This question is: ___ **Trade Secret**
_X_ **Public**

State of Minnesota
Public Utilities Commission

Utility Information Request

Docket Number: E-015/AA-24-64 Date of Request: June 10, 2026

Requested From: Minnesota Power Response Due: June 17, 2026

Analyst Requesting Information: Justin Andringa

Type of Inquiry:

x	Financial		Rate of Return		Rate Design
	Engineering		Forecasting		Conservation
	Cost of Service		CIP		Other:

If you believe your responses are proprietary, please indicate.

PUC Request Number 1	On August 7, 2025, the Minnesota Public Utilities Commission issued an Order in Minnesota Power's 2024 Annual FCA True-Up in Docket No. E-015/AA-23-180. The Order stated as follows in Ordering Paragraphs 4-5: 4. Required Minnesota Power, in its next annual filing, to provide the following information: a. A list of all segments eligible for Auction Revenue Rights (ARRs); b. A list of all segments for which ARRs were awarded; c. A list of all ARR segments converted to Financial Transmission Rights (FTRs); d. A comprehensive discussion of ARR nomination and FTR conversion strategies. 5. Required Minnesota Power, in its next annual filing, to provide the following information: a. A list of all the strategies Minnesota Power considered and implemented to address congestion and curtailment of energy. At a minimum, the list must include Grid Enhancing Technologies (e.g.

	Dynamic Line Rating, system reconfiguration, and system optimization), ARRs, FTRs, planning of transmission line projects to address congestion and curtailment within and between Regional Transmission Organizations, sequencing of transmission line outages, and sequencing of the construction schedule of pending transmission line projects; and b. A comprehensive discussion on the merit of each strategy and how Minnesota Power decides whether to implement each strategy. Minnesota Power must provide a cost-benefit analysis for each strategy or provide a justification for why a cost-benefit analysis cannot be performed. Please provide this information, as ordered, for review in the 2025 fuel clause adjustment annual true up.

Response:

Order Point 4

"*Required Minnesota Power, in its next annual filing, to provide the following information:*

a. A list of all segments eligible for Auction Revenue Rights (ARRs);

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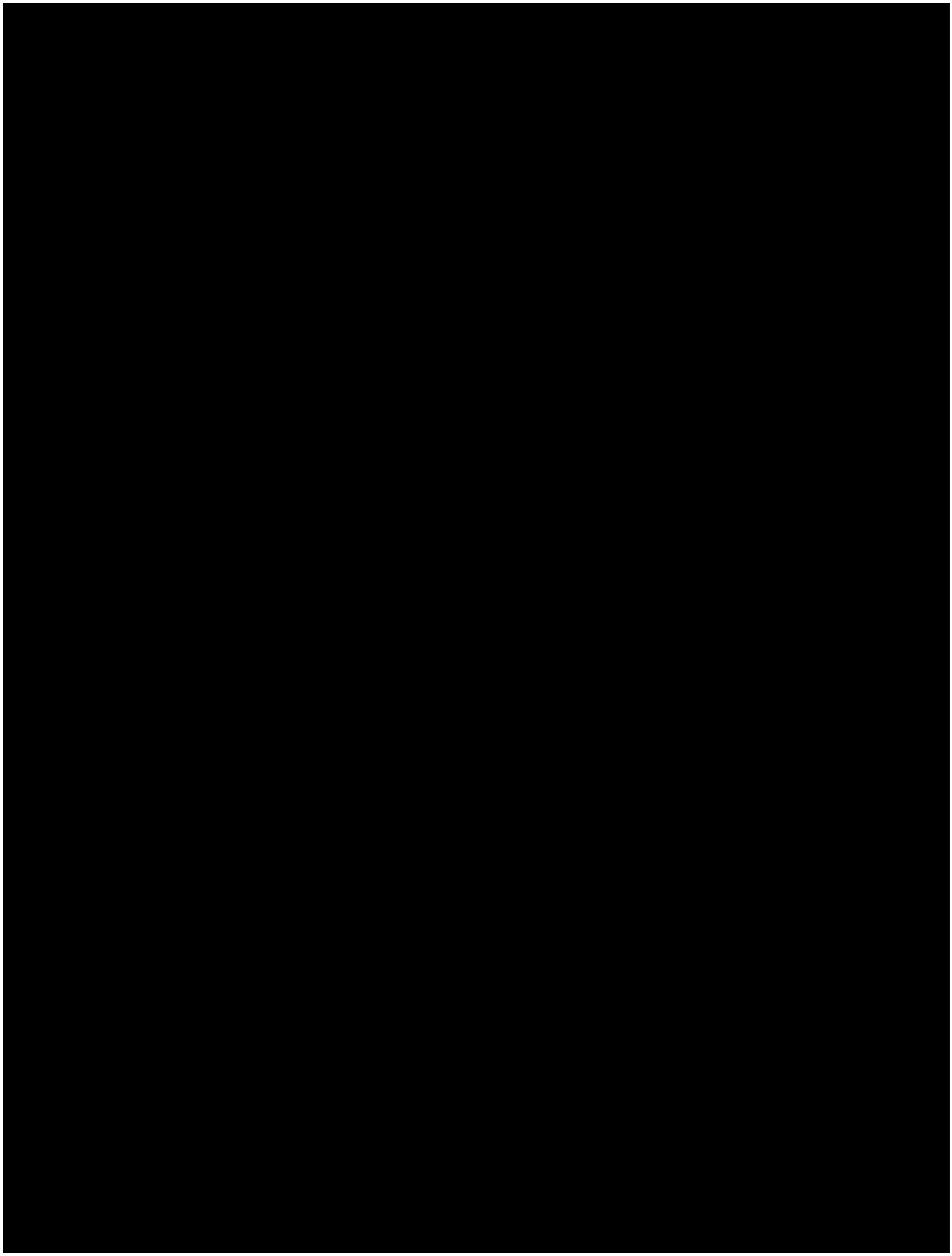

