MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	September 1, 2022		Agenda Item 5**
Company	Otter Tail Power Company		
Docket No.	**E017/M-21-612**		
	In the Matter of Distribution System Planning for Otter Tail Power Company		
Issues	1. Should the Commission accept or reject Otter Tail Power's Integrated Distribution Plan (IDP)? 2. Does the IDP filed by Otter Tail Power achieve the planning objectives outlined in the filing requirements as amended by the Commission's November 2, 2020 Order?[1] 3. What IDP filing requirements provide the most value to the process, and why? 4. Are there filing requirements that are not informative and/or should be deleted or modified, and why? 5. Are there other issues or concerns related to this matter?		
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✓**Relevant Documents**

	Date
Otter Tail Power, *Integrated Distribution Plan presentation*	August 10, 2021
Otter Tail Power, *Initial Filing- Integrated Distribution Plan*	November 1, 2021
Department of Commerce, *Letter*	February 9, 2022
Department of Commerce, *Comments*	March 22, 2022
Otter Tail Power, *Reply Comments*	April 15, 2022
Department of Commerce, *Reply Comments*	April 26, 2022

[1] Docket E017/M-19-693

Table of Acronyms

Acronym	Definition
AMI	Advanced Metering Infrastructure
CAIDI	Customer Average Interruption Duration Index
CIP	Conservation Improvement Program
CIS	Customer Information System
CVR	Conservation Voltage Reduction
DER	Distributed energy resources
DG	Distributed generation
EV	Electric vehicle
EE	Energy efficiency
ESS	Energy storage system (e.g. battery storage)
GIS	Geographic Information System
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers
IMS	Interruption Monitoring System
IRP	Integrated Resource Plan
LMS	Load Management System
MAIFI	Momentary average interruption frequency index
MISO	Midcontinent Independent System Operator
NWA	Non-wires alternative
OH	Overhead (as in overhead lines}
SAIDI	System Average Interruption Duration Index
SIRI	System Infrastructure and Reliability Improvements
UG	Underground (as in underground cable)

Statement of the Issues

Should the Commission accept or reject Otter Tail Power's Integrated Distribution Plan (IDP)?

Background

On November 1, 2021, Otter Tail Power (OTP) filed an updated IDP, a process that originated out of the Commission's February 20, 2019 Order in Docket Number E015/CI-18-253.

The Commission's filing requirements, established in the February 20, 2019 Order, intended to facilitate a utility's IDP filing that would meet the following planning objectives:

> 1) Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
>
> 2) Enable greater customer engagement, empowerment, and options for energy services;
>
> 3) Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
>
> 4) Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
>
> 5) Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

On November 15, 2021, the Commission issued a *Notice of Comment Period,* seeking input on the following topics:

- Should the Commission accept or reject Otter Tail Power Company's (Otter Tail, OTP, or the Company) Integrated Distribution Plan (IDP)?
- Does the IDP filed by OTP achieve the planning objectives outlined in the filing requirements as amended by the Commission's November 2, 2020 Order?[2]
- What IDP filing requirements provide the most value to the process, and why?
- Are there filing requirements that are not informative and/or should be deleted or modified, and why?

On March 22, 2022, the Department of Commerce – Division of Energy Resources (Department) filed Initial Comments.

After an Extension Variance Request from OTP, OTP and the Department both filed Reply Comments on April 15, 2022 and April 26, 2022 respectively.

[2] Docket E017/M-19-693

In Xcel Energy's 2017 and 2018 Transmission Cost Recovery (TCR) rider, the Commission requested "the Commissioner of Commerce seek authority from the Commissioner of Minnesota Management and Budget to incur costs for specialized technical professional investigative services under Minn. Stat. § 216B.62, subd. 8, to investigate the potential costs and benefits of grid modernization investments proposed for recovery by Xcel in its next rate case or TCR filing and to assist the Department in providing recommendations to the Commission regarding any such investments."[3] On February 9, 2022, the Department contract a professional to investigate potential costs and benefits of grid modernization investments and to then assist the Department in making its recommendations to the Commission. On February 9, 2022, the Department filed a letter explaining its contract with Synapse Energy Economics, Inc. (Synapse) who performed an economic evaluation of all Xcel Energy's grid modernization investments. Synapse created a broad economic guide that gave a standard approach to evaluating utility grid modernization investments (herein, Guidance Document). The Department contended that the Guidance Document provides sufficient information for stakeholder understand and influence grid modernization plans.

The Department simultaneously filed this guide in other related dockets, including Xcel Energy's ongoing Transmission Cost Recovery Rider, and Dakota Electric, Minnesota Power, and Xcel Energy's IDPs. The Department made similar recommendations across all four utility IDPs related to the Guidance Document and future grid modernization filings. The Guidance Document is referenced in portions of this briefing papers; however, Staff addresses the Department's recommendations for the Guidance Document in a separate set of briefing papers that covers all utility IDPs, also up for consideration at the September 1, 2022 agenda meeting.

The Commission's February 20, 2019 Order established the following categories of filing requirements: baseline distribution data and financial data, preliminary hosting capacity data, a distributed energy resources (DER) scenario analysis, a long-term distribution system modernization and infrastructure investment plan, and a non-wires alternative analysis.

At the end of its IDP, on pages 46-47, Otter Tail includes a "Checklist of Requirements," which lists the Company's filing requirements and the section of the IDP where the information is discussed. Staff provides this table below both to familiarize the Commission with Otter Tail's requirements as well as to provide a general idea of the topics covered in the report:

Filing Requirement	Description	Report Section
Planning Objectives	How does OTP's IDP meeting the Commission's planning objectives?	3
3.A.1	Modeling software	4

[3] Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, September 27, 2019, Docket No. E002/M-17-797

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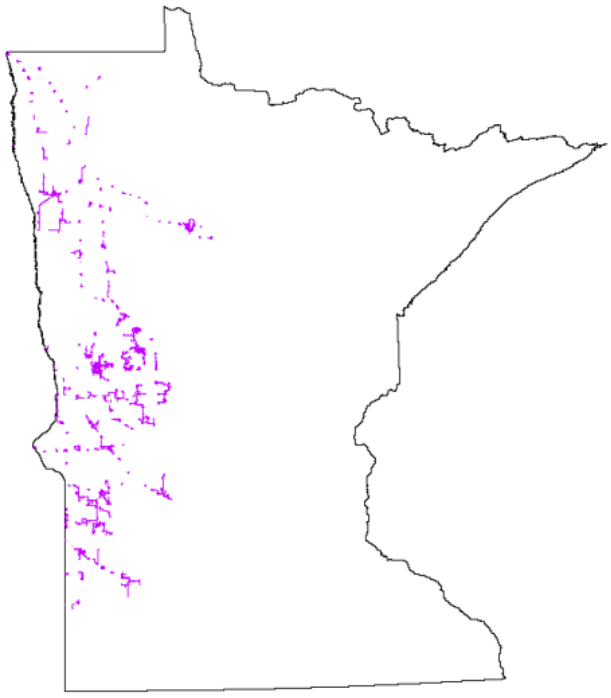
Introduction to Otter Tail Power and their IDP

In previous Integrated Distribution Plans (IDPs), Otter Tail Power (Otter Tail or OTP) highlighted a generally stagnant load growth with decreasing population and increasing average age of their clientele. Otter Tail Power serves a dispersed population of 422 rural communities with an average population of 400. Only two of Otter Tail's communities in Minnesota have populations exceeding 10,000: Fergus Falls and Bemidji. Otter Tail's average distribution substation transformer size is around 3.3 MWs and the average demand is around 1.7MWs.[4] Below, we see a map of OTP's distribution system to better understand their service territory location and dispersion.

