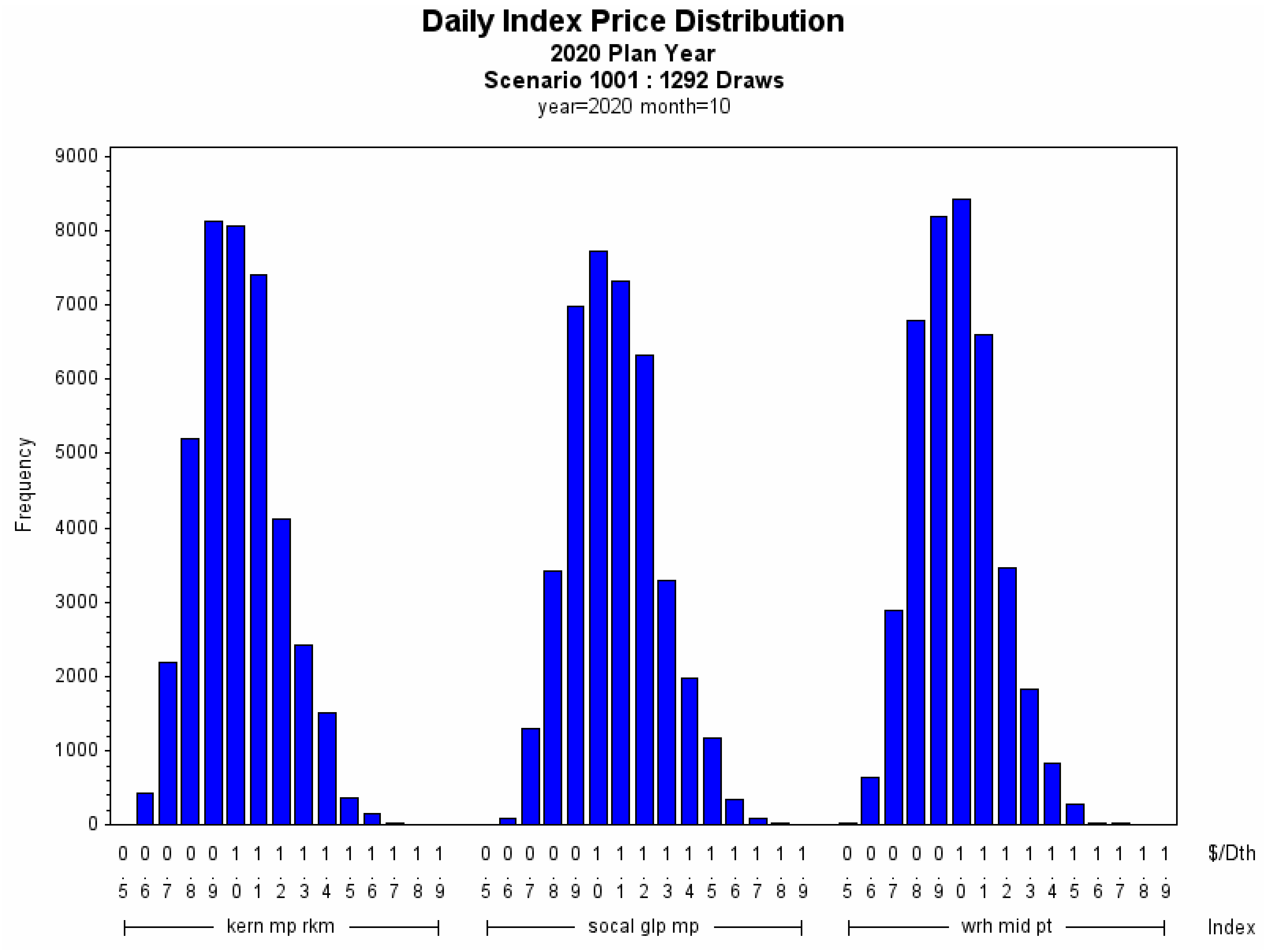

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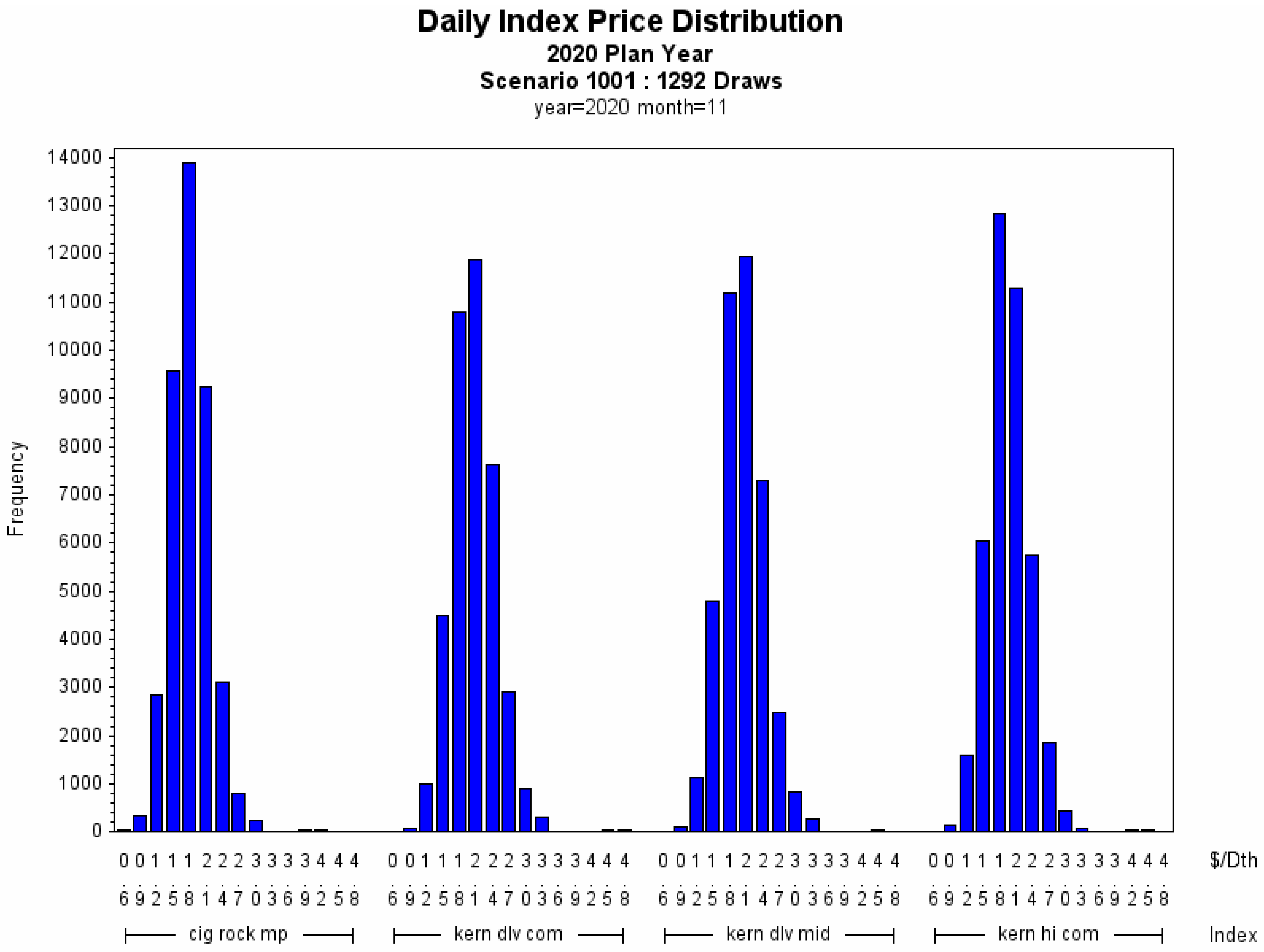

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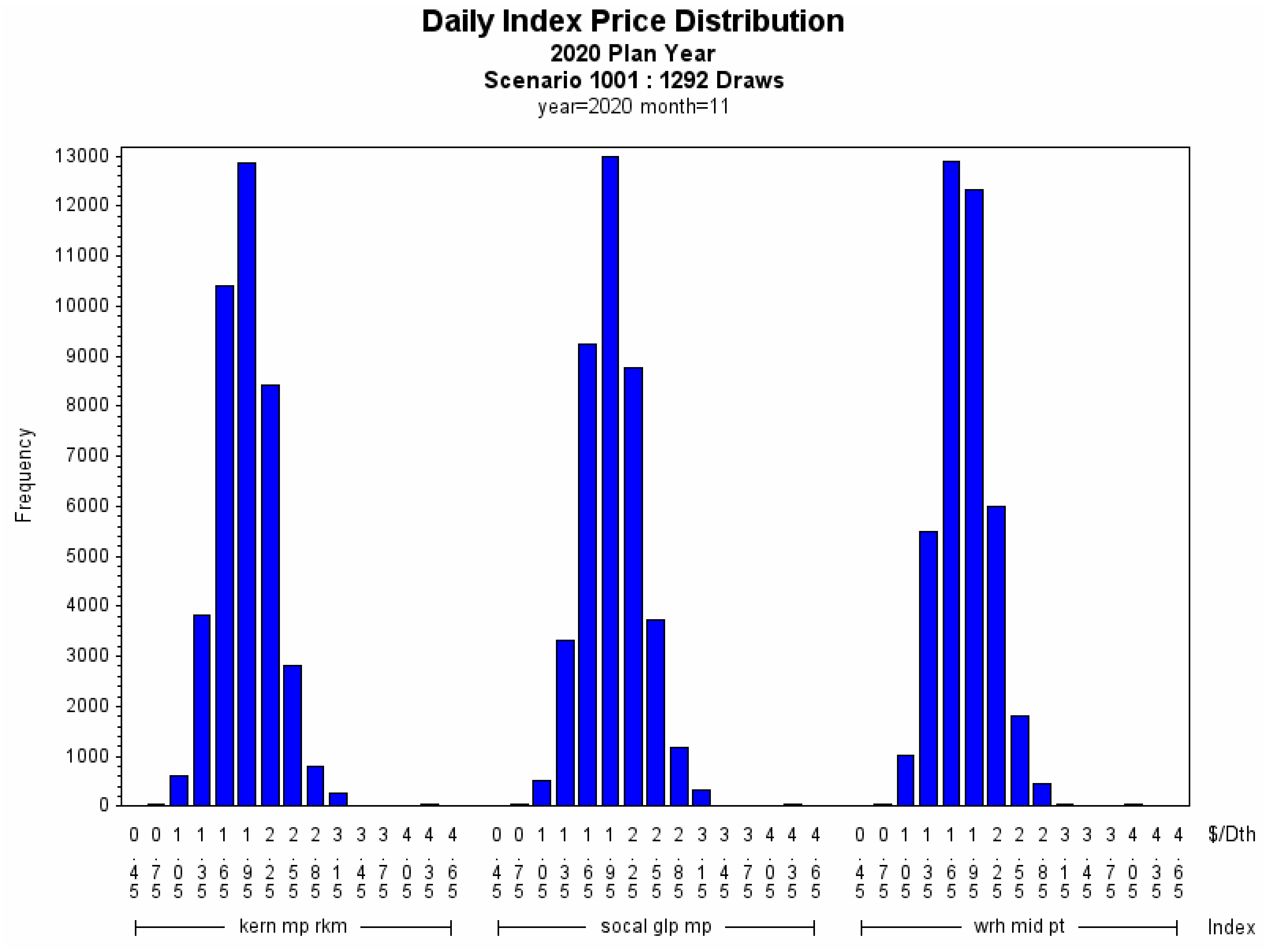

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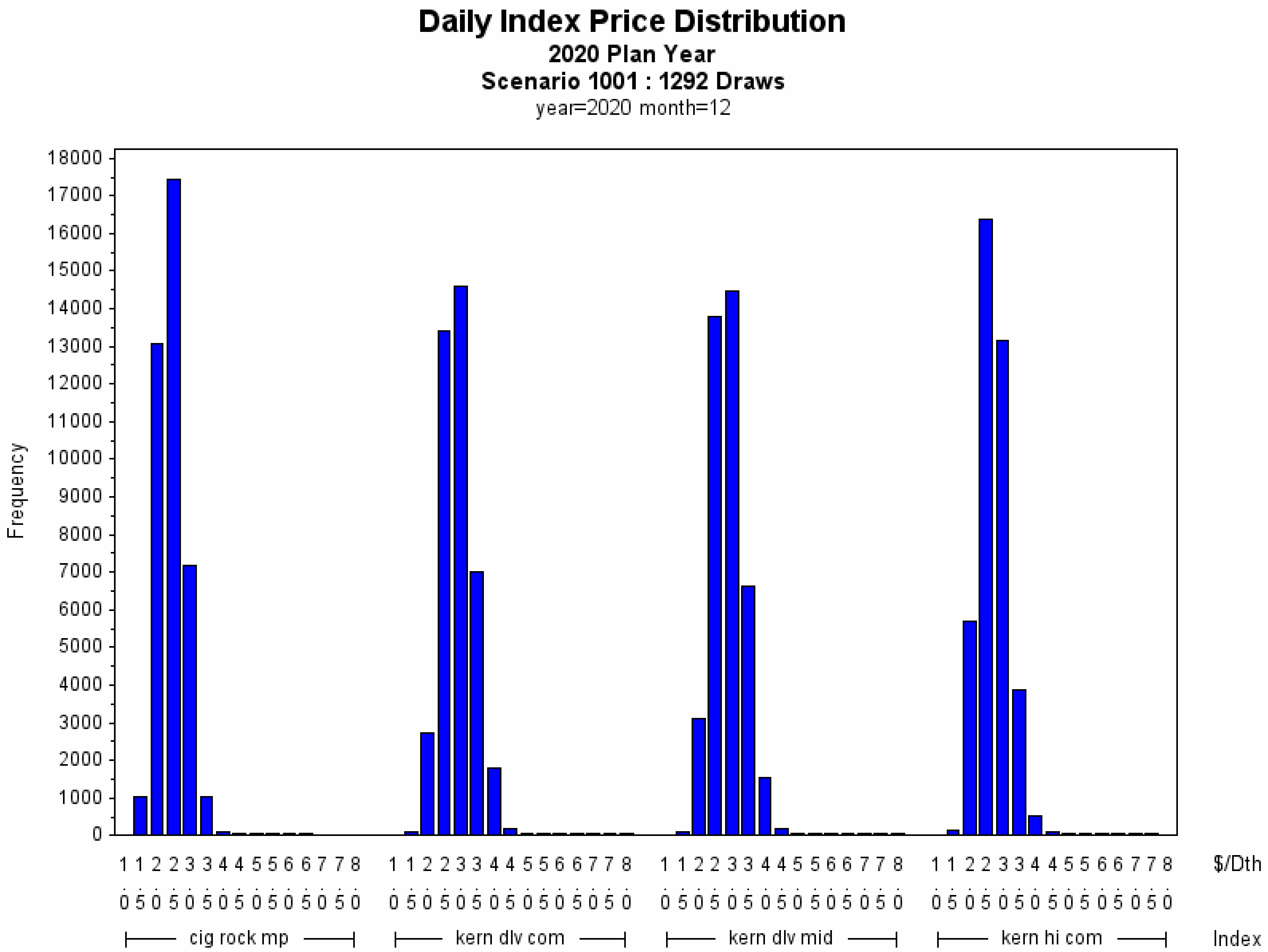

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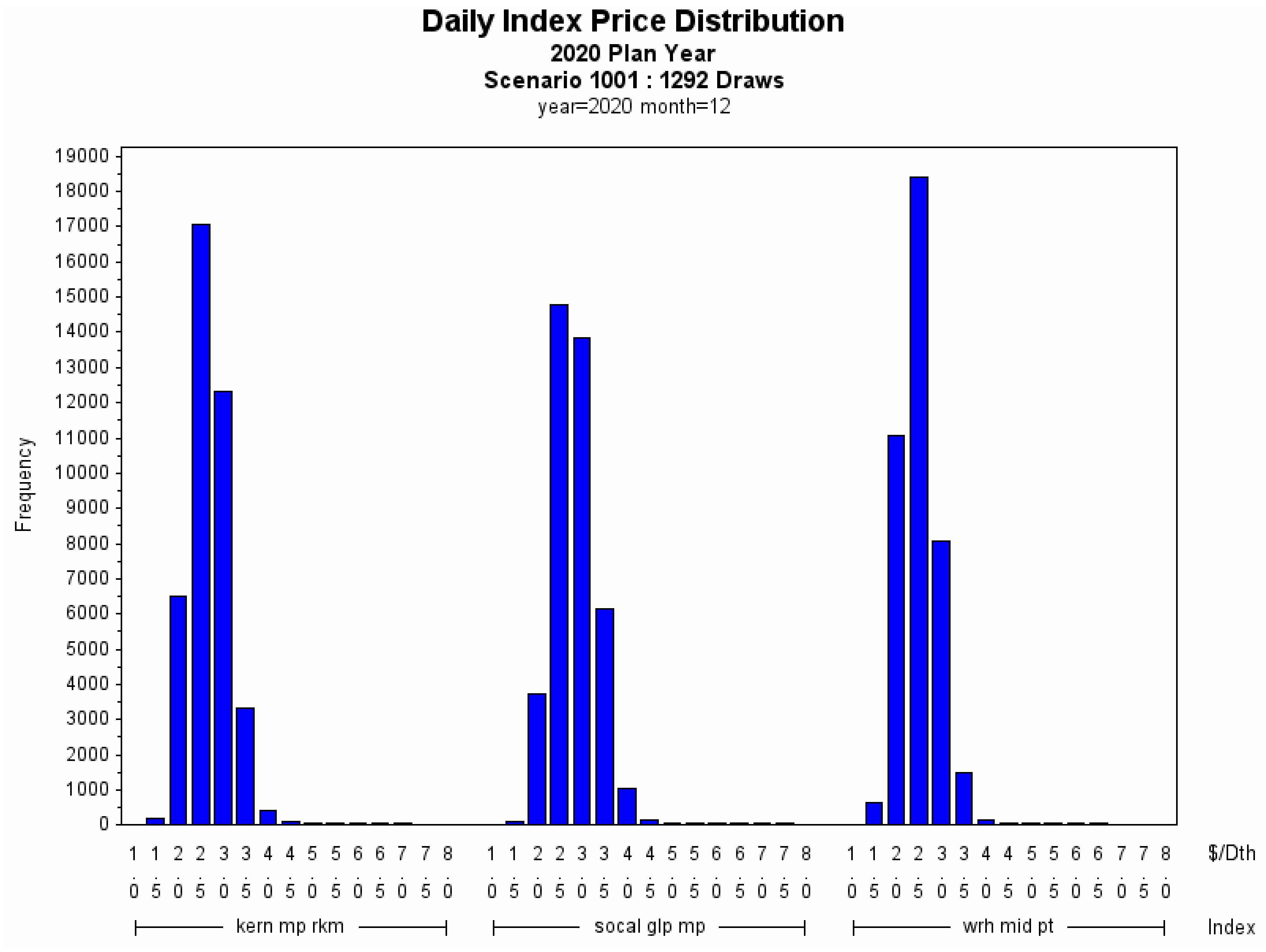

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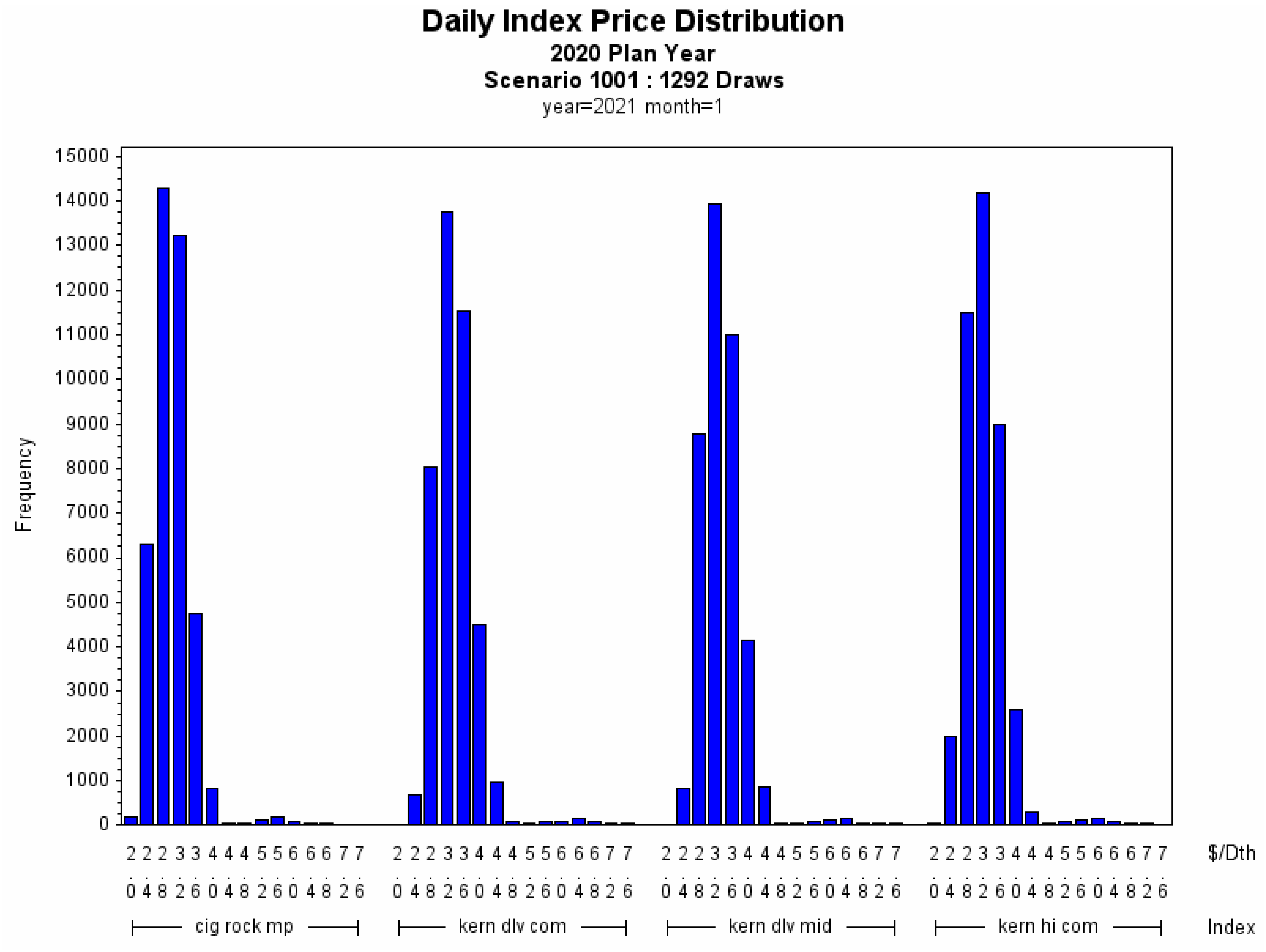


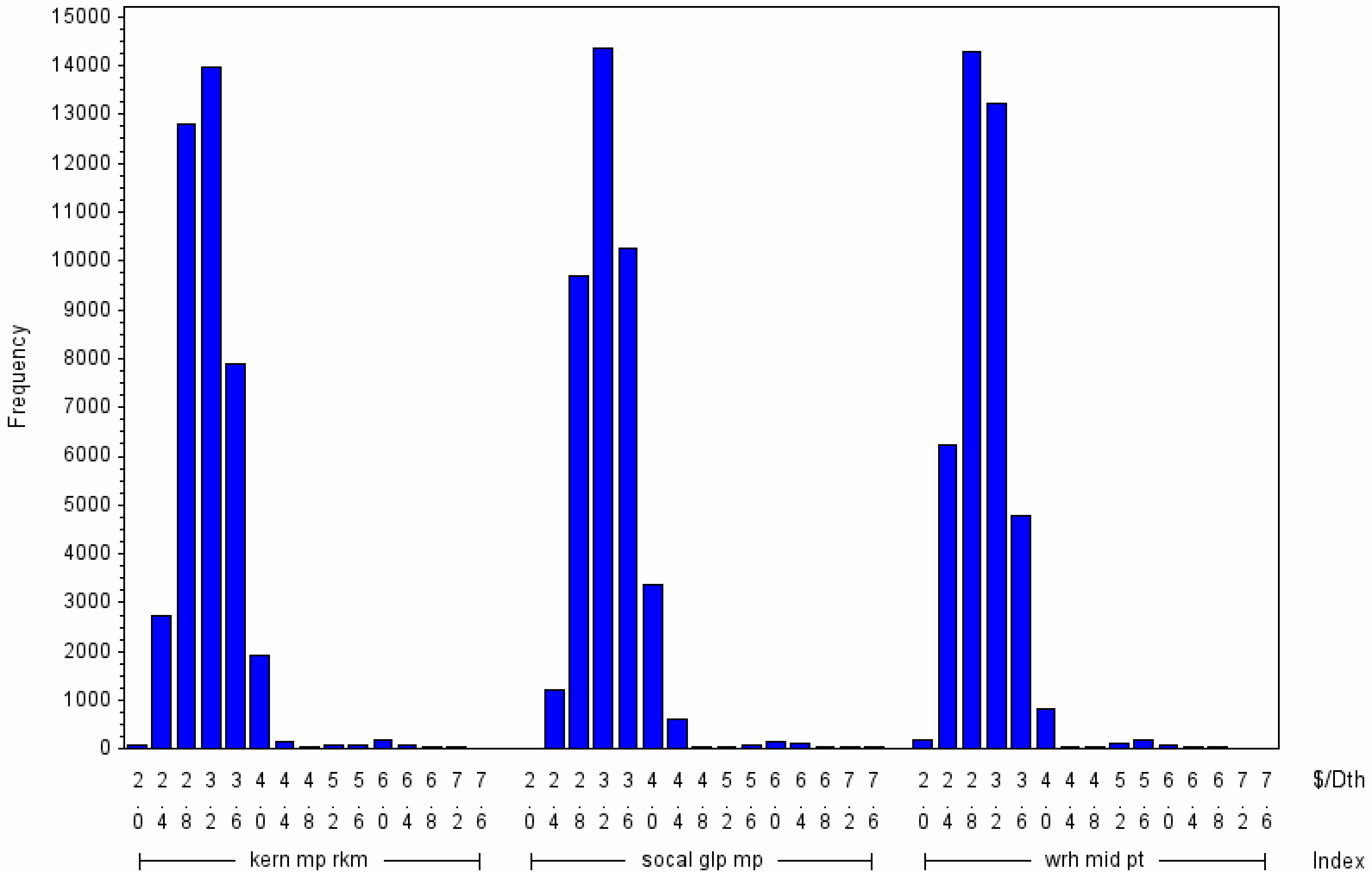
Exhibit 13.27

Daily Index Price Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2021 month=1



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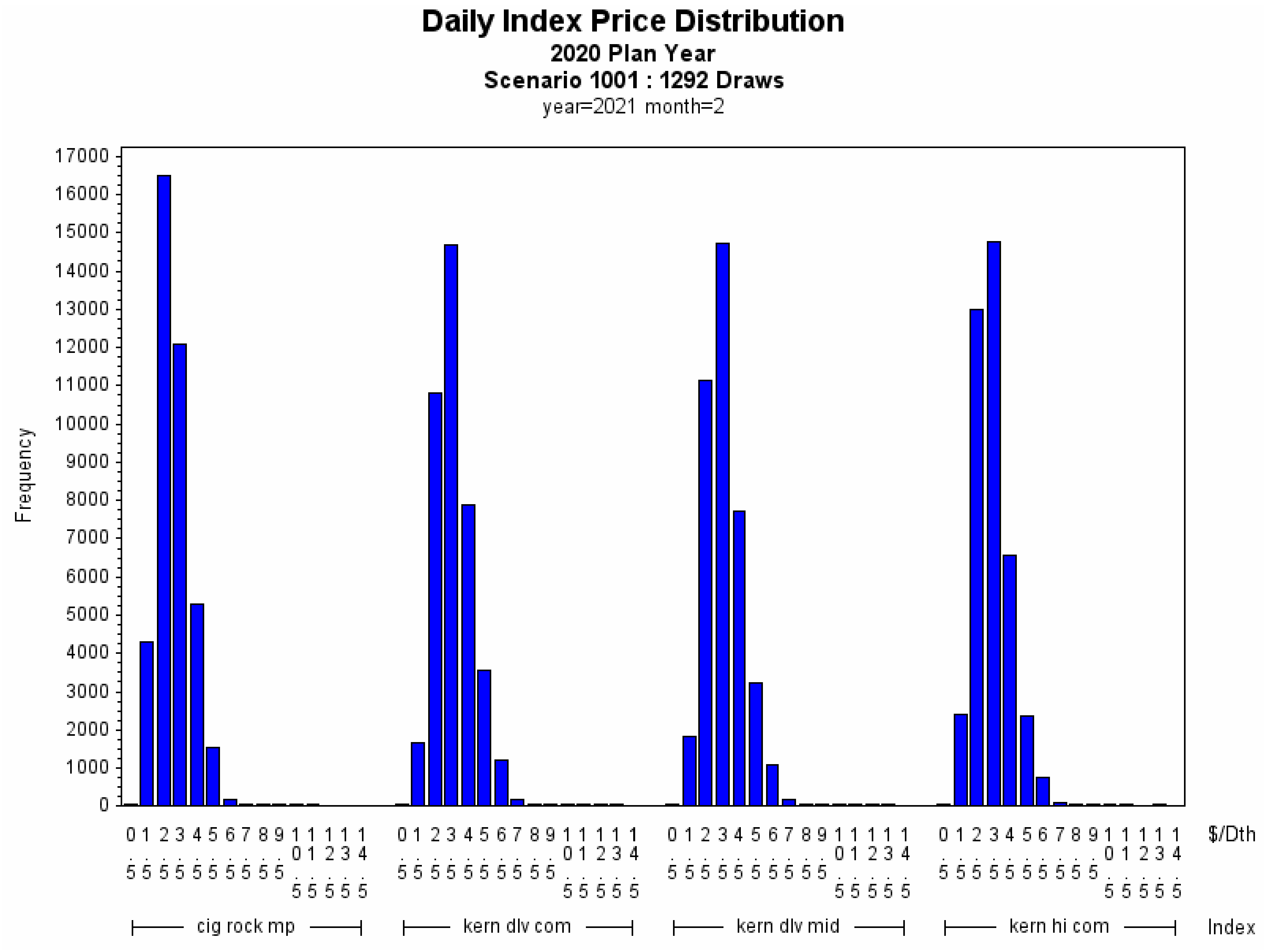

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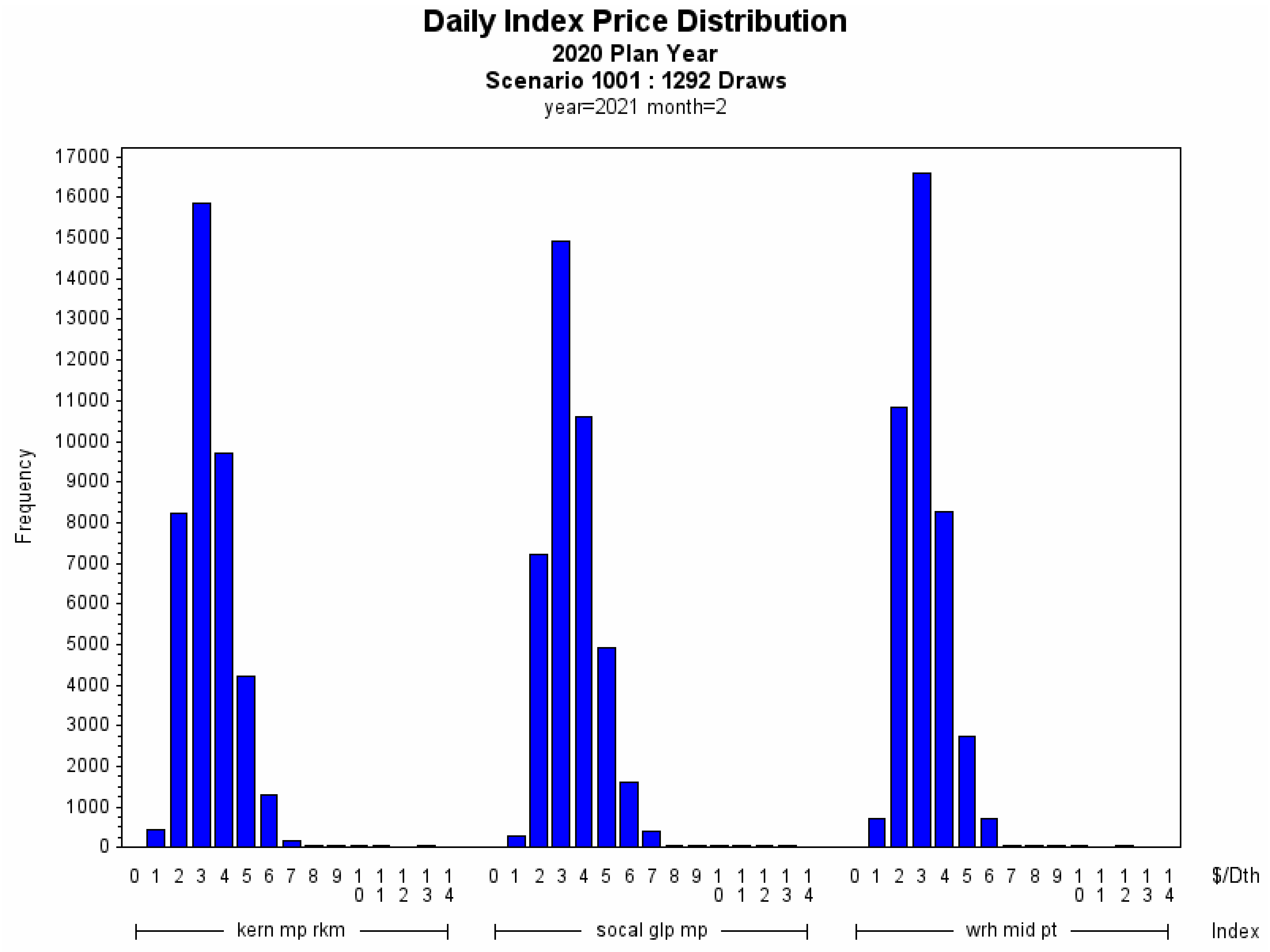