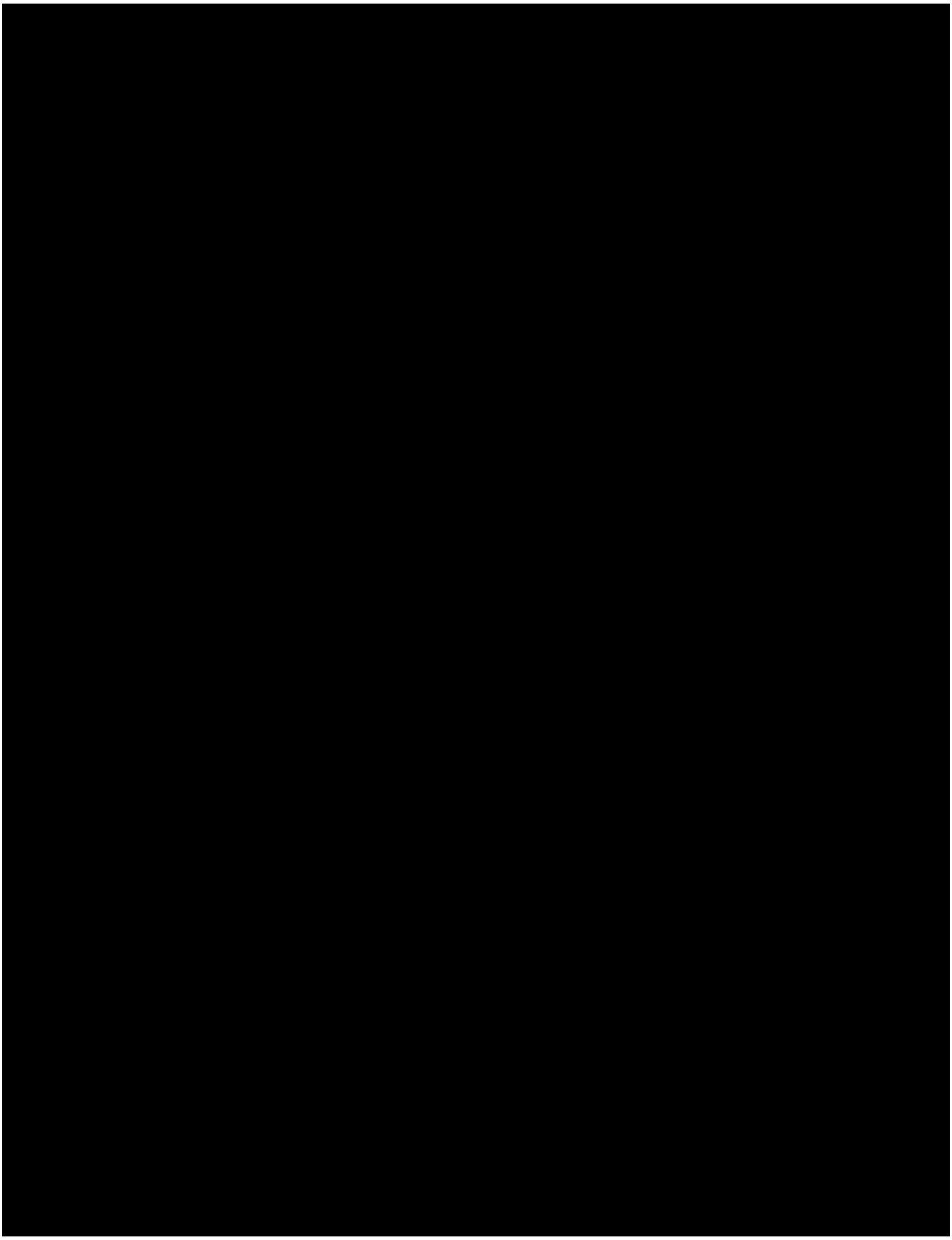

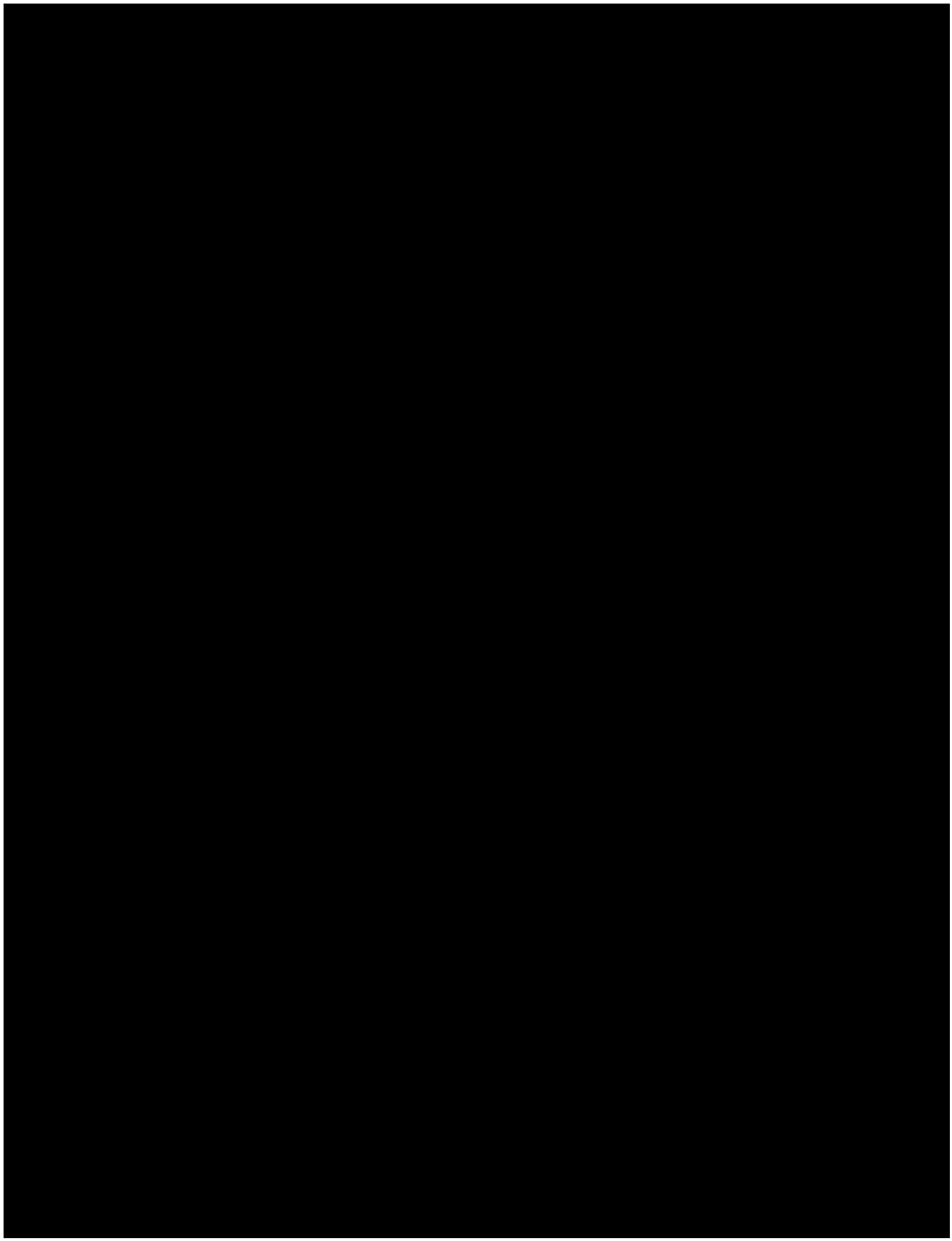

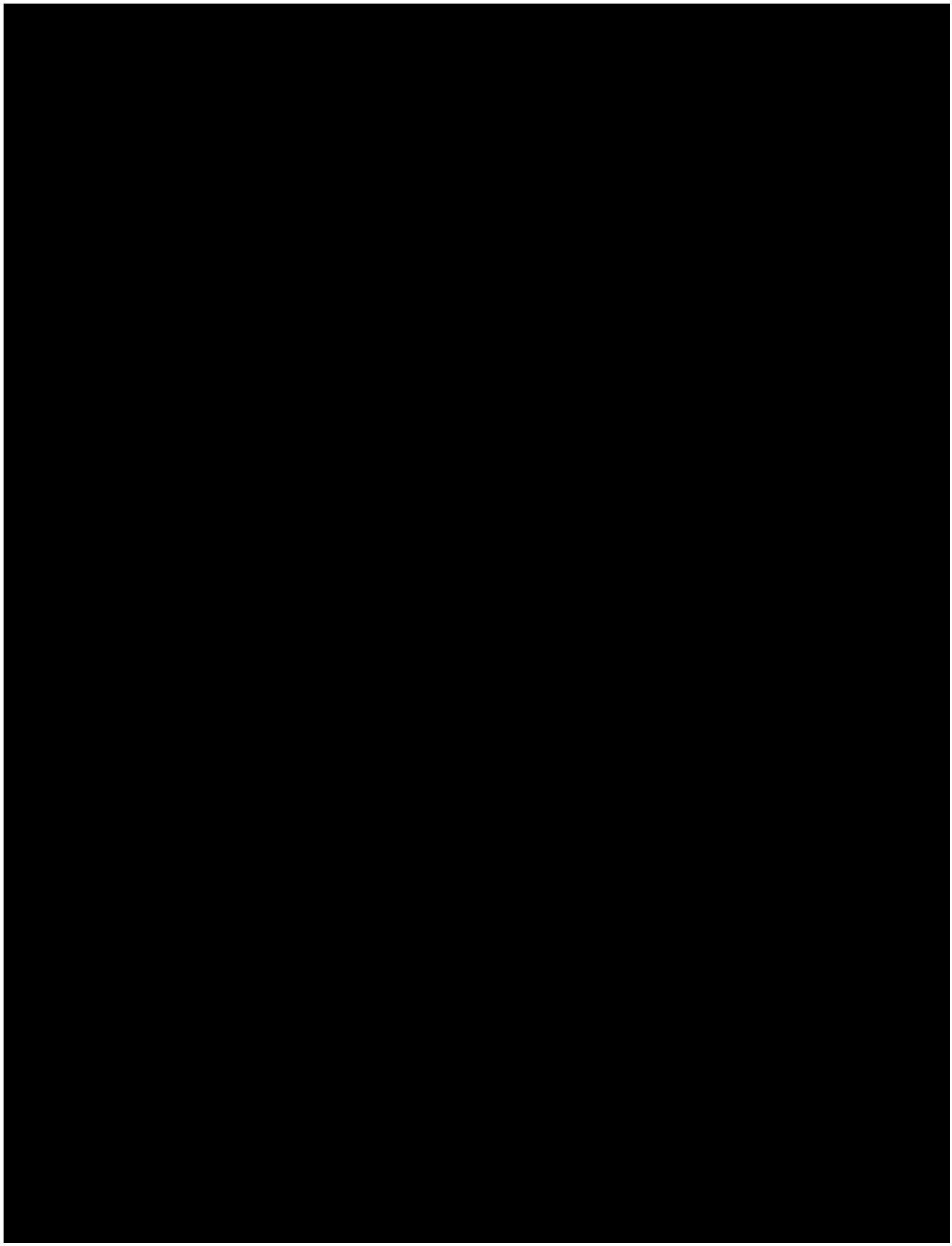

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b. A