[4] 21-612, OTP, Initial Filing, pdf p. 11

Figure 1. Map of Otter Tail's Minnesota Distribution System[5]



The factors stated above lead to the general assumption of no or minor load growth system wide. However, this does not negate growth or decline in localized areas. To summarize, Otter Tail provided demand trends for their Minnesota Distribution system.

Figure 2. Minnesota Distribution System Demand Growth Trends (kW) – Winter Season (Metered Substations)[6]

[5] 21-612 OTP, Initial Filing, pdf p. 28
[6] 21-612 OTP, Initial Filing, pdf p. 14

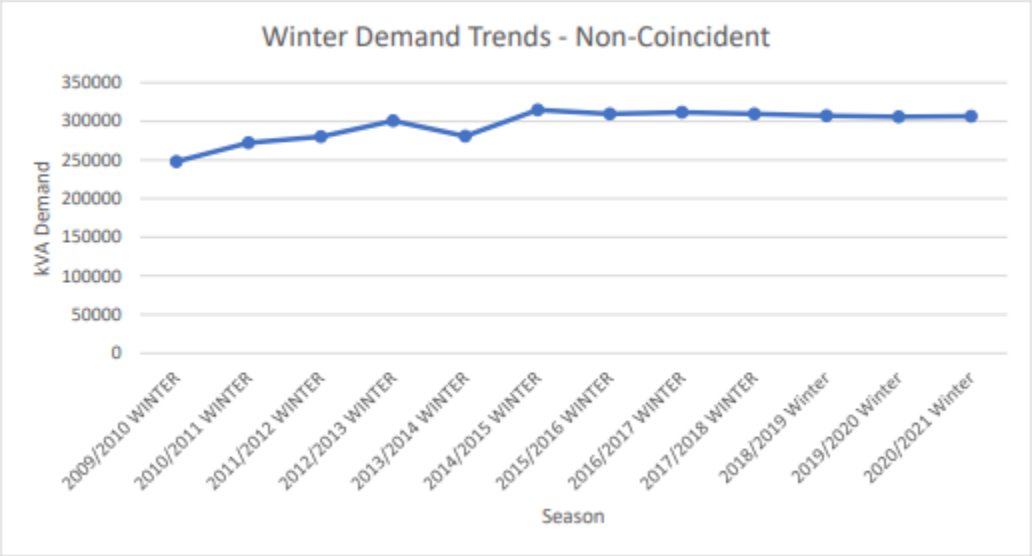
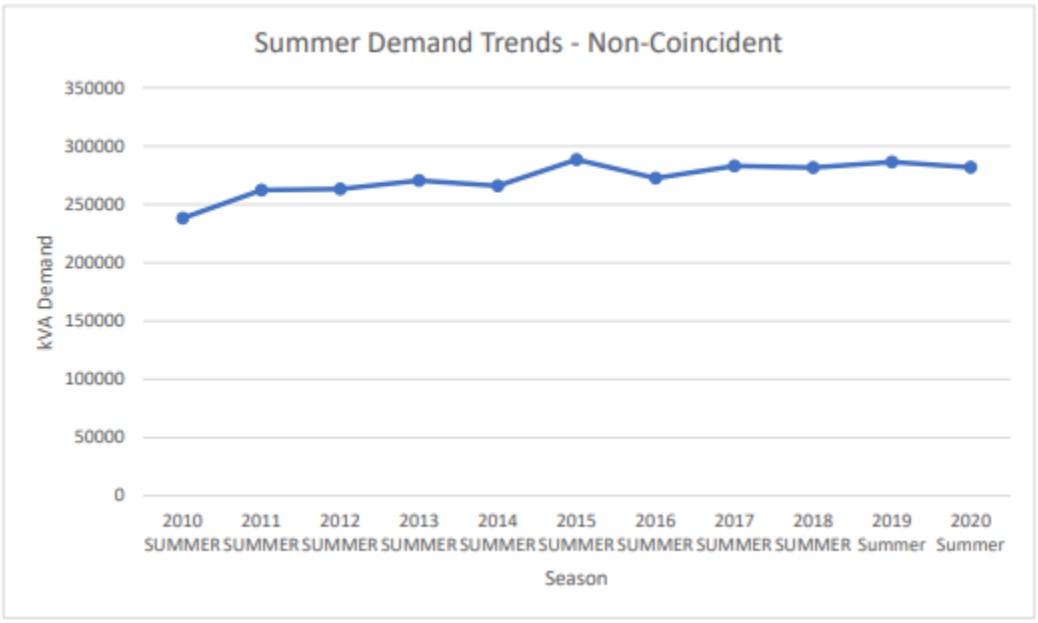


Figure 3. Minnesota Distribution System Demand Growth Trends (kW) – Summer Season (Metered Substations)



As we can see from above, there are seasonal differences due to yearly weather patterns. The distribution system demand is not static or constant across space nor time.

Because of this, Otter Tail collects information from the field regarding potential high value projects to meet the goal of cost-effectively improving reliability, system efficiency, and reducing risk (such as capacity concerns, compliance, and safety and have their engineers review distribution studies, metering reports, and reliability reports.[7]

[7] 21-612 OTP, Initial Filing, pdf p. 16

Otter Tail's Proposed IDP

Distribution Operations Overview

Day-to-day distribution operations include asset management and customer service with approximately 60 linemen, 110 service representatives, and 40 customer service representatives. These roles and their impacts are further described in the annual Service Quality and Service Reliability (SQSR) filing.[8] While those employees provide the backbone to the operation, Otter Tail also recently deployed a new Customer Information System to help improve their customer service and customer relations when handling maintenance and general customer inquiries. Otter Tail coordinates responses to both business hours and after-hour outages without the use of a centralized distribution desk or a formal outage management system.[9] Otter Tail explained the Customer Information System will provide future flexibility for customers to have more energy choices.[10]

Otter Tail has limited visibility of distribution facilities throughout their system on a real-time basis. With 565 distribution substations, just 11 of those substations have control and monitoring within Otter Tail's System Operations Energy Management System which is used to monitor and control the transmission system. Otter Tail meters 396 of the 565 distribution substations, covering more than 90 percent of Otter Tail's delivered energy. This can be seen in Table 1 below. Otter Tail estimates that adding metering capabilities to substations where metering currently does not exist to be between $5,000 and $10,000 depending on the site. That means, adding full metering capacity to all substations would range from $900,000 to $1,800,000. Otter Tail believes that at this time, metering the remaining substations has not been cost justifiable to serve the needs of customers and will continue to evaluate on a case-by-case basis.[11]

Table 1. Substation and Feeder Statistics[12]

Distribution Substation	Minnesota	North Dakota	South Dakota	Total
Substation Count	217	273	75	565
Control/Monitoring	6	4	1	11
Metering	140	203	53	396
Substation/Transformer Capacity (MVA)	677	728	266	1,671

Distribution Feeder	Minnesota	North Dakota	South Dakota	Total
Feeder Count	282	352	90	724
Control/Monitoring	24	9	4	37

[8] Docket No. E017/M-21-225
[9] 21-612 OTP, Initial Filing, pdf p. 23
[10] 21-612 OTP Initial Filing, pdf p. 35
[11] 21-612 OTP, Initial Filing, pdf p. 27
[12] 21-612 OTP, Initial Filing, pdf p. 26

Otter Tail also provided more insight into their asset counts for their distribution system. Table 2 presents the number of miles of primary and secondary distribution lines as well as the number of distribution poles and service transformers by state. Primary distribution lines are the main lines from substations to the high side of service transformers. Secondary distribution lines are the lines used for streetlight circuits and the low side of service transformers to individual customer service lines owned by Otter Tail. Distribution poles are used to attach the primary and secondary distribution lines for overhead circuits. Service transformers are used to shift the voltage from primary to secondary levels.