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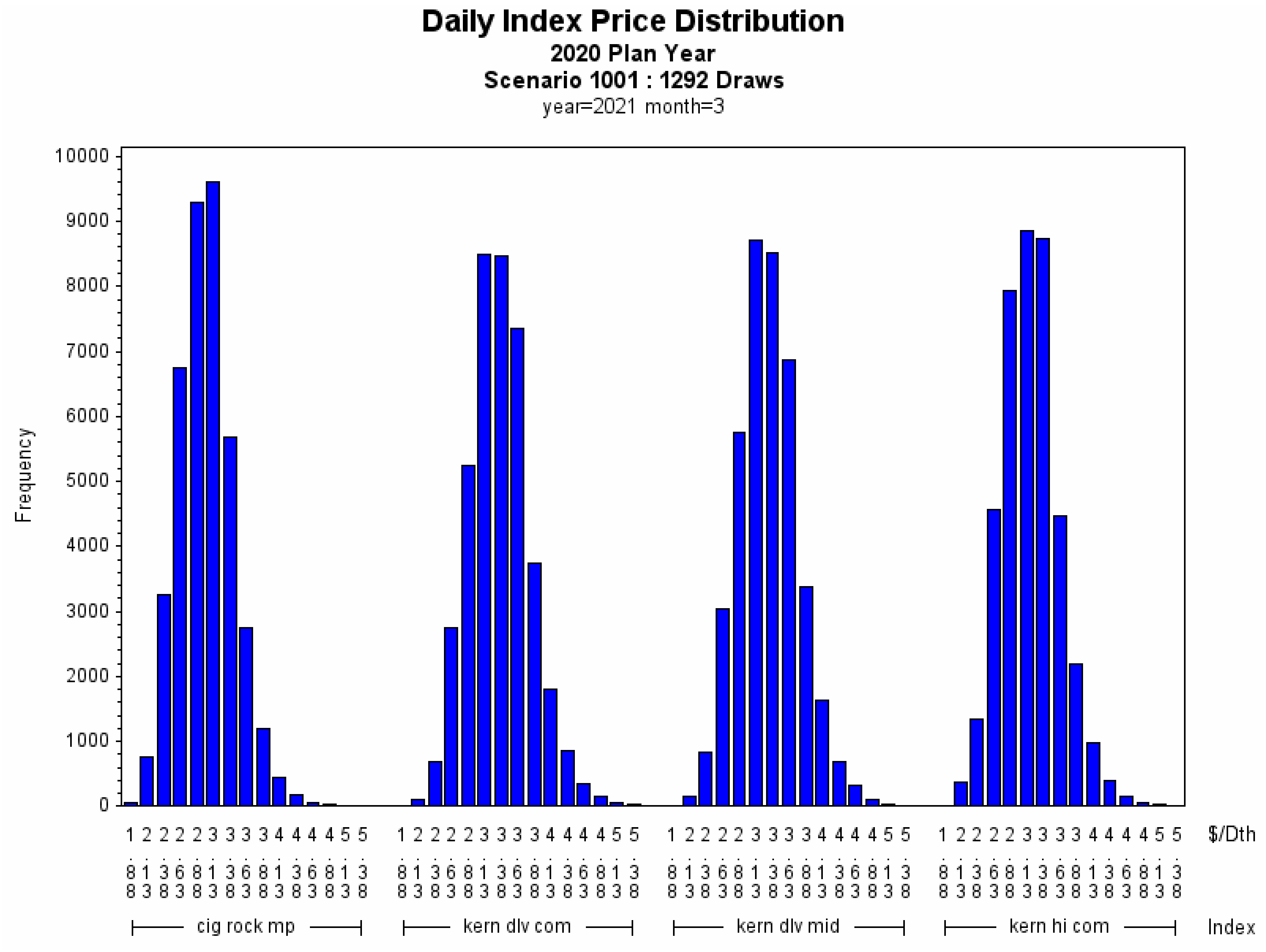

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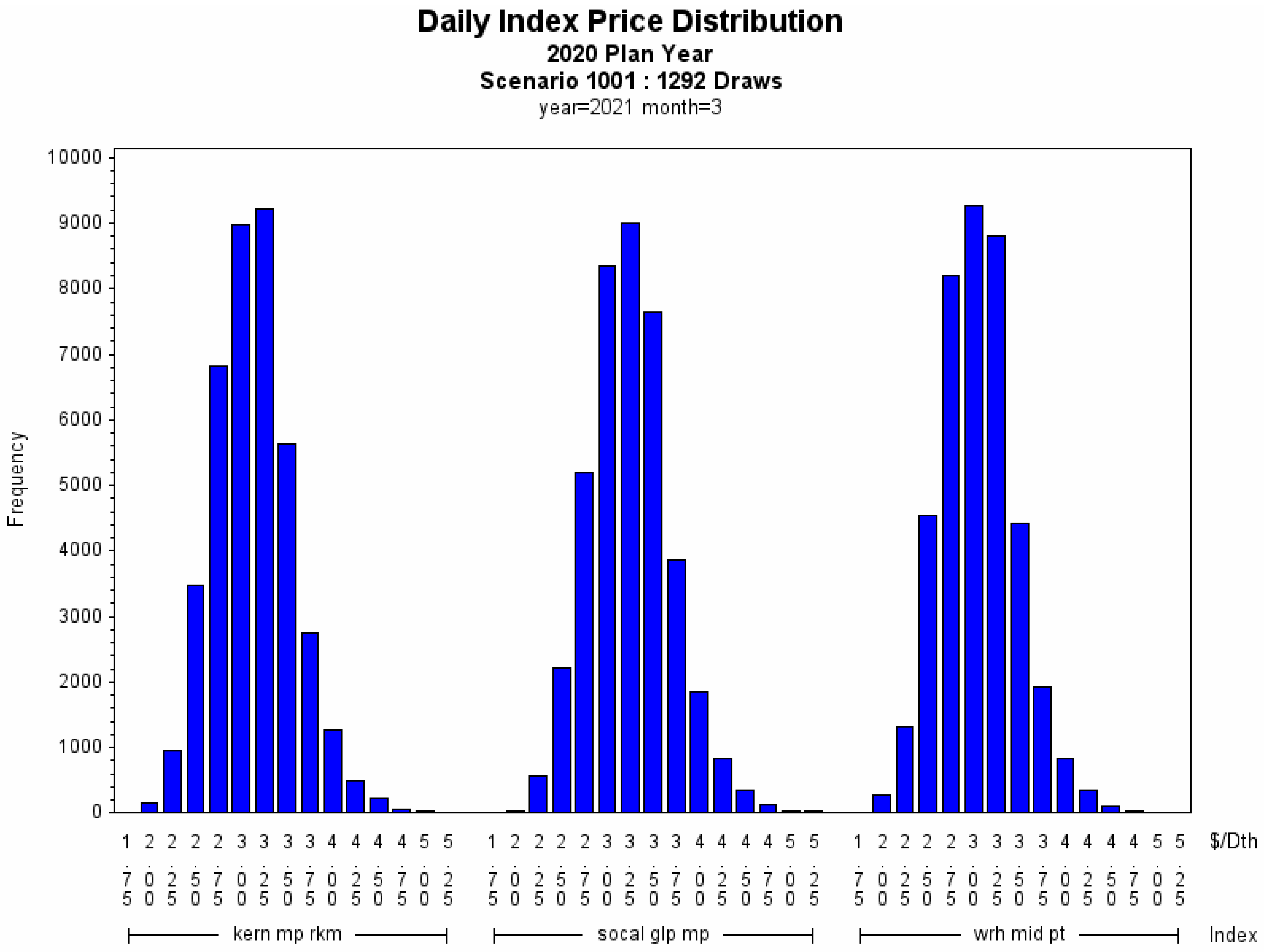

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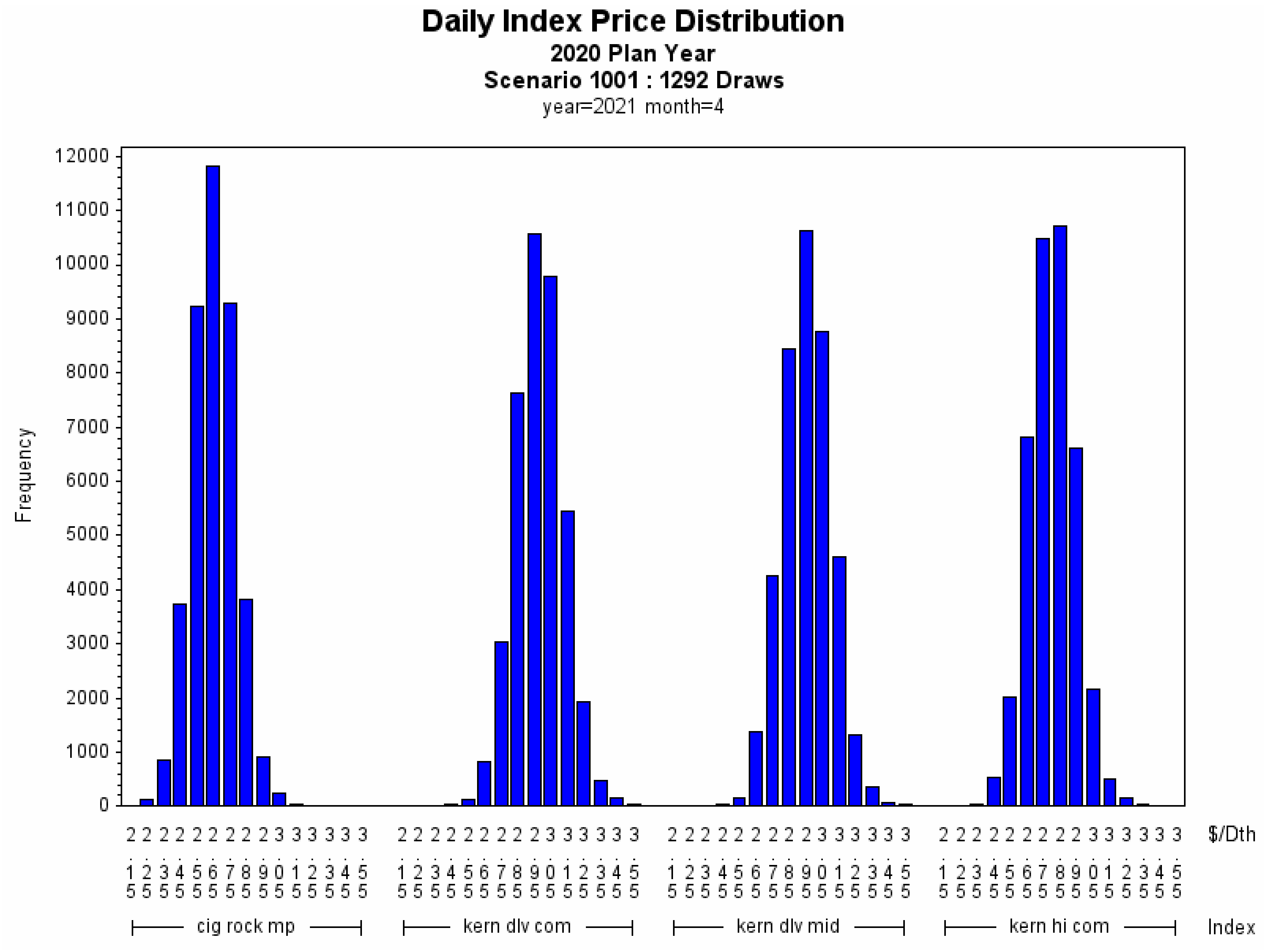

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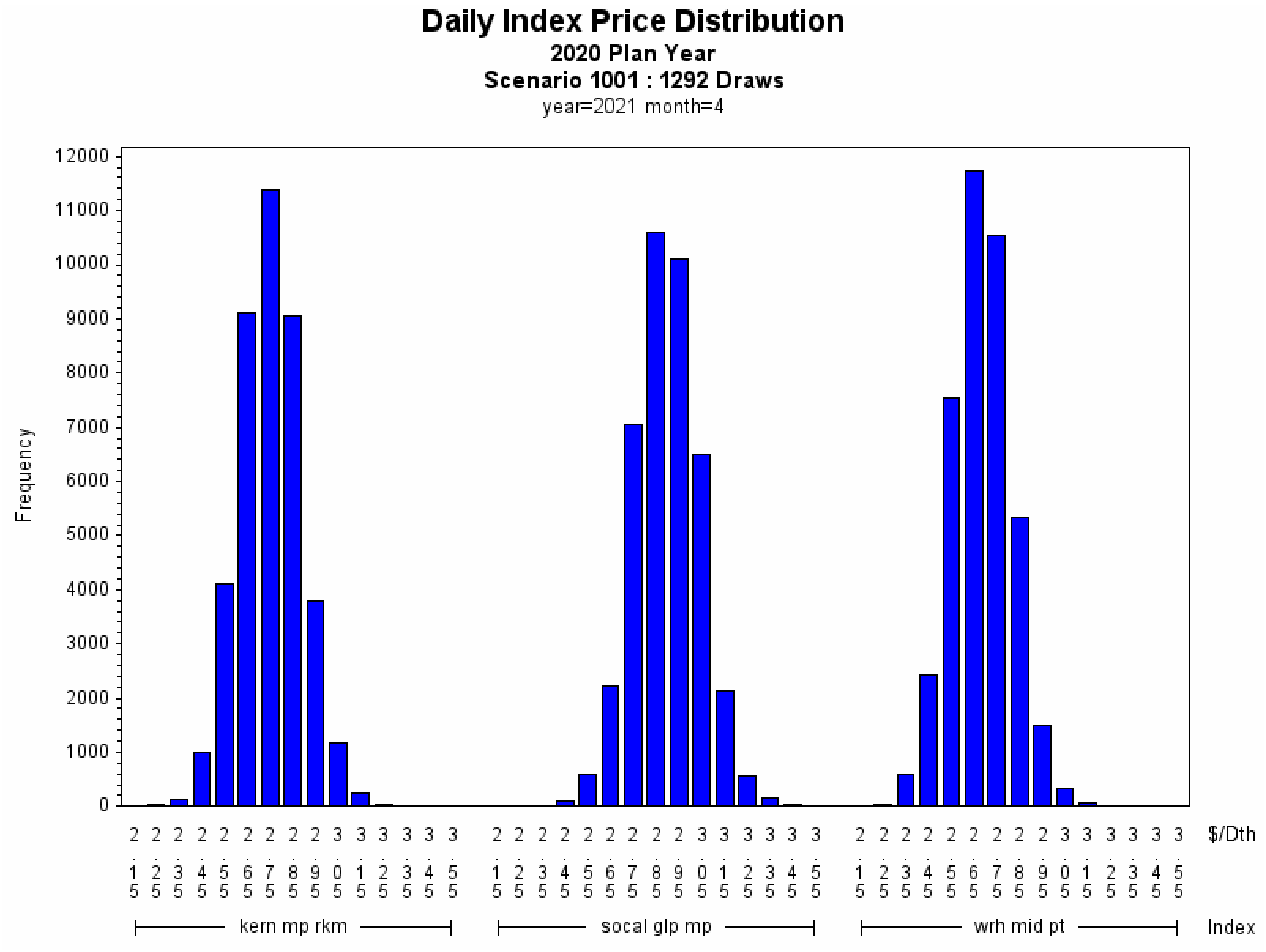

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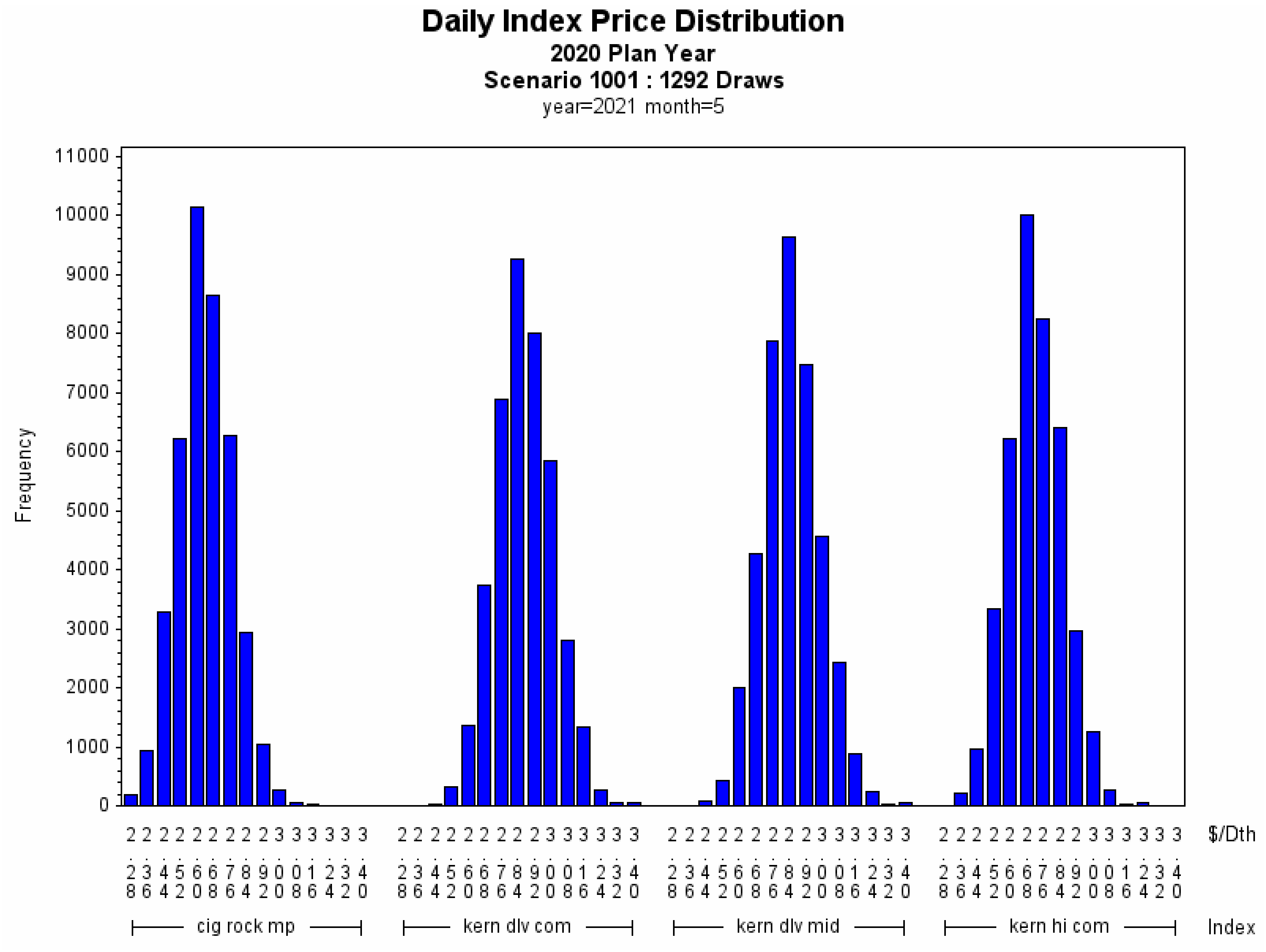

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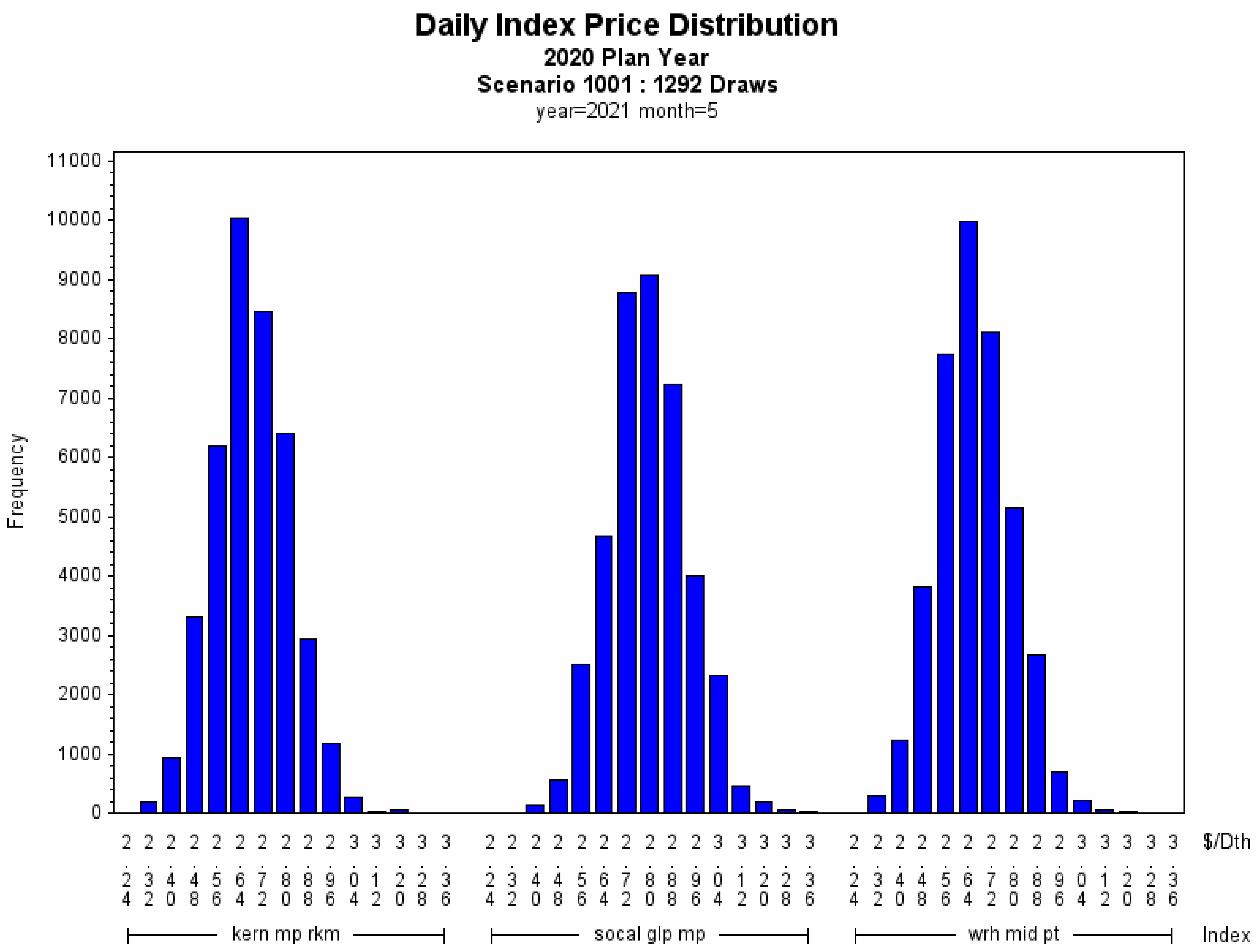

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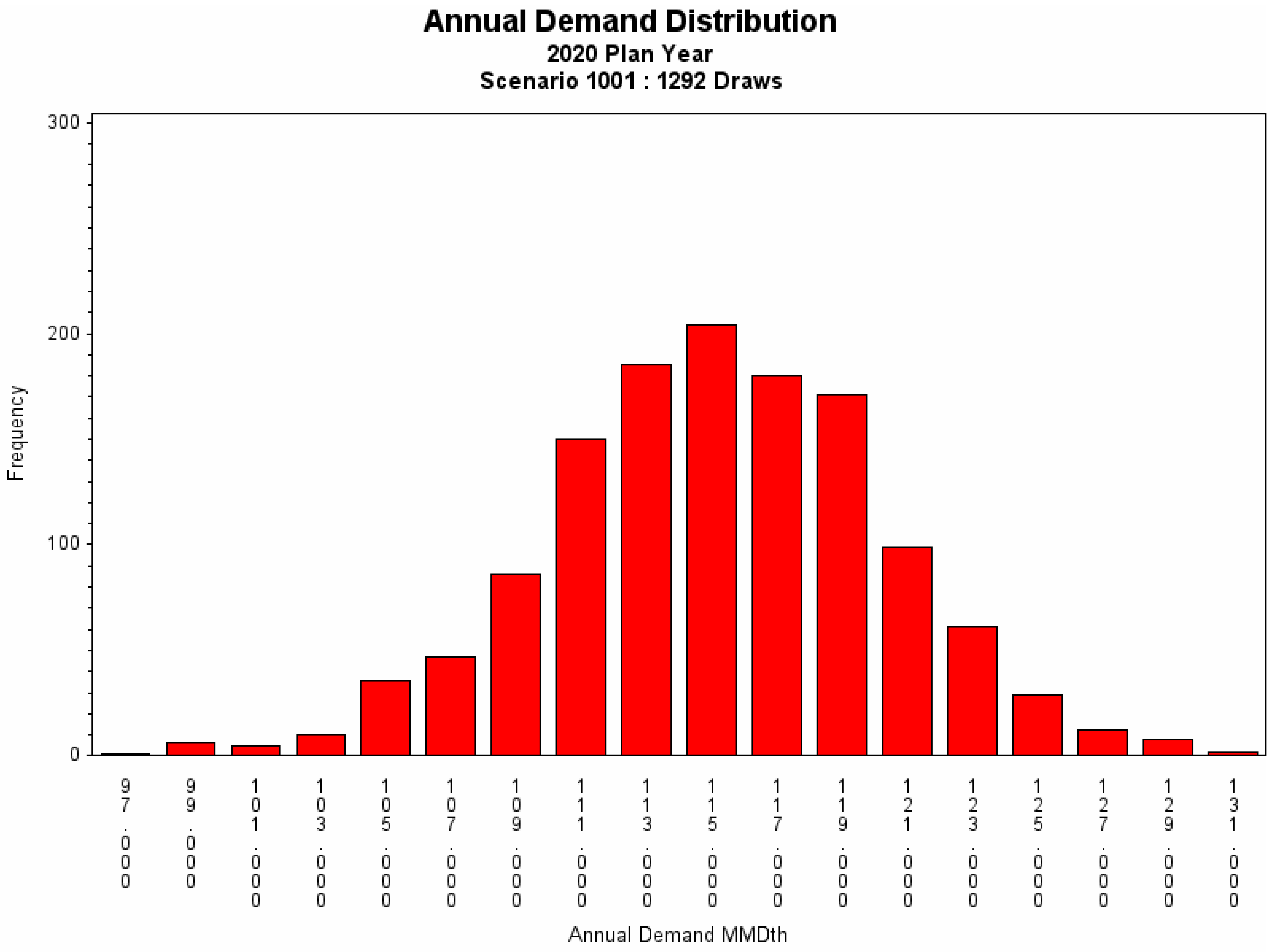

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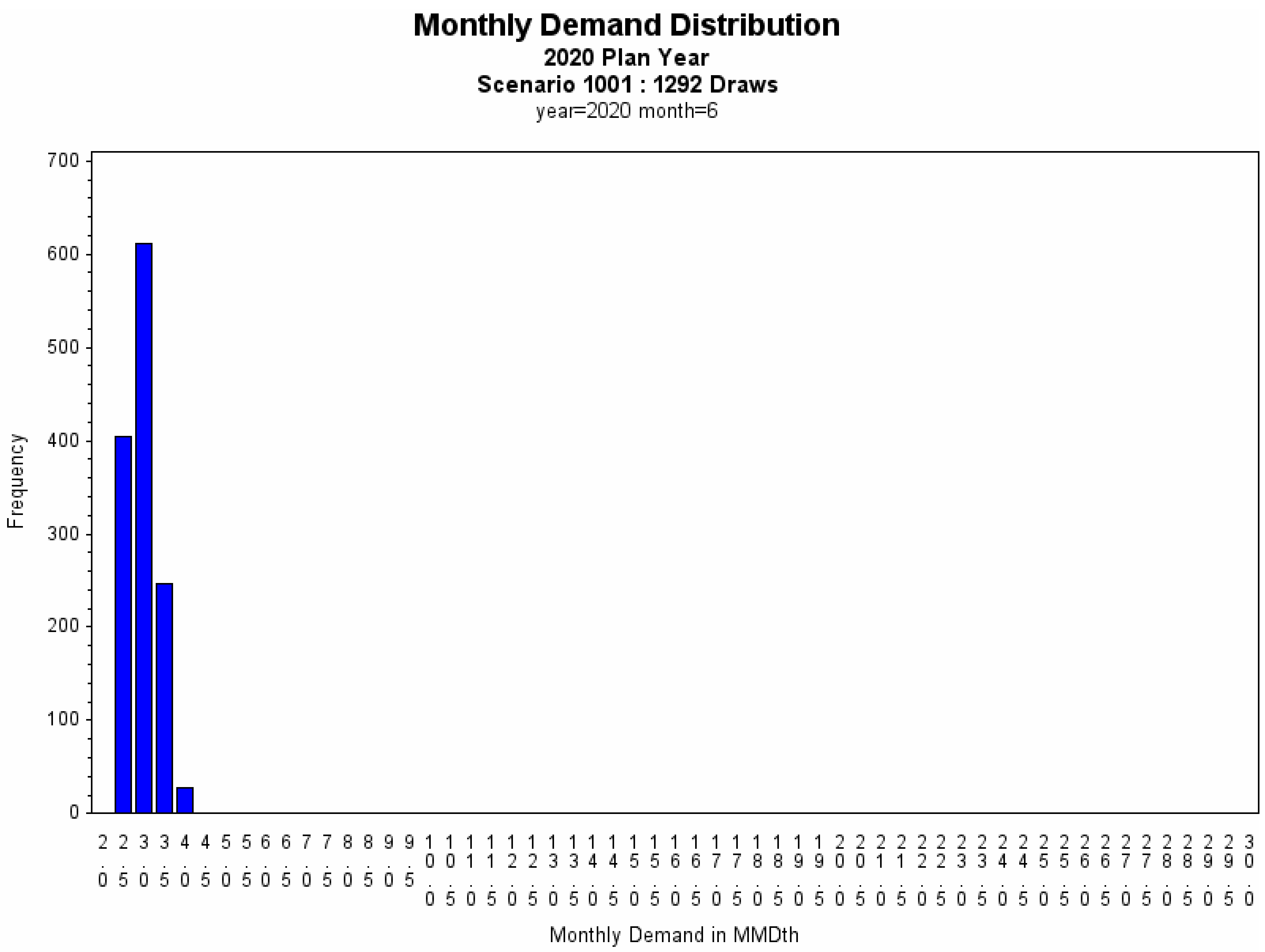


