IN THE UNITED STATES BANKRUPTCY COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

In re:	Chapter 11
ZACHRY HOLDINGS, INC., *et al.*,[1]	
Reorganized Debtors.	Case No. 24-90377
ZACHRY HOLDINGS, INC., *et al.*,	
Plaintiffs,	
v.	Adv. Pro. No. 25-03025 (MI)
OMAHA PUBLIC POWER DISTRICT,	
Defendant.	

REORGANIZED DEBTORS' MOTION FOR PARTIAL SUMMARY JUDGMENT RE LIQUIDATED DAMAGES

[1] The last four digits of Zachry Holdings, Inc.'s tax identification number are 6814. A complete list of each of the Reorganized Debtors in these chapter 11 cases and the last four digits of their federal tax identification numbers may be obtained on the website of the Reorganized Debtors' claims and noticing agent at https://www.veritaglobal.net/ZHI. The location of the Reorganized Debtors' service address in these chapter 11 cases is P.O. Box 240130, San Antonio, Texas 78224.

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Plaintiffs Zachry Holdings, Inc., Zachry Industrial, Inc. ("Zachry"), and their debtor affiliates (collectively, the "Reorganized Debtors") respectfully move this Court pursuant to Rule 56 of the Federal Rules of Civil Procedure made applicable herein by Rule 7056 of the Federal Rules of Bankruptcy Procedure, and pursuant to this Court's invitation at the hearing held on April 12, 2025, for summary judgment on the First Cause of Action in the Reorganized Debtors' First Amended Adversary Complaint [Docket No. 22] ("Complaint"), declaring that the liquidated damages provision in Article XI of the Engineer, Procure, and Construct Contract between Zachry and Defendant Omaha Public Power District ("OPPD"), as amended for a second time in August 2024 (the "Liquidated Damages Provision"), is an unenforceable penalty. In support of their motion, the Reorganized Debtors would show the following:

INTRODUCTION

This action stems from a dispute over the cause of, and damages associated with, a delay in the substantial completion of two electric generating stations and associated sub-stations that Zachry has built for OPPD, namely, Standing Bear Lake Station and Turtle Creek Station. The parties entered into the Engineer, Procure, and Construct Contract in September 2021 ("Original EPC"); the EPC was amended twice for the purpose, among others, to extend the Guaranteed Substantial Completion Dates of the Stations. At the time of the second amendment in August of 2024 ("Second Amended EPC"), the Reorganized Debtors were in the thick of these bankruptcy proceedings, and the Stations were more than 90 percent complete.

Even so, the Liquidated Damages Provision in the Second Amended EPC increased daily charge for delay of each station by increments of $100,000, $125,000, or $150,000 — with no stated justification. Because delay-related damages with respect to power plants are not difficult to ascertain, and because the Liquidated Damages Provision of the Second Amended EPC is not a reasonable forecast of just compensation for delay, the Reorganized Debtors move for partial summary judgment on their First Claim for Relief. Specifically, Reorganized Debtors seek a declaratory judgment that the Liquidated Damages Provision is an unenforceable penalty under Nebraska law. *See* Complaint at 36–39, ¶¶ 112–118.

RELEVANT FACTS AND PROCEEDINGS

A. Standing Bear Lake and Turtle Creek Generating Stations

As described by OPPD, the Original EPC is the means by which "OPPD contracted with Zachry to provide services for all activities associated with designing, procuring, installing, starting up, and testing two (2) power plant sites: (i) the Standing Bear Lake Station . . . ; and (ii) the Turtle Creek Station," both "located in the Omaha metropolitan area." OPPD Motion to Dismiss [Docket No. 11] at 3 ("Motion to Dismiss"). As described by the Original EPC, both Stations will generate electricity by means of multiple generating units whose "[p]rimary fuel . . . will be pipeline quality natural gas." Exhibit B, at 6, 8.