list of all segments for which ARRs were awarded;

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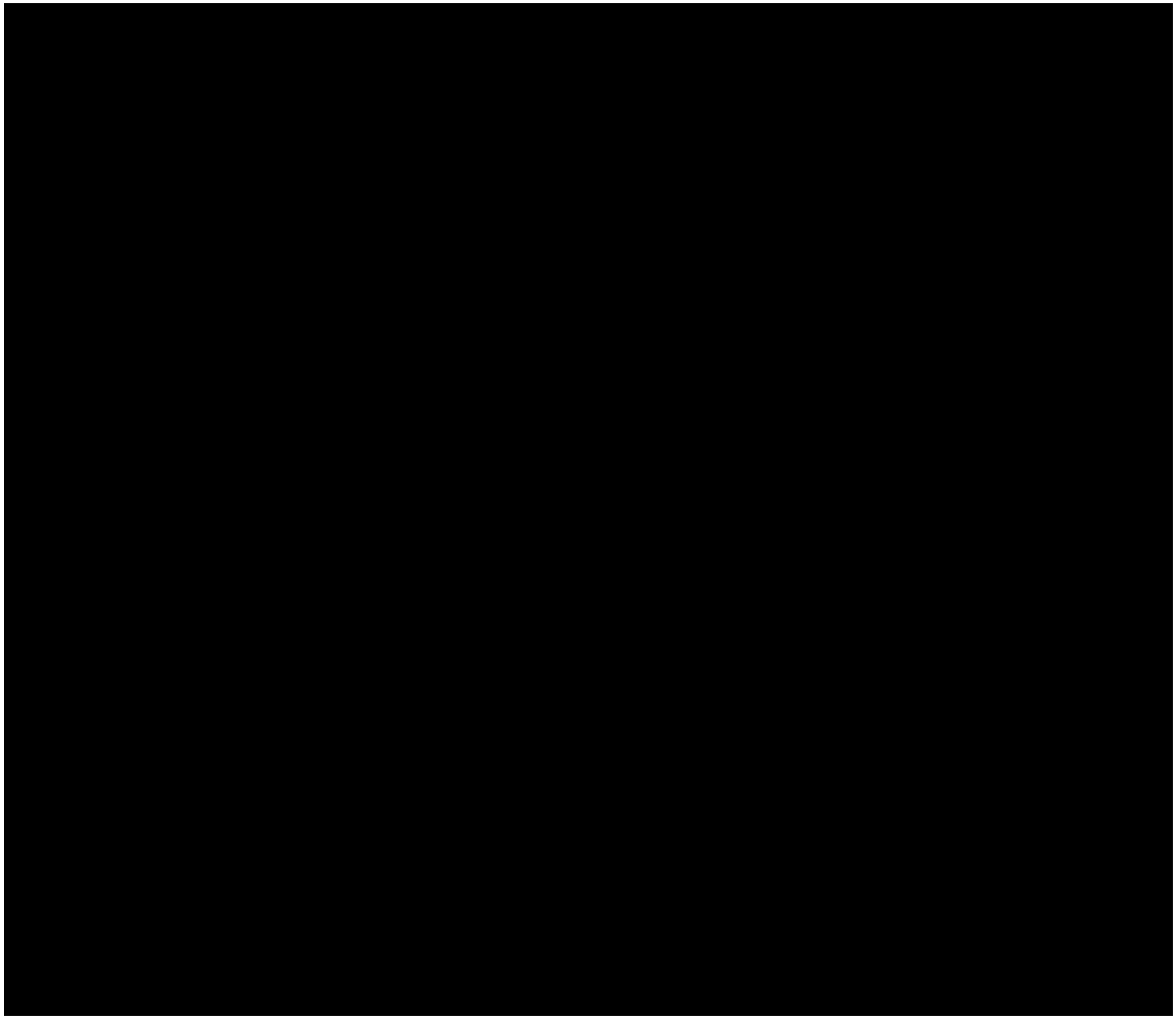