Table 2. Distribution System Asset Statistics[13]

Primary Distribution Line (miles)	Minnesota	North Dakota	South Dakota	Total
Overhead	2,033	1,893	473	4,399
Underground	689	639	107	1,435
Total	2,722	2,532	580	**5,834**

Secondary Distribution Line (miles)	Minnesota	North Dakota	South Dakota	Total
Overhead	938	1,011	238	2,187
Underground	197	220	36	453
Total	1,135	1,231	274	**2,640**

Distribution Poles	Minnesota	North Dakota	South Dakota	Total
Total	79,332	81,163	17,821	**178,316**

Service Transformers	Minnesota	North Dakota	South Dakota	Total
Overhead	12,229	10,528	2,685	25,442
Pad-mount	5,977	4,948	862	11,787
Total	18,206	15,476	3,547	**37,229**

Distribution System Loss Analysis

Otter Tail completed its most recent loss analysis in 2020 using 2019 data. From this analysis, they estimated energy loses to be 4.5 percent which comes from losses starting from the distribution substation transformer though the primary distribution system, the secondary distribution transformer and ultimately to the secondary distribution system.[14] OTP stated that further information about their loss analysis can be found in their current general rate case filing, Docket No. E017/GR-20-719.

[13] 21-612 OTP, Initial Filing, pdf p. 27
[14] 21-612 OTP, Initial Filing, pdf p. 33

DER Scenarios

Historical and Baseline Scenarios

The distribution system is actively designed to withstand peaks and other possible scenarios which may arise on the system in emergency conditions. With Bemidji, Fergus Falls, Morris, Pelican Rapids, and Perham experiencing the most demand and growth activity over the past few years, they are monitored more closely for capacity constraints. The expectation is as DER penetration increases, OTP will need to be aware of areas of the system that are decreasing in demand or where DER is masking potential load.

In developing their DER scenarios, they created a baseline scenario that incorporated EV adoption, energy efficiency, and demand response, as well as DER penetration.[15]

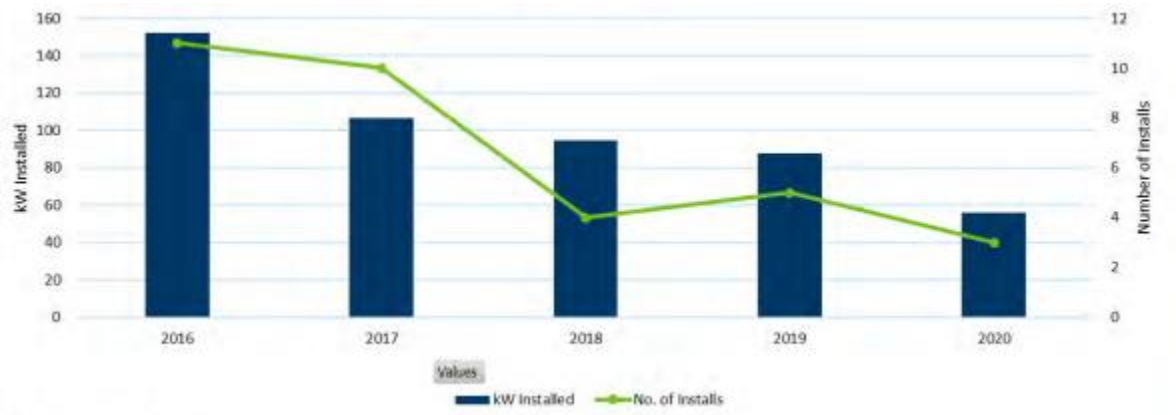
Medium and High DER Penetration Scenarios

As DER penetration increases, OTP plans to carefully track areas of the system that are decreasing in demand or where DER is masking load. For example, compared to historical levels, there is expectations that electric vehicle (EV) growth may boom. OTP reports 70 customer-owned electric vehicles, offers an off-peak rate for charging these vehicles, and services three Direct Current fast-charger sites that equate to a total of approximately 850 kW of name plate capacity. Otter Tail plans to minimize on-peak charging impacts with rate design and controllability of the additional load expected from electric vehicle growth.[16] OTP is looking at opportunities to minimize on-peak charging impacts and demand associated with large growth and penetration exhibited if Minnesota were to increase electric vehicle growth significantly.

We can also look at solar DER installations. Solar DER installations have declined the past few years as can be seen below in Figure 4. However, Otter Tail expects the number of installations to return to 2016 and 2017 levels or even increase from that. While drastic changes in DER penetration is not expected, system wide impacts of a high penetration scenario are not expected to create issues to the system or the interconnection process.[17]

Figure 4. Solar Installations[18]

[15] 21-612 OTP, Initial Filing, pdf pp. 29-30
[16] 21-612 OTP, Initial Filing, pdf p. 30
[17] 21-612 OTP, Initial Filing, pdf p. 32
[18] 21-612 OTP, Initial Filing, pdf p. 32



Financials

When looking at the Otter Tail financial information, distribution spending is broken down into the following categories:

a) Age-related replacements and asset renewal
b) System expansion or upgrades for capacity
c) System expansion or upgrades for reliability and power quality
d) New customer projects and new revenue
e) Grid modernization and pilot projects
f) Projects related to local (or other) government-requirements
g) Metering
h) Other

Tables 3 and 4 depict historical and forecasted distribution spending in the above categories for Otter Tail Power. Figure 5 combines the 5-years of historical and 5-years of forecasted spending by the categories.

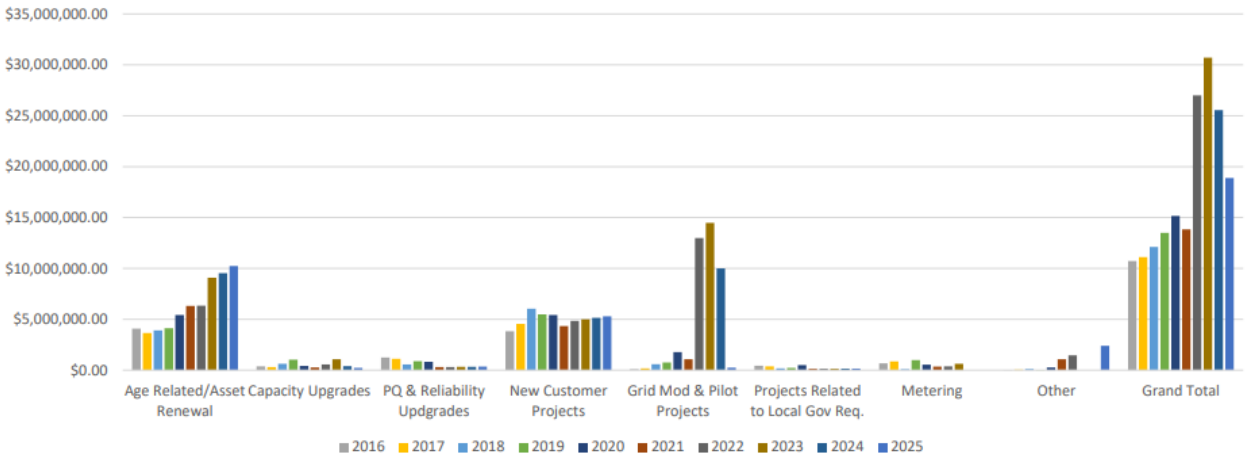
Table 3. Historical Distribution Spends for Minnesota