Crucially, in contrast to a "baseload" facility that runs more frequently, each Station will "be operated as a regulating and **peaking** power Facility, with the [generators] operating in a cyclic manner to support grid demands." *Id.* (emphasis added). That is to say, Standing Bear Lake Station and Turtle Creek Station are designed to be generating "units that are **only utilized during peak hours**." Exhibit G, at 14 (emphasis added) (OPPD's

definition of "Peaker" facility). Specifically, OPPD anticipates the Stations to operate only 15% of the time, primarily during summer months when demand for electricity is typically higher in Nebraska and the broader system in which OPPD participates. *See* Exhibit I, at 11, ¶ 31 (declaration of expert Tanya Bodell, citing OPPD webpages).

B. OPPD's costs since December 2024

As executed in August 2024, the Second Amended EPC set December 30, 2024 as the Substantial Completion Date for Standing Bear Lake Station and December 16, 2024 as such date for Turtle Creek Station. *See* Exhibit E, at 4, ¶ 8. Unfortunately, the Stations were not substantially completed by those dates.[2] Consequently, in lieu of the (presumed) lower-cost electricity products that would have been generated by the two Stations since December 2024, OPPD has been unable to sell the energy from the plant during peak hours in the winter and spring, and it may have needed to acquire (presumed) higher-cost capacity and ancillary services in order to fulfill its obligations to the Southwest Power Pool ("SPP," a regional electricity market in which OPPD participates). Therefore, as elaborated in the Argument below, OPPD's (presumed) damages for Zachry's alleged delay in completing the Stations are measured by the additional costs that OPPD incurred, i.e., the difference between the higher purchase costs that OPPD **actually** incurred and the lower generation costs that OPPD **would have** incurred had the Stations been completed.

We first examine OPPD's actual purchase costs, including the ease of estimating them beforehand. We then examine the costs that OPPD would have incurred for generating

[2] As set forth in the Complaint, the Reorganized Debtors allege that the delays in achieving Substantial Completion have been, and continue to be, caused by OPPD and the contractors under its control.

winter and spring electricity products had each Station been operational on its respective Substantial Completion Date.

1. OPPD's Actual Purchase Costs and their estimation beforehand

The actual cost of OPPD's purchases of electricity products that are not covered by what the two Stations would have produced is readily available in OPPD's "tradebook," along with a key input to their production costs (e.g., fuel). Yet despite Zachry's requests, OPPD refused to provide that information. *See* Exhibit H.

Even in the absence of that information, however, it is fairly easy to estimate OPPD's higher purchase costs using two simple inputs:

- quantity: the amount of energy, ancillary services, and capacity that the Stations would have produced; and
- price: the cost of those electricity products, either under contracts between OPPD and suppliers of those electricity products or on the spot market.

See Exhibit I, at 21, ¶ 50. The prices for energy and ancillary services can be obtained from historical data that is publicly available from SPP; other pricing information is necessarily in the possession of OPPD or can be estimated using neighboring markets. *See id.* at 21–22, ¶¶ 52–53. Using that data, Actual Purchase Costs can be **calculated** now using a simple spreadsheet model. *See id.* at 22, ¶ 54.

Furthermore, OPPD's Actual Purchase Costs (i.e., the costs of replacing the power not generated by the Stations) could have been **estimated** to a high degree of certainty in August 2024. Indeed, "these types of 'ex-ante' calculations are performed all the time by industry investors and market participants." *Id.* at 33, ¶ 87. For price, one could simply use prices from the "SPP North" futures market for electricity (supplemented by historical data

on "price shapes"). *See id.* at 33, ¶ 88(1)(a). For quantity, one could simply use the size of the Stations and projected price spreads to estimate when each of the Stations would operate — an estimation that utilities like OPPD routinely undertake as part of their budgeting and procurement process, as well as their planning process to meet their energy and reserve requirements. *See id.* at 7–8, ¶ 21(7); Exhibit G, at 27–28 (explaining Cost of Service Studies that OPPD conducts to comply with its statutory duty to set fair and reasonable rates). Zachry's experts have performed this ex-ante estimation. *See* Exhibit I, at 34, ¶ 90.