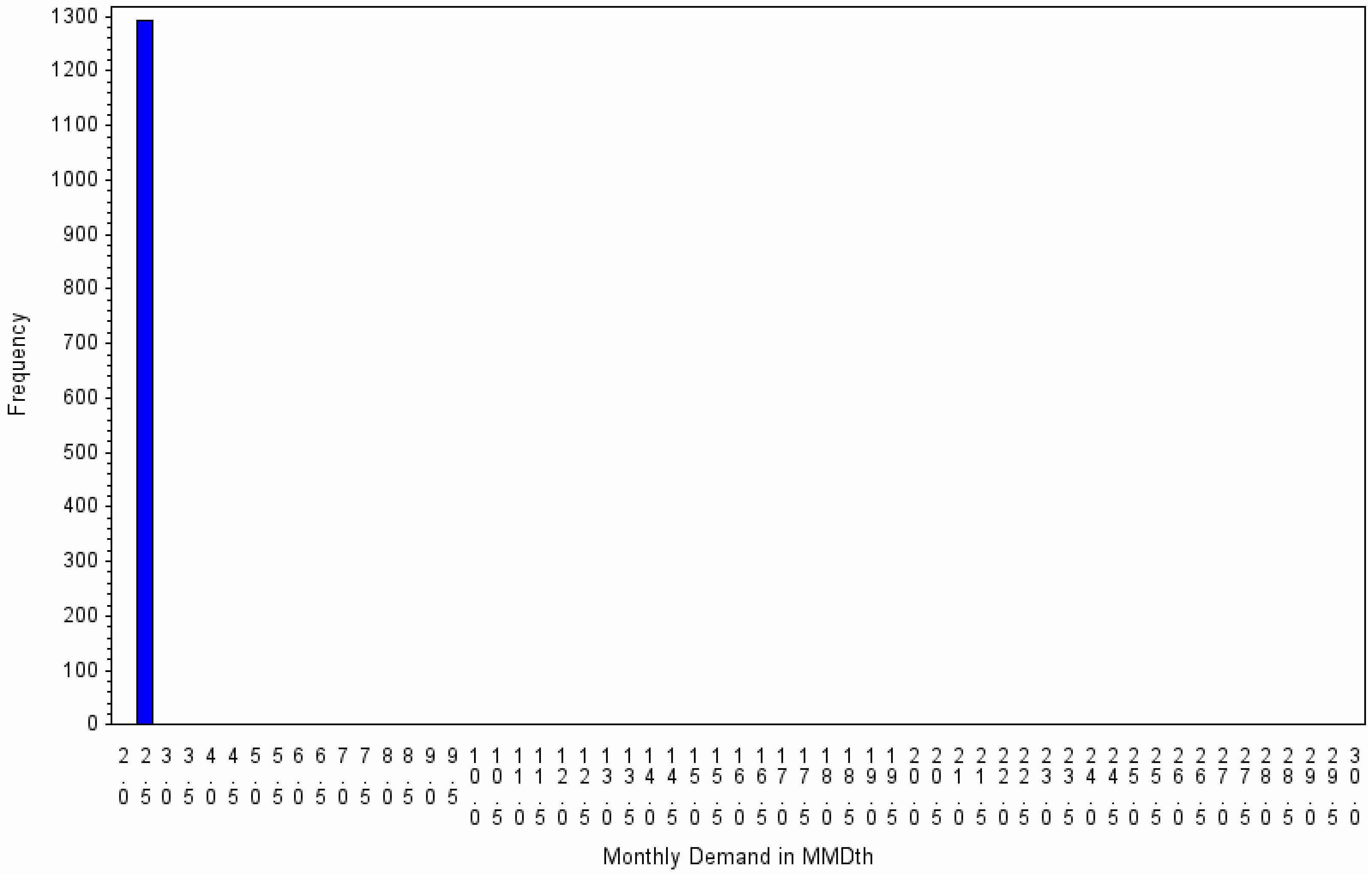
Exhibit 13.38

Monthly Demand Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2020 month=7



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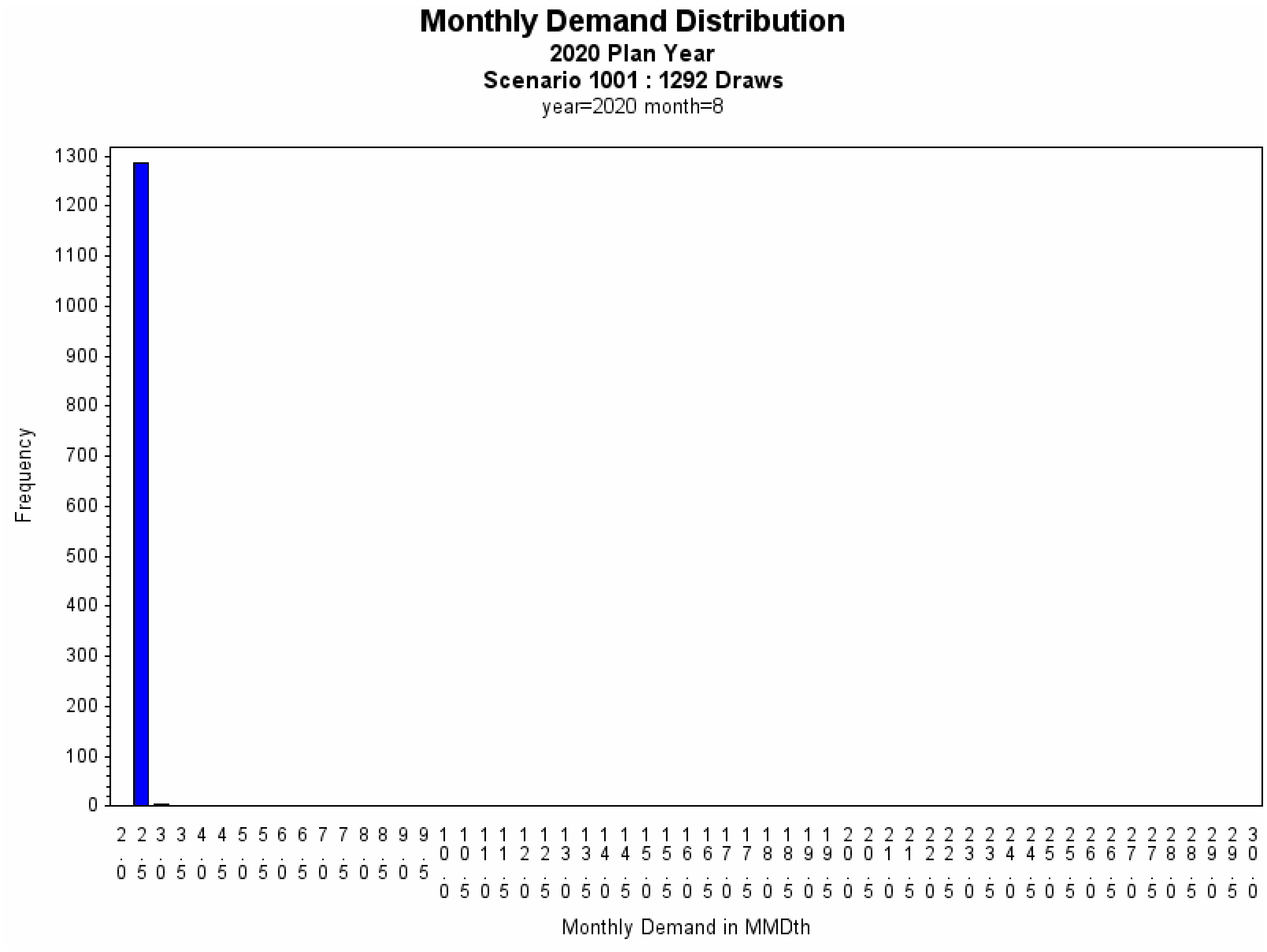

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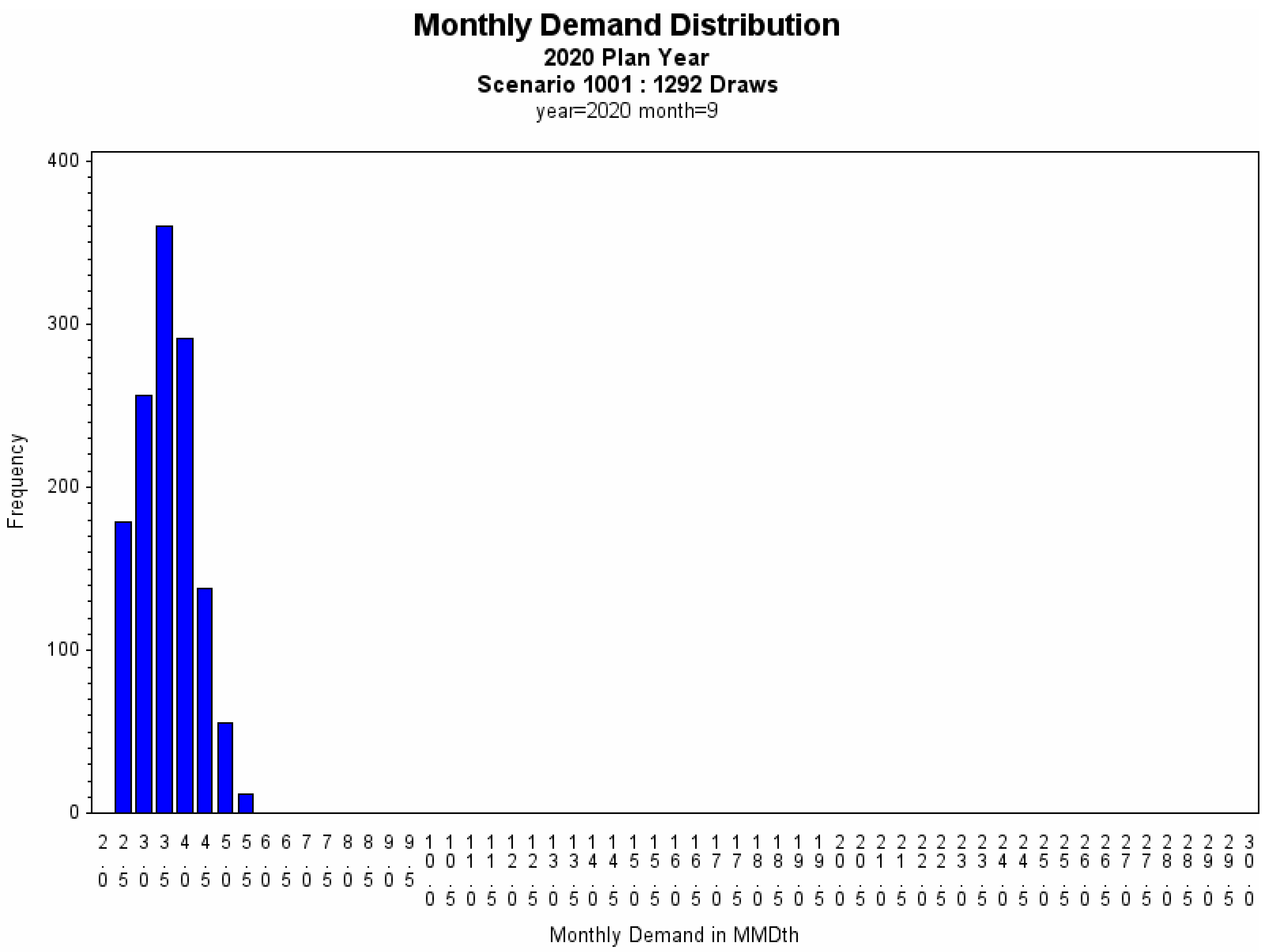

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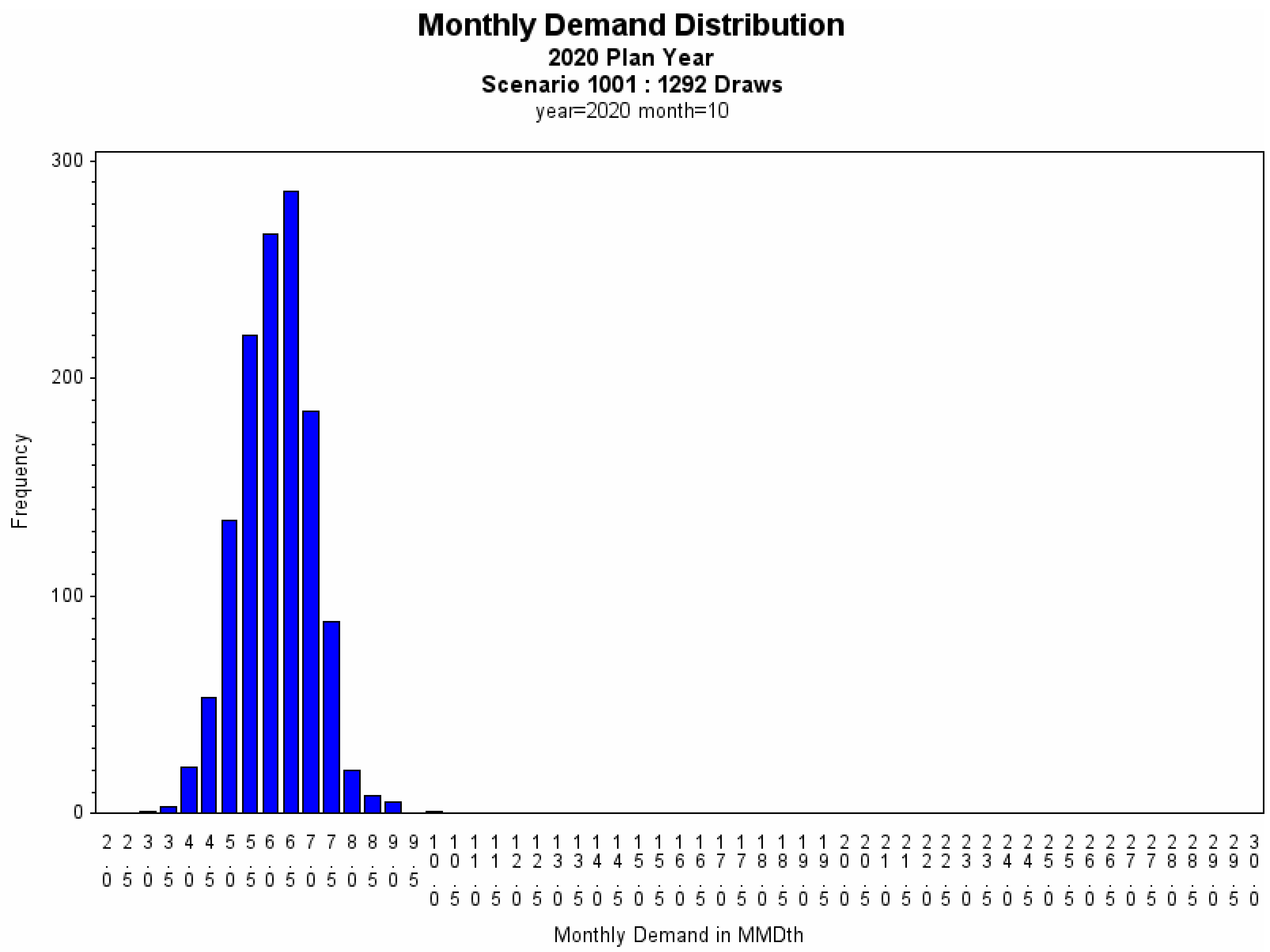

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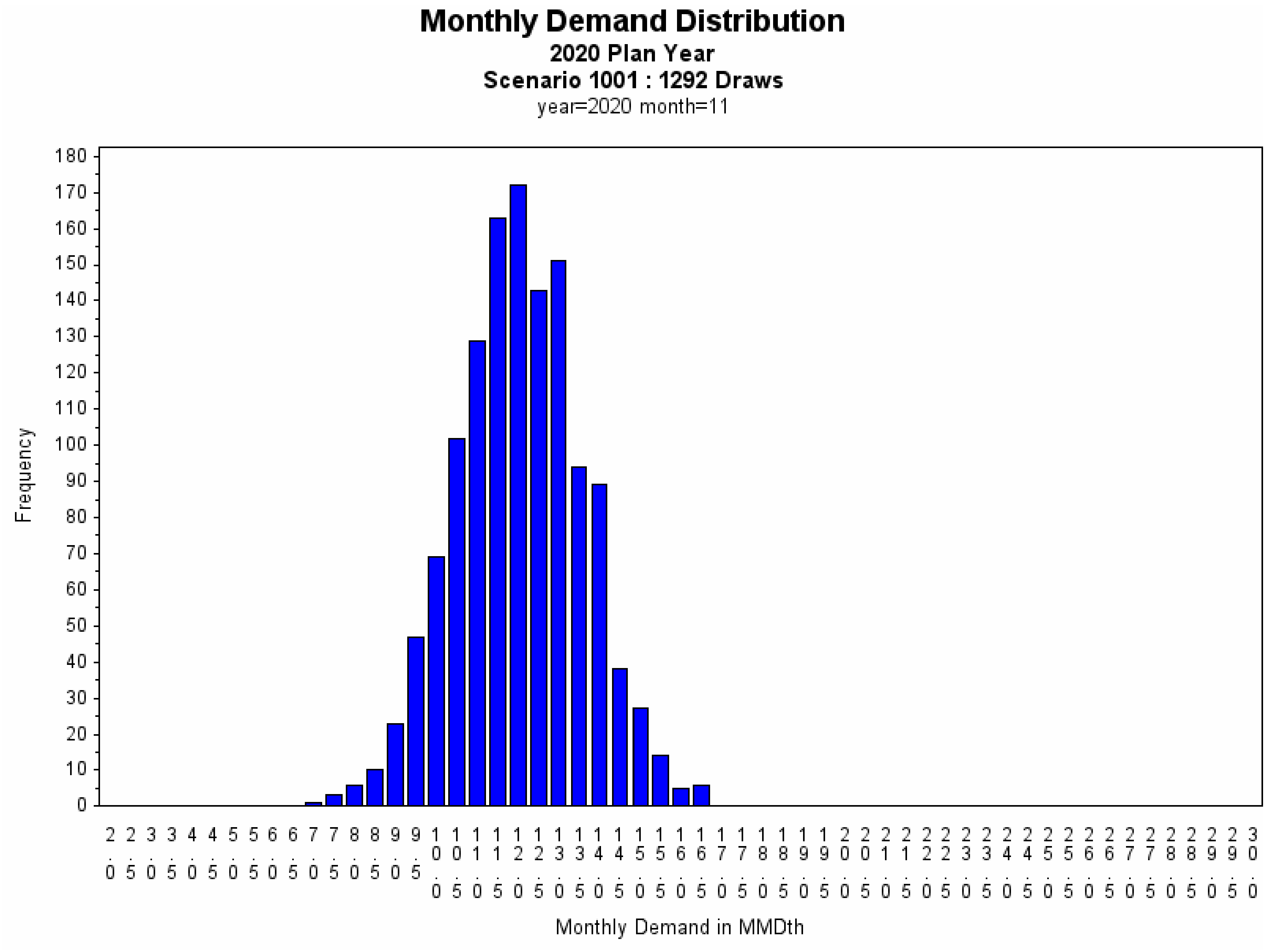

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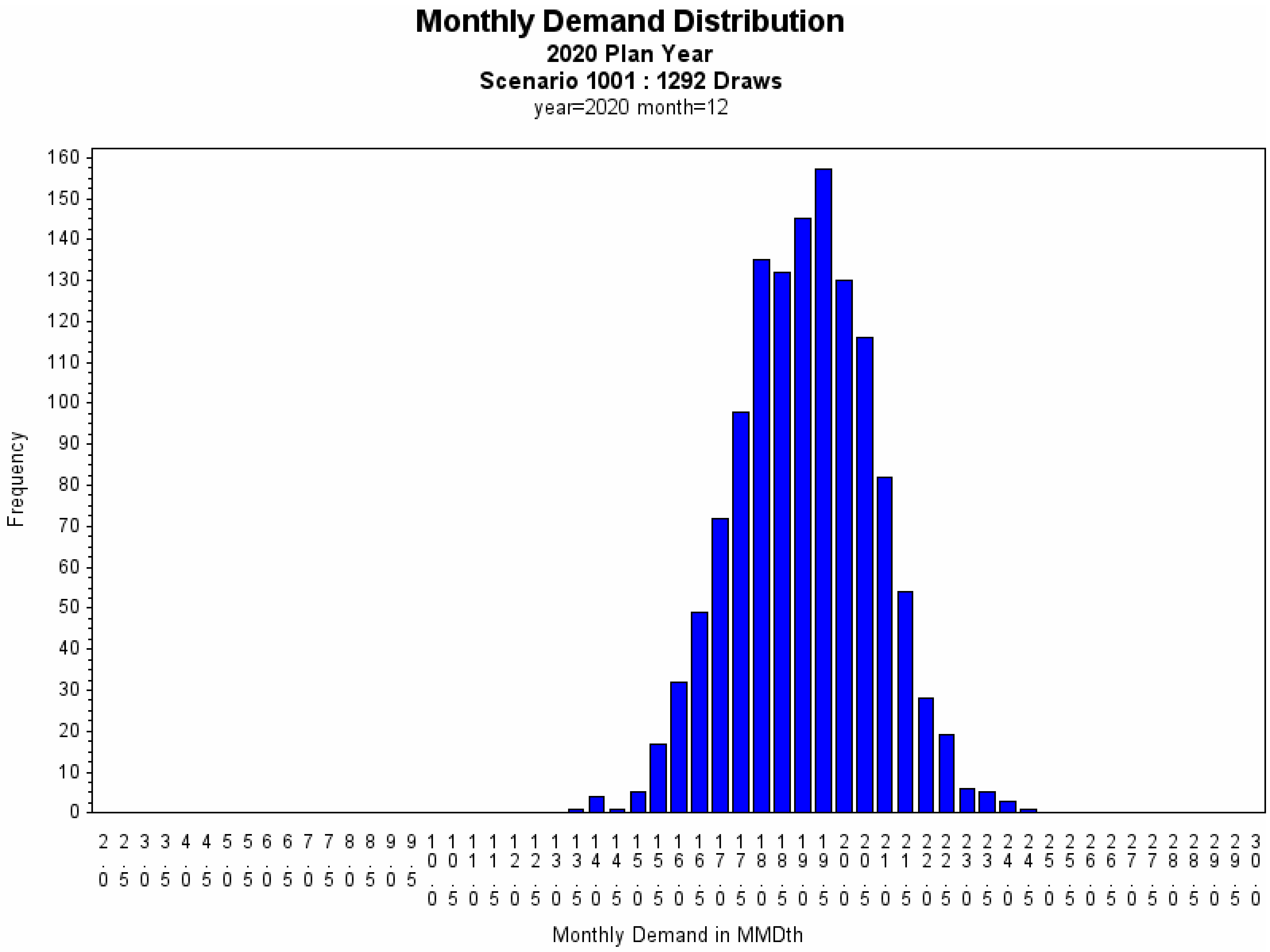

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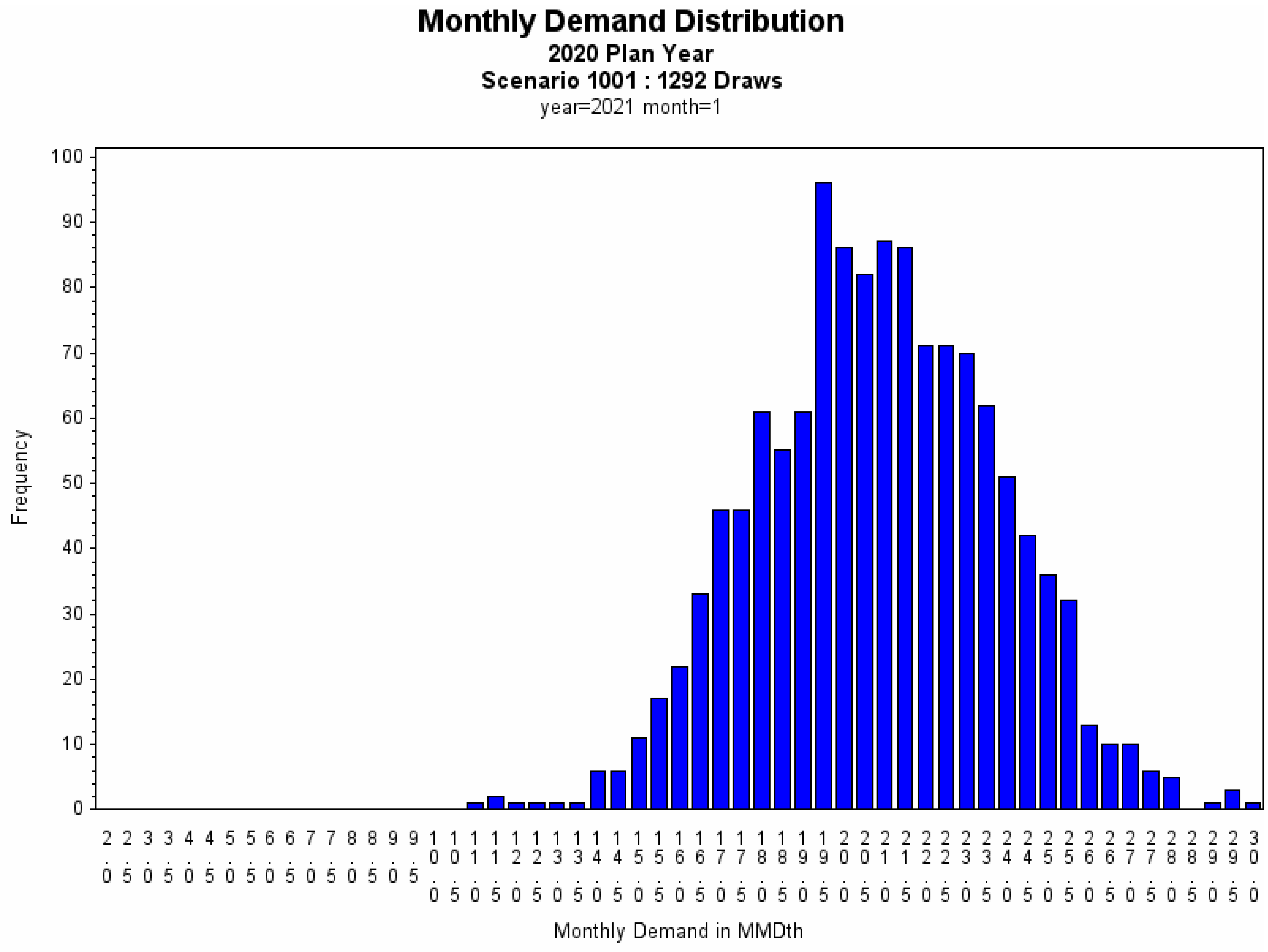

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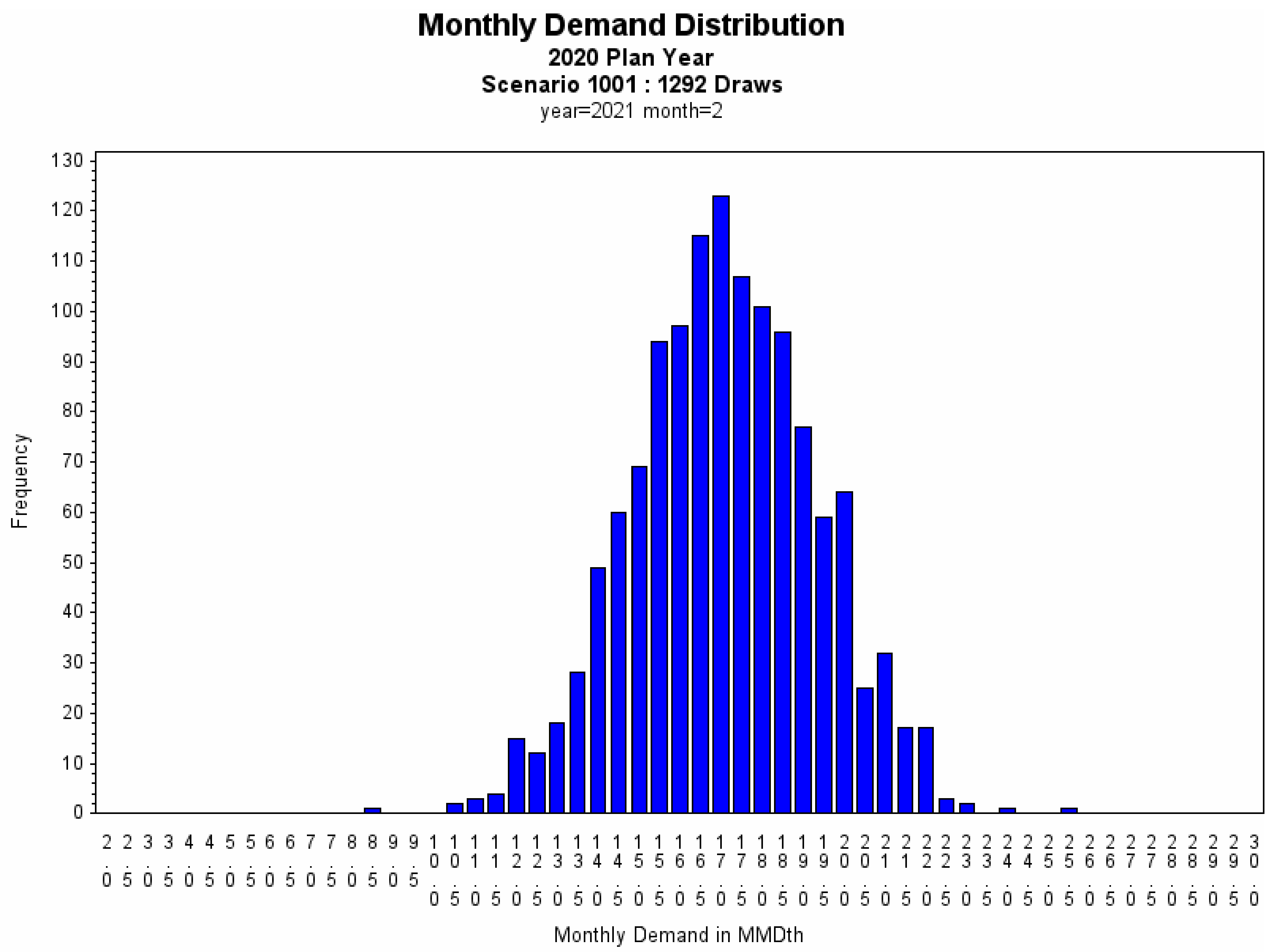

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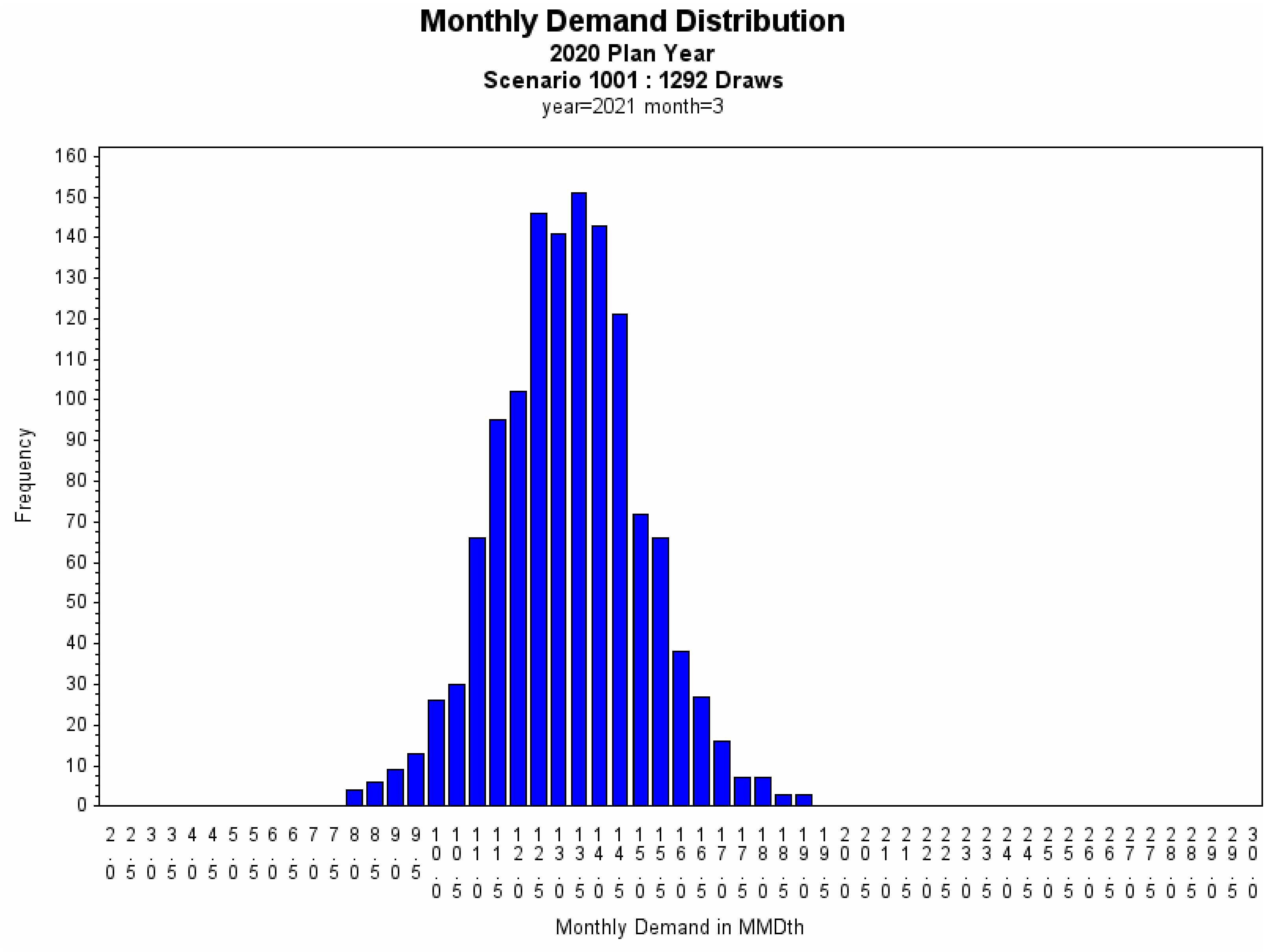

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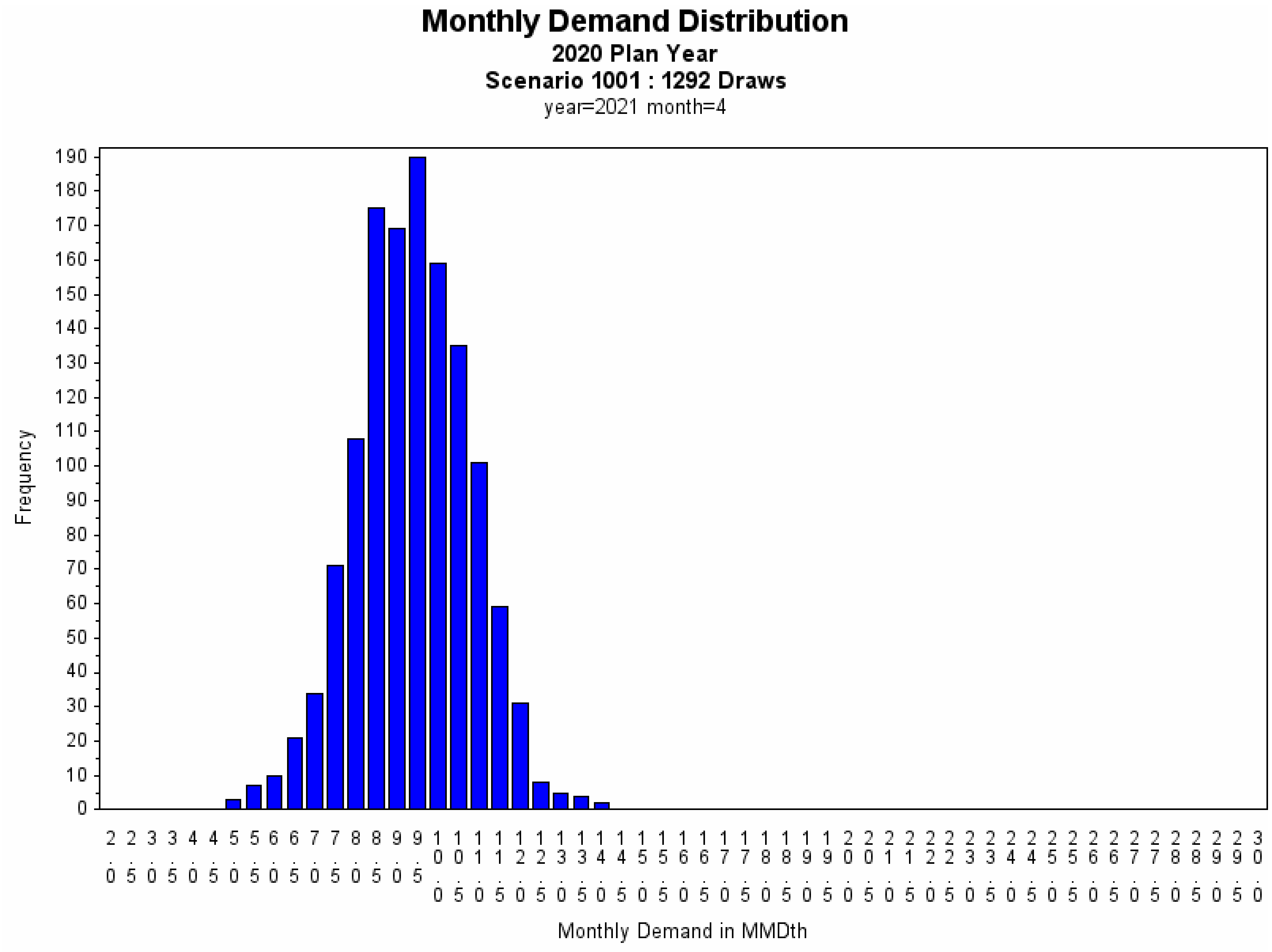