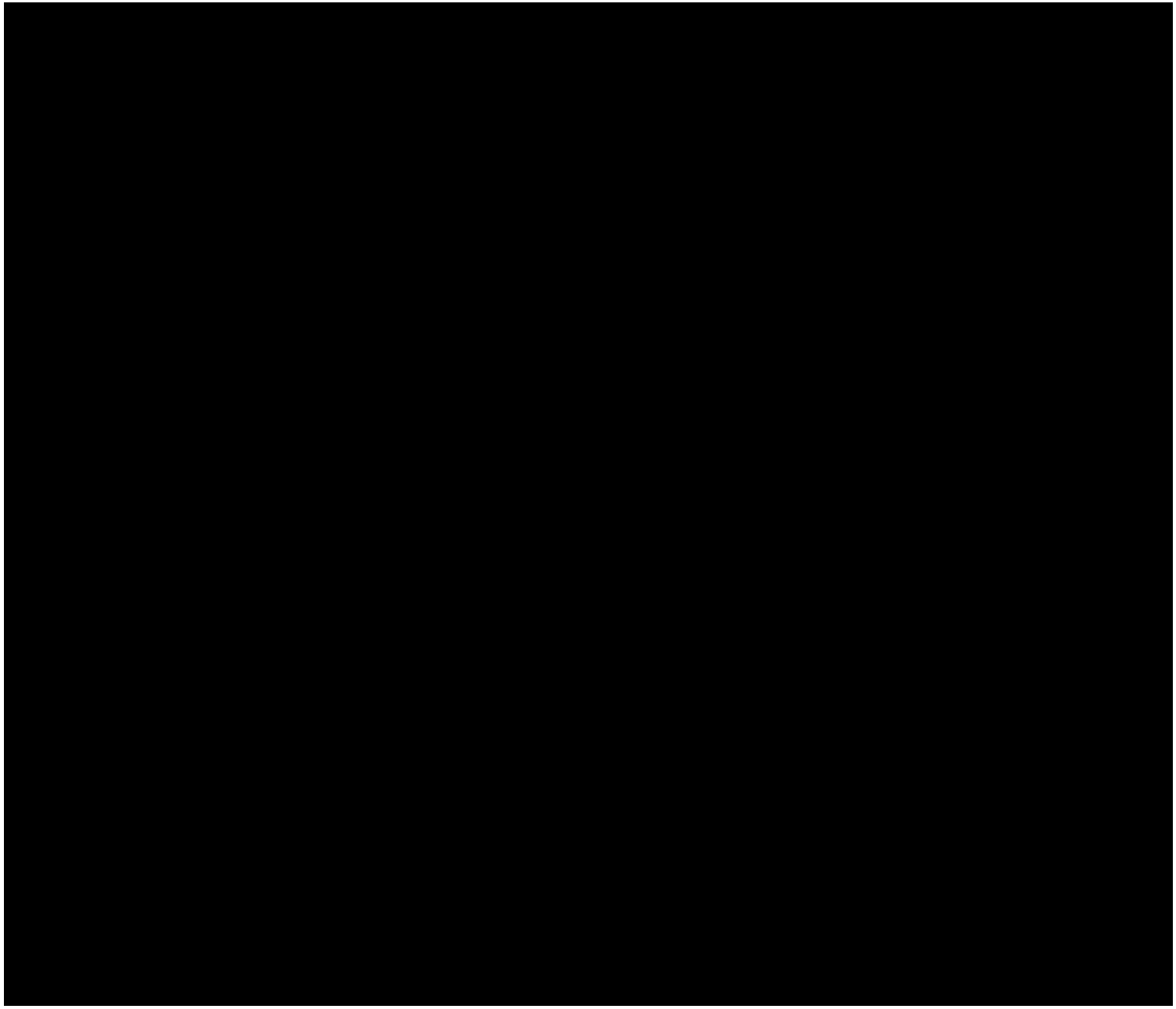

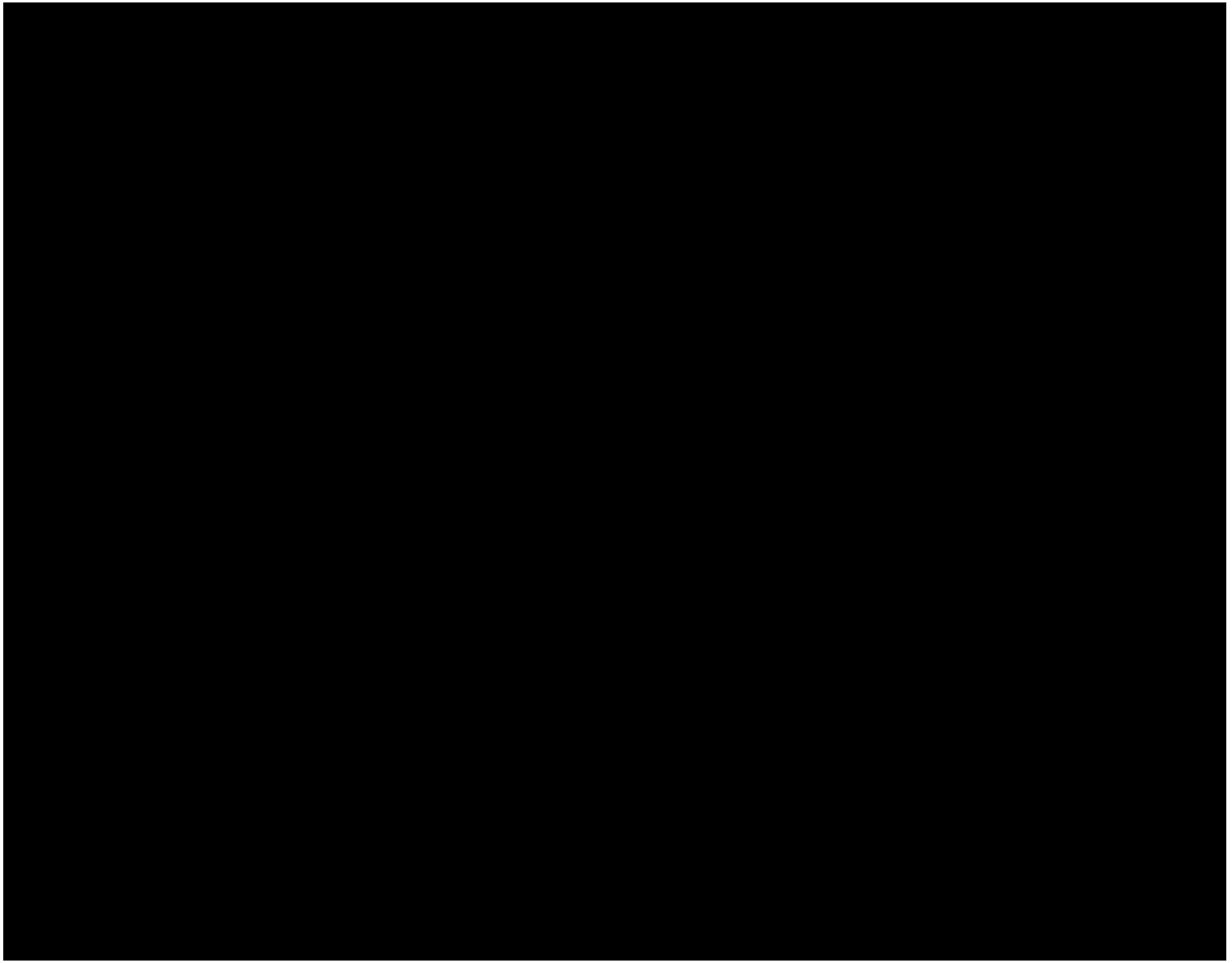

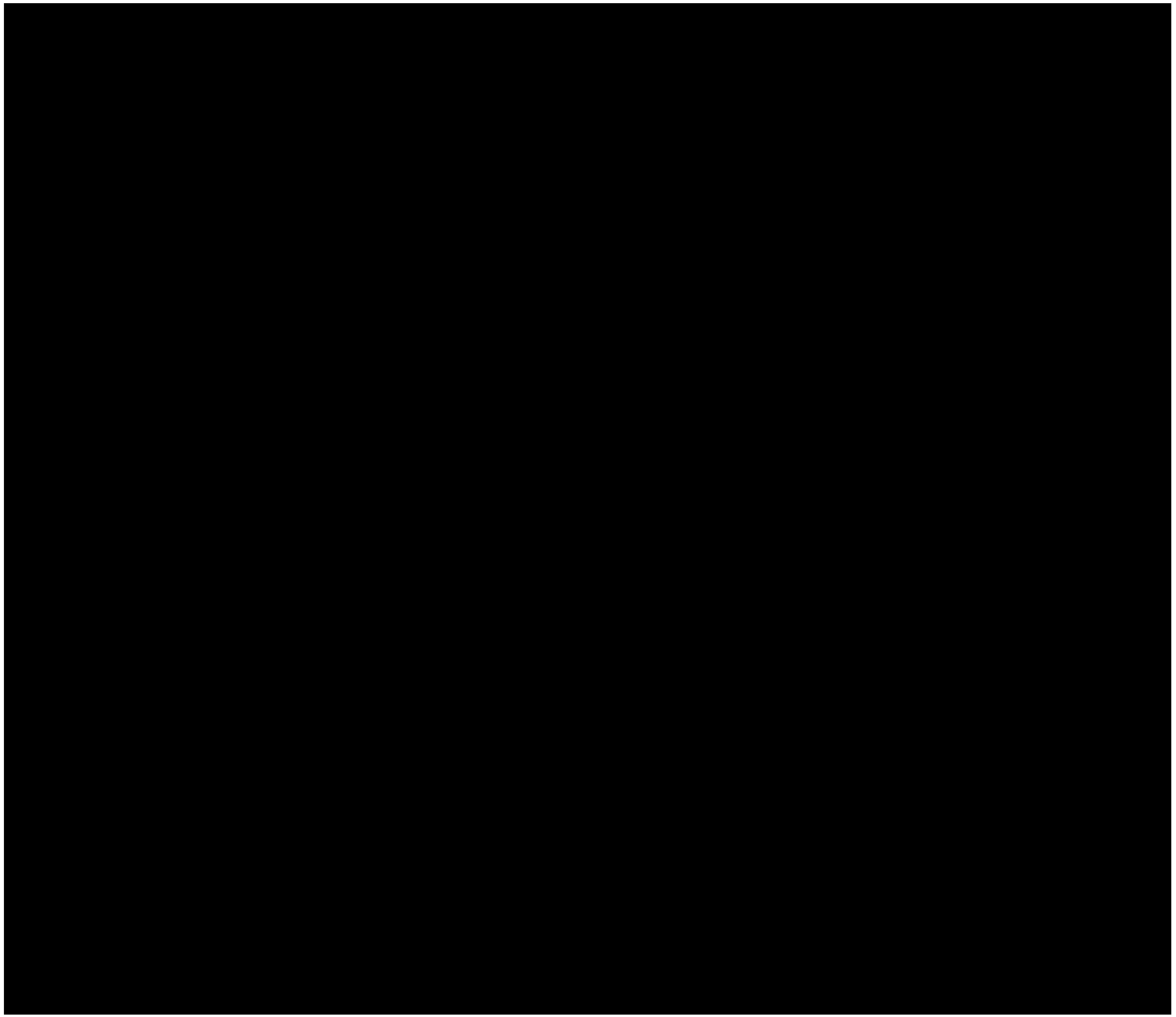

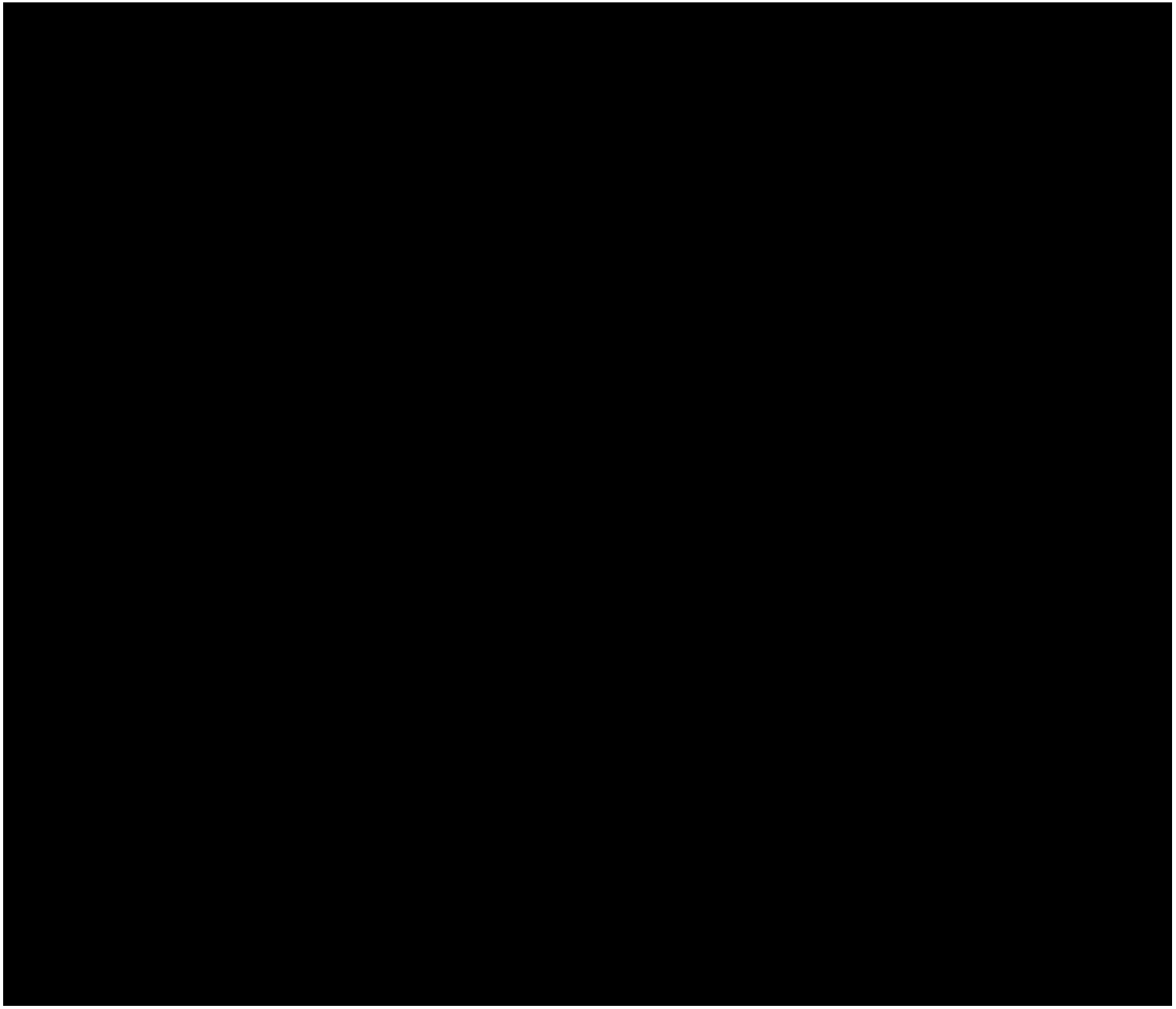

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c. A list of all ARR segments converted to Financial Transmission Rights (FTRs);

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d. A comprehensive discussion of ARR nomination and FTR conversion strategies."

Each year Minnesota Power reviews Stage 1A and Stage 1B Entitlements and determines which paths to nominate as ARRs and which ARRs to self-schedule (convert) to FTRs.

Based on internal guidelines, Minnesota Power will not self-schedule an FTR on a path that does not have generation associated with it. If Minnesota Power expects that generation will flow on a specific path, the company determines the amount of allocated ARRs on that specific path to be converted to FTRs based on historical congestion, historical annual auction clearing prices, and projected congestion, which includes transmission outage expectations. When an FTR is self-scheduled, the cost/benefit of the FTR is included in the MISO costs that are allocated to the Fuel Adjustment Clause.