2. OPPD's Estimated Generation Costs both now and in August 2024

Estimating the costs that OPPD would have incurred for generating winter and spring peak load electricity had Standing Bear Lake Station and Turtle Creek Station been operational may be accomplished now based on three inputs:

- quantity: the amount of energy, ancillary services, and capacity that the Stations would have produced (exactly the same as for actual costs above);
- fuel cost: the cost of the natural gas required to generate the foregoing quantity of electricity, which has two components:
    - quantity: the volume of that natural gas, which depends on the "heat rates" at which the engines at each Station transform gas into electricity; and
    - price: the market price for that natural gas;
- non-fuel cost: the variable operations-and-maintenance costs to run the generating equipment at each Station.

See Exhibit I, at 61–69 (Sections E.1.2–E.1.6). As noted, the quantity of electricity is the same for both the real world in which the Stations are not fully operational (referred to as the "Actual World" in Exhibit I) and the hypothetical world in which the Stations were fully operational in December 2024 (referred to as the "But-for World" in Exhibit I). The

heat rates of the generating equipment at each Station are generally known and are in any case available in the technical specifications and thermal guarantees from the manufacturer; and the market price of natural gas is historical data that is publicly available from public and proprietary data sources. *See id.* at 61–63, 67–69 (Sections E.1.3 and E.1.6). All of these inputs to calculate damages are necessarily in OPPD's possession. Combining all of this information (or an estimate based on industry data) in a relatively simple spreadsheet model yields a reasonable, transparent, and replicable cost estimate. *See id.* at 22, ¶ 54.

Making the foregoing estimate in August 2024 would have been essentially similar, but with two differences. First, as with estimating the Actual Purchase Costs, an estimate of when the Stations would have produced in response to projected market price spreads can be made using a simple spreadsheet model. *See id.* at 21, ¶ 51. Second, for the prices of both electricity and natural gas, one would use (instead of historical data) monthly futures data shaped by historical price shapes. *See id.* at 75–80 (Sections E.2.1 and E.2.2). Again, "these types of 'ex-ante' calculations are performed all the time by industry investors and market participants." *Id.* at 33, ¶ 87.

OPPD itself makes these very determinations as part of its annual budgeting process. *See, e.g.*, Exhibit F, at 33 (OPPD's 2025 Corporate Operating Plan, projecting customer demand and differences from 2024 in OPPD's budget for purchases of power and operations and maintenance costs resulting from the availability of the Standing Bear Lake and Turtle Creek Stations). And again, Zachry's experts have performed this ex-ante estimation for both Standing Bear Lake Station and Turtle Creek Station. *See* Exhibit I, at 34, ¶ 90.

C. Liquidated Damages Provision

The Original EPC contains a Liquidated Damages Provision. But that contract was executed prior to work commencing on the Stations and years before the Stations became operational. As noted above, at the time of the Second Amended EPC, the Stations were more than 90% complete. In addition to revising the Substantial Completion Date for each Station, the Second Amended EPC also revised the Liquidated Damages Provision:

- For Standing Bear Lake Station, the revised provision imposes a daily charge of "$350,000 per calendar day [for the first 30 days], and $500,000 per calendar day until the Work is accepted as complete."
- For Turtle Creek Station, the revised provision imposes a daily charge of "$250,000 per calendar day [for the first 30 days], and $400,000 per calendar day until the Work is accepted as complete."

Combining these changes yields the following:

Station	Substantial Completion Date	Original Maximum Daily Charge	Current Maximum Daily Charge	Multiple
Standing Bear Lake	December 30, 2024	$250,000	$500,000	2.0
Turtle Creek	December 16, 2024	$100,000	$400,000	4.0

See Exhibit A, at 14–15, art. XI(c)(1)(i)–(ii); Exhibit E, at 3–4, ¶¶ 7–8.