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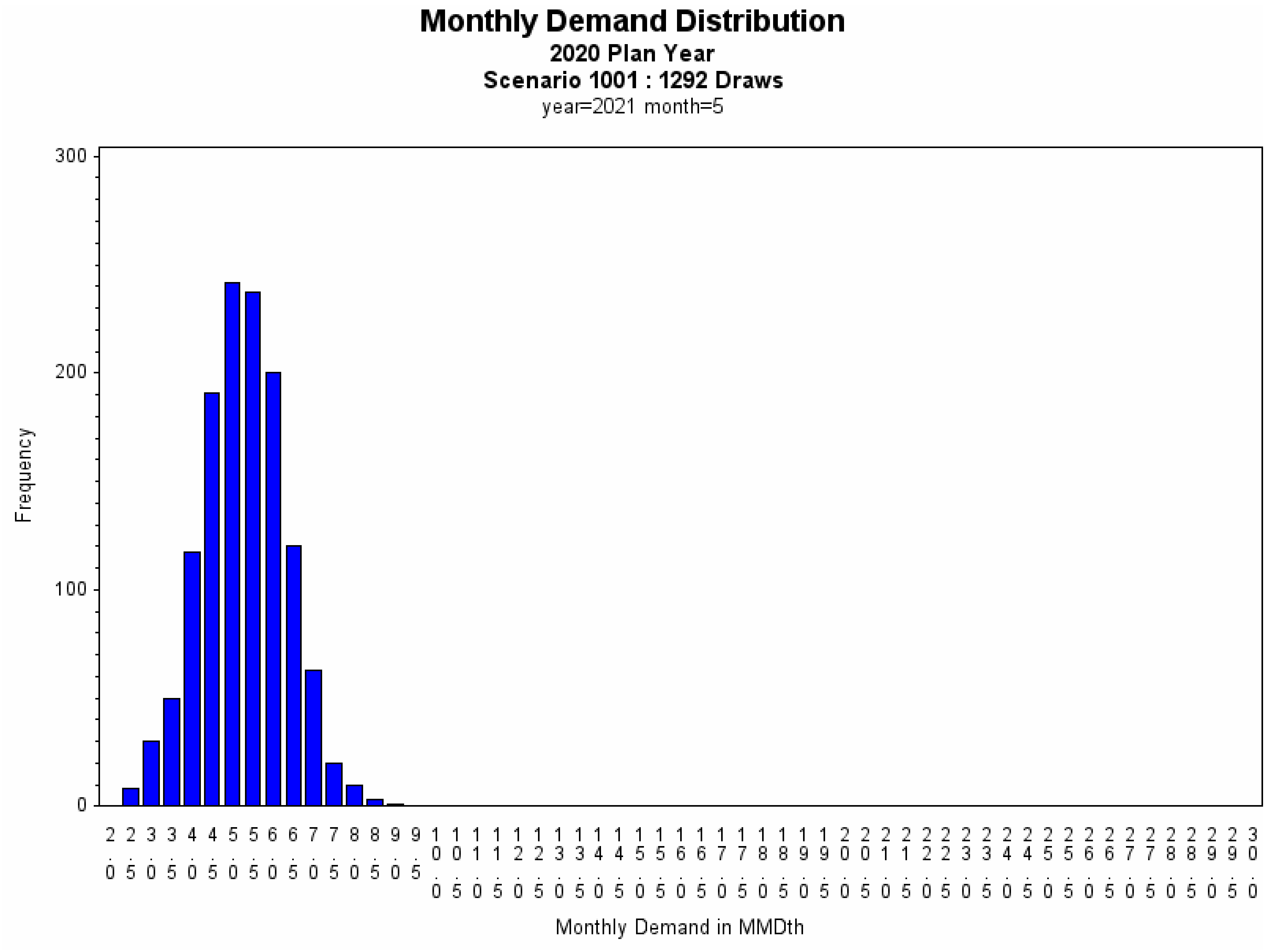
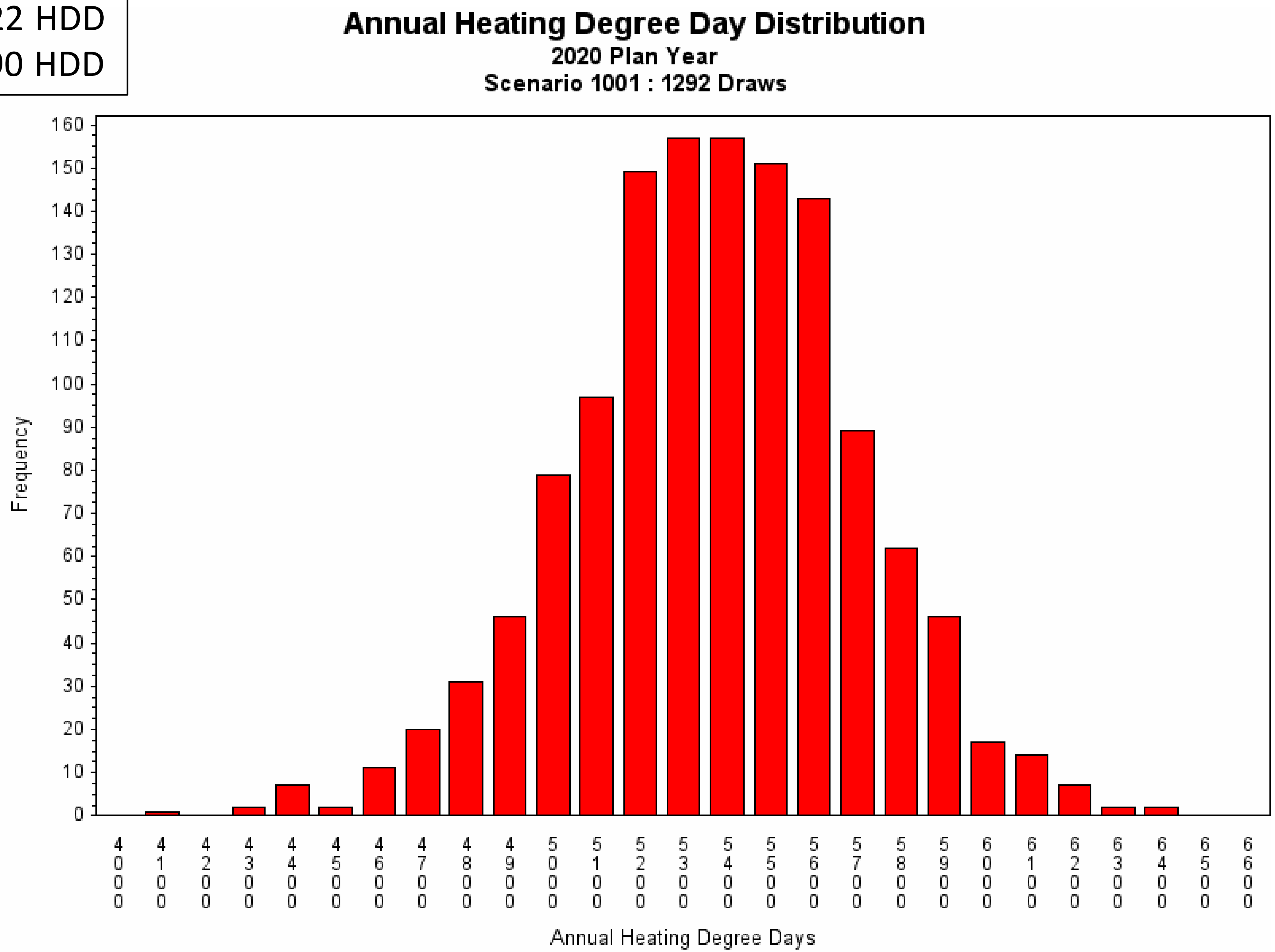


Exhibit 13.49

Mean:	5,371.75 HDD
Median:	5,374.22 HDD
Normal Case:	5,352.90 HDD



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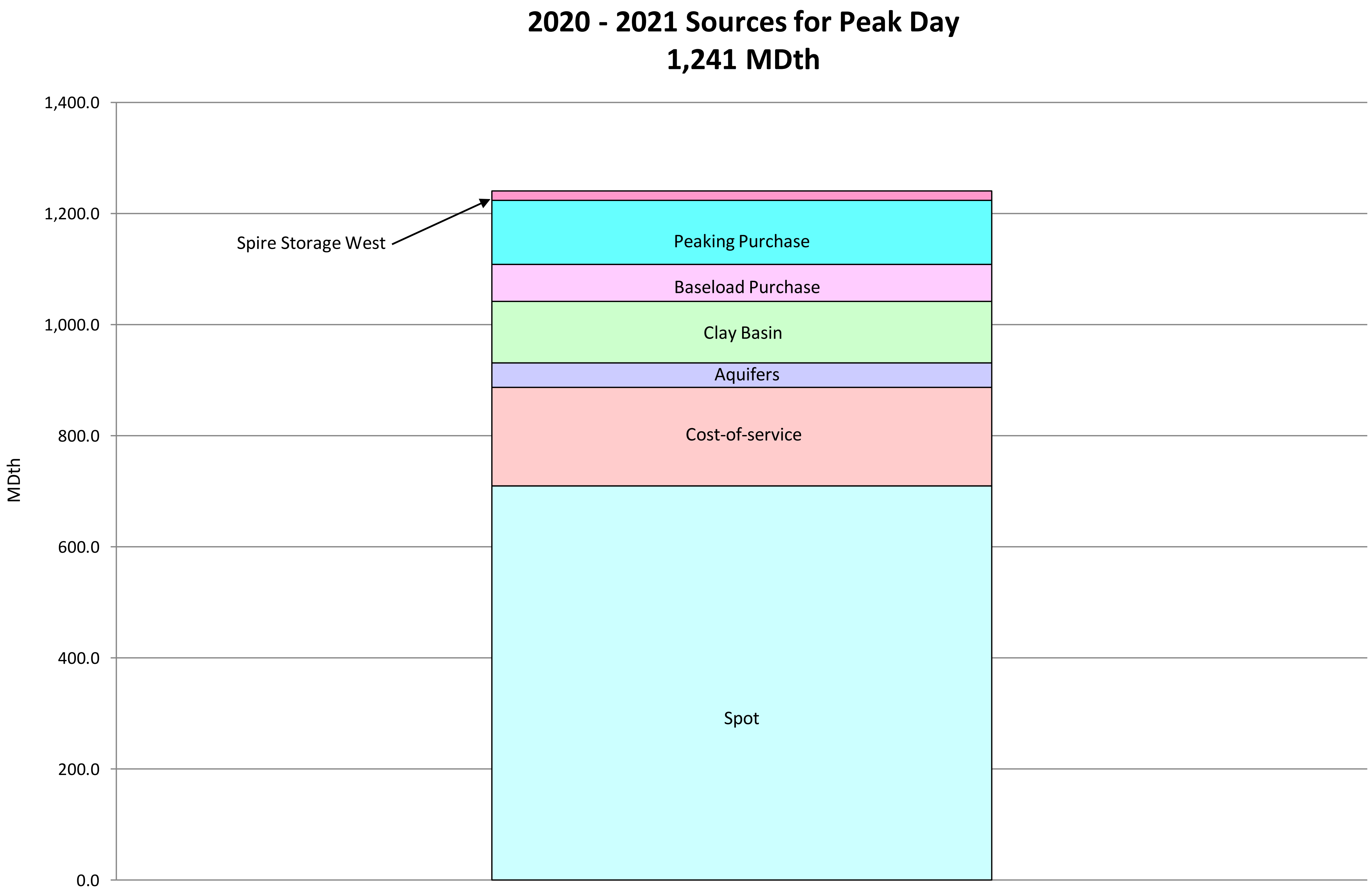

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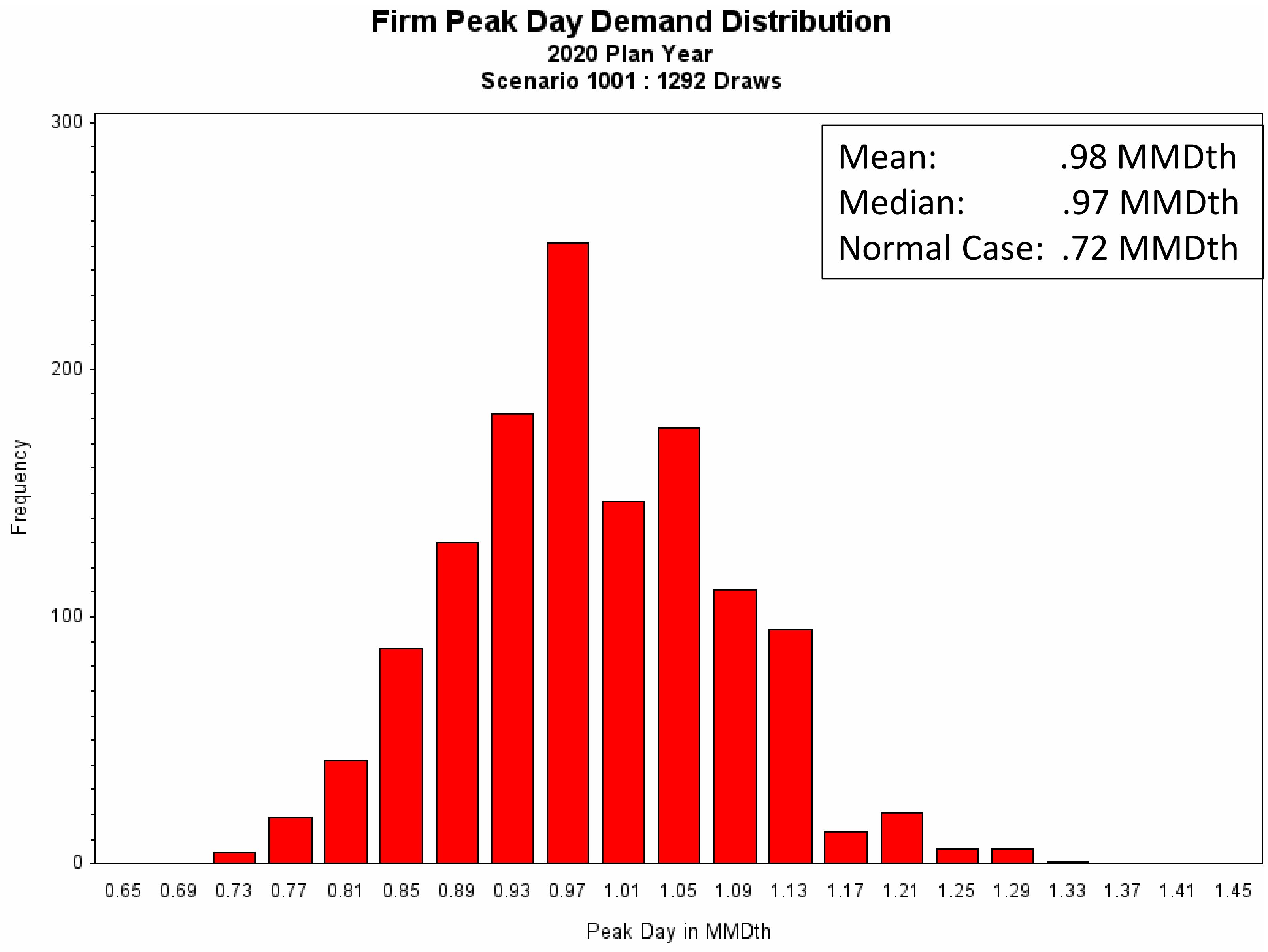
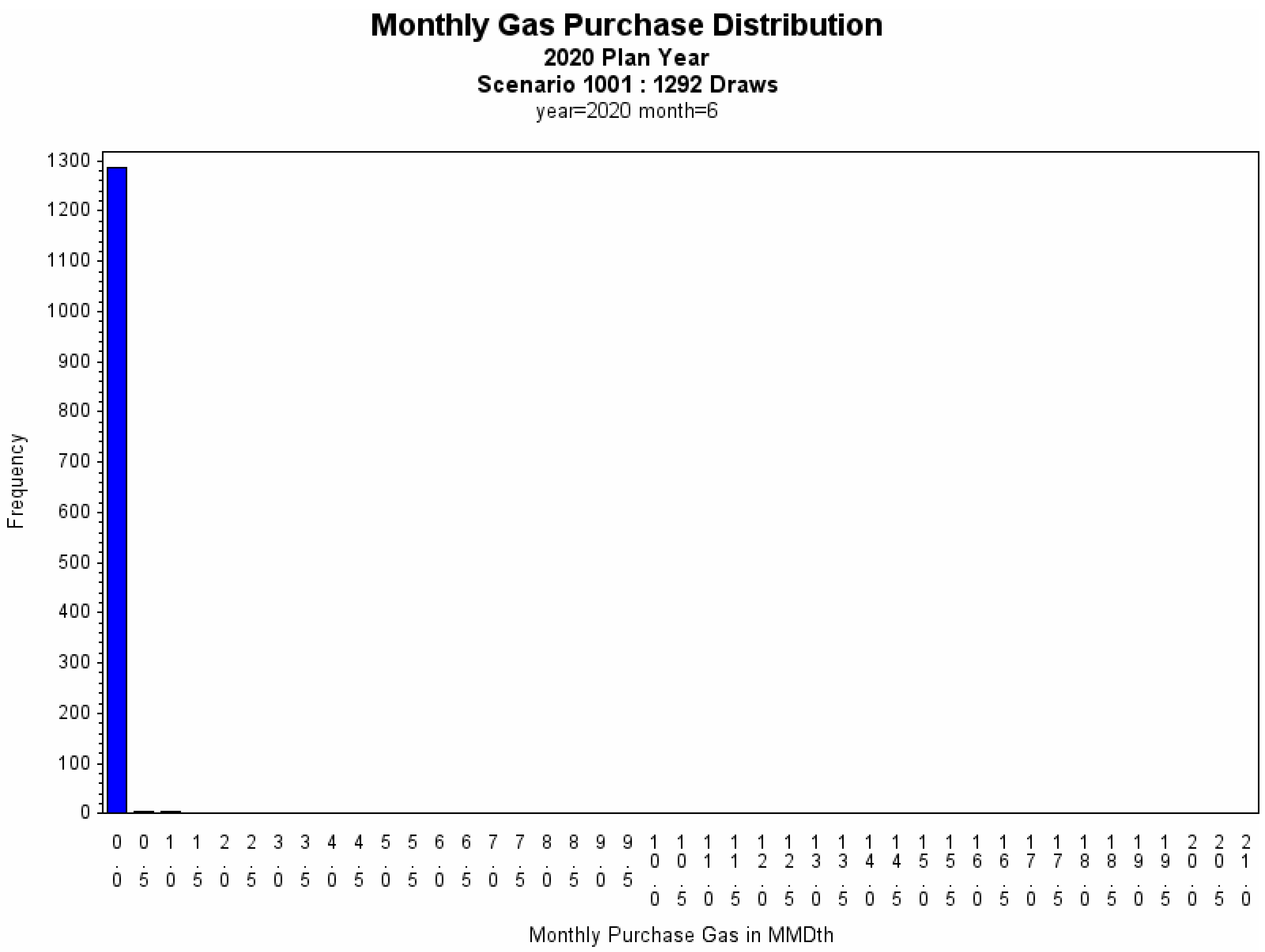


Exhibit 13.52



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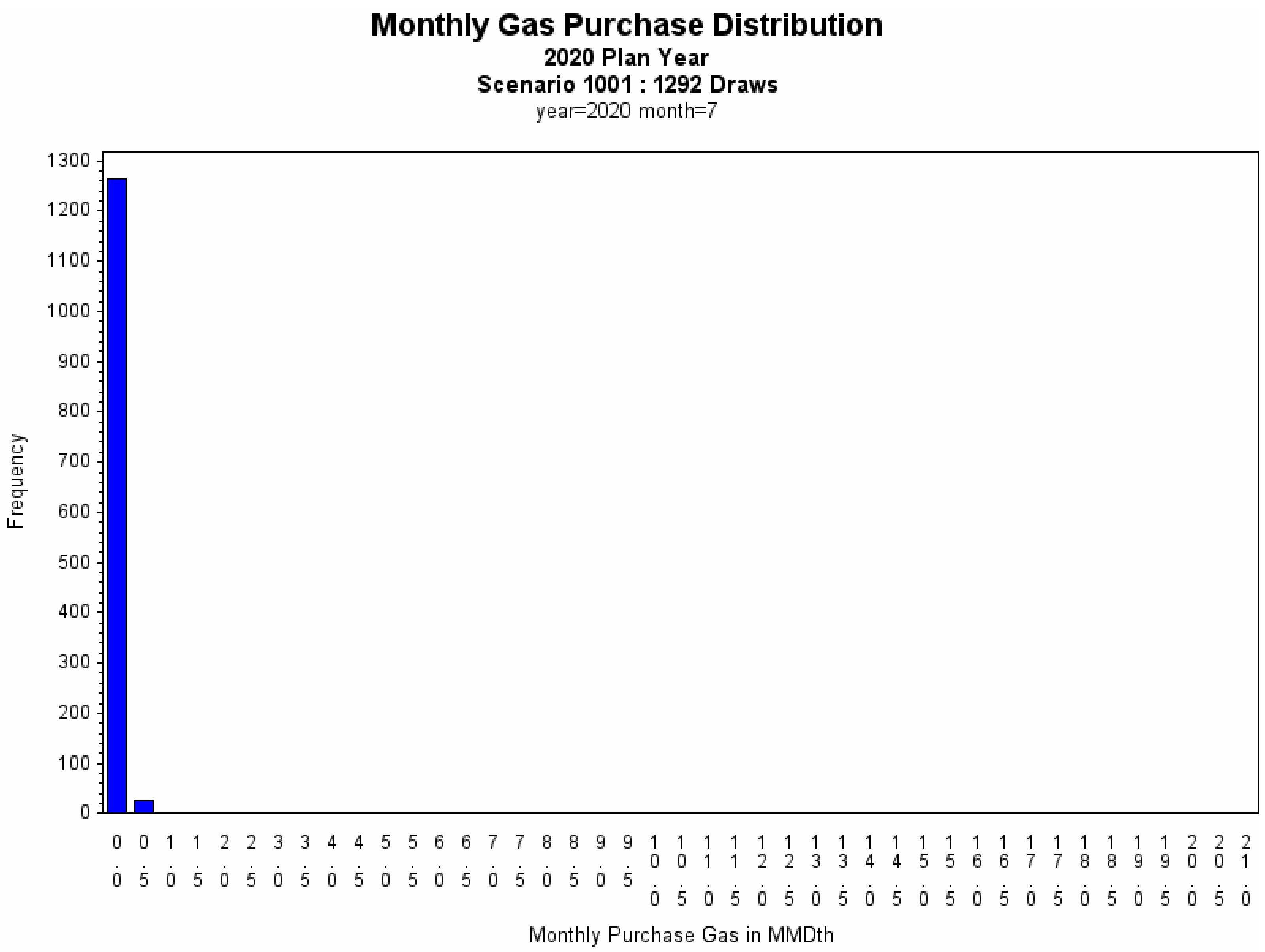

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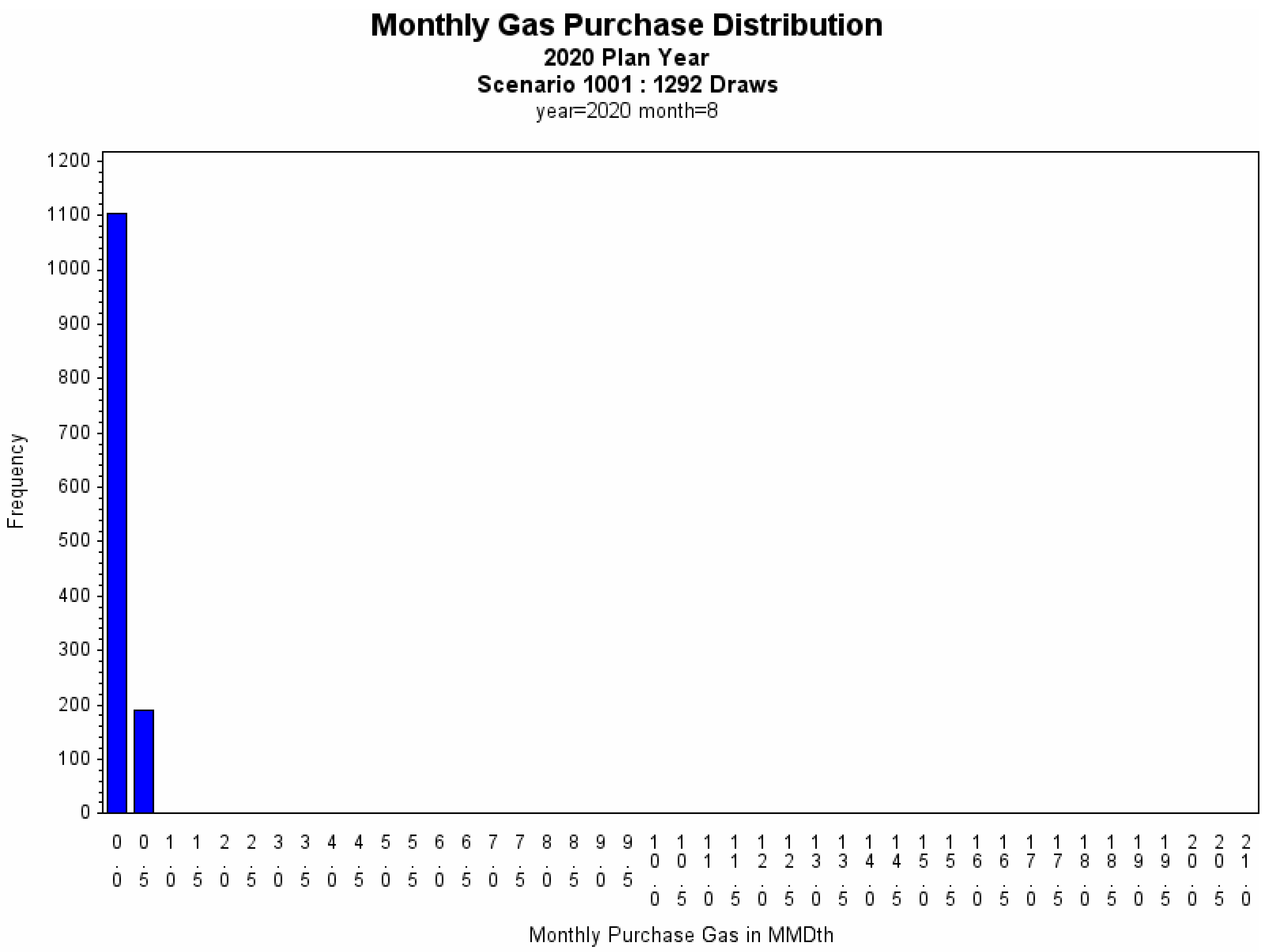


Exhibit 13.55

Monthly Gas Purchase Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2020 month=9