When Minnesota Power does not have or does not expect any generation to flow on a specific ARR path, the company will determine whether or not to nominate the ARR based on historical and projected auction clearing prices. Minnesota Power will nominate these specific ARR paths with no expectation of converting to an FTR if the company expects that the annual auction price will clear positive. Any ARR paths that are nominated and clear positive in the annual auction and are not converted to an FTR result in a benefit that reduces MISO costs. Conversely, any ARR paths that are nominated and clear negative in the annual auction and are not converted to an FTR result in a cost that increases MISO costs.

Order Point 5

"Required Minnesota Power, in its next annual filing, to provide the following information:

a. A list of all the strategies Minnesota Power considered and implemented to address congestion and curtailment of energy. At a minimum, the list must include Grid Enhancing Technologies (e.g. Dynamic Line Rating, system reconfiguration, and system optimization), ARRs, FTRs, planning of transmission line projects to address congestion and curtailment within and between Regional Transmission Organizations, sequencing of transmission line outages, and sequencing of the construction schedule of pending transmission line projects; and

b. A comprehensive discussion on the merit of each strategy and how Minnesota Power decides whether to implement each strategy. Minnesota Power must provide a cost-benefit analysis for each strategy or provide a justification for why a cost-benefit analysis cannot be performed."

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Minnesota Power will continue to optimize the use of its HVDC transmission line to cost-effectively deliver its 600 MW wind portfolio in North Dakota to customers. Minnesota Power's HVDC line operates like a physical FTR, providing a financial mechanism that reduces congestion cost for customers. The HVDC line is an important congestion mitigation asset that Minnesota Power is using today to manage customer cost. In October 2024 the Company received a Certificate of Need and Route Permit to modernize and upgrade its HVDC terminals and interconnect the upgraded HVDC terminals to the existing alternating-current ("AC")

transmission system. The HVDC terminals have been operating successfully for more than 47 years – well beyond its 30-year design life. As the HVDC system continues to experience increased unplanned terminal outages due to failures with aging components, modernizing the HVDC terminals will allow Minnesota Power to continue delivering these cost-savings for customers.