Category[2]	2016	2017	2018	2019	2020
Age Related/Asset Renewal	$ 4,068,793	$ 3,657,971	$ 3,906,987	$ 4,120,160	$ 5,422,553
Capacity Upgrades	$ 380,374	$ 309,530	$ 630,390	$ 1,020,920	$ 424,199
PQ & Reliability Upgrades	$ 1,254,703	$ 1,107,103	$ 571,619	$ 885,530	$ 810,697
New Customer Projects	$ 3,819,386	$ 4,542,570	$ 6,029,587	$ 5,488,487	$ 5,421,652
Grid Mod & Pilot Projects	$ 85,278	$ 187,538	$ 587,615	$ 751,989	$ 1,779,686
Projects Related to Local Gov Req.	$ 425,179	$ 366,055	$ 184,657	$ 215,958	$ 493,195
Metering	$ 673,123	$ 869,316	$ 97,761	$ 995,095	$ 538,828
Other	$ 18,588	$ 58,329	$ 109,119	$ 10,379	$ 261,716
Grand Total	**$ 10,725,428**	**$ 11,098,414**	**$ 12,117,739**	**$ 13,488,522**	**$ 15,152,530**

Table 4. Forecasted 5-Year Distribution Spend for Minnesota

Category[3]	2021	2022	2023	2024	2025
Age Related/Asset Renewal	$ 6,315,099	$ 6,332,432	$ 9,089,317	$ 9,521,567	$ 10,235,864
Capacity Upgrades	$ 265,000	$ 564,500	$ 1,070,750	$ 400,000	$ 227,250
PQ & Reliability Upgrades	$ 306,532	$ 316,467	$ 325,962	$ 335,740	$ 345,810
New Customer Projects	$ 4,325,000	$ 4,841,000	$ 4,986,230	$ 5,135,817	$ 5,289,891
Grid Mod and Pilot Projects	$ 1,566,415	$ 14,440,937	$ 14,468,191	$ 10,008,702	$ 234,141
Projects Related to Local Gov. Req.	$ 137,689	$ 142,312	$ 146,581	$ 150,978	$ 155,508
Metering	$ 350,000	$ 360,574	$ 625,000		
Other	$ 564,000				$ 2,400,000
Grand Total	**$ 13,829,736**	**$ 26,998,224**	**$ 30,712,032**	**$ 25,552,805**	**$ 18,888,465**

Figure 5. Historical and Forecasted Spends[19]



Each category's budget has specific uses related to their definitions. Age-related replacement and asset renewal covers replacement of infrastructure that field crews, engineers, and other stakeholders have identified. System expansion or upgrades for capacity includes expanding the distribution system such as substation upgrades due to capacity drivers, line upgrades due to voltage or amperage needs, and upgrades to 3-phase substations. OTP explained that this category is usually lower than others due to overall low demand growth in their service territory.[20]

The system expansion or upgrades for reliability and power quality include items such as overhead and underground conversion projects as well as adding alternative feeds to the distribution system. This category also includes capital projects generated by storm systems. The new customer projects and

[19] 21-612 OTP, Initial Filing, pdf pp. 35-37
[20] 21-612 OTP, Initial Filing, pdf pp 33-35

new revenue category includes building or installing new facilities to connect new customers and upgrade existing facilities while the projects related to local government requirements category includes relocation projects that many times require the construction of new facilities and removal of old to accommodate roads and infrastructure replacement or improvement. [21]

The final categories include the grid modernization category and the metering category. Metering includes replacement and additions of metering materials such as potential and current transformers and support hardware for residential, commercial, and industrial metering while grid modernization adheres to this definition: "a modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network."[22] For example, this could include reconductoring of a line, LED street lighting projects, EV charging station infrastructure, AMI, OMS (Outage Management System) projects or other load management upgrades. The final category is a catch all "other" category including telecommunication spending, tools, and other billable projects.[23]

As we can see from Figure 5, age related renewal and grid modernization and pilots are the two largest categories with age related renewal experiencing consistent yet exponential growth historically and with its forecast. Grid modernization and pilots on the other hand have historically been low with an explosive increase forecasted over the next few years before dropping again in 2025 to levels not experienced since 2017. Appendix B of the IDP provides a full list of the distribution projects planned for the next five years with Minnesota specific costs.

Department Response to OTP's Financials

The Department of Commerce (DOC) highlights that OTP projected total distribution spending of approximately $93.9 million between 2019 and 2023 in their 2019 IDP. That projection has increased in their 2021 IDP to $115.98 million between 2021 and 2025. DOC provided the table below for reference. In the far-right column, we can see how much each category has increased or decreased in nominal value compared to the previous IDP in 2019.

Table 5. Comparison of OTP Distribution System Spending Projections: 2019 and 2021 IDPs[24]

[21] Ibid
[22] 21-612 OTP, Initial Filing, pdf p. 34
[23] 21-612 OTP, Initial Filing, pdf pp 33-35
[24] 21-612 DOC, Initial Comment, pdf p. 4

IDP Budget Category	2019 IDP (2019 - 2023) Spending (Millions)	2021 IDP (2021 - 2025) Spending (Millions)	Δ (Millions)
Age-Related Replacement and Asset Renewal	$ 30.98	$ 41.49	$ 10.52
System Expansion or Upgrades for Capacity	$ 1.74	$ 2.53	$ 0.79
System Expansion or Upgrades for Reliability and Power Quality	$ 2.07	$ 1.63	$ (0.44)
New Customer Projects and New Revenue	$ 32.53	$ 24.58	$ (7.95)
Grid Modernization and Pilot Programs	$ 22.58	$ 40.72	$ 18.14
Projects related to Local (or other) Government Requirements	$ 1.00	$ 0.73	$ (0.26)
Metering	$ 3.01	$ 1.34	$ (1.67)
Other	$ -	$ 2.96	$ 2.96
Total Spending	**$ 93.90**	**$ 115.98**	**$ 22.09**

DOC notes however that this is not a direct comparison given the periods analyzed in each filing and therefore to provide a better comparison between filings, provided the table below for just the 2021-2023 period for both of the IDPs. In this table, we can see how the Department controlled the data provided so that we can look at just comparable years of 2021 to 2023, instead of 2019 to 2023 and 2021 to 2025 respectively.