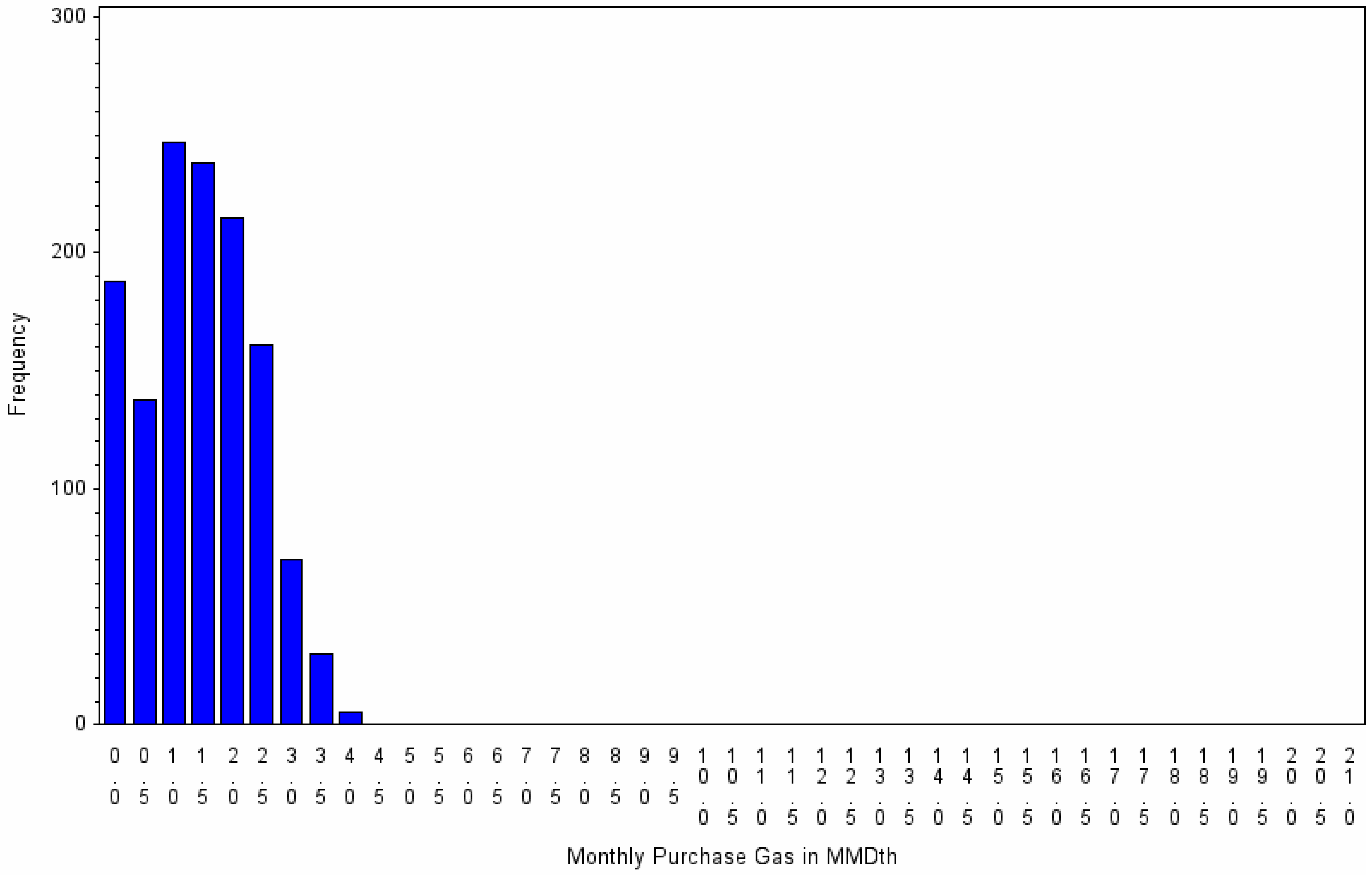


Exhibit 13.56

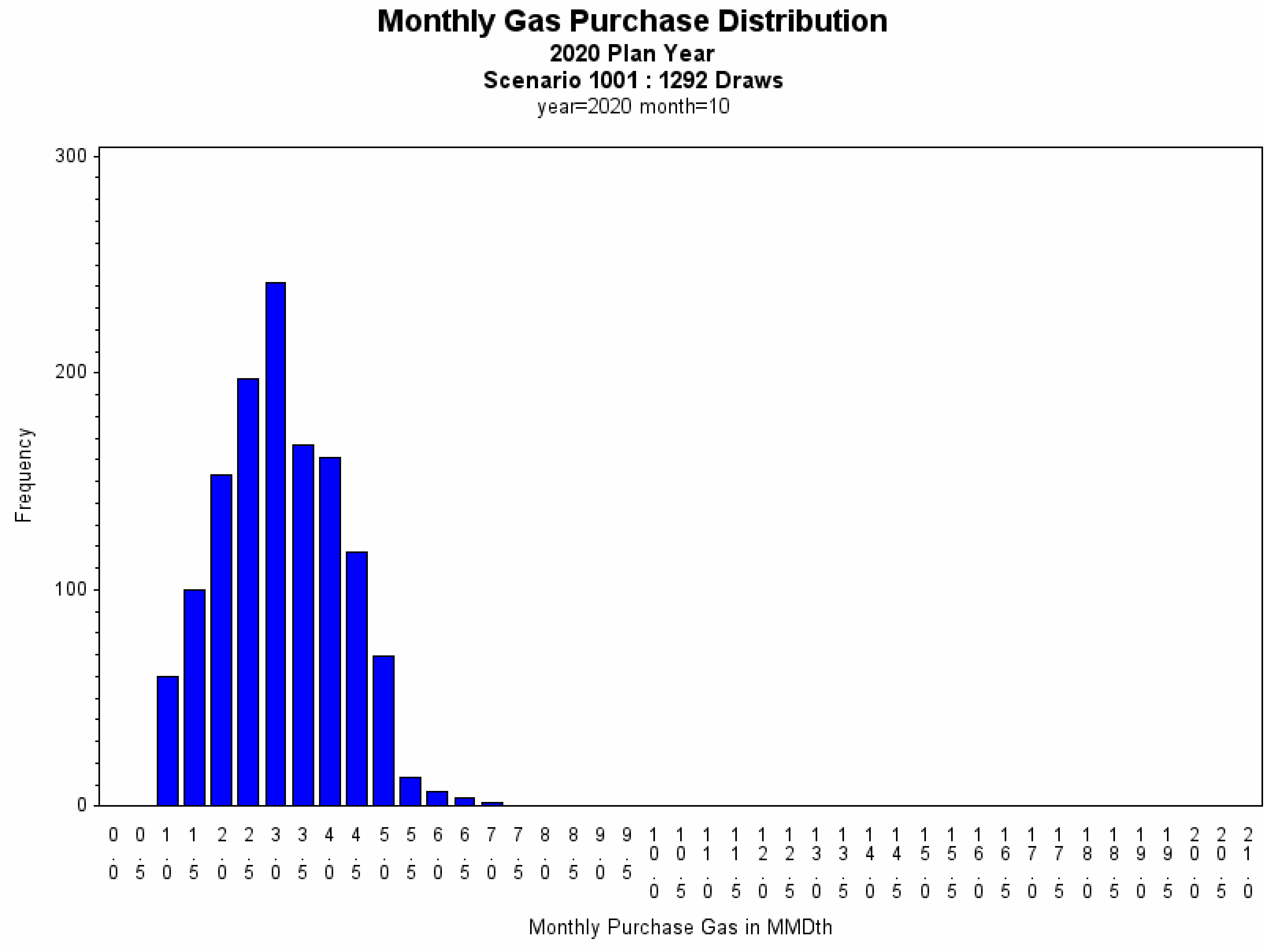


Exhibit 13.57

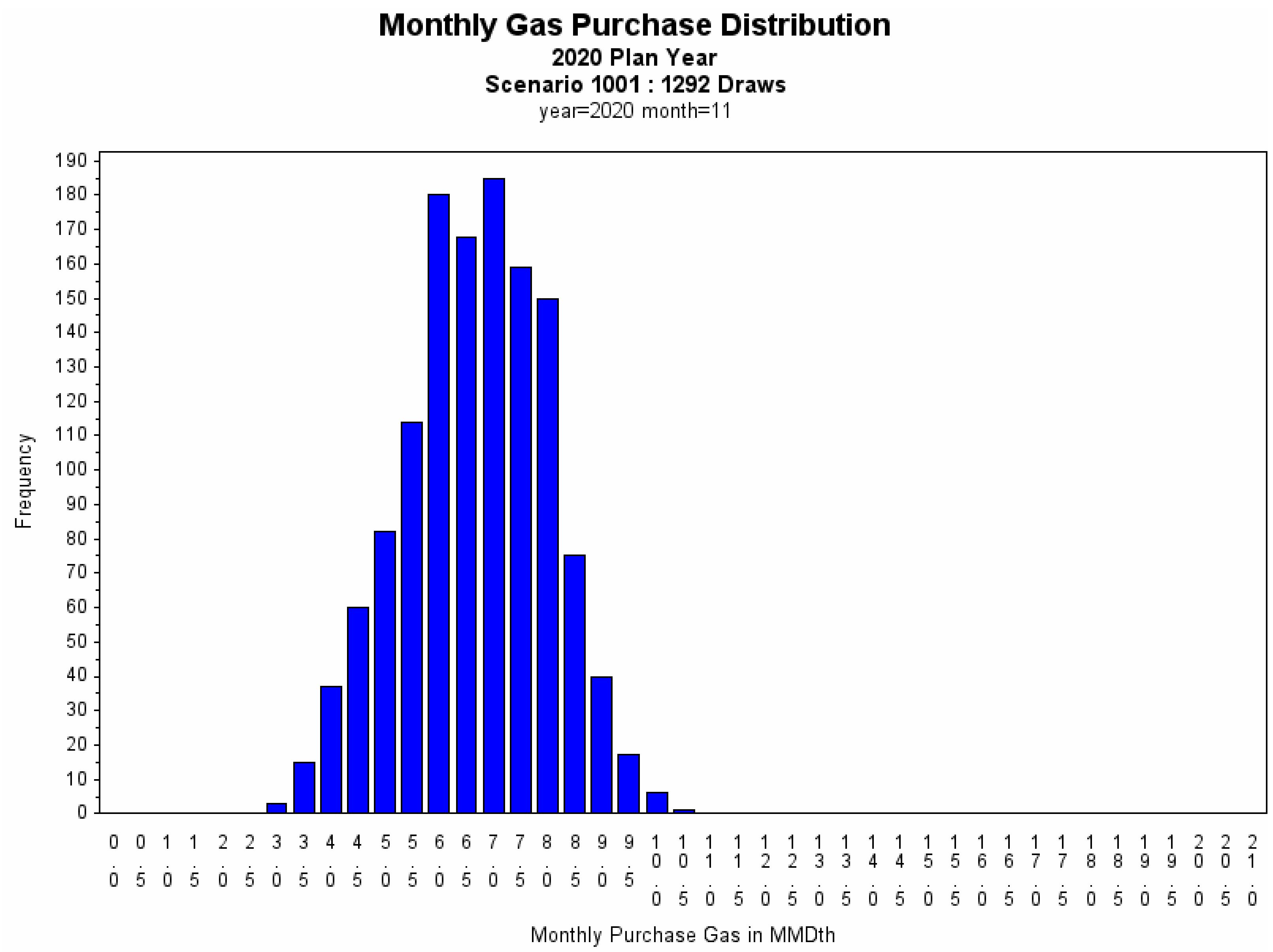
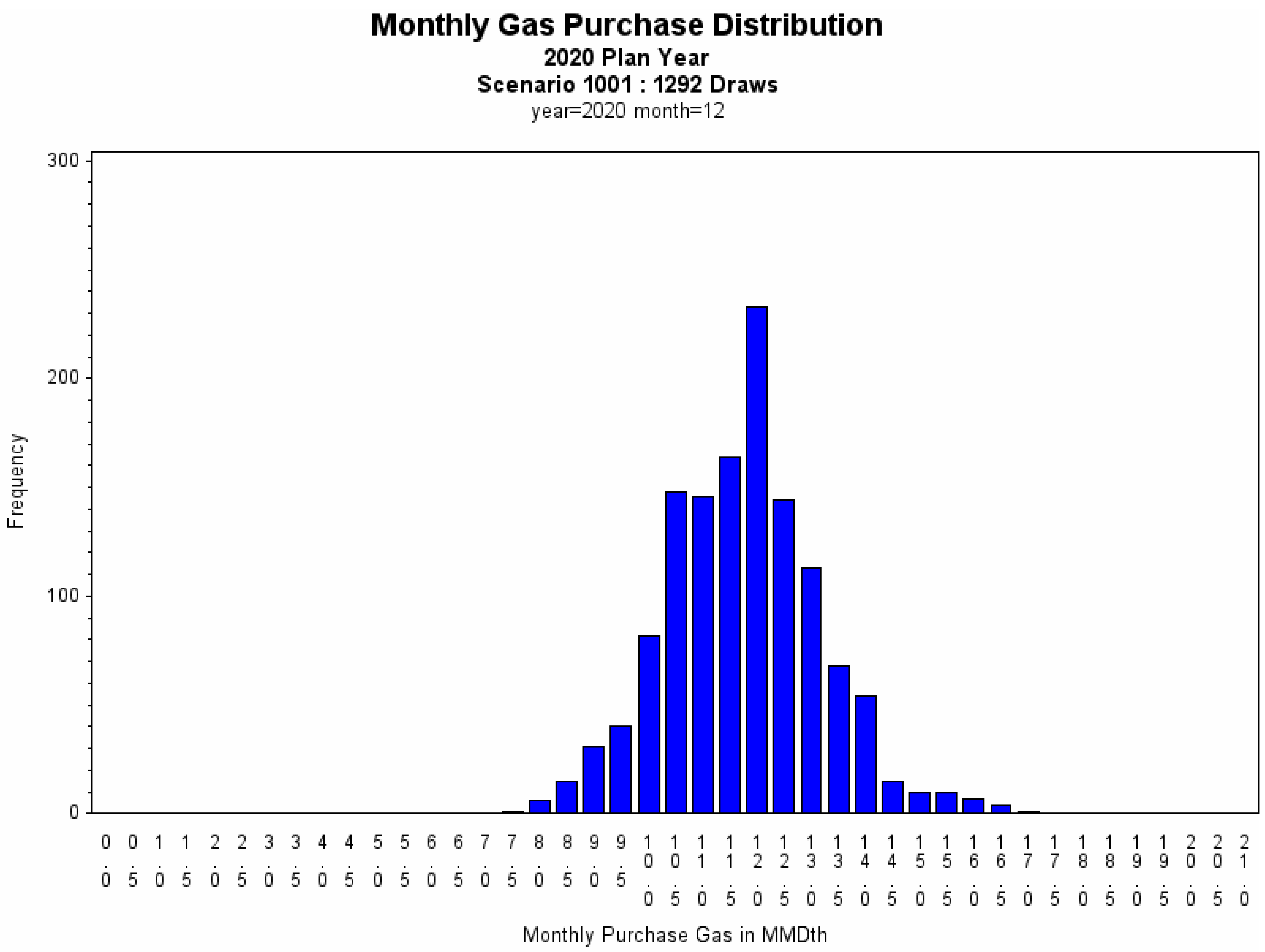


Exhibit 13.58



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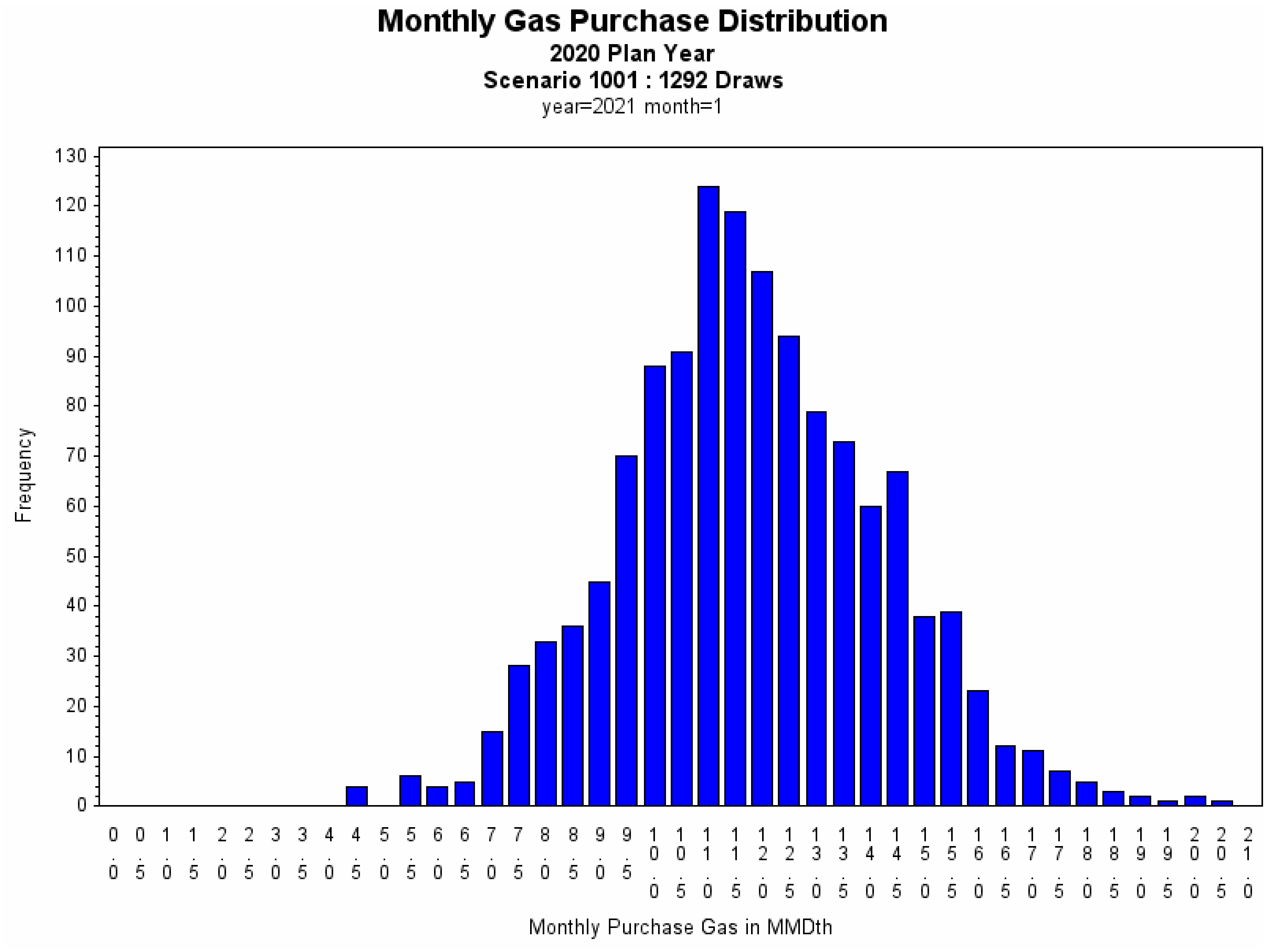


Exhibit 13.60

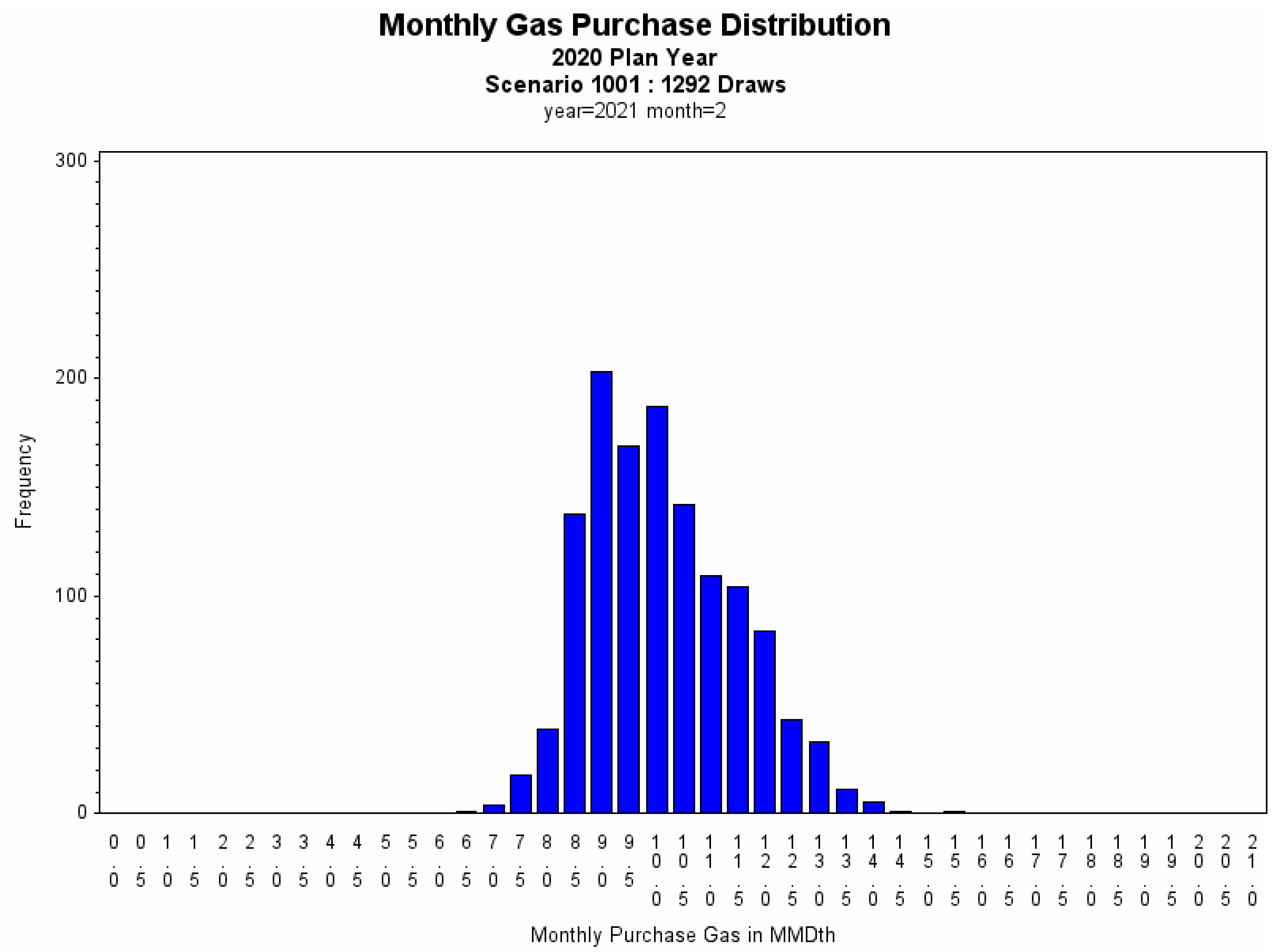


Exhibit 13.61

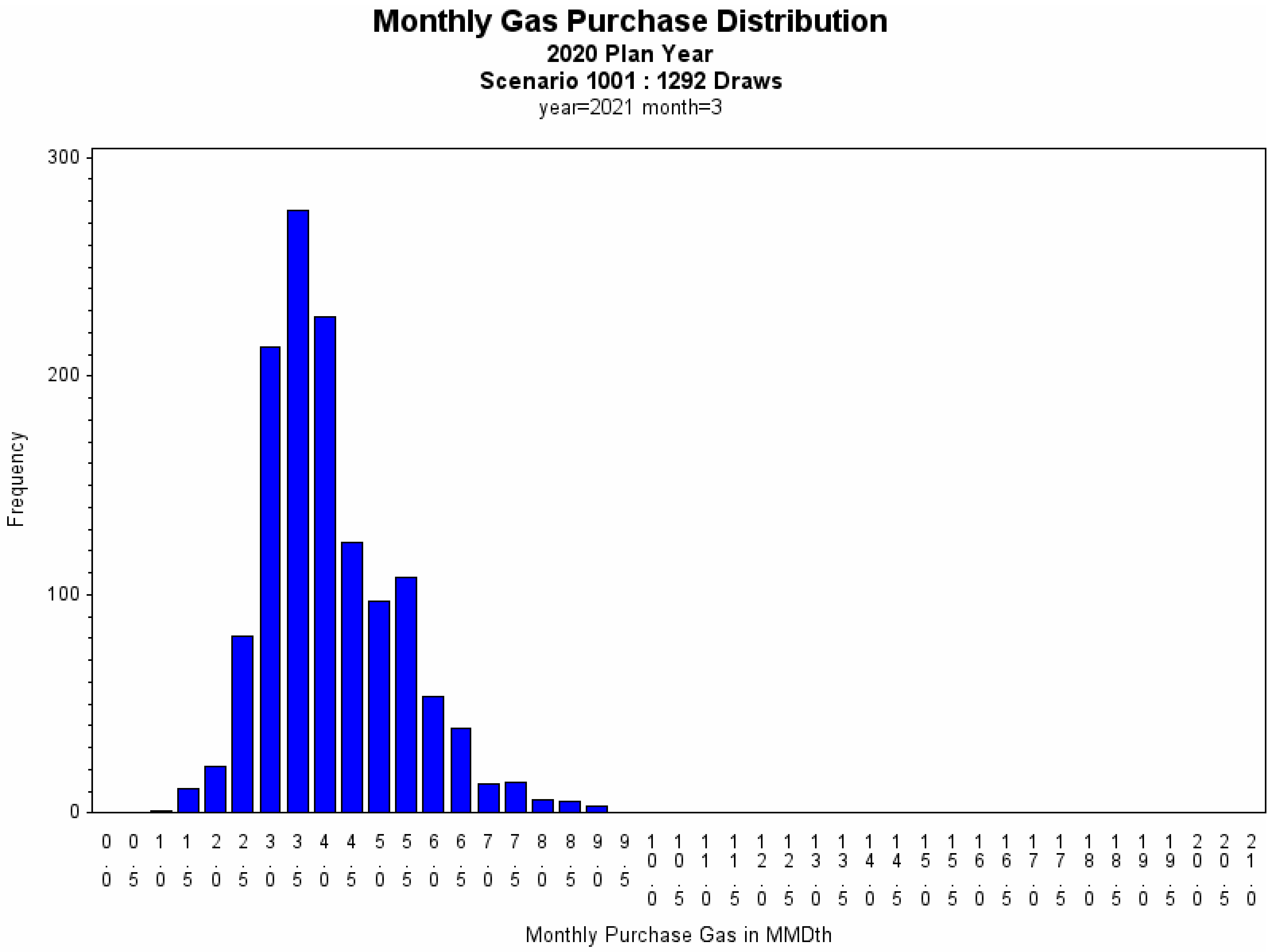


Exhibit 13.62

Monthly Gas Purchase Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2021 month=4

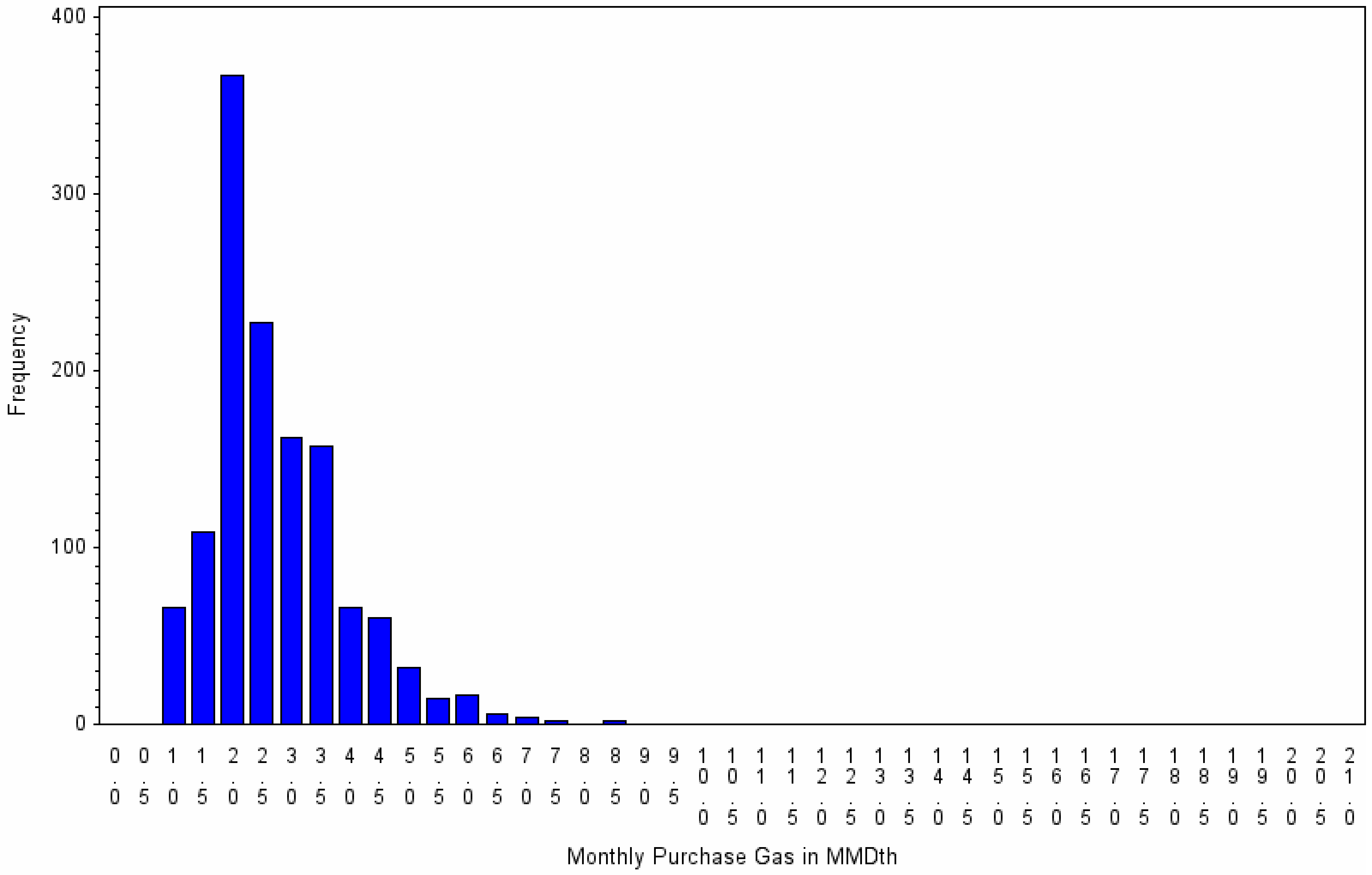


Exhibit 13.63

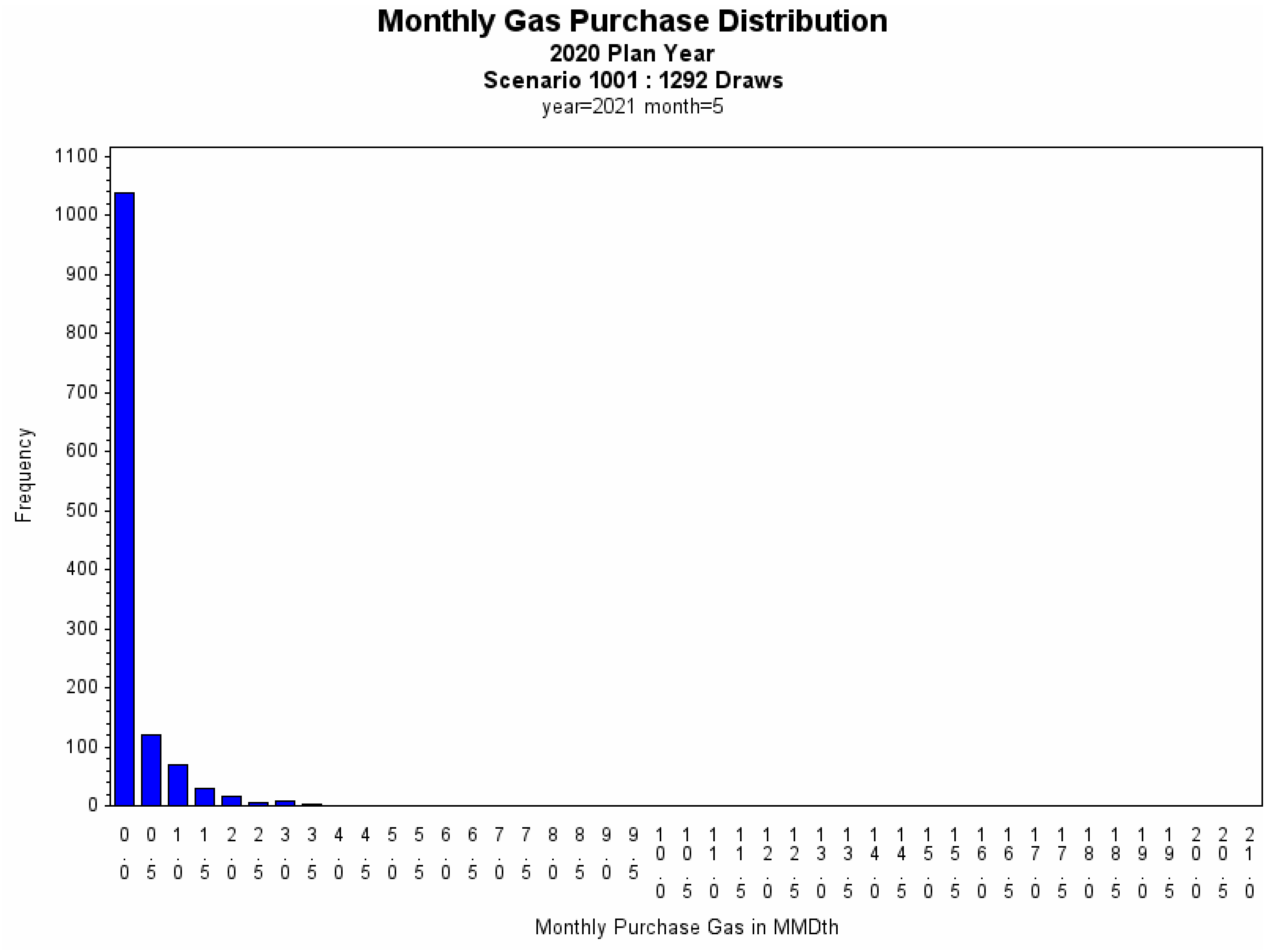


Exhibit 13.64

Annual Gas Purchase Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

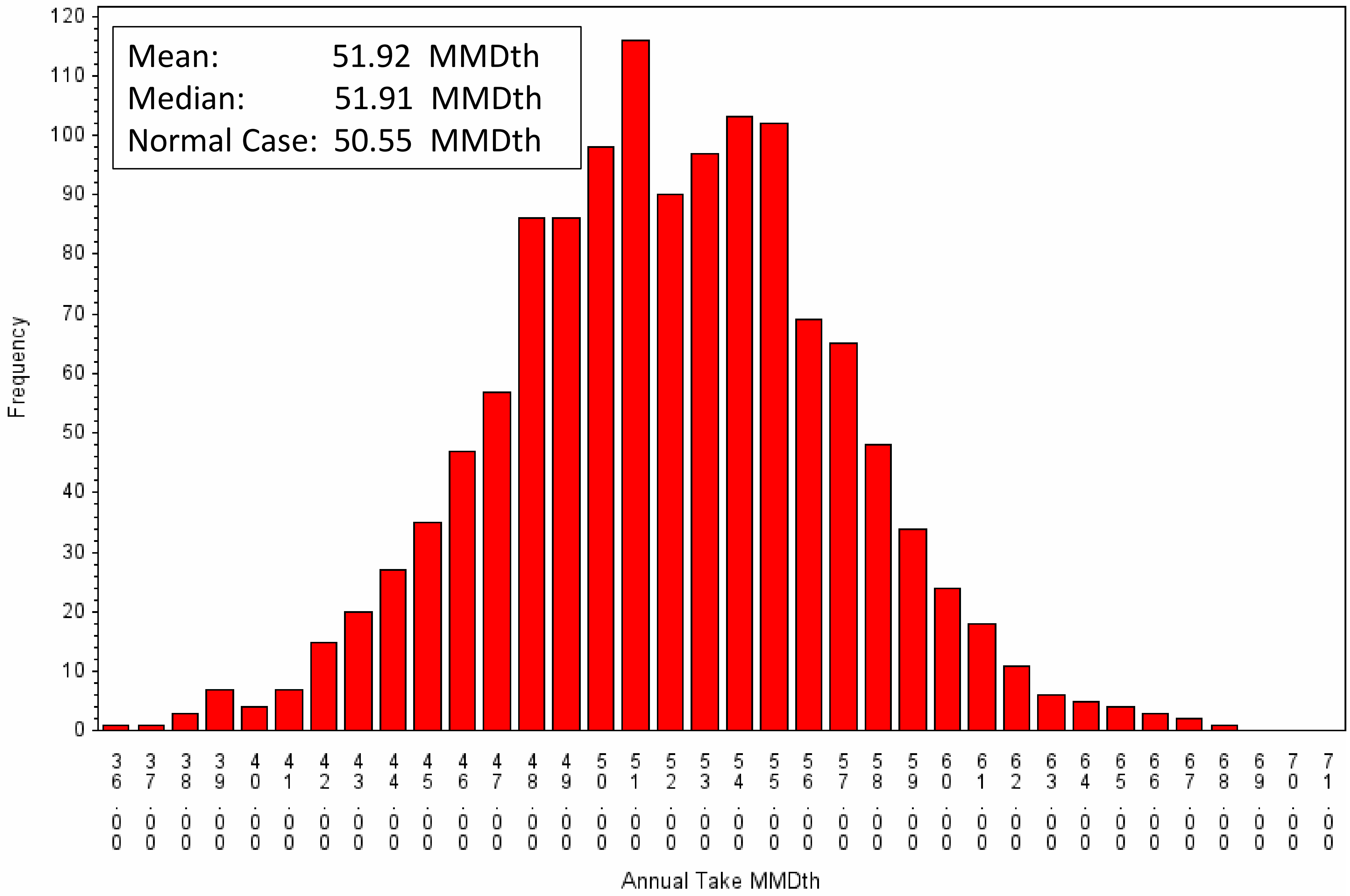


Exhibit 13.65

Monthly Purchase Gas Distribution in Mdth

2020 Plan Year

Scenario 1001 : 1292 Draws

year	month	mean	max	p95	p90	med	p10	p5	min
2020	6	0.00	0.94	0.00	0.00	0.00	0.00	0.00	0.00
2020	7	0.01	0.26	0.00	0.00	0.00	0.00	0.00	0.00
2020	8	0.06	0.55	0.39	0.34	0.00	0.00	0.00	0.00
2020	9	1.42	3.89	2.94	2.65	1.41	0.02	0.00	0.00
2020	10	3.08	6.92	4.86	4.57	3.03	1.61	1.31	0.93
2020	11	6.66	10.57	8.75	8.29	6.71	4.86	4.35	2.89
2020	12	11.75	16.97	13.99	13.50	11.78	10.02	9.47	7.28
2021	1	11.79	20.56	15.80	14.94	11.69	8.72	7.84	4.58
2021	2	10.11	15.52	12.62	12.03	9.92	8.55	8.27	6.64
2021	3	4.10	9.01	6.45	5.77	3.88	2.79	2.49	1.19
2021	4	2.75	8.72	4.86	4.36	2.60	1.51	1.22	0.90
2021	5	0.20	3.52	1.22	0.77	0.00	0.00	0.00	0.00