Moreover, "Total liquidated damages in the aggregate for both sites shall not exceed Fifteen percent (15%) of the Contract Price." Exhibit A, at 14, art. XI(a). As adjusted by Change Order No. 1 in November 2023, the Contract Price is $428.7 million. *See* Exhibit D, at 3, ¶ 7. Fifteen percent of that figure is $64.3 million. OPPD has asserted that "if Zachry fails to reach substantial completion of [Turtle Creek Station] by February 14, 2025, and of [Standing Bear Lake Station] by February 28, 2025, respectively" — which did come to

pass — "Zachry will be obligated to pay the remainder of the maximum liquidated damages, totaling fifteen percent (15%) of the total EPC contract price." OPPD Application at 6, ¶ 20. Accordingly, if the Liquidated Damages Provision is enforceable, OPPD's position is that Zachry is liable to OPPD for liquidated damages in the amount of $64.3 million.

D. Proceedings to date

The Reorganized Debtors instituted this adversary proceeding by filing an original complaint against OPPD on February 2, 2025. Docket No. 1. OPPD moved to dismiss, and the Reorganized Debtors filed a First Amended Complaint. Docket Nos. 11 and 22. OPPD recently filed a motion to dismiss the amended complaint. Docket No. 34.

OPPD also moved to withdraw the reference and separately to transfer this action to the District of Nebraska; the Reorganized Debtors filed a combined response; and OPPD filed a reply. Docket Nos. 12, 13, 24, and 31.

In a hearing held on April 12, 2025, the Court invited the Reorganized Debtors to file this motion. Although the Court suggested "voluntary" discovery between the parties, OPPD has spurned Zachry's limited requests for relevant information. *See* Exhibit H.

ARGUMENT
The Liquidated Damages Provision is an unenforceable penalty.

For purposes of this Motion, the sole dispute between the Parties is whether the Liquidated Damages Provision — daily charges that are capped out at $64.3 million — are enforceable "liquidated damages" or instead constitute an unenforceable "penalty."[3] The

[3] The Reorganized Debtors dispute that the delays in achieving the Substantial Completion Dates are caused solely by Zachry. In fact, for the reasons set forth in the Complaint, the delays are caused by OPPD, by OPPD-controlled contractors, or by some combination of both. For purposes of this Motion only the Reorganized Debtors assume arguendo that Zachry breached the Second Amended EPC, and that the Liquidated Damages Provision is triggered.

parties agree that Nebraska law applies to this dispute, and that such law is accurately stated by the federal district court's decision in *Lund-Ross Constructors, Inc. v. Vecino Natural Bridge, LLC*, 2021 WL 6202667, at *4 (D. Neb. Nov. 3, 2021). *See* Motion to Dismiss at 7 (asserting that "Nebraska law governs the [EPC] Contract"); *id.* at 8–9, 11 (favorably citing *Lund-Ross* four times). *Lund-Ross* explains that, in general, "the question whether a sum mentioned in a contract is to be considered as liquidated damages or as a penalty is a question of law." 2021 WL 6202667, at *4 (quoting *Berens & Tate, P.C. v. Iron Mountain Information Management, Inc.*, 747 N.W.2d 383, 387 (Neb. 2008)). In particular,

> [1] if the damages arising from a breach are difficult to ascertain or measure, **and**
>
> [2] if the stipulated amount is either
>
> > [i] a reasonable estimate of the damages that might result from a breach **or**
> >
> > [ii] is reasonably proportional to the actual damages caused by the breach,
>
> the amount will usually be regarded as a provision for liquidated damages.