Table 6. Comparison of OTP's Distribution System Spending Projections for the 2021-2023 Period: 2019 and 2021 IDPs[25]

[25] 21-612 DOC, Initial Comment, pdf p. 5

IDP Budget Category	2019 IDP (2021 - 2023) Spending (Millions)	2021 IDP (2021 - 2023) Spending (Millions)	Δ (Millions)
Age-Related Replacement and Asset Renewal	$ 23.18	$ 21.74	$ (1.44)
System Expansion or Upgrades for Capacity	$ 0.88	$ 1.90	$ 1.02
System Expansion or Upgrades for Reliability and Power Quality	$ 1.30	$ 0.95	$ (0.35)
New Customer Projects and New Revenue	$ 21.00	$ 14.15	$ (6.85)
Grid Modernization and Pilot Programs	$ 21.35	$ 30.48	$ 9.13
Projects related to Local (or other) Government Requirements	$ 0.43	$ 0.43	$ -
Metering	$ 1.87	$ 1.34	$ (0.53)
Other	$ -	$ 0.56	$ 0.56
Total Spending	**$ 70.01**	**$ 71.54**	**$ 1.53**

DOC highlights there was a large shift in allocation of funding from New Customer Projects and New Revenue to Grid Modernization and Pilot Programs in the 2021 IDP.

The DOC also compares the historical and budgeted spending as well for 2016-2020 and 2021-2025. This helps us examine the changes in not just numeric values but in percentage of the total distribution spending as well as the changes between historic and budgeted in the far-right columns.

Table 7. Comparison of Distribution System Spending Reported in OTP's 2021 IDP, Historical Actual (2016-2020) vs. Budgeted (2021-2025)[26]

[26] 21-612 DOC, Initial Comment, pdf p. 6

IDP Budget Category	Historical Actual (2016 - 2020)		Budgeted (2021 - 2025)		Δ	
	Spending (Millions)	*% of Total Spend*	*Spending (Millions)*	*% of Total Spend*	*(Millions)*	*%*
Age-Related Replacement and Asset Renewal	$ 21.18	33.84%	$ 41.49	35.78%	$ 20.32	95.95%
System Expansion or Upgrades for Capacity	$ 2.77	4.42%	$ 2.53	2.18%	$ (0.24)	-8.60%
System Expansion or Upgrades for Reliability and Power Quality	$ 4.63	7.40%	$ 1.63	1.41%	$ (3.00)	-64.78%
New Customer Projects and New Revenue	$ 25.30	40.43%	$ 24.58	21.19%	$ (0.72)	-2.86%
Grid Modernization and Pilot Programs	$ 3.39	5.42%	$ 40.72	35.11%	$ 37.33	1100.39%
Projects related to Local (or other) Government Requirements	$ 1.69	2.69%	$ 0.73	0.63%	$ (0.95)	-56.50%
Metering	$ 3.17	5.07%	$ 1.34	1.15%	$ (1.84)	-57.92%
Other	$ 0.46	0.73%	$ 2.96	2.56%	$ 2.51	546.98%
Total Spending	**$ 62.58**		**$ 115.98**		$ 53.40	85.33%

DOC highlights that OTP's distribution system spending is projected to increase by 85.33% over the next five years vs the previous five. With budgeted decreases in every category except Age-Related Replacement and Asset Renewal and Grid Modernization and Pilot Programs, these two categories account for 70.9% of the total planned distribution investment over the coming five years. This signifies a strong realignment of priorities from recent spending patterns towards the Company's Innovation 2030 (I2030) grid modernization initiative.[27] The "Other" category is also expected to increase over the five-year planning horizon, mostly attributed to the one-time, $2.15 million investment in telecommunication upgrades in 2025.[28]

OTP's Grid Modernization and Infrastructure Action Plan

Advanced Metering Infrastructure

Advanced Metering Infrastructure (AMI) is viewed by Otter Tail as a significant enabler of other technologies and benefits. AMI will enable distribution automation, outage detection and management, conservation voltage reduction, load management replacement, and distribution supervisory control and data acquisition (SCADA). Otter Tail believes AMI can also produce net savings for by reducing manual meter reads. AMI allows for the development of new rates, provides enhanced services and choices to customers, improves field personnel efficiencies, reduces meter related expenses, improves

[27] In Docket No. E017/M-21-201 and in Section 9.G of OTP's Initial Comment of Docket 21-612
[28] 21-612 DOC, Initial Comment, pdf p. 6

outage assessment and restoration, and reduce safety incidents due to meter reading. Otter Tail has included the costs for mass deployment of AMI starting in the 2022 timeframe. It has been further described in the electric utility infrastructure costs (EUIC) filing[29] as Otter Tail is seeking to have AMI approved as an EUIC eligible project.[30]

Outage Management System and GIS

Without a formal Outage Management System, Otter Tail is now in need of added tools and functionality to provide better service to customers. Therefore in 2012, Otter Tail implemented a Geographic Information System (GIS) and is looking to address both the outage process limitations and GIS limitations. As part of their project, Otter Tail will develop modeling from meter to substation and specific attribution data of Otter Tail's GIS features. More complete data will help Otter Tail respond to outages and refine various asset health programs, such as underground cable replacement and overhead line replacement projects. This modeling will be utilized by the AMI project and will be available for future tools such as demand response controls, volt/var optimization and more. Ultimately, implementation of AMI will decrease restoration times further.[31]

Load Management Plans

Currently the Otter Tail Load Management System (LMS) consists of a workstation-based master control system. This system is interfaced with the customer information system but is antiquated and no longer supported by Otter Tail's vendor. The LMS master control system facilitates control of approximately 50,000 field-based LMS receivers but due to significant latency inherent to the two-way radio system it employs, a group-based load control is necessary to ensure that control can be completed in a reasonable timeframe. Because of these challenges, there is a need to integrate and install a new LMS. Otter Tail has completed an evaluation of a proposed AMI system and has selected a vendor with a system that can be integrated with Otter Tail's future LMS as well. Otter Tail hired a consultant to review and update its load management and demand response strategy and is looking forward to exploring the recommendations for new load control approaches.[32]

Telecommunication Architecture Plans

Otter Tail developed a telecommunication backbone strategic plan which is a combination of microwave systems and leased circuits from local and regional telephone companies. The current microwave systems are linear non-redundant segments, at capacity, and the hardware platforms have reached the end of their life, causing availability, reliability, and security concerns. Neighboring utilities employ Otter Tail's microwave system to provide various services, reducing critical infrastructure dependency on public service to operate the bulk electric system. Otter Tail currently relies on leased services to

[29] Docket No. E017/M-21-238
[30] 21-612 OTP, Initial Filing, pdf pp. 38-9
[31] 21-612 OTP, Initial Filing, pdf pp. 39-40
[32] 21-612 OTP, Initial Filing, pdf pp 40-1

provide business, industrial network, and interpersonal communication services throughout much of its service territory. The microwave backbone is at the end of its life and becoming increasingly congested due to bandwidth limitations. From a security standpoint, Otter Tail believes the remote management is at end of support, leaving security concerns because there are no additional security patches being developed for known vulnerabilities.