Exhibit 13.66

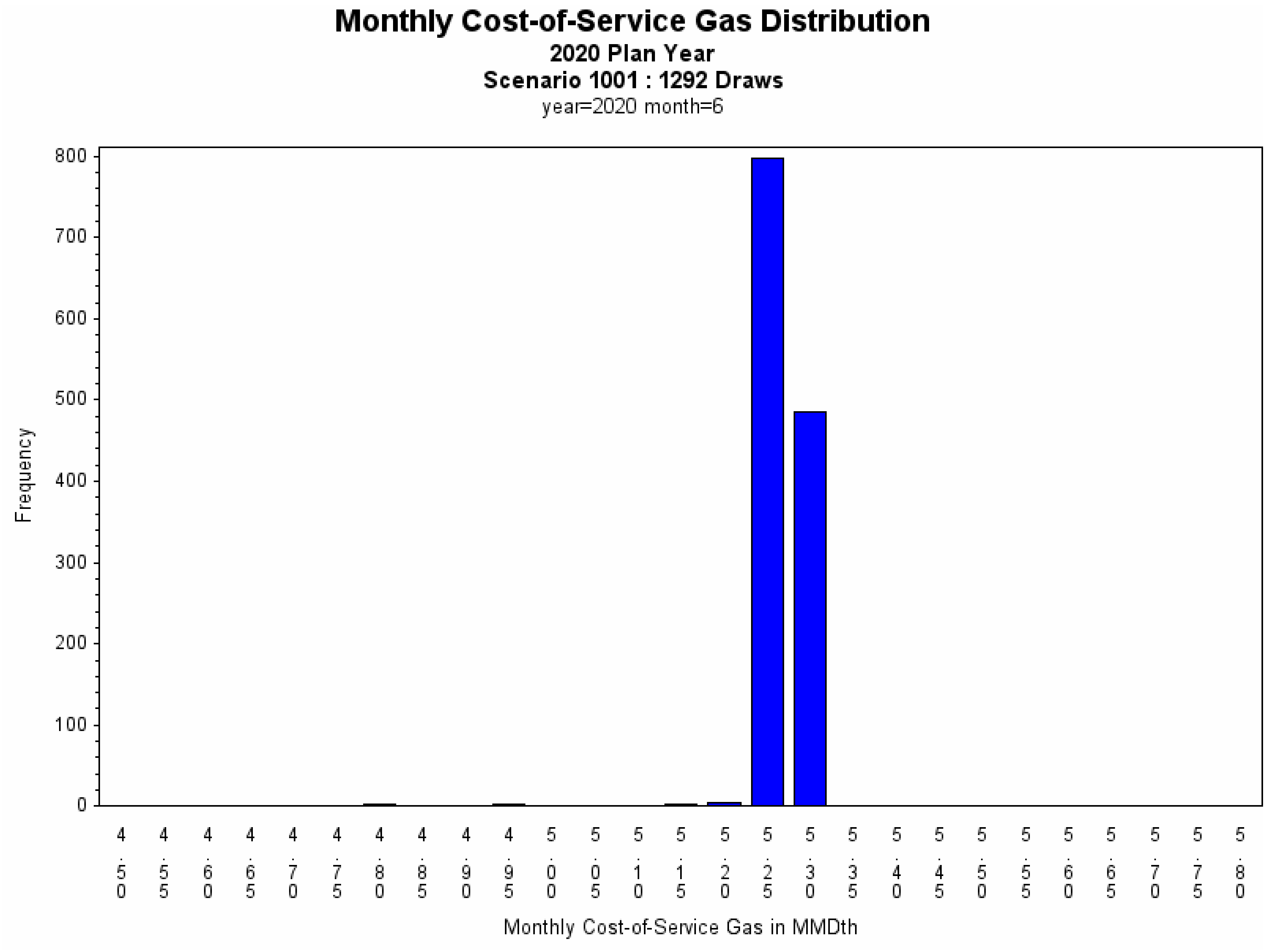


Exhibit 13.67

Monthly Cost-of-Service Gas Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2020 month=7

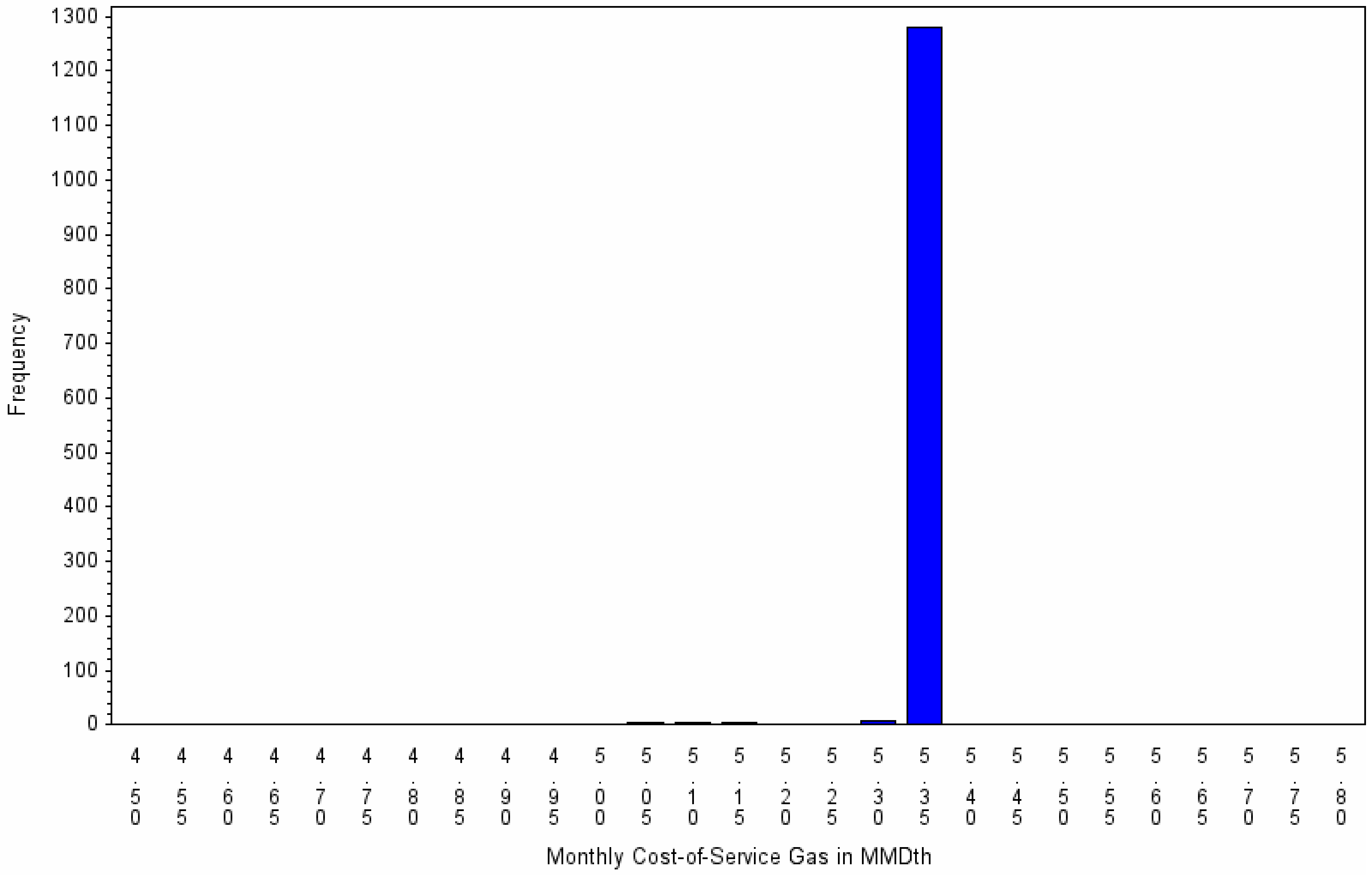


Exhibit 13.68

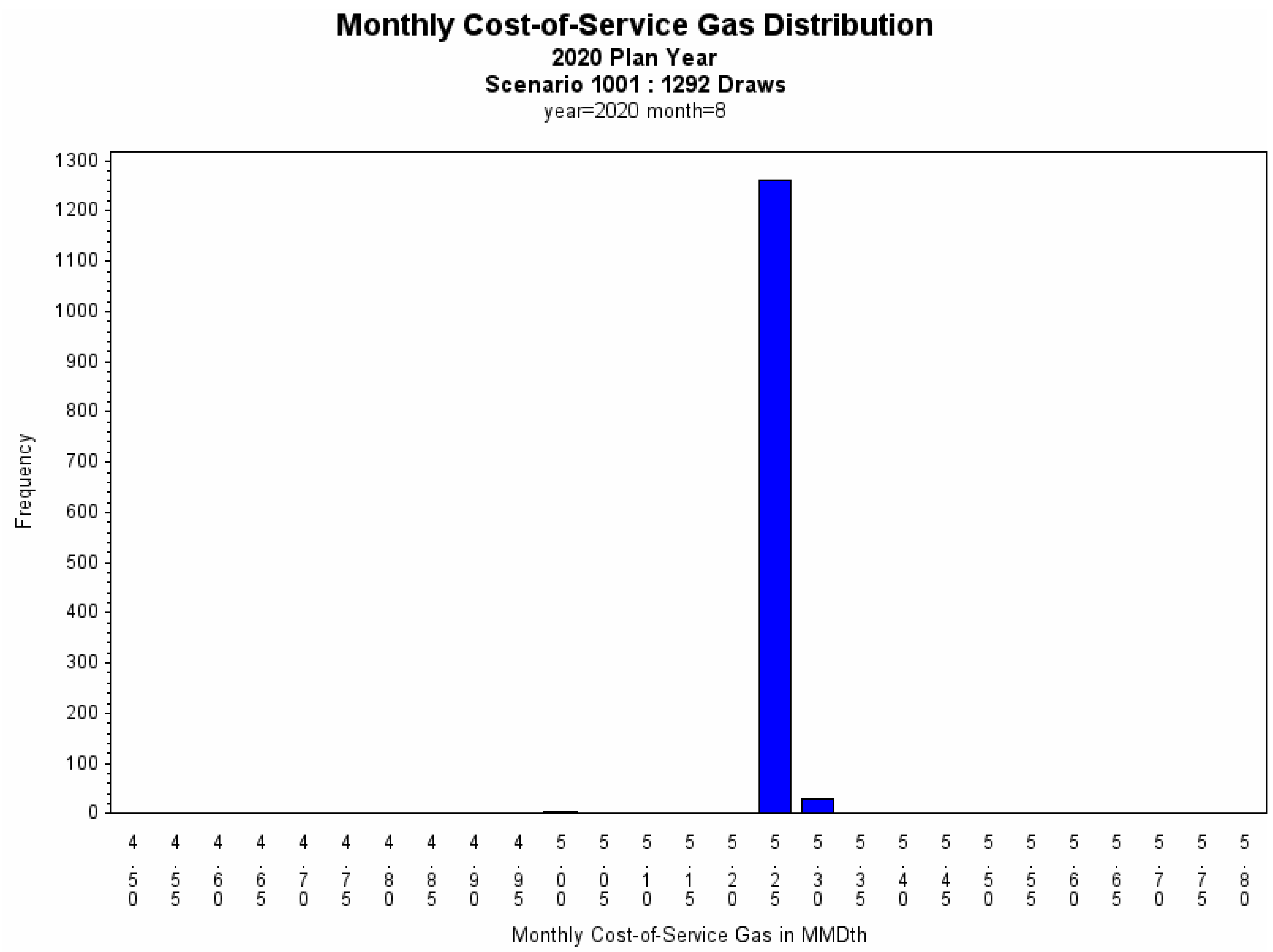


Exhibit 13.69

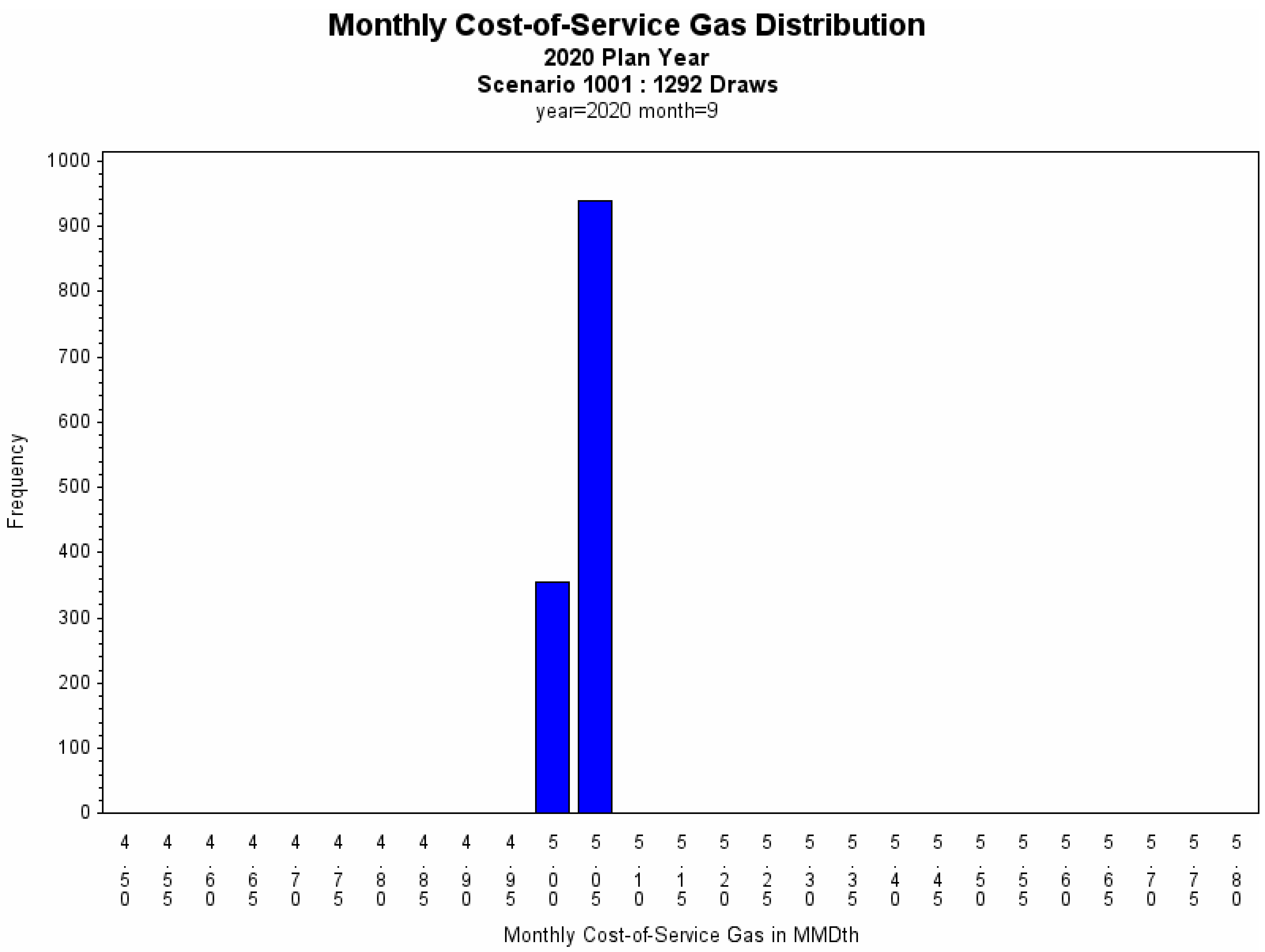


Exhibit 13.70

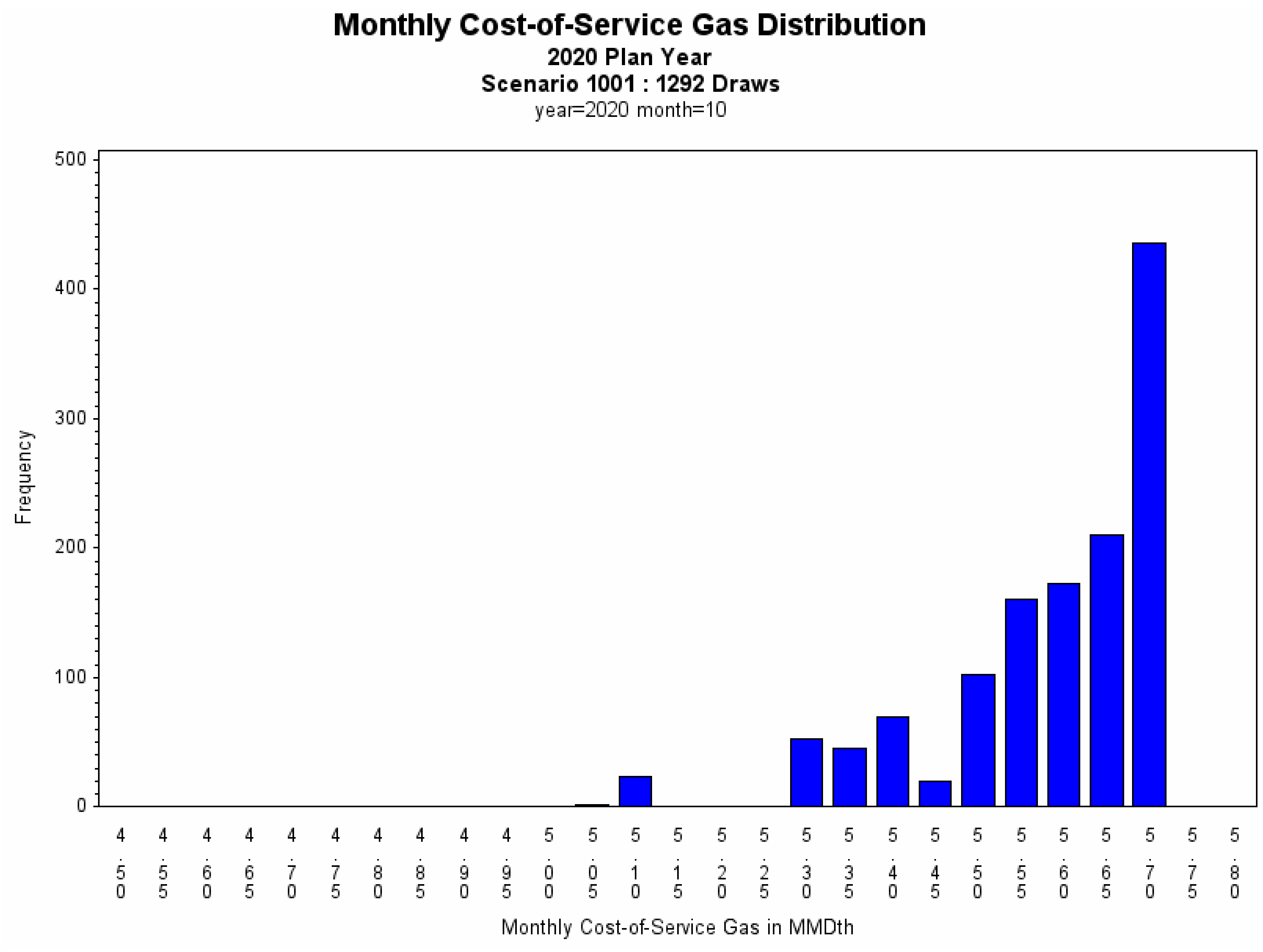


Exhibit 13.71

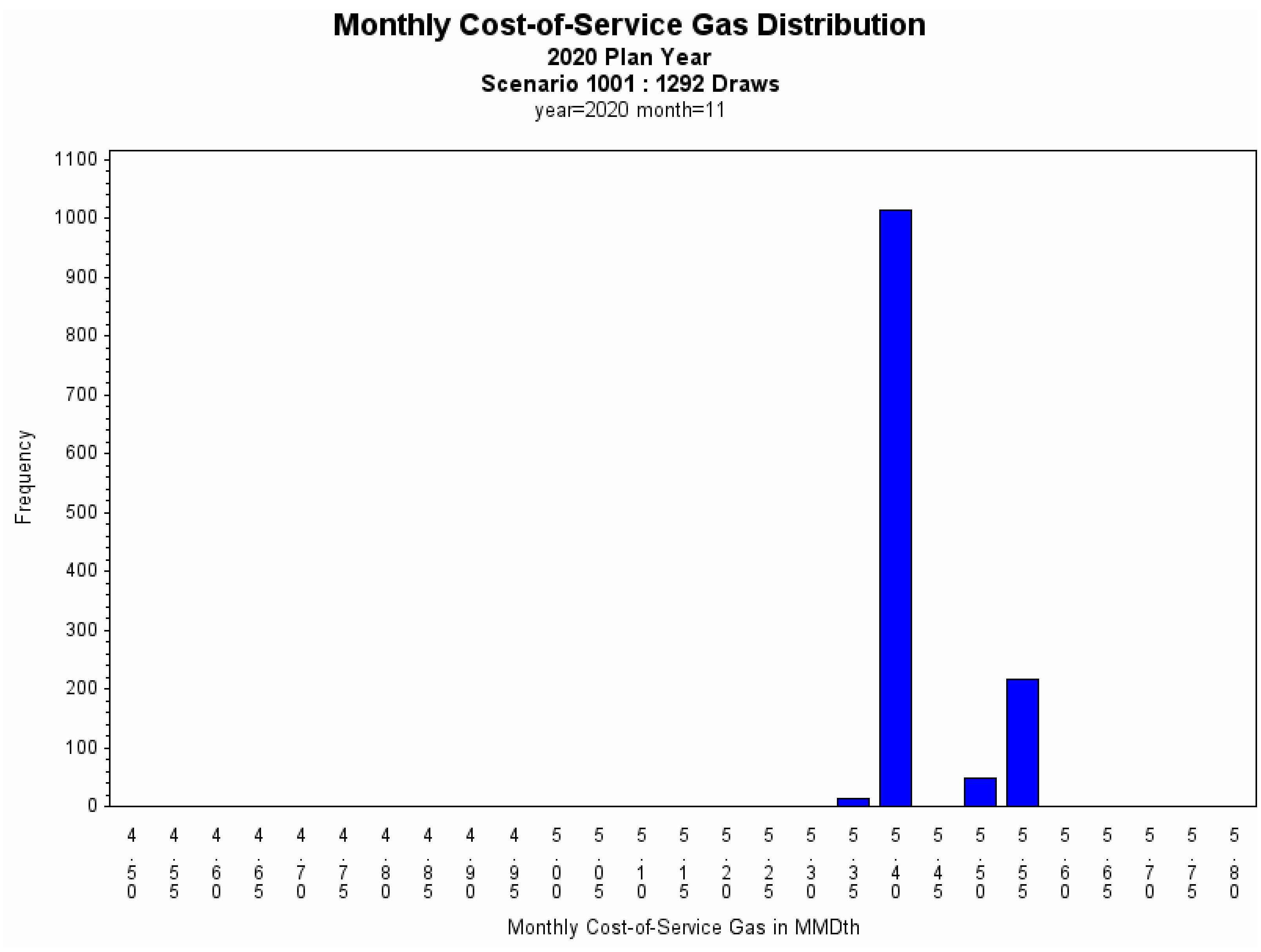
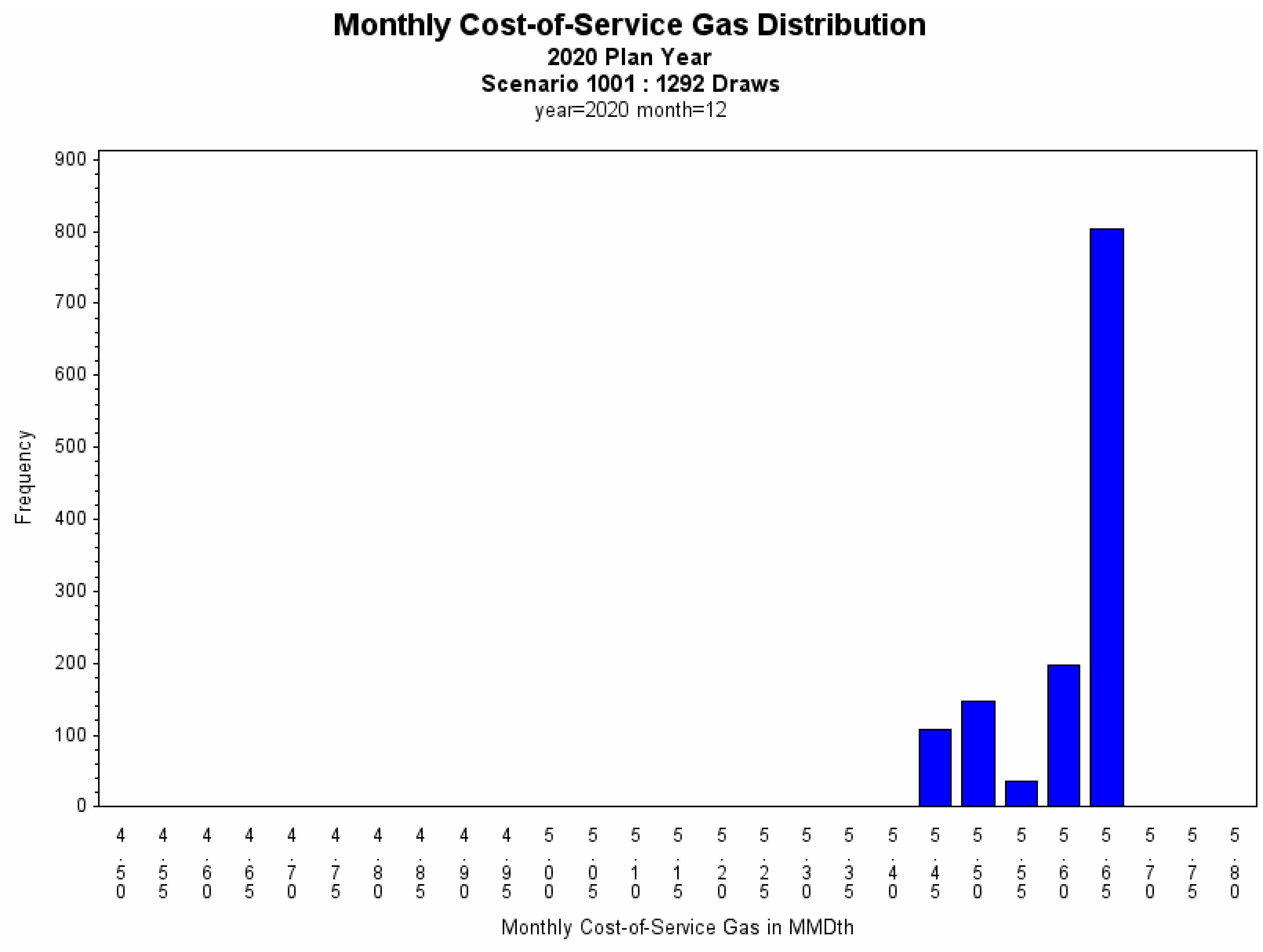


Exhibit 13.72



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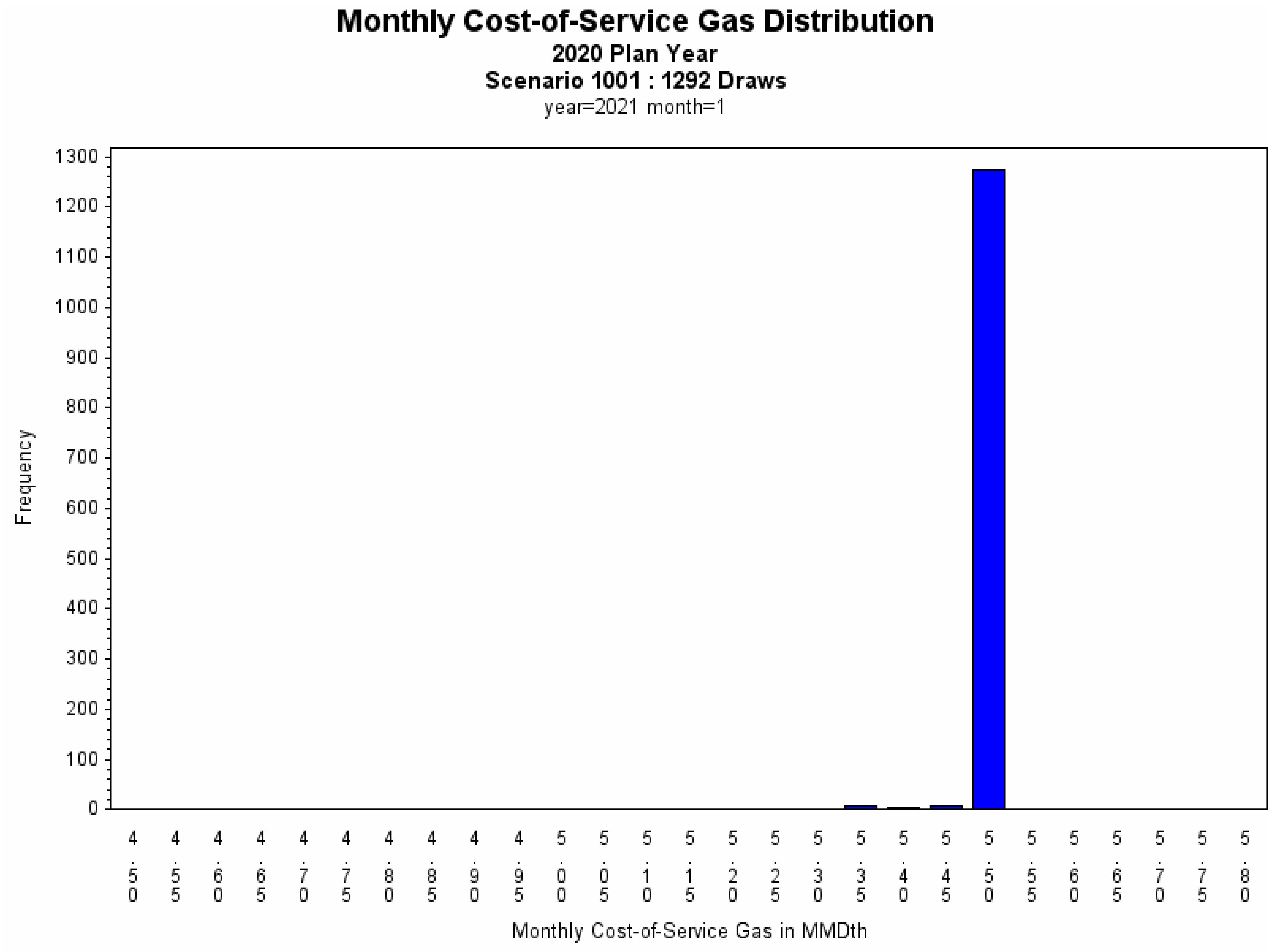

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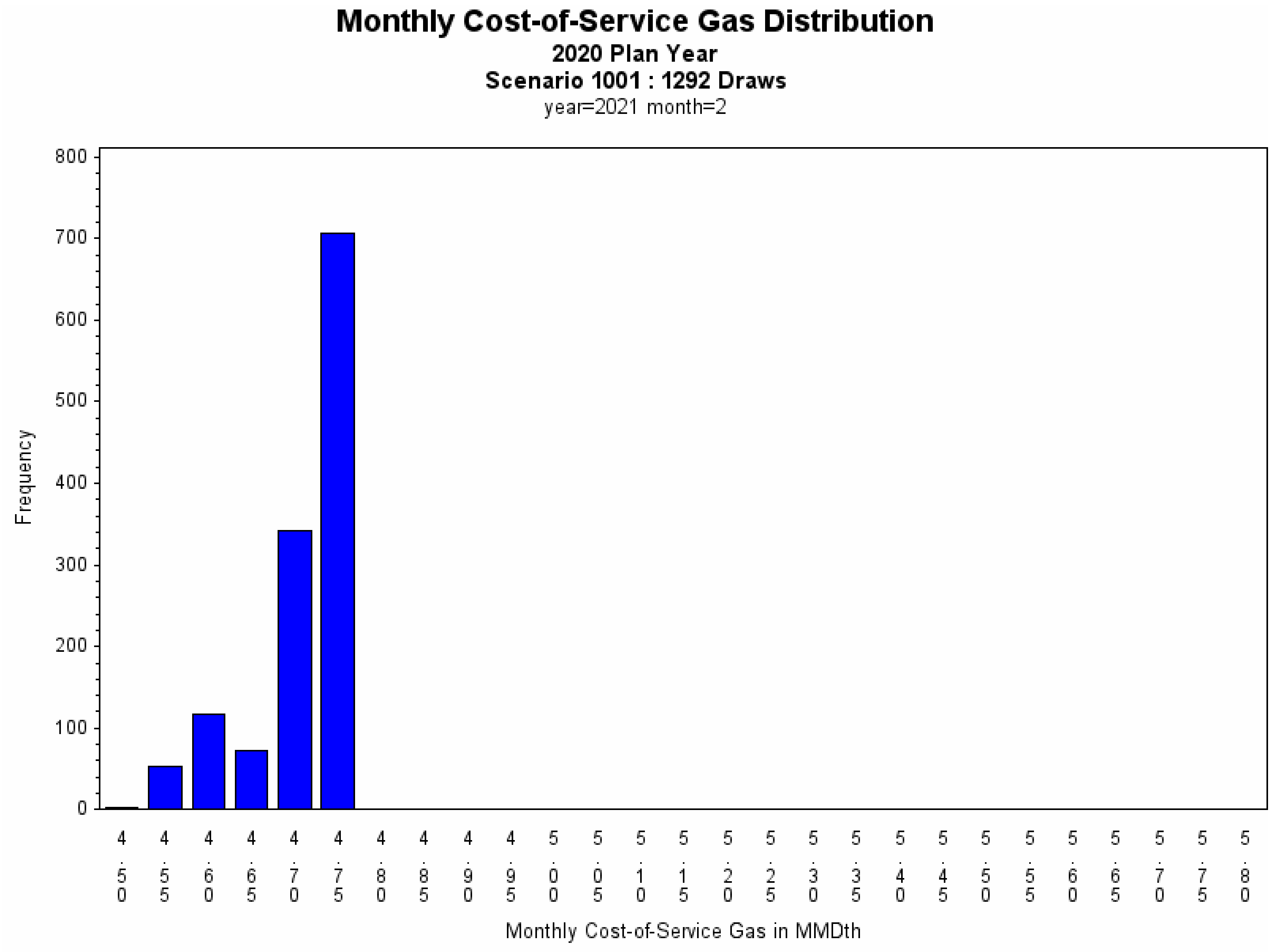