Id. (emphasis added; cleaned up; quoting *Kozlik v. Emelco, Inc.*, 483 N.W.2d 114, 121 (Neb. 1992)); *accord, e.g., Berens & Tate*, 747 N.W.2d at 387; *In re Papio Keno Club, Inc.*, 247 B.R. 453, 461 (B.A.P. 8th Cir. 2000), *aff'd*, 262 F.3d 725 (8th Cir. 2001).

Therefore, to qualify as true liquidated damages that are enforceable against Zachry, the Liquidated Damages Provision must satisfy **both** the "difficult to ascertain" requirement **and** the "reasonable estimate" or "reasonably proportional" requirement. As explained in the following two parts, the Liquidated Damages Provision satisfies **neither** requirement.

A. Damages of the kind at issue here are not difficult to ascertain or measure.

Under Nebraska law, "the measure of damages for a breach of a contract claim is an amount that would place [the plaintiff] in as good a position as it would have enjoyed if the contract had been performed." *Infogroup, Inc. v. DatabaseLLC*, 956 F.3d 1063, 1068 (8th Cir. 2020) (approving jury instruction so stating; citing *Bachman v. Easy Parking of America, Inc.*, 562 N.W.2d 369, 373 (Neb. 1997)). It is not difficult to state the "position" that OPPD would have enjoyed had the parties achieved the Substantial Completion Dates established by the Second Amended EPC: Standing Bear Lake Station would have been operational on December 30, 2024, and Turtle Creek Station would have been operational on December 16, 2024. *See supra* p. 9 (table). Had that scenario materialized, OPPD would have operated the Stations to produce energy and cover its reserve requirements between those dates and April 15, 2025. In so doing, OPPD would have incurred operational costs in generating peak load electricity at each Station. We shall call those (presumably lower) costs OPPD's "Estimated Generation Costs."

But because of Zachry's (presumed, for present purposes only) breach of the Second Amended EPC, neither Standing Bear Lake Station nor Turtle Creek Station was operational between December 2024 and April 2025. As a result, OPPD was unable to sell energy from those Stations into the market to offset its purchases and may have been required to purchase capacity and regulating reserves from the market to cover its peak load requirements during that period. We shall call those (presumably higher) costs OPPD's "Actual Purchase Costs." To put OPPD in "as good a position" as it would have enjoyed if the Second Amended EPC had been timely performed requires merely subtracting the former from the latter:

Actual Purchase Costs – Estimated Generation Costs = Damages

Are OPPD's Actual Purchase Costs or its Estimated Generation Costs "difficult to ascertain or measure"? In a word, *no*.

1. Actual Purchase Costs

These costs are simply what OPPD actually paid to cover its peak load requirements during the relevant period that it could not cover with its own generation. Whether such out-of-pocket costs were incurred pursuant to one or more contracts entered into before the Second Amended EPC was executed (as alleged in ¶ 44 of the Complaint), or rather simply involved spot purchases, does not matter for present purposes. What matters is only the amount that OPPD paid to suppliers of peak load power that it could not cover with its own generation — a sum that is easily ascertained by examining OPPD's own books.

OPPD refused to provide any financial information from its books. *See* Exhibit H. Even so, Zachry's expert readily estimated OPPD's Actual Purchase Costs using the methodology described in Subsection B.1 above (pp. 6–7). Those costs amount to $25.7 million combined for energy, capacity and ancillary services. *See* Exhibit I, at __.

2. Estimated Generation Costs

These costs, though slightly more complicated, are likewise not difficult to ascertain or measure. As described in detail above, they are what it would have cost OPPD to operate Turtle Creek Station and Standing Bear Lake Station during the relevant periods. Zachry's expert readily estimated these costs using the methodology described in Subsection B.2 above (pp. 7–8). Those costs amount to $17.0 million. *See* Exhibit I, at __.

Accordingly, it is not difficult to ascertain or measure Damages, which is the simple difference between the two figures, or **$8.7 million**. *See id.* at 29, ¶ 77.