Minnesota Power is taking an "all of the above" approach and has explored options to mitigate cost impacts to customers, by optimizing FTRs, transmission assets (i.e. HVDC), and as discussed below, working with other Minnesota utilities and MISO to identify transmission related projects that reduce congestion cost. As part of the "all of the above" strategy, in 2024 Minnesota Power entered into a unique contract with NewGrid, a consulting firm that provides services to identify system congestion events that impact Minnesota Power's generation portfolio and the FAC. The Company worked with NewGrid on evaluating an opportunity to reduce congestion costs for a wind facility in southwest Minnesota that has a Purchase Power Agreement with Minnesota Power. NewGrid's work showed promise as an approach to reduce congestion with targeted operational reconfiguration of the transmission system and working with other transmission owners in the region. The reconfiguration recommendations are designed to maximize the transmission system capabilities in the near term and are not intended to replace recommendations for long-term transmission studies. The reconfiguration is intended to reduce congestion for serving load while maintaining all transmission planning and operation best practices and standards. Through this work with NewGrid the Company developed an understanding on how the NewGrid alternative configuration study work could be presented to a transmission owner. The NewGrid study work included a congestion savings estimate, which has the challenge of simulating the system congestion with and without the alternative configuration. Minnesota Power participated in a reconfiguration request where the transmission owner didn't take any action due to the complexity of needing to update a system stability study. Minnesota Power recognizes that operating the system safely and reliably is critical and having a third-party propose a reconfiguration solution can be a challenge to make sure there aren't any unintended consequences from the recommended configuration. Another challenge is studying and implementing solutions with adequate lead time prior to a known event occurring (i.e. transmission outage for maintenance) so the congestion savings can be realized. NewGrid has had success working with other utilities on mitigating congestion, although, in 2025 Minnesota Power did not extend the contract due to challenges noted above. Minnesota Power continues to have discussions with NewGrid and the Company will continue to evaluate the value of working with NewGrid in the future.

There is currently a misalignment in the cost recovery for NewGrid consulting service fees through base rates and the benefits of reduced congestion costs customers receive through the FAC. At the time of the 2024 FAC True-Up filing, Minnesota Power was considering a miscellaneous petition requesting to align the consulting cost with the associated benefits. Given Minnesota Power did not extend the contract with NewGrid there are no current plans to submit a miscellaneous petition. This still remains a cost recovery concern, and the Company may consider a petition in the future if the Company engages with NewGrid again and there are demonstrated benefits through reduced congestion costs.

In 2023 Minnesota Power participated in a study with neighboring utilities to identify transmission solutions to reduce congestion cost. Grid North Partners, a joint initiative of utilities in Minnesota, Wisconsin, South Dakota, and North Dakota, performed an elective study in 2023 to identify and develop near-term solutions to incrementally resolve congestion. The Grid North Partners Tech Team collectively analyzed both historical and forward-looking congestion, identified physical limiting equipment on every congested element, and forecasted congestion relief for each solution. The Tech Team identified 19 congestion relief solutions with a cost of $130 million, which will provide an expected congestion benefit of more than $300 million, a greater than 2:1 benefit to cost ratio. Expected in-service dates range from 2023-2026 for solutions developed by Grid North Partners. In part, due to the success of the 2023 Grid North Partners congestion study, a legislative requirement by the State of Minnesota was enacted that requires similar study work to be performed by transmission owners within the state. This analysis was performed by the Grid North Partners group in 2025.

Two of the identified congestion relief solutions from the 2023 study work were on Minnesota Power facilities, the Blackberry – Riverton 230 kV line and the Forbes – Iron Range 230 kV line. Based on analysis of the historical and projected congestion on these facilities, along with the equipment ratings comprising the facilities, Minnesota Power determined that Ambient-Adjusted Ratings should be developed. Ambient-Adjusted Ratings are facility ratings calculated using actual ambient temperatures, rather than the default

seasonal temperature assumptions. Ambient-Adjusted Ratings provide for potential increased ratings and reduced congestion as ambient conditions allow, without capital costs. Minnesota Power developed and implemented both Ambient-Adjusted Ratings sets in March 2023. Minnesota Power currently has a total of 19 transmission lines that have Ambient-Adjusted ratings developed for real-time use in operations.

Medium Term:

As noted above, in 2025 Minnesota Power participated in a study with neighboring utilities within the Grid North Partners group to identify transmission solutions, specifically Grid Enhancing Technologies ("GETs") to address congestion throughout Minnesota. The study reviewed historical congestion that occurred in the previous three years, and forecasted congestion based on the years 2026 and 2030. These congestion costs were used to determine cost effective potential solutions. The Report was filed in conjunction with the 2025 Biennial Transmission Plan Report in October 2025.2

Four Minnesota Power facilities were included in the section for Constraints with Solution Proposals (Payback Period Threshold Met). These facilities were determined to be a good fit for GETs solutions, specifically the application of dynamic line ratings. It should be noted that additional upgrades to other limiting equipment to maximize the benefits from the GETs solution could be required. Minnesota Power is actively working towards implementing a targeted deployment of dynamic line ratings in 2026 that will include several of the facilities included in the GETs report.

Minnesota Power anticipates there will be reduced congestion as part of FERC Order 881 compliance, which requires all transmission providers to use Ambient-Adjusted Ratings as the basis for evaluating near-term transmission service. The order was issued with a compliance date of July 2025, although MISO filed and was granted an extension request in June 2025 with a final implementation date of no later than December 31, 2028. When in place, operating and near-term limits will take into account ambient air temperatures as well as solar heating impacts. Minnesota Power anticipates more renewable energy will be allowed to flow across congested transmission corridors resulting in lower congestion cost across the system.

Minnesota Power continues to stay engaged with neighboring utilities on efforts being made to reduce congestion in the medium-term.

Long Term:

Minnesota Power continues to work with MISO on future transmission additions through the Long Range Transmission Plan ("LRTP"). The LRTP Tranche 1 and Tranche 2.1 portfolios have several new transmission projects identified in Minnesota and North Dakota. MISO expects the addition of the LRTP Tranche 1 and 2.1 Portfolios to increase the operational flexibility to better allow timely outage scheduling to maintain the reliability of the system and to reduce the economic impacts due to congestion caused by outages. The new transmission paths also help reduce market price volatility by providing access to a broader pool of generation resources, including dispatchable and renewable generation resources. According to MISO's analysis, the LRTP Tranche 1 Portfolio is expected to provide economic savings more than two times the total cost of the portfolio and the LRTP Tranche 2.1 Portfolio is expected to provide similar economic savings and increased reliability of the grid.

In August 2023, Minnesota Power and Great River Energy filed a combined Certificate of Need and Route Permit Application for the Northland Reliability Project (LRTP Project #3), both of which were granted by the Commission in a February 2025 order.[3] Analysis produced by Minnesota Power and Great River Energy in the application identified that by itself, the Northland Reliability Project is projected to provide approximately $127 million to $2.1 billion in economic savings over the first twenty years of the Project's service by reducing system congestion and providing access to lower cost generation. These economic savings will help offset the capital cost of the Project.