To mitigate these concerns, Otter Tail's strategy is to establish fiber communications infrastructure to meet future connectivity requirements for their business as well as their security needs. Strategies include partnering with planned transmission projects to include optical ground wire (OPGW) as well as outreach to neighboring utilities and telecommunication companies for strategic partnerships. While not fully defined, early projects are developed and forecasted in the 5-year plan. Long-term, the plan is estimated to be between $30 and $50 million system-wide over 15 years. It is subject to continued evaluation of feasibility as more research is completed. Within the 5-year forecast, $2.7 million has been budgeted and classified as "other" costs within the forecast. Otter Tail believes these projects have been well defined and critical to the replacement of the microwave system while leveraging existing fiber and OPGW investments that have already been completed with the CapX 2020 projects. Otter Tail hopes to center scalable security measures at the forefront of this build out so that the system is protected right away and can be malleable to confront security breaches. Security best practices will include reoccurring patch management, remote management, encryption, and asset monitoring, while allowing for future NERC regulation changes.[33]

Company-Owned Street and Area Lighting

Otter Tail also provides lighting services for 161 Minnesota communities, maintaining approximately 19,677 street and area fixtures. Docket No. E017/M-27-252 approved Otter Tail's plan to change out all Company-owned High Intensity Discharge (HID) lighting to Light Emitting Diode (LED) technology. It was also approved by the Department of Commerce in Otter Tail's Conservation Improvement Plan, Docket No. E017/CIP-16-116. This will save an expected annual first-year savings of 2,936,340 kWh. The first year resulted in over $750,000 in net benefits. Otter Tail is on pace to complete field installation of the project by year-end 2021.[34]

Demand Response (DR)

In 2020, Otter Tail contracted Brattle to perform a DR Potential Study for their system. The study is included in their Integrated Resource Plan (IRP) filed in September 2021.[35] Brattle found that Otter Tail has a large existing demand response portfolio which is actively utilized. Brattle stated:

> "OTP's existing DR capability is in the top 10 percent of the U.S. IOUs." Based on 2019 EIA-861 data, Brattle found Otter Tail to be at the 90th percentile in Peak Reduction

[33] 21-612 OTP, Initial Filing, pdf pp. 41-2
[34] 21-612 OTP, Initial Filing, pdf p. 43
[35] 21-339 OTP, Initial Filing Appendices, pdf pp. 167-211

> Capability, 95th percentile in Residential Customer Enrolled in a DR program, and 90th percentile in Non-Residential Customers enrolled in a DR program."[36]

Brattle found that the maximum achievable potential irrespective of cost-effectiveness available to Otter Tail included expanding existing direct load control for Commercial and Industrial (C&I) customers, increasing dynamic pricing to all classes of customers, adding critical peak pricing (CPP) rates for residential, and increasing participation among C&I in existing CPP and Time of Use (TOU) rates.

While these recommendations above do not take into account cost-effectiveness, other modeling from Brattle did. Current resource forecasts did not need new capacity until 2033, so there was no need to avoid generation capacity through DR. Brattle also modeled a "High Value Sensitivity Case" which assumed a need for capacity on the Otter Tail system and higher capacity prices. This helps Otter Tail determine what strategies to target if there was a need for higher capacity. Most opportunities consisted of expanding CPP and TOU rate offerings to large and medium C&I customers. Lesser opportunities included expansion of the large C&I interruptible program and CPP for residential customers. Otter Tail's ongoing AMI projects will allow for the expansion of these programs if ultimately needed in the future. [37]

System Infrastructure and Reliability Improvement Initiative

In 2019, Otter Tail introduced their System Infrastructure and Reliability Improvement Initiative (SIRI) to focus on the transmission and distribution system and leverage data to drive business decisions regarding spending plans. This year's report highlights the main replacement programs that comprise the age-related spending within the forecast: general distribution replacement, underground asset replacement, distribution substation replacement, overhead replacements, trip savers, electronic reclosures, and line sensors. These programs replace items that are an immediate risk to safety and reliability, failing underground cables, maintenance and replacement of substations, and overhead pole or transformer replacement. Then, there are technology programs as well such as trip savers which create lateral energy deliveries to customers which helps reduce momentary outages. Currently Otter Tail has 20 of these devices and are monitoring their performance with the expectation that they will deliver on fewer momentary and sustained interruptions. Other devices are being examined including electronic reclosers that require less maintenance than traditional oil-based reclosers as well as line sensors that can be connected to cellular and field area networks to report information.[38]

Non-Wires Alternatives

Otter Tail does not have any distribution projects within the 5-year forecast above the $2 million threshold for Non-Wire Alternative (NWA) analysis. However, when Power System Operators observe transmission constraints on the system, they have the authority to use controllable load to bring the system within tolerances. Though not widely used, Otter Tail notes this is a valuable resource and has

[36] Id.
[37] 21-612 OTP, Initial Filing, pdf pp. 43-5
[38] 21-612 OTP, Initial Filing, pdf pp. 45-8

been engaged 3 times since the previous IDP report. Otter Tail Power is also partnering with the University of Minnesota Morris to develop a utility-scale electrical battery in the distribution system within Morris. Otter Tail plans to bring forth a request for recovery of Otter Tail's contributions to the project later this year. The goal of the project will be to understand how a utility scale battery can better utilize locally produced renewable energy, how the battery can provide additional benefits to the rest of the system throughout the greater Morris area, and to gain a better understanding of utility-scale battery storage technology.[39]

Department of Commerce Initial Comment

The Department of Commerce (Department or DOC) provides a summary and high-level overview of OTP's IDP and the IDP process. The IDP process is meant to provide an overview of the OTP distribution system management strategies and how the Company responds to state energy policies while meeting current and future customer needs. DOC notes that the Commission's IDP filing requirements require utilities to provide information and analysis related to internal distribution system planning processes, historical actuals and budgeted capital expenditures, present and forecasted levels of DER, forecasted levels of energy demand, hosting capacity data, and NWA analysis. Utilities are also required to discuss how their IDP fulfills the Commission's IDP planning objectives.[40] OTP therefore provided a checklist in their initial filing which starts on page 4 above.[41]

Department Analysis

In their analysis, DOC highlighted what they feel is the need for a detailed and consistently applied benefit-cost analysis (BCA) framework to ensure that all distribution and grid modernization investments are responsive to state policy and customer needs as well as clearly justified. For that reason, DOC submitted the Guidance Document intended to help the Commission, stakeholders, and utilities approach these investments. The Department also affirmed the following:[42]

> "It is the Department's intention to evaluate utility grid modernization proposals based on the prescriptions of the Guidance Document and will do so absent Commission action.
>
> Nevertheless, **the Department recommends that the Commission require utility grid modernization proposals to adhere to the filing requirements, methods of evaluation, and ratepayer protections detailed in the Guidance Document."**

[39] 21-612 OTP, Initial Filing, pdf p. 49
[40] 21-612 DOC, Initial Comment, pdf p. 3
[41] 21-612 OTP, Initial Filing, pdf pp. 51-2
[42] 21-612 DOC, Letter, p. 10

The Department's Guidance Document is discussed in depth in a separate set of briefing papers also up for Commission consideration at the September 1, 2022 agenda meeting.

The Department organized its analysis in response to the Commission's questions in the November 15, 2022 Notice for Comment. Therefore, to keep organized, staff utilized their format to make sure their responses to the questions were included. Below are said questions in bold.

1. **Should the Commission Accept or Reject Otter Tail Power Association's Integrated Distribution Plan (IDP)?**

The Department reviewed the filing in its entirety and concluded that OTP has sufficiently addressed each of the IDP Filing Requirements and Commission Orders. However, the Department asked for additional information expanded upon below in order to provide a final recommendation.

2. **Does the IDP Filed by Otter Tail Power Company Achieve the Planning Objectives Outlined in the Filing Requirements as Amended by the Commission's February 20, 2019 Order?**

According to the Department, OTP addressed and met the Commission's Planning Objectives. The Department reviewed how OTP maintains and enhances safety, security, reliability, and resiliency of the electricity grid.