Exhibit 13.75

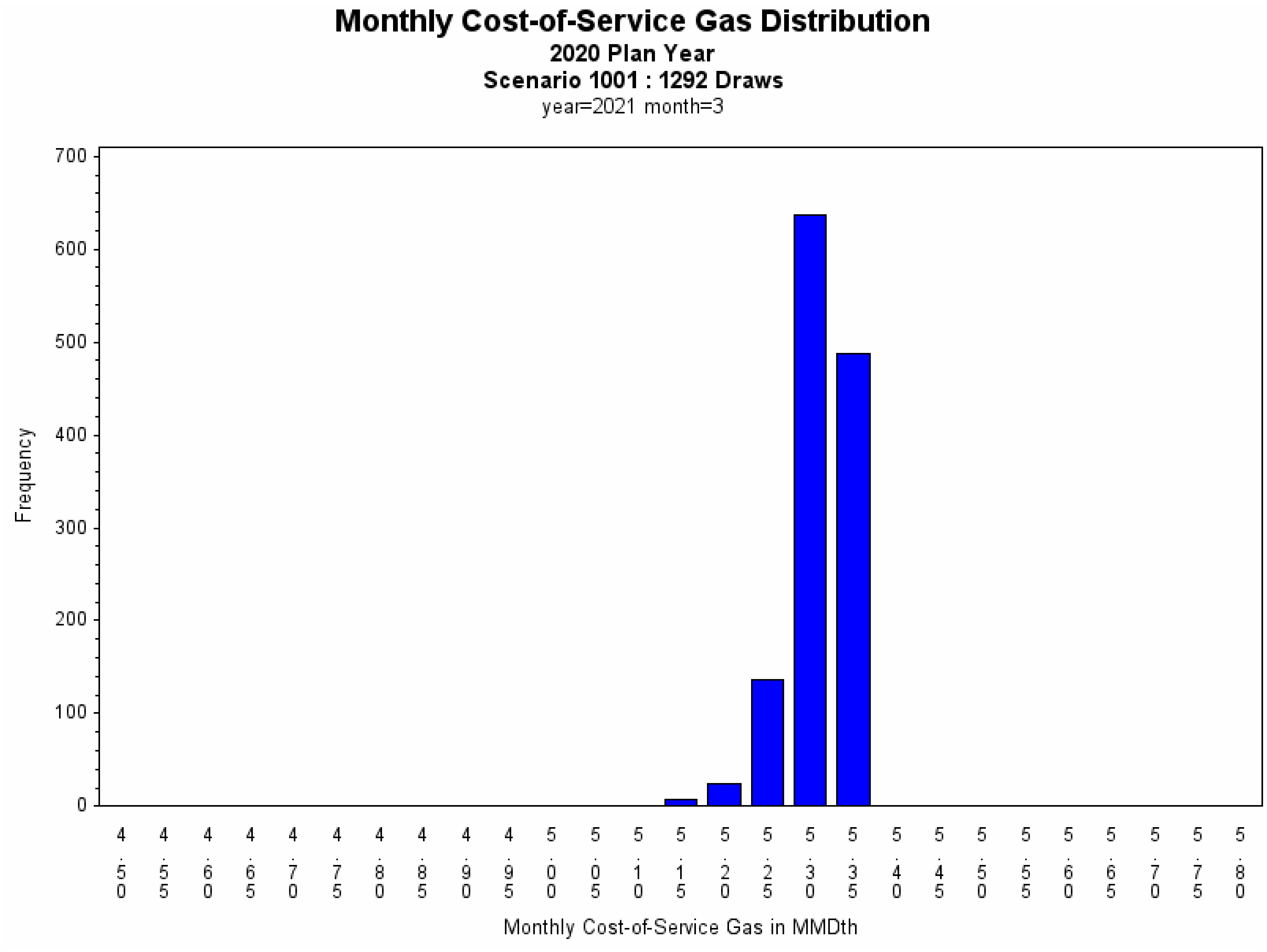

Exhibit 13.76

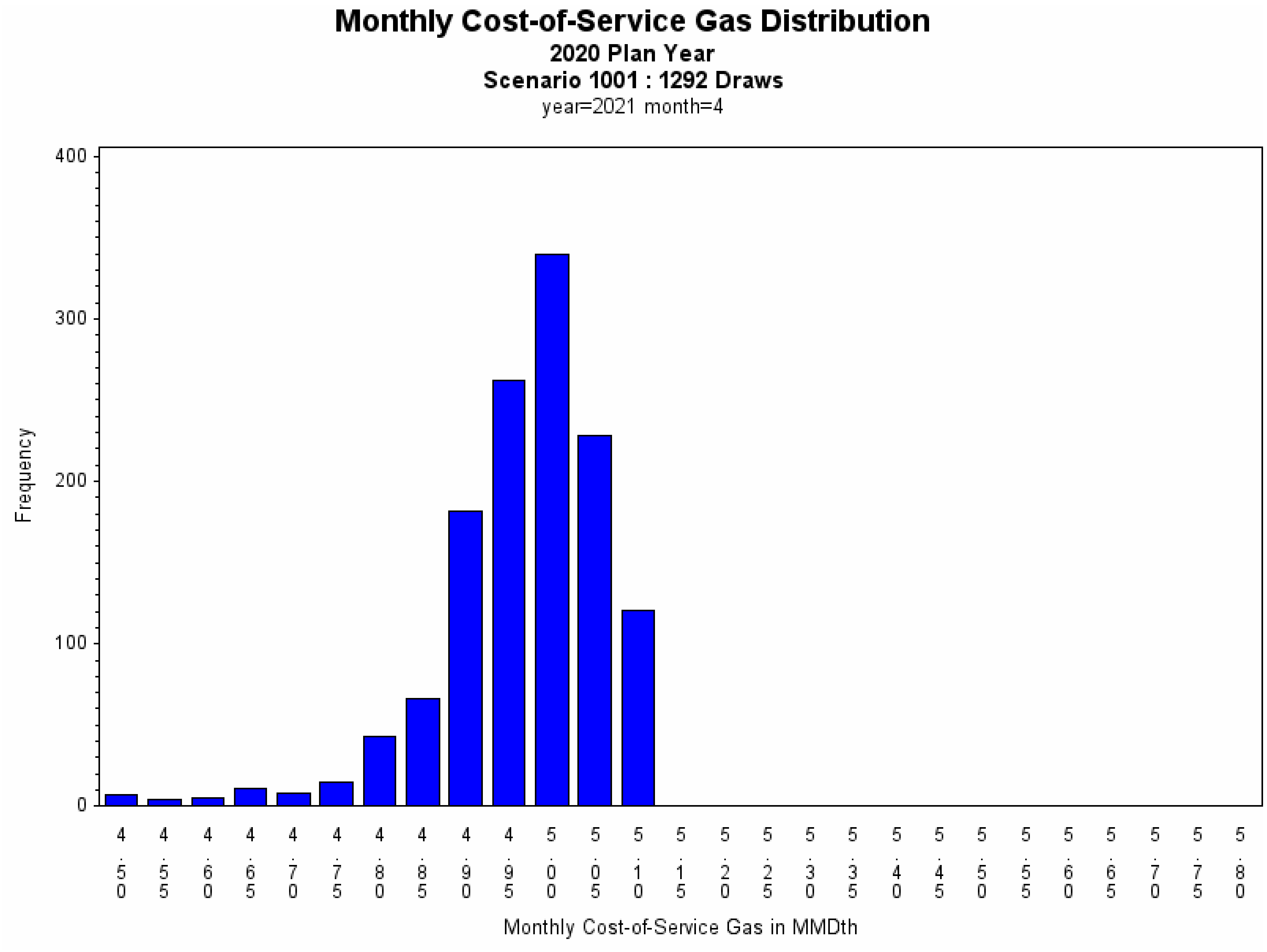

Exhibit 13.77

Monthly Cost-of-Service Gas Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year=2021 month=5

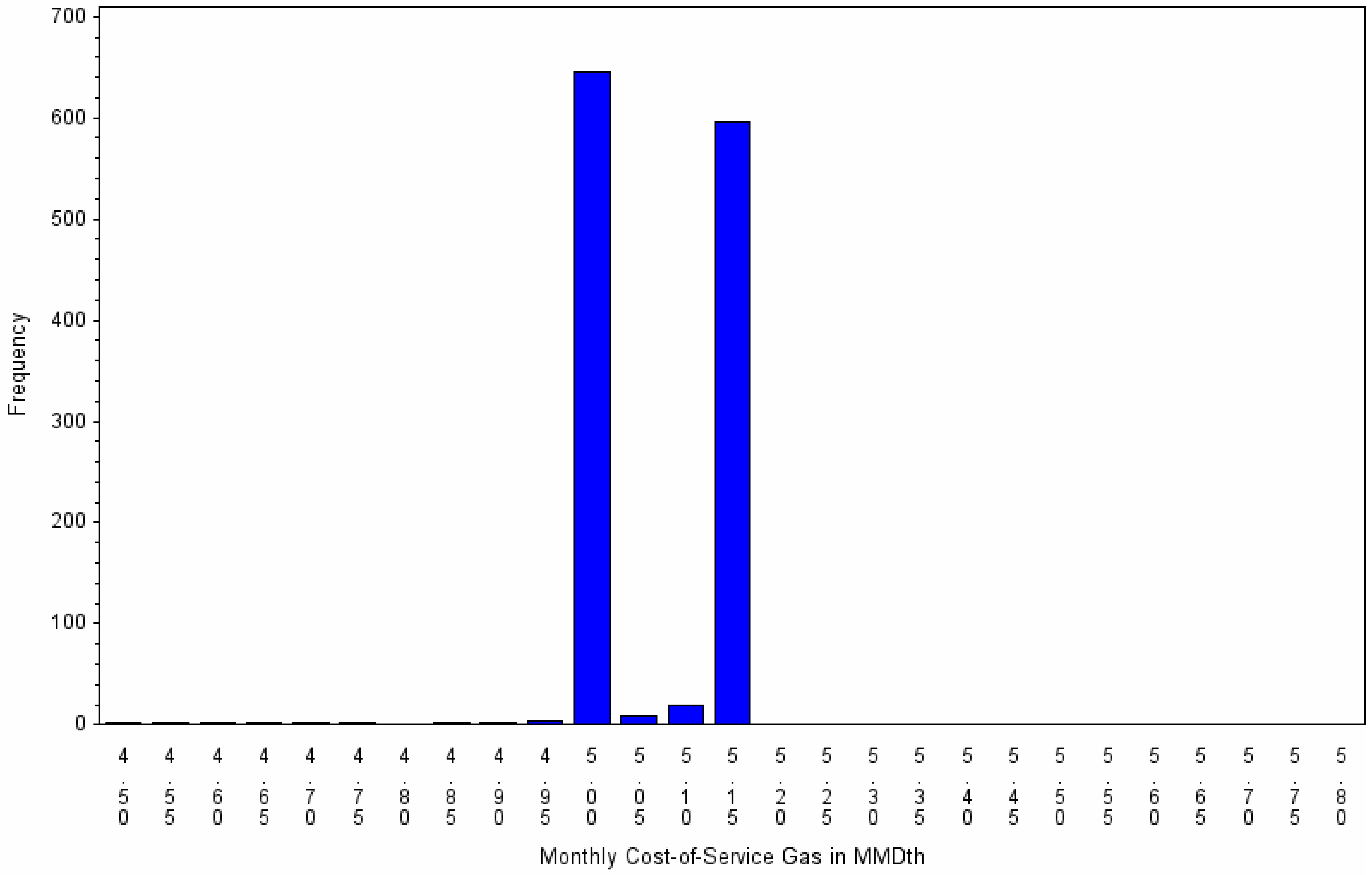

Exhibit 13.78

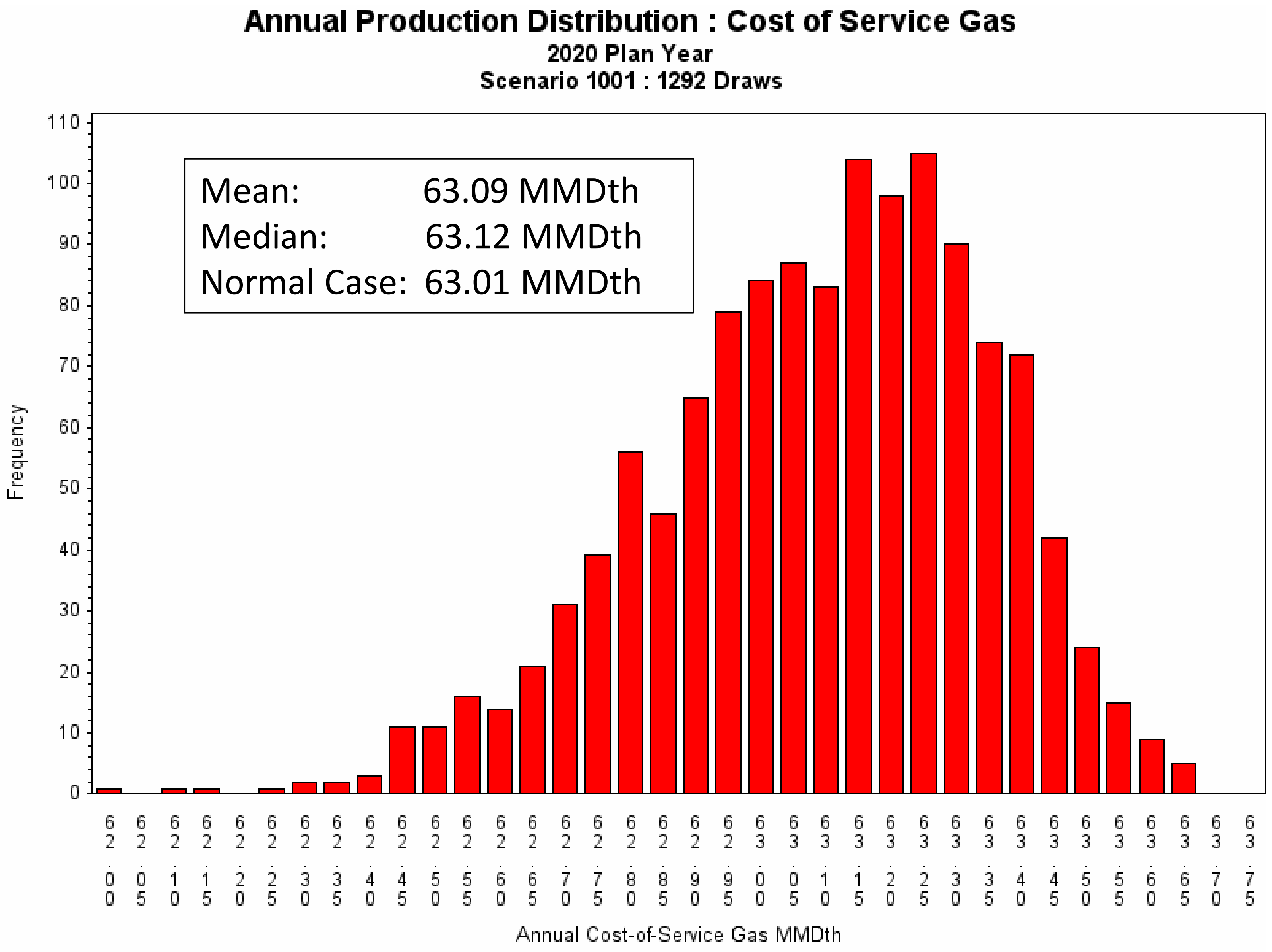

Exhibit 13.79

Monthly Cost-of-Service Gas Distribution

2020 Plan Year

Scenario 1001 : 1292 Draws

year	month	mean	max	p95	P90	med	p10	p5	min
2020	6	5.27	5.28	5.28	5.28	5.27	5.27	5.26	4.79
2020	7	5.36	5.36	5.36	5.36	5.36	5.35	5.35	5.03
2020	8	5.27	5.28	5.27	5.27	5.27	5.27	5.27	5.02
2020	9	5.02	5.03	5.03	5.03	5.03	5.02	5.02	5.02
2020	10	5.58	5.72	5.72	5.71	5.62	5.62	5.31	5.07
2020	11	5.43	5.57	5.57	5.56	5.40	5.39	5.39	5.35
2020	12	5.60	5.63	5.63	5.63	5.63	5.49	5.46	5.45
2021	1	5.51	5.52	5.52	5.52	5.52	5.51	5.51	5.34
2021	2	4.70	4.73	4.73	4.73	4.73	4.60	4.58	4.52
2021	3	5.31	5.33	5.33	5.33	5.32	5.27	5.25	5.16
2021	4	4.97	5.08	5.08	5.07	4.99	4.84	4.79	4.47
2021	5	5.07	5.07	5.17	5.17	5.01	4.99	4.99	4.52

Exhibit 13.80

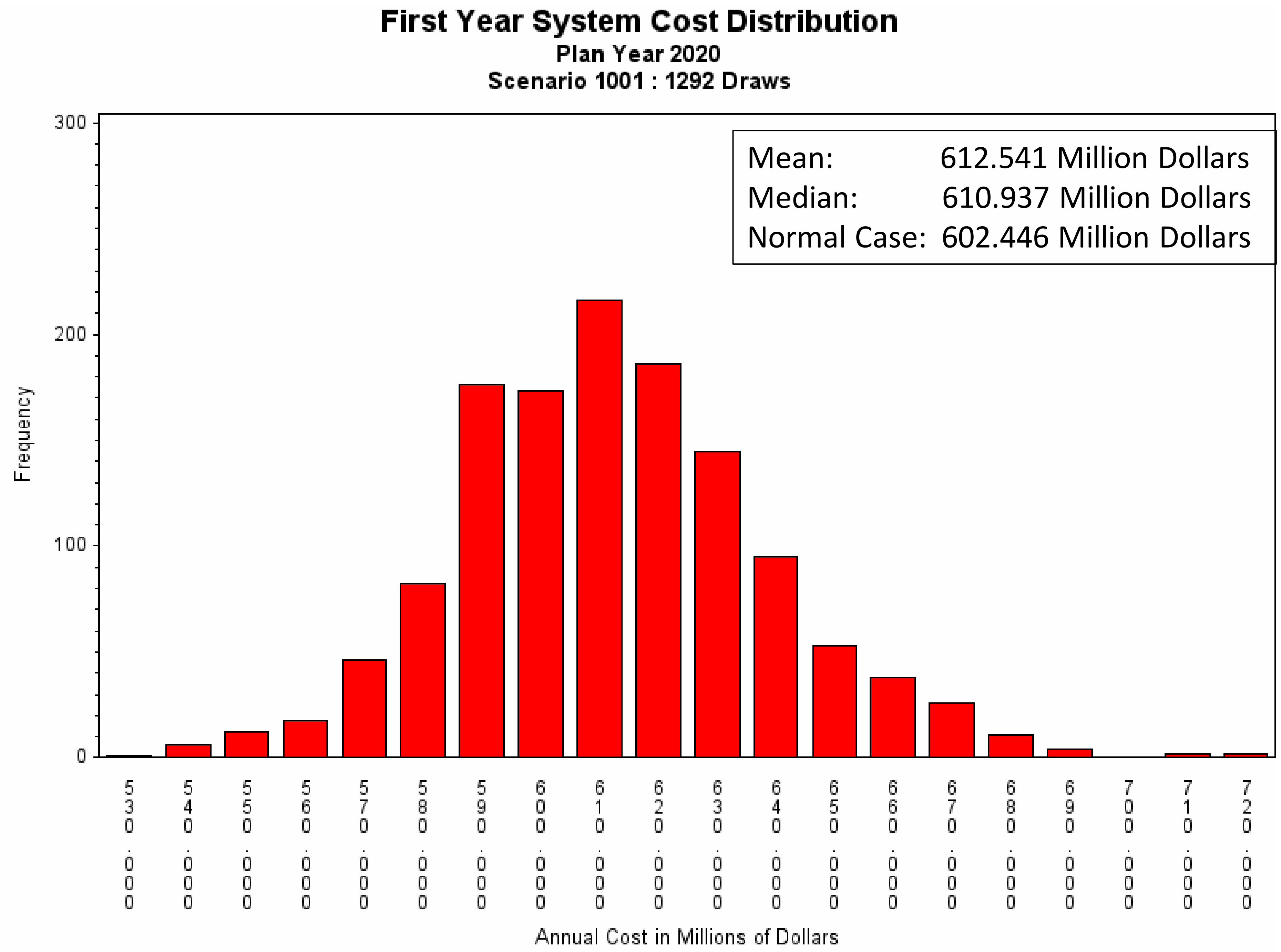

Exhibit 13.81

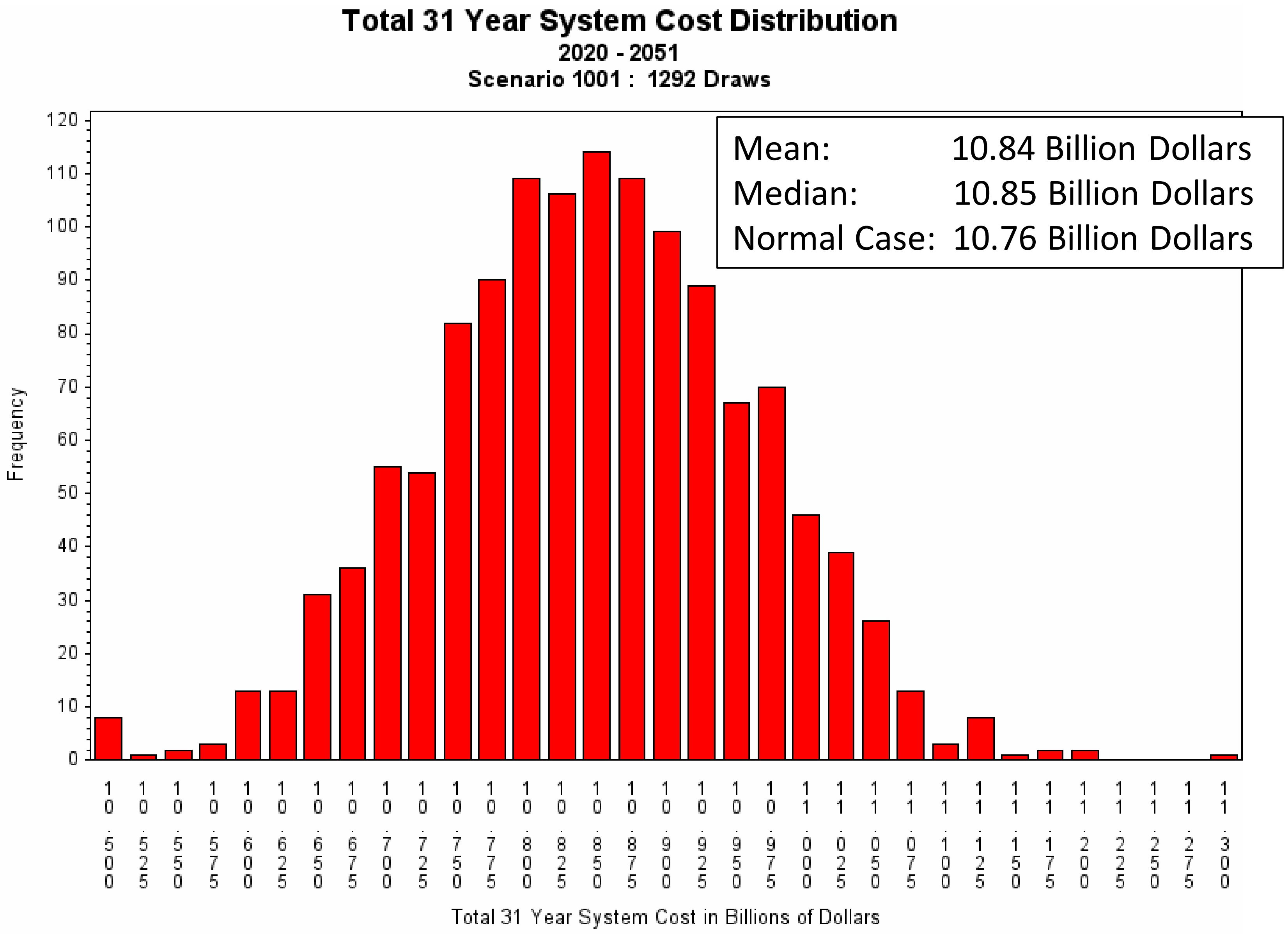

Exhibit 13.82

Required vs. Supply

Area	Class	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	Total
Ut/Id	FS_COM	123.196	120.086	120.280	126.798	155.994	184.874	228.594	264.259	239.303	208.993	190.816	160.963	2124.153
Wy QGC	FS_COM	9.078	8.496	8.528	9.563	16.028	16.462	19.143	20.122	18.764	17.505	14.529	13.855	172.071
Ut/Id	FS_IND	43.253	43.012	43.039	43.988	52.967	57.553	64.750	69.380	65.863	59.997	57.074	46.749	647.626
Ut Geo	GS_COM	40.591	36.782	37.139	51.066	88.466	175.044	274.210	296.510	242.354	188.723	133.128	75.963	1639.976
Ut KRGT	GS_COM	4.713	4.278	4.319	5.928	10.271	20.337	31.877	34.461	28.183	21.920	15.463	8.835	190.584
UT NPC	GS_COM	3.088	2.803	2.827	3.888	6.737	13.328	20.862	22.611	18.447	14.398	10.158	5.783	124.929
Ut/Id	GS_COM	649.177	589.210	595.430	833.196	1453.251	2936.293	4647.091	5025.577	4089.375	3167.357	2215.047	1237.566	27438.570
Wy QGC	GS_COM	30.034	22.380	22.742	29.575	82.902	154.633	216.651	231.799	201.034	164.539	118.817	75.325	1350.432
Ut Geo	GS_RES	114.060	95.873	97.135	134.535	231.420	457.689	717.102	786.743	643.271	500.745	353.281	201.517	4333.372
Ut KRGT	GS_RES	13.254	11.139	11.285	15.633	26.893	53.181	83.314	91.412	74.736	58.179	41.049	23.412	503.487
UT NPC	GS_RES	8.692	7.304	7.401	10.251	17.633	34.871	54.646	59.934	49.017	38.153	26.914	15.349	330.164
Ut/Id	GS_RES	1823.858	1535.766	1557.343	2195.890	3801.248	7676.596	12155.473	13335.620	10849.655	8402.113	5878.808	3282.855	72495.225
Wy QGC	GS_RES	49.539	34.655	35.430	45.808	128.401	239.374	335.366	358.918	311.346	254.794	184.056	116.659	2094.348
Ut/Id	IS_COM	4.373	4.068	4.085	4.173	5.254	8.792	10.039	14.085	11.783	11.108	7.445	5.813	91.017
Wy QGC	IS_COM	4.063	4.071	4.072	4.113	10.169	13.905	16.322	17.042	16.665	17.347	14.478	9.354	131.601
Ut/Id	IS_IND	3.450	3.383	3.387	3.539	3.694	4.918	6.018	7.668	5.895	4.383	4.097	4.006	54.438
Wy QGC	IS_IND	0.038	0.000	0.002	0.061	1.143	2.064	0.378	1.083	0.820	0.620	0.071	1.151	7.432
Ut Geo	L_and_U	0.874	0.750	0.759	1.049	1.807	Required vs. Supply		6.120	5.004	3.895	2.748	1.568	33.749
Ut KRGT	L_and_U	0.102	0.087	0.088	0.122	0.210	0.415	0.651	0.711	0.581	0.453	0.319	0.182	3.922
UT NPC	L_and_U	0.067	0.057	0.058	0.080	0.138	0.272	0.427	0.466	0.381	0.297	0.209	0.119	2.571
Ut/Id	L_and_U	14.957	12.970	13.128	18.123	30.919	61.410	96.683	105.749	86.230	66.975	47.196	26.769	581.108
Wy QGC	L_and_U	0.524	0.393	0.400	0.504	1.348	2.409	3.321	3.554	3.100	2.570	1.876	1.222	21.221
Off-Sys Dmd	Off_Sys	38.888	39.973	39.736	38.250	39.314	37.817	38.866	38.655	34.724	38.234	36.797	37.812	459.065
Total		2979.867	2577.536	2608.612	3576.132	6166.207	12155.813	19027.384	20792.481	16996.530	13243.297	9354.376	5352.827	114831.063
Fuel	Transport	174.813	172.22	170.12	174.853	220.773	262.228	345.358	362.979	298.67	286.648	234.168	205.231	2908.061
Fuel	Injection	30.985	37.237	35.793	48.117	30.106	2.153	0.01	0	0	0	0	0	184.400
Fuel	Withdrawl	0	0	0	0	0	0	0	6.089	8.799	25.418	3.53	0	43.836
	Total Fuel	205.798	209.457	205.913	222.970	250.879	264.381	345.368	369.068	307.469	312.066	237.698	205.231	3136.297
Inject	Clay Basin	1751.233	2220.875	2107.068	2400.000	829.823	0.000	0.000	0.000	0.000	0.000	0.000	0.000	9309.000
Inject	Aquafer	0.000	0.000	0.000	420.000	583.368	120.000	1.000	0.000	0.000	0.000	0.000	0.000	1124.368
Inject	Spire	341.728	353.119	353.119	341.728	353.119	37.188	0.000	0.000	0.000	0.000	0.000	0.000	1780.000
	Total Inject	2092.961	2573.994	2460.187	3161.728	1766.310	157.188	1.000	0.000	0.000	0.000	0.000	0.000	12213.368
Total Required		5278.626	5360.987	5274.712	6960.830	8183.396	12577.382	19373.752	21161.549	17303.999	13555.363	9592.074	5558.058	130180.729

Exhibit 13.89

Required vs. Supply

Supply	Spot	0.000	0.000	0.000	1934.312	1537.238	3725.531	7890.641	5678.121	3985.907	2472.448	1203.954	390.151	28818.303
Supply	Peak	0.000	0.000	0.000	0.000	930.000	900.000	2092.500	2092.500	1890.000	930.000	900.000	0.000	9735.000
Supply	Base	0.000	0.000	0.000	0.000	0.000	2550.000	3255.000	3255.000	2940.000	0.000	0.000	0.000	38553.303
	Total	0.000	0.000	0.000	1934.312	2467.238	7175.531	13238.141	11025.621	8815.907	3402.448	2103.954	390.151	50553.303

Withdraw	Clay Basin	0	0.000	0.000	0.000	0.000	0.000	0.000	4104.000	3112.042	3410.050	1873.380	0.000	12499.472
Withdraw	Aquafers	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	184.026	899.862	40.796	0.000	1124.684
Withdraw	Spire	0.000	0.000	0.000	0.000	0.000	0.000	508.000	514.600	464.800	514.600	498.000	0.000	2500.000
Production	Company	3013.62	3081.98	3051.44	2924.28	2992.526	2880.714	3117.794	3087.885	2668.109	3030.566	2906.078974	2976.37	35731.351
Production	Wexpro I	1142.32	1140.68	1105.27	1038.74	1247.989	1155.849	1149.815	1111.415	939.7024	1047.161	986.694006	994.322	13059.957
Production	Wexpro II	1080.64	1095.11	1075.03	1022.15	1433.136	1324.401	1317.981	1276.233	1081.87	1209.338	1143.387002	1156.34	14215.621
	Total	5236.581	5317.768	5231.749	4985.163	5673.651	5360.964	6093.589	10094.133	8450.549	10111.577	7448.336	5127.025	79131.086

Off-System	Off System	42.0451	43.2187	42.9623	41.3558	42.50643	40.88713	42.02211	41.79419	37.54374	41.33836	39.78430176	40.8825	496.34064
	Total	42.0451	43.2187	42.9623	41.3558	42.50643	40.88713	42.02211	41.79419	37.54374	41.33836	39.78430176	40.8825	496.34064

Total Supply	5278.626	5360.987	5274.711	6960.831	8183.395	12577.382	19373.752	21161.548	17304.000	13555.364	9592.074	5558.058	130180.729