In January 2026, Minnesota Power and American Transmission Company submitted an application for a Certificate of Need and Route Permit for the Iron Range – St. Louis County – Arrowhead ("ISA") 345 kV Transmission Line Project.[4] The ISA project was studied, reviewed, and approved by MISO as part of its LRTP Tranche 2.1 portfolio of projects included in MISO's 2024 Transmission Expansion Plan ("MTEP24"). The Project, as part of the LRTP Tranche 2.1 portfolio, is needed to enhance grid reliability in the Upper Midwest as grid operating conditions become more variable, to increase grid efficiency and

regional transfer capability as energy is transferred from where it is produced to where it is needed, and to meet the growing demand for reliable clean energy in the Upper Midwest.

In January 2026, Minnesota Power, Otter Tail Power Company, and Great River Energy filed an application with the Minnesota Public Utilities Commission for a Certificate of Need to build the Maple River – Cuyuna 345 kilovolt Transmission Project ("Maple River – Cuyuna Project",[5] a high-voltage transmission line that will stretch about 160-180 miles from Minnesota Power's Cuyuna Substation near Riverton, Minnesota, to Otter Tail Power Company's Maple River substation near Fargo, North Dakota. The Maple River – Cuyuna Project was approved by MISO as part of its LRTP Tranche 2.1 portfolio and is needed to support the reliability of the regional transmission system, particularly in northern Minnesota and eastern North Dakota. The Maple River-Cuyuna Project will provide additional transmission capacity and regional transfer capability to reliably integrate future generation resources, meet growing electrical demand, enhance resiliency during extreme weather events, and enable cost-effective regional energy transfers supporting economical grid operations.

Minnesota Power anticipates that congestion cost will be lower due to the LRTP projects being placed into service in the 2030-2033 timeframe. However, it is important to note that the magnitude of congestion reduction can vary, especially if new wind and solar builds outpace the capability of new transmission in the area. Building new transmission to better distribute energy production from renewable rich regions will be needed to reduce congestion cost as Minnesota moves towards meeting the Carbon Free Standard.

ARR to FTR Cost/Benefit

The following tables represent the cost/benefit of Minnesota Power's decision to convert ARRs to FTRs. A positive value represents the FTR value to be greater than the ARR value from the Annual FTR Auction. A negative value represents the FTR value to be less than the value from the Annual FTR Auction.

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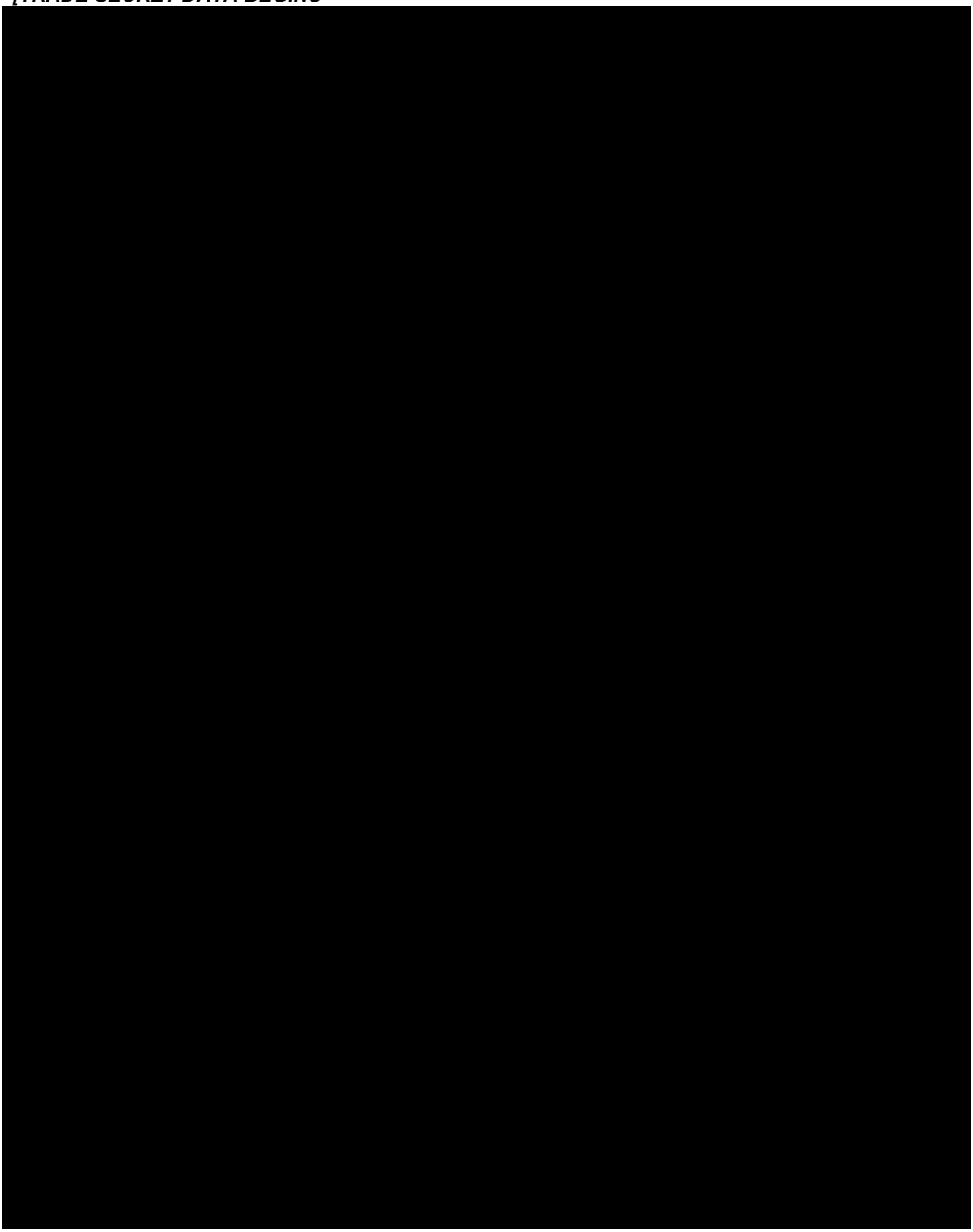

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ARR Cost Benefit

The following tables represent the cost benefit of Minnesota Power's ARRs that were not converted to FTRs. A positive number represents that the annual FTR auction cleared positive and the ARR was a benefit. A negative number represents that the annual FTR auction cleared negative and the ARR was a cost.

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