The Department specifically requested OTP provide narrative explanations of their planned investments to address reliability needs of their system given shifts in spending in their IDP budget category and a decrease in their SAIDI and SAIFI performance. The Department asked if spending in other IDP budget categories is intended to address the reliability needs of the system. The Department asked this because as stated in their 2021 Safety, Reliability and Service Quality Report comments, the Department believes OTP has struggled to meet the majority of its reliability goals since 2010.[43] The Department noted that this has corresponded with decreasing investments in the System Expansion or Upgrades for Reliability and Power Quality IDP Budget Categories with a reduction of 64.8% over the 2021-2025 period relative to the 2016-2020 period.[44]

The Department also examined how OTP enables greater customer engagement, empowerment, and options for energy services. From this examination, the Department requested that future filings regarding customer-facing utility offerings and programs that may be enabled by new investments in grid modernization technologies such as OMS, LMS or ADMS (Advanced Distribution Management System) projects include the following items: benefit-cost analyses for reference and investment case scenarios, assumptions and data supporting the projected customer participation rates, sensitivity analysis for varying rates of adoption of the proposed programs, and a discussion of how the offerings may interact with existing CIP or Next Generation Energy Act programs.[45]

[43] 21-225 DOC, Comments, pdf p. 15
[44] 21-612 DOC, Comments, pdf p. 14
[45] 21-612 DOC, Comments, pdf p. 16

The Department requested that OTP provide clarification regarding what specific programs or equipment was included under the project entitled "SIRI – Innovation 2030." The Department asked what is attributed to each of the IDP Budget Categories of Age-Related Replacement and Asset Renewal and Grid Modernization and Pilot Programs in the Utility's Reply Comments.[46] This request is based on their analysis of the Planning Objective that states: "Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies."[47] In that analysis, the Department examined Table 7, reproduced below, and noted the $6 million shifted into this project.

Table 7. Comparison of Distribution System Spending Reported in OTP's 2021 IDP, Historical Actual (2016-2020) vs. Budgeted (2021-2025)[48]

	Historical Actual (2016 - 2020)		Budgeted (2021 - 2025)		Δ	
IDP Budget Category	*Spending (Millions)*	*% of Total Spend*	*Spending (Millions)*	*% of Total Spend*	*(Millions)*	*%*
Age-Related Replacement and Asset Renewal	$ 21.18	33.84%	$ 41.49	35.78%	$ 20.32	95.95%
System Expansion or Upgrades for Capacity	$ 2.77	4.42%	$ 2.53	2.18%	$ (0.24)	-8.60%
System Expansion or Upgrades for Reliability and Power Quality	$ 4.63	7.40%	$ 1.63	1.41%	$ (3.00)	-64.78%
New Customer Projects and New Revenue	$ 25.30	40.43%	$ 24.58	21.19%	$ (0.72)	-2.86%
Grid Modernization and Pilot Programs	$ 3.39	5.42%	$ 40.72	35.11%	$ 37.33	1100.39%
Projects related to Local (or other) Government Requirements	$ 1.69	2.69%	$ 0.73	0.63%	$ (0.95)	-56.50%
Metering	$ 3.17	5.07%	$ 1.34	1.15%	$ (1.84)	-57.92%
Other	$ 0.46	0.73%	$ 2.96	2.56%	$ 2.51	546.98%
Total Spending	$ 62.58		$ 115.98		$ 53.40	85.33%

The Department wanted to highlight Power System Engineering, Inc.'s (PSE) Strategic Technology Plan report that OTP commissioned (2016 PSE report). Received by issuing an Information Request (IR MN-DOC-001) in OTP's EUIC Rider petition in Docket No. E017/M-21-382, the Department felt this report significantly influenced the proposal of these projects and therefore included it in their trade secret Comments as Attachment 1. Because of the report's influence, the Department requested that OTP provide more detail regarding how the Company employed the 2016 PSE report to inform their short- and long-term distribution system planning and investments. The Department recommended OTP

[46] 21-612 DOC, Comment, pdf p. 18
[47] 21-612 DOC, Comment, pdf p. 17
[48] 21-612 DOC, Initial Comment, pdf p. 6

highlight how quantitative data was incorporated into internal distribution system planning as well as how it was or can be used to verify performance of these initiatives and their needed cost recoveries.[49]

The second to last Planning Objective asks to ensure optimized utilization of electricity grid assets and resources to minimize total system costs. The Department worked to evaluate OTP's forecasting and planning process and how it informs spending on its distribution. The Department noted that in general, OTP has kept actual expenditures close to budgeted estimates for each category.[50] To get a better understanding of non-capacity related projects, the Department suggested that OTP apply the "right-sizing" concept to the Age-Related Replacement and Asset Renewal IDP Budget Category. The Department defines right-size analysis as "the process of matching utility investments to the need identified by the engineering analysis of the distribution system so performance and reliability of the distribution system is achieved at the lowest possible cost."[51] Importantly, this includes the process of looking for opportunities to eliminate redundancies, downsizing, repurposing or redeploying equipment. Right-size analysis will allow OTP to answer the question of if they are spending on specific components of the distribution system appropriately given the issues the Company is trying to address and prevent. The Department asked for feedback on this proposed approach.

The final Planning Objective provides the Commission with necessary information to understand the utility's short- and long-term distribution system plans, the cost and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value. The Department again highlighted the need for information to fill out IDP filing requirement 3.D that leads to and plays a role in selecting the projects the Company is seeking cost recovery for in its EUIC Rider. The Department believes there should be a clear connection between the information and the analysis provided for this requirement and is concerned broadly that OTP did not provide important information that could otherwise play a role in the Company selecting the projects is seeking cost recover in its EUIC rider for.

3. What IDP Filing Requirements Provide the Most Value to the Process, and Why?

The Department felt that the following IDP filing requirements provided significant value to the process:

- 3.C, distributed energy resource scenario analysis
- 2.A.26 and 3.E, the historical spending in categories and non-wire alternative screening
- 3.D, the long-term distribution grid evolution

These requirements provide value to the Department because they help them analyze what alignment exists between the planning process of integrated distribution systems planning and integrated resource planning to provide mutually beneficial outcomes for both processes and consistent use of data and information in the processes.[52]

[49] 21-612 DOC, Comment, pdf p. 19
[50] 21-612 DOC, Comment, pdf p. 22
[51] 21-612 DOC, Comment, pdf p. 23
[52] 21-612 DOC, Comment, pdf p. 25

4. Are There Filing Requirements that are Not Informative and/or Should be Deleted or Modified, and Why?

The Department recommended that the Commission clarify its intent in Filing Requirement 3.A.28, which requires a utility to provide "[p]rojected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects."[53] The Department is concerned that some respondents are defining non-traditional distribution projects as being synonymous with non-wires alternatives and are therefore only presenting itemized cost data for those projects. The Department invited feedback from stakeholders and the Commission regarding the definition of "non-traditional" in this context and whether it should be centered around the ability of a proposed project or technology to enable two-way information or power flows on the distribution system.[54]

The Department also highlighted the importance of benefit-cost analyses (BCAs) to help understand utilities proposals specifically for grid modernization investments. The Department feels modification of IDP filing requirements may be necessary in the future if detail regarding utilities BCAs are not provided but is not currently recommending a change.