Exhibit 13.90

Exhibit 13.83

Normal Temperatue Case: Plan Year 1

MDth

Name	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	Total
Birch Creek													
BIRCH CREEK	116.937	120.091	119.353	114.795	117.893	113.391	116.451	115.413	100.033	114.003	109.650	112.611	1370.620
Total	116.937	120.091	119.353	114.795	117.893	113.391	116.451	115.413	100.033	114.003	109.650	112.611	1370.620
D24													
CHBT MT	15.252	15.670	15.581	14.994	15.404	14.823	15.230	15.144	13.132	14.970	14.406	14.802	179.408
HWA MT	2.811	2.883	2.861	2.748	2.818	2.709	2.778	2.756	2.386	2.716	2.607	2.675	32.747
PDW MT	195.888	200.613	198.865	190.800	195.498	187.617	192.277	190.715	164.982	187.674	180.183	184.729	2269.842
ACEJDMT D24	8.334	8.540	8.466	8.124	8.323	7.989	8.184	8.116	7.017	7.979	7.656	7.843	96.572
BRFM D24	1.854	1.906	1.894	1.821	1.872	1.800	1.848	1.838	1.593	1.817	1.746	1.795	21.785
BRFQ D24	0.000	0.000	0.000	0.000	0.000	0.000	138.294	137.308	118.891	135.365	130.068	133.452	793.378
BRFQMT D24	4.674	4.805	4.777	4.599	4.724	4.548	4.672	4.647	4.029	4.597	4.422	4.545	55.039
BRFW D24	55.536	56.966	56.550	54.324	55.722	53.391	54.768	54.371	47.071	53.583	51.477	52.805	646.565
CBFR D24	15.627	16.002	15.860	15.210	15.574	14.937	15.299	15.162	13.104	14.889	14.280	14.626	180.570
CCRUNIT D24	497.460	509.178	504.429	483.660	495.231	474.936	486.387	482.087	416.732	473.702	454.464	465.589	5743.855
CCRUNITMTD24	42.117	43.189	42.861	41.163	42.213	40.038	41.066	40.765	35.288	40.167	38.589	39.584	487.039
CHBTBUFF D24	0.000	0.000	0.000	0.000	0.000	0.717	0.735	0.732	0.636	0.722	0.696	0.716	4.953
CHBTCAT2 D24	93.465	95.939	95.300	91.614	94.038	90.402	92.792	92.178	79.853	90.960	87.441	89.757	1093.741
CHBTCAT3 D24	156.852	160.971	159.870	153.657	157.430	151.317	155.298	154.247	133.602	151.816	145.905	149.420	1830.385
DRYPINY6 D24	1.026	1.051	1.042	0.999	1.023	0.981	1.004	0.995	0.860	0.976	0.936	0.961	11.854
DRYPINYU D24	1.836	1.888	1.879	1.809	1.860	1.791	1.841	1.832	1.590	1.817	1.749	1.798	21.690
DRY PINY MT	0.000	0.000	0.000	0.000	0.000	5.106	5.233	5.189	4.488	5.106	4.902	5.025	35.049
HWA DEEP D24	0.141	0.140	0.133	0.123	0.124	0.114	0.115	0.108	0.092	0.099	0.093	0.093	1.376
HWADEEPMTD24	13.287	13.646	13.566	13.047	13.401	12.891	13.240	13.160	11.407	12.998	12.504	12.843	155.990
HWPL1&3MTD24	7.710	7.924	7.880	7.581	7.790	7.497	7.703	7.660	6.644	7.576	7.290	7.493	90.749
HWPLT1&3 D24	77.904	79.611	78.731	75.351	77.001	73.698	75.314	74.487	64.246	72.859	69.738	71.272	890.212
HWPLT2 D24	4.938	5.069	5.034	4.842	4.969	4.776	4.904	4.870	4.220	4.805	4.620	4.743	57.790
HWPLT2MT D24	4.215	4.312	4.269	4.089	4.182	4.008	4.098	4.058	3.503	3.977	3.813	3.900	48.424
ISLAND D24	52.905	53.676	53.311	51.240	52.585	50.544	51.872	50.257	42.986	48.958	46.455	47.681	602.471
JNSNRDG D24	2.097	2.158	2.148	2.073	2.133	2.055	2.114	2.108	1.828	2.089	2.013	2.074	24.891
JRDG WFS D24	2.721	2.796	2.778	2.673	2.743	2.640	2.709	2.694	2.335	2.660	2.559	2.629	31.937
KNY FLD D24	15.231	15.605	15.475	14.853	15.221	14.610	14.973	14.855	12.852	14.620	14.037	14.393	176.726
MESA D24	755.478	772.923	765.316	733.383	750.464	719.238	736.073	729.042	629.737	713.955	684.414	700.591	8690.613
MOSUMT D24	0.000	0.000	0.000	0.000	0.000	1.164	1.181	1.159	0.994	1.119	1.062	1.079	7.758
PDW1A1B D24	0.588	0.604	0.601	0.576	0.592	0.570	0.583	0.580	0.501	0.573	0.549	0.564	6.882
PDWCUT D24	0.000	0.000	0.000	0.000	0.000	1.440	1.482	1.476	1.280	1.463	1.407	1.448	9.995
PDWMT D24	27.228	27.878	27.630	26.505	27.150	26.049	26.691	26.468	22.890	26.034	24.990	25.615	315.128
PDWPLT2 D24	4.653	4.780	4.749	4.569	4.690	4.512	4.635	4.607	3.993	4.551	4.377	4.495	54.610
SGRLF D24	1.692	1.736	1.724	1.656	1.699	1.635	1.677	1.665	1.442	1.643	1.578	1.618	19.764
SGRLFMT D24	10.383	10.655	10.580	10.170	10.435	10.029	10.292	10.221	8.851	10.078	9.687	9.939	121.319
TRAIL D24	370.329	375.432	368.683	350.667	356.395	339.435	345.393	340.290	292.513	330.758	315.762	321.991	4107.647
TRAILMT D24	56.688	57.663	56.801	54.183	55.214	52.719	53.766	53.088	45.727	51.807	49.545	50.611	637.812
WHLA D24	0.000	0.000	0.000	0.000	0.000	0.000	30.544	30.318	26.244	29.872	28.692	29.431	175.102
WWILSON D24	0.000	0.000	0.000	0.000	0.000	3.288	3.376	3.354	2.906	3.311	3.183	3.267	22.686
Total	2500.920	2556.210	2529.643	2423.103	2478.521	2386.014	2610.442	2584.606	2232.446	2534.662	2429.895	2487.893	29754.356
PC													
BRUFF MT	4.836	4.966	4.935	4.746	4.873	4.689	4.814	4.783	4.147	4.724	4.545	4.666	56.725
BKSPUNT6MTPC	2.715	2.793	2.781	2.679	2.756	2.655	2.731	2.716	2.358	2.691	2.592	2.666	32.132
HWPL1&3MTPC	6.414	6.578	6.529	6.270	6.429	6.174	6.330	6.284	5.438	6.188	5.943	6.095	74.671
ACEJDMT PC	3.669	3.776	3.757	3.618	3.723	3.585	3.689	3.670	3.186	3.636	3.501	3.602	43.413
BRFM PC	0.141	0.146	0.146	0.138	0.143	0.138	0.140	0.140	0.120	0.136	0.132	0.136	1.655
BRFQ PC	9.687	9.954	9.898	9.528	9.793	9.426	9.688	9.635	8.358	9.533	9.177	9.433	114.109
BRFQMT PC	3.285	3.370	3.348	3.216	3.302	3.174	3.255	3.233	2.800	3.190	3.066	3.143	38.382
BRFW PC	9.750	10.019	9.963	9.591	9.855	9.486	9.746	9.694	8.408	9.588	9.228	9.483	114.812
CBFR PC	57.915	59.312	58.788	56.394	57.769	55.425	56.783	56.299	48.684	55.357	53.121	54.436	670.282
CCRUNIT PC	50.976	52.282	51.894	49.845	51.128	49.113	50.378	50.009	43.294	49.284	47.349	48.577	594.129
CCRUNITMT PC	16.563	17.003	16.889	16.236	16.669	16.023	16.449	16.340	14.157	16.126	15.501	15.912	193.868
CHBTC1 MT PC	19.689	19.880	19.431	18.375	18.560	17.556	17.732	17.335	14.778	16.569	15.678	15.841	211.425
CHBTCAT1 PC	46.020	47.170	46.791	44.919	46.044	44.202	45.310	44.950	38.889	44.240	42.474	43.546	534.555
CHBTCAT2 PC	2.403	2.461	2.440	2.343	2.399	2.301	2.359	2.337	2.022	2.297	2.205	2.257	27.825
DRYPINY6 PC	1.083	1.116	1.110	1.071	1.100	1.062	1.091	1.088	0.944	1.079	1.038	1.069	12.851
DRYPINYU PC	12.264	12.592	12.515	12.036	12.360	11.886	12.208	12.130	10.514	11.981	11.523	11.833	143.842
FOGARTY PC	0.474	0.487	0.481	0.462	0.474	0.453	0.465	0.462	0.398	0.453	0.435	0.446	5.489
HWA DEEP PC	1.122	1.150	1.144	1.098	1.128	1.086	1.113	1.107	0.958	1.091	1.050	1.079	13.126
HWPLT1&3 PC	55.722	57.183	56.789	54.582	56.017	53.841	55.257	54.882	47.538	54.145	52.044	53.419	651.420
HWPLT2 PC	0.852	0.871	0.865	0.828	0.849	0.816	0.803	0.797	0.689	0.784	0.753	0.775	9.682
ISLAND PC	0.678	0.697	0.691	0.666	0.685	0.657	0.676	0.673	0.582	0.663	0.639	0.654	7.962
JNSNRDG PC	2.436	2.508	2.496	2.406	2.477	2.385	2.455	2.446	2.122	2.424	2.337	2.402	28.895
KNY FLD PC	2.943	3.029	3.019	2.910	2.995	2.886	2.970	2.961	2.570	2.936	2.829	2.914	34.961
MOSUMT PC	11.925	12.233	12.143	11.667	11.966	11.496	11.792	11.706	10.136	11.538	11.085	11.371	139.057
PDW1A1B PC	0.000	0.000	0.000	0.000	0.000	0.978	1.004	0.998	0.862	0.983	0.741	0.760	6.326
PDW1AB MT PC	3.513	3.612	3.593	3.462	3.559	3.429	3.525	3.509	3.044	3.475	3.345	3.441	41.506
PDWCUT PC	0.615	0.636	0.632	0.609	0.626	0.606	0.623	0.620	0.540	0.617	0.594	0.611	7.329
PDWPLT2 PC	4.218	4.337	4.318	4.158	4.275	4.119	4.235	4.216	3.660	4.176	4.020	4.135	49.866
PDWPLT3 PC	5.238	5.385	5.360	5.163	5.307	5.112	5.258	5.233	4.542	5.183	4.992	5.134	61.906
SGRLF PC	36.582	37.522	37.250	35.787	36.713	35.274	36.189	35.932	31.116	35.430	34.047	34.937	426.780
TRAIL PC	1.218	1.252	1.243	1.194	1.224	1.176	1.209	1.200	1.039	1.184	1.137	1.166	14.242
WHLA PC	8.106	8.305	8.234	7.902	8.094	7.770	7.961	7.896	6.826	7.766	7.452	7.638	93.949
WWILSON PC	12.708	13.051	12.974	12.480	12.818	12.330	12.663	12.586	10.912	12.434	11.961	12.285	149.203
Total	395.760	405.675	402.445	386.379	396.112	381.309	390.901	387.866	335.630	381.901	366.534	375.863	4606.375

Exhibit 13.84

Normal Temperatue Case: Plan Year 1

MDth

PW

MOSU MT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Off-System

OFF SYS D24	33.633	34.563	34.344	33.052	33.963	32.655	33.553	33.362	30.222	32.978	31.729	32.596	396.651
OFF SYS PC	8.412	8.655	8.618	8.304	8.544	8.232	8.469	8.432	7.322	8.361	8.055	8.286	99.690
OFF SYS PW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	42.045	43.219	42.962	41.356	42.506	40.887	42.022	41.794	37.544	41.338	39.784	40.883	496.341

Wexpro I

CCRUNIT MT	52.401	53.013	51.937	49.275	49.944	47.436	48.134	47.291	40.536	45.703	43.509	44.246	573.425
yCCRUNIT MT	21.792	22.044	21.598	20.490	20.770	19.725	20.017	19.663	16.856	19.006	18.093	18.399	238.452
CCRUNIT D8	246.846	247.414	240.541	226.764	227.816	213.921	214.839	209.101	177.716	198.834	187.944	189.875	2581.612
yCCRUNIT D8	18.612	18.978	18.761	17.973	18.061	16.707	16.548	15.900	13.350	14.765	13.806	13.804	197.266
KNY FLD D8	20.472	20.875	20.609	19.692	20.097	19.215	19.620	19.394	16.719	18.960	18.147	18.550	232.350
MESA D8	681.747	677.353	653.406	611.604	612.650	575.838	578.872	563.968	479.769	537.270	508.290	513.940	6994.706
TRAIL D8	100.449	101.001	98.422	92.940	93.818	88.788	89.807	87.984	75.233	84.646	80.427	81.651	1075.166
Total	1142.319	1140.679	1105.274	1038.738	1043.156	981.630	987.837	963.300	820.179	919.184	870.216	880.465	11892.977

Wexpro I New Drill

z20 TRAIL D8	0.000	0.000	0.000	0.000	204.833	174.219	161.978	148.115	119.524	127.977	116.478	113.857	1166.980
z21 CCRK D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
z21 CHBT D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
z21 TRAIL D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	204.833	174.219	161.978	148.115	119.524	127.977	116.478	113.857	1166.980

Wexpro II

CCOPA 2E	4.782	4.913	4.886	4.701	4.830	4.650	4.777	4.749	4.119	4.696	4.518	4.641	56.262
CCRUNIT2EMT	24.402	25.029	24.847	23.868	24.484	23.313	23.917	23.746	20.560	23.408	22.494	23.076	283.144
CCRUNIT 2D8	81.639	81.465	78.861	74.028	74.335	70.011	70.506	68.801	58.612	65.720	62.247	63.004	849.230
CCRUNIT 2E	284.988	290.498	286.703	273.948	279.611	267.366	273.070	269.976	232.831	264.086	252.846	258.546	3234.469
TRAIL 2E	404.244	409.928	402.650	383.046	389.360	370.881	377.431	371.888	319.698	361.522	345.147	351.974	4487.770
TRAIL 2E MT	54.507	55.437	54.603	52.080	53.066	50.664	51.668	51.014	43.938	49.774	47.601	48.620	612.971
WHISKEYC 2E	98.289	99.743	98.013	93.261	94.804	90.300	91.881	90.514	77.790	87.941	83.934	85.566	1092.035
WHISKEY MT	33.267	33.703	33.065	31.410	31.877	30.318	30.802	30.299	26.004	29.357	27.981	28.489	366.572
TRAIL 2D8	94.527	94.395	91.407	85.806	86.146	81.111	81.654	79.639	67.810	75.993	71.937	72.776	983.201
Total	1080.645	1095.112	1075.033	1022.148	1038.512	988.614	1005.705	990.627	851.362	962.497	918.705	936.693	11965.654

Wexpro II New Drill

z20 TRAIL2D8	0.000	0.000	0.000	0.000	394.624	335.787	312.275	285.606	230.507	246.841	224.682	219.644	2249.966
z21 CCRK 2D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
z21 TRAIL2D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
z21 WSKY 2D8	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	394.624	335.787	312.275	285.606	230.507	246.841	224.682	219.644	2249.966

Exhibit 13.85

Normal Temperatue Case: Plan Year 1
MDth

	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	Total
Withdraw													
Chalk Creek	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	45.004	235.200	40.796	0.000	321.000
Clay Bsn 935	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1824.000	1383.130	1515.578	832.613	0.000	5555.321
Clay Bsn 988	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1140.000	864.456	947.236	520.383	0.000	3472.075
Clay Bsn 997	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1140.000	864.456	947.236	520.383	0.000	3472.075
Coalville	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	60.079	300.107	0.000	0.000	360.186
Leroy	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	78.943	364.555	0.000	0.000	443.498
Spire	0.000	0.000	0.000	0.000	0.000	0.000	508.000	514.600	464.800	514.600	498.000	0.000	2500.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	508.000	4618.600	3760.868	4824.512	2412.175	0.000	16124.155
Inject													
Chalk Creek	0.000	0.000	0.000	75.000	124.000	120.000	1.000	0.000	0.000	0.000	0.000	0.000	320.000
Clay Bsn 935	1066.680	843.111	729.304	1066.680	431.558	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4137.334
Clay Bsn 988	336.061	688.882	688.882	666.660	205.348	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2585.833
Clay Bsn 997	348.492	688.882	688.882	666.660	192.917	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2585.833
Coalville	0.000	0.000	0.000	120.000	240.372	0.000	0.000	0.000	0.000	0.000	0.000	0.000	360.372
Leroy	0.000	0.000	0.000	225.000	218.996	0.000	0.000	0.000	0.000	0.000	0.000	0.000	443.996
Spire	341.728	353.119	353.119	341.728	353.119	37.188	0.000	0.000	0.000	0.000	0.000	0.000	1780.000
Total	2092.961	2573.994	2460.187	3161.728	1766.310	157.188	1.000	0.000	0.000	0.000	0.000	0.000	12213.368
Purchase Gas													
Spot	0	0	0	547.55	285.533	3117.032	7178.804	5342.634	3119.942	1364.254	606.412	0	21562.161
Spot	0	0	0	1372.542	1227.198	560.028	711.837	335.383	798.12	1055.346	560.261	368.9	6989.615
Spot	0	0	0	14.22	24.507	48.471	0	0.104	67.845	52.848	37.281	21.251	266.527
Base	0	0	0	0	930	900	930	930	840	930	900	0	6360
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Base	0	0	0	0	0	0	232.5	232.5	210	0	0	0	675
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Peak	0	0	0	0	0	300	310	310	280	0	0	0	1200
Peak	0	0	0	0	0	900	775	775	700	0	0	0	3150
Peak	0	0	0	0	0	0	775	775	700	0	0	0	2250
Peak	0	0	0	0	0	750	775	775	700	0	0	0	3000
Peak	0	0	0	0	0	600	620	620	560	0	0	0	2400
Total	0	0	0	1934.312	2467.238	7175.531	13238.141	11025.621	8815.907	3402.448	2103.954	390.151	50553.303

78890.826

Exhibit 13.86

Normal Temperature Case : Plan Year 2
MDth

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	
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													
CHBT MT	14.241	14.632	14.548	14.001	14.384	13.842	14.223	14.139	12.698	13.981	13.452	13.820	167.961
HWA MT	2.568	2.635	2.616	2.511	2.576	2.475	2.539	2.517	2.257	2.480	2.382	2.443	29.999
PDW MT	177.378	181.874	180.473	173.313	177.726	170.691	175.048	173.733	155.025	170.351	163.632	167.831	2067.075
ACEJDMT D24	7.527	7.713	7.648	7.338	7.517	7.215	7.390	7.328	6.563	7.204	6.915	7.083	87.443
BRFM D24	1.725	1.773	1.761	1.695	1.739	1.674	1.720	1.708	1.534	1.689	1.623	1.668	20.310
BRFQ D24	0.000	0.000	0.000	0.000	0.000	0.000	127.019	126.130	113.128	0.000	0.000	0.000	366.278
BRFQMT D24	4.374	4.495	4.470	4.302	4.421	4.254	4.374	4.349	3.906	4.300	4.140	4.253	51.638
BRFW D24	50.733	52.043	51.668	49.638	50.914	48.870	49.991	49.631	44.506	48.921	47.004	48.221	592.139
CBFR D24	14.028	14.365	14.235	13.653	13.981	13.410	13.733	13.609	12.183	13.367	12.822	13.128	162.515
CCRUNIT D24	446.733	457.718	453.868	435.555	446.329	428.352	438.489	434.890	389.595	427.828	410.670	420.937	5190.963
CCRUNITMTD24	38.028	39.007	38.725	37.203	38.164	36.177	37.113	36.843	33.040	36.317	34.890	35.796	441.304
CHBTBUFF D24	0.690	0.707	0.704	0.678	0.697	0.669	0.688	0.685	0.616	0.676	0.651	0.670	8.131
CHBTCAT2 D24	86.286	88.573	87.987	84.585	86.825	83.469	85.681	85.117	76.370	83.994	80.751	82.891	1012.529
CHBTCAT3 D24	143.634	147.430	146.447	140.775	144.497	138.903	142.578	141.627	127.070	139.748	134.340	137.897	1684.946
DRYPINY6 D24	0.921	0.942	0.933	0.897	0.918	0.879	0.902	0.893	0.801	0.877	0.843	0.862	10.668
DRYPINYU D24	1.731	1.779	1.773	1.707	1.755	1.689	1.739	1.730	1.554	1.714	1.650	1.696	20.517
DRY PINY MT	0.000	4.944	4.904	4.710	4.827	4.635	4.752	4.715	4.228	4.644	4.458	4.573	51.390
HWA DEEP D24	0.087	0.087	0.084	0.075	0.074	0.072	0.071	0.068	0.059	0.062	0.057	0.056	0.852
HWADEEPMTD24	12.354	12.688	12.611	12.129	12.459	11.985	12.307	12.233	10.982	12.087	11.625	11.941	145.400
HWPL1&3MTD24	7.209	7.409	7.366	7.089	7.285	7.011	7.204	7.164	6.434	7.083	6.816	7.006	85.077
HWPLT1&3 D24	68.217	69.722	68.960	66.006	67.462	64.575	66.002	65.286	58.327	63.875	61.146	62.499	782.077
HWPLT2 D24	4.560	4.681	4.650	4.470	4.588	4.410	4.526	4.498	4.035	4.439	4.266	4.380	53.503
HWPLT2MT D24	3.738	3.822	3.785	3.627	3.714	3.558	3.639	3.605	3.226	3.537	3.390	3.469	43.111
ISLAND D24	45.228	46.423	46.112	44.328	45.499	43.740	44.894	44.597	40.012	44.005	42.300	42.476	529.613
JNSNRDG D24	1.998	2.055	2.049	1.974	2.030	1.959	2.015	2.006	1.806	1.990	1.920	1.975	23.778
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	29.749
KNY FLD D24	13.821	14.173	14.065	13.509	13.857	13.308	13.652	13.553	12.152	13.355	12.831	13.166	161.442
MESA D24	671.652	687.571	681.179	653.094	668.620	641.079	656.344	650.020	581.725	638.151	611.838	626.451	7767.724
MOSUMT D24	1.026	1.038	1.020	0.969	0.986	0.936	0.949	0.933	0.826	0.899	0.855	0.868	11.305
PDW1A1B D24	0.543	0.555	0.552	0.531	0.546	0.525	0.536	0.021	0.000	0.000	0.000	0.000	3.809
PDWCUT D24	1.395	1.435	1.429	1.377	1.417	1.362	1.401	1.395	1.254	1.383	1.332	1.370	16.551
PDWMT D24	24.588	25.206	25.008	24.012	24.620	23.640	24.239	24.053	21.560	23.690	22.752	23.334	286.702
PDWPLT2 D24	4.323	4.442	4.414	4.245	4.362	4.194	4.309	4.284	3.844	4.232	4.071	4.182	50.902
SGRLF D24	1.557	1.597	1.587	1.524	1.562	1.503	1.541	1.531	1.375	1.510	1.452	1.491	18.230
SGRLFMT D24	9.552	9.802	9.734	9.354	9.601	9.225	9.467	9.402	8.434	9.272	8.910	9.145	111.898
TRAIL D24	307.605	313.878	310.031	296.433	302.718	289.578	295.849	292.563	261.366	286.260	274.098	280.286	3510.665
TRAILMT D24	48.426	49.488	48.952	46.869	47.926	45.903	46.953	46.485	41.574	45.582	43.689	44.721	556.568
WHLA D24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
WWILSON D24	0.000	0.000	3.202	3.081	3.162	3.039	3.122	3.100	2.783	3.060	0.000	0.000	24.549
Total	2221.005	2279.303	2262.132	2169.738	2222.306	2131.257	2309.519	2288.943	2049.093	2125.038	2035.950	2085.026	26179.310
PC													
BRUFF MT	4.488	4.610	4.582	4.404	4.523	4.350	4.467	4.442	3.987	4.386	4.218	4.334	52.791
BKSPUNT6MTPC	2.568	2.641	2.629	2.535	2.607	2.511	2.582	2.570	2.310	2.545	2.454	2.523	30.476
HWPL1&3MTPC	5.853	6.002	5.955	5.718	5.865	5.634	5.775	5.732	5.138	5.645	5.421	5.558	68.297
ACEJDMT PC	3.471	3.568	3.553	3.420	3.519	3.390	3.484	3.469	3.119	3.438	3.312	3.404	41.146
BRFM PC	0.129	0.133	0.133	0.129	0.130	0.126	0.130	0.127	0.115	0.127	0.123	0.124	1.527
BRFQ PC	9.081	9.334	9.288	8.943	9.191	8.850	9.099	9.052	8.134	8.962	8.628	8.872	107.434
BRFQMT PC	3.021	3.100	3.081	2.961	3.038	2.919	2.995	2.976	2.668	2.933	2.820	2.892	35.404
BRFW PC	9.126	9.381	9.328	8.979	9.226	8.880	9.126	9.077	8.154	8.978	8.640	8.878	107.772
CBFR PC	52.245	53.540	53.100	50.967	52.238	50.142	51.392	50.979	45.674	50.161	48.156	49.364	607.958
CCRUNIT PC	46.671	47.883	47.539	45.678	46.866	45.033	46.206	45.880	41.149	45.241	43.476	44.612	546.233
CCRUNITMT PC	15.297	15.705	15.599	14.997	15.395	14.802	15.193	15.094	13.544	14.896	14.319	14.700	179.540
CHBTC1 MT PC	14.994	15.153	14.818	14.028	14.179	13.422	13.572	13.277	11.735	12.713	12.042	12.177	162.110
CHBTCAT1 PC	41.808	42.864	42.529	40.833	41.866	40.200	41.218	40.901	36.658	40.272	38.673	39.655	487.476
CHBTCAT2 PC	2.166	2.220	2.198	2.109	2.161	2.073	2.124	2.105	1.884	2.071	1.986	2.034	25.129
DRYPINY6 PC	1.029	1.060	1.054	1.017	1.045	1.008	1.038	1.032	0.930	1.023	0.987	1.014	12.237
DRYPINYU PC	11.382	11.687	11.616	11.172	11.473	11.034	11.330	11.262	10.108	11.123	10.698	10.986	133.872
FOGARTY PC	0.426	0.437	0.434	0.417	0.425	0.408	0.419	0.415	0.372	0.406	0.390	0.400	4.949
HWA DEEP PC	1.038	1.063	1.057	1.017	1.045	1.002	1.029	1.023	0.918	1.011	0.972	0.998	12.173
HWPLT1&3 PC	51.348	52.706	52.353	50.325	51.658	49.659	50.973	50.639	45.436	49.972	48.042	49.315	602.426
HWPLT2 PC	0.744	0.763	0.756	0.729	0.747	0.717	0.735	0.732	0.655	0.719	0.693	0.710	8.700
ISLAND PC	0.000	0.648	0.642	0.000	0.000	0.612	0.626	0.623	0.563	0.623	0.000	0.000	4.337
JNSNRDG PC	2.316	2.384	2.375	2.286	2.353	2.268	2.334	2.325	2.089	2.303	2.220	2.285	27.537
KNY FLD PC	2.808	2.889	2.880	2.775	2.855	2.754	2.833	2.821	2.540	2.799	2.700	2.778	33.432
MOSUMT PC	10.923	11.207	11.123	10.686	10.962	10.533	10.804	10.726	9.618	10.571	10.155	10.419	127.726
PDW1A1B PC	0.000	0.000	0.000	0.000	0.000	0.705	0.722	0.722	0.652	0.722	0.000	0.000	3.524
PDW1AB MT PC	3.315	3.407	3.391	3.267	3.360	3.234	3.326	3.311	2.976	3.280	3.159	3.249	39.276
PDWCUT PC	0.588	0.608	0.604	0.582	0.601	0.579	0.595	0.592	0.535	0.589	0.567	0.586	7.026
PDWPLT2 PC	3.984	4.095	4.076	3.927	4.036	3.888	3.999	3.980	3.578	3.943	3.798	3.906	47.212
PDWPLT3 PC	4.944	5.084	5.059	4.875	5.013	4.827	4.963	4.941	4.441	4.895	4.713	4.848	58.603
SGRLF PC	33.576	34.460	34.221	32.892	33.759	32.448	33.303	33.080	29.680	32.643	31.380	32.212	393.654
TRAIL PC	1.122	1.150	1.144	1.098	1.128	1.083	1.113	1.104	0.991	1.088	1.047	1.073	13.141
WHLA PC	7.332	7.514	7.456	7.158	7.338	7.044	7.220	7.164	6.418	7.049	6.768	6.938	85.398
WWILSON PC	11.817	12.140	12.065	11.607	11.920	11.466	11.777	11.706	10.511	11.566	11.127	11.427	139.128
Total	359.610	369.433	366.637	351.531	360.521	347.601	356.503	353.881	317.279	348.694	333.684	342.271	4207.645

Exhibit 13.87

Normal Temperature Case : Plan Year 2
MDth

PW

MOSU MT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Off-System

OFF SYS D24	31.357	32.440	32.474	31.462	32.545	31.531	32.616	32.650	29.521	32.719	31.696	32.790	383.802
OFF SYS PC	7.986	8.215	8.181	7.881	8.110	7.812	8.038	8.004	7.199	7.936	7.647	7.865	94.873
OFF SYS PW	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	39.343	40.655	40.655	39.343	40.655	39.343	40.655	40.655	36.720	40.655	39.343	40.655	478.675

Wexpro I

CCRUNIT MT	42.153	42.898	42.259	40.299	41.050	39.171	39.922	39.386	35.106	38.362	36.654	37.402	474.662
yCCRUNIT MT	17.529	17.837	17.574	16.758	17.069	16.290	16.601	16.377	14.599	15.953	15.243	15.553	197.382
CCRUNIT D8	179.808	181.964	178.340	169.269	171.656	163.125	165.621	162.815	144.637	157.573	150.114	152.768	1977.689
yCCRUNIT D8	12.948	12.980	12.611	11.868	11.941	11.259	11.349	11.076	9.775	10.580	10.017	10.131	136.535
KNY FLD D8	17.763	18.163	17.980	17.226	17.624	16.890	17.286	17.124	15.324	16.811	16.125	16.514	204.830
MESA D8	487.077	493.288	483.802	459.492	466.265	443.355	450.384	442.978	393.714	429.114	408.978	416.367	5374.812
TRAIL D8	77.673	78.941	77.683	74.013	75.327	71.829	73.166	72.149	64.282	70.230	67.086	68.448	870.829
Total	834.951	846.071	830.248	788.925	800.931	761.919	774.327	761.906	677.438	738.625	704.217	717.182	9236.739

Wexpro I New Drill

z20 TRAIL D8	104.733	103.286	98.912	91.938	91.487	85.455	85.399	82.742	72.526	78.033	73.488	73.988	1041.986
z21 CCRK D8	0.000	0.000	134.314	238.113	217.697	190.443	253.608	231.384	193.304	199.907	182.067	178.117	2018.953
z21 CHBT D8	0.000	0.000	0.000	0.000	0.000	0.000	26.257	21.836	17.200	17.072	15.087	14.424	111.877
z21 TRAIL D8	0.000	0.000	0.000	0.000	62.019	113.202	200.093	179.171	147.526	150.818	136.077	132.091	1120.996
Total	104.733	103.286	233.225	330.051	371.203	389.100	565.356	515.133	430.556	445.830	406.719	398.620	4293.812

Wexpro II

CCOPA 2E	4.467	4.591	4.563	4.392	4.514	4.341	4.461	4.436	3.984	4.386	4.221	4.337	52.694
CCRUNIT2EMT	22.176	22.751	22.590	21.708	22.274	21.198	21.750	21.598	19.370	21.294	20.463	20.996	258.167
CCRUNIT 2D8	59.772	60.590	59.473	56.532	57.409	54.627	55.533	54.656	48.608	53.013	50.556	51.500	662.270
CCRUNIT 2E	247.638	253.307	250.787	240.318	245.926	235.722	241.075	238.827	213.727	234.469	224.856	230.271	2856.922
TRAIL 2E	336.258	343.120	338.923	324.060	330.931	316.566	323.420	319.824	285.715	312.926	299.628	306.385	3837.757
TRAIL 2E MT	46.521	47.539	47.021	45.021	46.032	44.088	45.096	44.643	39.925	43.772	41.955	42.941	534.553
WHISKEYC 2E	81.720	83.362	82.317	78.687	80.330	76.824	78.470	77.581	69.294	75.882	72.648	74.279	931.395
WHISKEY MT	27.174	27.689	27.311	26.076	26.595	25.407	25.925	25.609	22.854	25.005	23.919	24.437	308.001
TRAIL 2D8	69.003	69.908	68.588	65.163	66.142	62.907	63.922	62.887	55.905	60.946	58.098	59.160	762.628
Total	894.729	912.857	901.573	861.957	880.152	841.680	859.652	850.060	759.382	831.693	796.344	814.308	10204.387

Wexpro II New Drill

z20 TRAIL2D8	202.053	199.271	190.842	177.399	176.533	164.895	164.796	159.669	139.955	150.592	141.822	142.789	2010.616
z21 CCRK 2D8	0.000	0.000	55.853	99.015	90.523	79.191	105.459	96.215	80.380	83.127	75.708	74.065	839.535
z21 TRAIL2D8	0.000	0.000	0.000	0.000	61.321	111.927	197.839	177.150	145.863	149.119	134.544	130.603	1108.366
z21 WSKY 2D8	0.000	0.000	0.000	0.000	0.000	0.000	33.430	29.500	24.038	24.385	21.867	21.123	154.343
Total	202.053	199.271	246.695	276.414	328.377	356.013	501.524	462.532	390.236	407.222	373.941	368.581	4112.859

Exhibit 13.88

Normal Temperature Case : Plan Year 2
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													
Chalk Creek	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	45.0040	0.0000	235.2000	8.6960	0.0000	288.900
Clay Bsn 935	0.0000	0.0000	0.0000	0.0000	0.0000	137.0300	1708.4480	1515.5780	1368.9090	666.7750	0.0000	0.0000	5396.740
Clay Bsn 988	0.0000	0.0000	0.0000	0.0000	0.0000	85.5720	1067.7800	947.2360	855.5680	416.7340	0.0000	0.0000	3372.890
Clay Bsn 997	0.0000	0.0000	0.0000	0.0000	0.0000	85.5720	1067.7800	947.2360	855.5680	416.7340	0.0000	0.0000	3372.890
Coalville	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	60.0790	0.0000	300.1070	0.0000	0.0000	360.186
Leroy	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	78.9430	0.0000	364.5550	0.0000	0.0000	443.498
Spire	0.0000	0.0000	0.0000	0.0000	0.0000	180.2025	514.6000	514.6000	464.8000	0.0000	0.0000	0.0000	1674.202
Total	0.0000	0.0000	0.0000	0.0000	0.0000	488.3765	4358.6080	4108.6760	3544.8450	2400.1050	8.6960	0.0000	14909.306
Inject													
Chalk Creek	0.000	0.000	0.000	75.000	124.000	120.000	2.000	0.000	0.000	0.000	0.000	0.000	321.000
Clay Bsn 935	1066.680	1102.236	1102.236	1066.680	836.450	0.000	0.000	0.000	0.000	0.000	420.168	620.248	6214.698
Clay Bsn 988	666.660	688.882	688.882	666.660	522.771	0.000	0.000	0.000	0.000	0.000	262.416	387.376	3883.647
Clay Bsn 997	666.660	688.882	688.882	666.660	522.771	0.000	0.000	0.000	0.000	0.000	262.416	387.376	3883.647
Coalville	0.000	0.000	0.000	120.000	240.186	0.000	0.000	0.000	0.000	0.000	0.000	0.000	360.186
Leroy	0.000	0.000	0.000	225.000	218.498	0.000	0.000	0.000	0.000	0.000	0.000	0.000	443.498
Spire	341.728	353.119	353.119	341.728	353.119	0.000	0.000	0.000	0.000	0.000	341.728	353.119	2437.658
Total	2741.728	2833.119	2833.119	3161.728	2817.795	120.000	2.000	0.000	0.000	0.000	1286.728	1748.119	17544.334
Purchase Gas													
Spot	0	0	0	547.55	1663.491	3163.727	4442.806	6600.151	3101.105	4130.905	3865.701	1413.783	28929.219
Spot	1215.152	745.752	645.98	1476.179	1512.517	455.086	33.205	49.6	1289.832	1048.36	1322.311	1050.425	10844.399
Spot	12.156	10.19	10.309	14.259	24.594	48.725	0.483	2.786	68.164	53.063	37.418	0	282.147
Base	0	0	0	0	930	900	930	930	840	930	900	0	6360
Base	0	0	0	0	0	0	310	465	420	0	0	0	1195
Base	0	0	0	0	0	0	465	465	420	0	0	0	1350
Peak	0	0	0	0	0	300	310	310	280	0	0	0	1200
Peak	0	0	0	0	0	900	930	775	700	0	0	0	3305
Peak	0	0	0	0	0	0	775	775	700	0	0	0	2250
Peak	0	0	0	0	0	750	775	775	700	0	0	0	3000
Peak	0	0	0	0	0	600	620	620	560	0	0	0	2400
Total	1227.308	755.942	656.289	2037.988	4130.602	7117.538	9591.494	11767.537	9079.101	6162.328	6125.43	2464.208	61115.765

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 2020-2021 gas-supply year are as follows:

- Produce approximately 63.0 MMDth 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 14.83 and 14.84, 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 50.6 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 the issue of additional price stabilization on an annual basis 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.
- Begin 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.

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

end devices

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

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.

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 CO_2, O_2, 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.

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.

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

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