Changes to Filing Requirement 3.A.28 are discussed further in concurrently filed briefing papers that discuss the Department's Guidance Document and changes recommended for all utility IDP filing requirements.

5. Are There Other Issues or Concerns Related to This Matter?

The Department recommended that IDP filing requirements should be published with each Commission Order so that stakeholders and utilities have an updated version of IDP filing requirements, including a red-line version if modifications are made to the utility's IDP filing requirements.[55] The Department found that the only comprehensive list of IDP filing requirements that reflect modifications made by the Commission's Orders can be found in the Commission's December 4th, 2020 *Notice of Stakeholder Meeting*.[56]

Based on the above analysis, the Department made the following recommendations for Otter Tail Power's IDP:

> The Department recommends that the Commission require utility grid modernization proposals to adhere to the filing requirements, methods of evaluation, and ratepayer protections detailed in the Guidance Document.
>
> The Department requests that in future filings regarding customer-facing utility offerings and programs (example: Docket No. EG999/CI-20-492 initiated ADMS platform) that may be enabled

[53] Commission 2019 Order
[54] 21-612 DOC, Comment, pdf p. 28
[55] 21-612 DOC, Comment pdf p. 30
[56] 21-612 DOC, Comment, pdf p. 3, footnote 3

by new investments in grid modernization technologies such as the OMS, LMS or potential future ADMS projects, Otter Tail Power provides the following information:

- Internal benefit-cost analyses for reference and investment case scenarios, including reasonably known and analyzed alternatives;
- Assumptions and data supporting the projected customer participation rates;
- Sensitivity analysis for varying rates of adoption of proposed programs; and
- Discussion of how the proposed customer-facing utility offerings and programs may interact with existing or proposed Conservation Improvement Plan or Next Generation Energy Act programs.

The above recommendation is covered in the Guidance Document briefing papers.

The Department recommends that the Commission include OTP's IDP Filing Requirements in its Order in this and future IDP proceedings, including a red-line version if modifications are made to OTP's IDP Filing Requirements.

Otter Tail Power Reply Comment

Otter Tail reiterated the results of their reliability indices (i.e. CAIDI, SAIDI, and SAIFI) and clarified that that the shift in some of the projects budgeted in the 'System Expansion or Upgrades for Reliability and Power Quality' category to other categories is a reclassification rather than a shift away from reliability as a prioritization. Otter Tail noted that reliability overlaps with all categories of distribution spend within the IDP and noted that the categories of asset renewal and reliability specifically have extensive overlap. OTP stated that because newer assets are more reliable than older assets, any asset renewal project will also improve reliability. Though for Otter Tail, this does not negate system improvement planning specifically for aging assets where reliability may be a concern in order to maximize reliability when completing these updates.[57]

Otter Tail clarified the SIRI- Innovation 2030 project for the Department as well. This project is included in the Asset Renewal category. Asset Renewal includes increased underground replacement spending and increased distribution pole reject spending. The Grid Modernization and Pilot Program budget includes Trip Saver pilot spending and Electronic Recloser pilot spending. OTP noted that Appendix B in their 2021 IDP filing lists the project budget in each category of Asset Renewal and Grid Modernization/Pilot Programs.[58]

OTP also expanded upon the 2016 PSE report and its impact on the IDP. Otter Tail noted that while the assessment and report were helpful, it is now more than 5 years old and therefore the assumptions are outdated. OTP said the report was used to understand various technologies in comparison to industry standards and peer institutions. The 2016 PSE report will continue to inform research and investigation for OTP however, OTP states that none of the quantitative data from the report has been used in project

[57] 21-612 OTP, Reply Comment, pdf p. 2
[58] 21-612 OTP, Reply Comment, pdf p. 3

justifications. OTP believes that the EUIC rider or other recovery mechanisms to be the venues to discuss particular project costs and justifications.[59]

Otter Tail agreed with the DOC that the Commission include IDP filing requirements in its Order and in subsequent IDP proceedings, along with red-line versions if modifications are made.[60]

OTP also gave an update regarding their ADMS. Since their initial EUIC filing, they have narrowed in on an OMS vendor that does not include an ADMS platform. Because of this, OTP does not foresee a full ADMS suite being applied.[61]

Department Reply Comment

The Department responded that OTP's additional information allowed the Department to better understand the importance and limitations of the 2016 PSE Report. The DOC encouraged the Company to provide further evaluation and analysis, if conducted, regarding the projects in future reporting.[62]

When reviewing OTP's reply comment, the Department cited concerns regarding a lack of consistent information between IDPs and other grid modernization plans. The DOC cited the SIRI-Innovation 2030 (or I2030) initiative as an example where there were more projects included in Docket No. E017/GR-20-719 (OTP's rate case) than in OTP's COVID-19 Relief proceeding (Docket EG999/CI-20-493) and the Company's 2021-2023 Triennial CIP Docket (No. E017/CIP-20-475). Currently there are three proposed variations of these projects in OTP's EUIC Rider petition.[63] These issues caused frustration by the Department:

> The Department, the Commission, and stakeholders who may participate in the Company's IDP proceeding now or in the future should not have to navigate the Company's filing in several disparate proceedings in order to ascertain what the Company's grid modernization plans are.[64]

Therefore, the Department recommended that the Commission require OTP to detail the status of the I2030 initiative in the Company's next IDP using the most up-to-date information and data available in describing their grid modernization plans.

After fulling reviewing the Company's response, the Department's recommendation to the Commission is to accept OTP's 2021 IDP. The Department stipulates an understanding that acceptance of the IDP does not have any bearing on prudency or certification of specific proposed investments.

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[59] 21-612 OTP, Reply Comment, pdf p. 4
[60] 21-612 OTP, Reply Comment, pdf p. 6
[61] 21-612 OTP, Reply Comment, pdf p. 6
[62] 21-612 DOC, Reply Comment, pdf p. 23
[63] 21-612 DOC, Reply Comment, pdf p. 28
[64] Ibid.

Staff Analysis

There were no significant disputes regarding Otter Tail Power's 2021 IDP and the issues brought before the Commission through this comment period. OTP achieved the planning objectives per the Department's analysis. The Department and Company recommended accepting OTP's IDP.

There was an important discussion of inconsistent information across dockets and the challenge for parties to fully understand utility investment proposals. OTP was comfortable moving forward with the Department's recommendation related to providing detailed information on the Innovation 2030 Initiative in the 2023 IDP.

Where there is disagreement is in the use of the Department's Guidance Document. This disagreement will be expanded upon in a separate briefing paper.

In regards to the Department's suggestion to create a redline set of IDP filing requirements, Staff has created individual documents with for each set of utility IDP filing requirements and will file it as an attachment to the Order in this docket. Staff will also attach the current set of filing requirements to future notices for comment in this docket.

Decision Options

1. Accept Otter Tail Power Company's 2021 Integrated Distribution Plan with the understanding that acceptance of the IDP has no bearing on prudency of specific proposed investments. (*Department, Otter Tail Power*)

2. Require Otter Tail Power Company to detail the status of the Innovation 2030 initiative in the Company's next IDP, and further, to use the most up-to-date information and data available in describing its grid modernization plans. (*Department, Otter Tail Power*)

3. Otter Tail Power shall file its next Integrated Distribution Plan by November 1, 2023.