3. Caselaw

Caselaw confirms that the actual damages arising from Zachry's (presumed) breach are not "difficult to ascertain or measure." On the one hand, these purely numerical calculations based on known historical facts are very different from the "[d]amages for lost profits, missed opportunities, and reputational harm" that *Lund-Ross Constructors* concluded are "hard to quantify." 2021 WL 6202667, at *6. By definition, lost profits and missed opportunities depend on **estimations** of sales or other revenue-generating activities that **might have** happened (but in fact did not happen). Reputational harm is even less amenable to quantification: it is an estimate of a decline in reputation, which might lead in turn to declines in sales or other revenue-generating activities, the magnitude of which must likewise be estimated.

OPPD's Actual Purchase Costs and its Estimated Generation Costs do not share these characteristics: as documented above, they are amenable to quantification; indeed, they have **actually been quantified**. *Cf. Aramark Uniform Services v. Meylan Enterprises, Inc.*, 2007 WL 1532329, at *4 (Neb. Ct. App. May 29, 2007) (finding that damages were difficult to ascertain in part because "there are also several variable factors that prevent Aramark's **overall** damages from being easily ascertained").

On the other hand, the actual damages arising from Zachry's (presumed) breach are very much like the kinds of damages that courts applying Nebraska law have concluded are **not** difficult to ascertain. In *Papio Keno Club*, the court concluded that it —

> would not be difficult to ascertain the actual damages for any of [the alleged] material breaches. The damages incurred by the City for the Debtor's failure to maintain liability insurance would be, at most, the difference between the amount of insurance the Debtor actually maintained and the amount it was required to maintain. Similarly, the damages sustained by the City for the Debtor's failure to maintain a $250,000 letter of credit would be, at most, the difference between the amount available under the letter of credit and $250,000. Furthermore, the damages incurred by the City for the Debtor's failure to timely apply to renew its license easily could be calculated based on the City's average daily share of the gross proceeds for each day that the Debtor was unable to operate because it was without a license.

247 B.R. at 461. Like the City's damages, OPPD's damages can be "calculated," mostly based on the "difference" between one financial figure and another.

Similarly, in *Browning Ferris Industries of Nebraska, Inc. v. Eating Establishment-90th & Fort, Inc.*, 6 Neb. App. 608, 613 (1998), the court concluded that "the actual damages would not be overly difficult to ascertain with some precision if BFI desired to do so. [BFI's district sales manager] testified that BFI was a sophisticated competitor in the disposal industry, with over 3,000 accounts in Nebraska, and had a full staff of accountants. [He] acknowledged that the company could probably determine what the profit was on an average contract." OPPD is likewise a sophisticated participant in the electric utility industry with a full staff of accountants. Doubtless OPPD could determine its Actual Purchase Costs, its Estimated Generation Costs, and the simple difference between those two figures. OPPD's public communications confirm that point. *See, e.g.*, Exhibit F, at 33.

In sum, damages of the kind at issue here are not difficult to ascertain or measure. For that reason alone, the Liquidated Damages Provision is an unenforceable penalty.

B. Alternatively, the amount stipulated in the Liquidated Damages Provision is not a reasonable estimate of, or reasonably proportional to, actual damages.

As quoted above, the party seeking to establish that a stipulated amount qualifies as enforceable liquidated damages must show **both** that the actual damages are difficult to ascertain "and" that such amount is either a reasonable estimate of, or reasonably proportional to, actual damages. *Lund-Ross Constructors*, 2021 WL 6202667, at *4; *Berens & Tate*, 747 N.W.2d at 387 (quoting *Kozlik*, 483 N.W.2d at 121); *cf. Aramark Uniform Services*, 2007 WL 1532329, at *4 (enforcing liquidated damages provision only after finding **both** "sufficient evidence that Aramark's damages were not easily ascertainable" **and** "sufficient evidence that the actual damages were reasonably related to the liquidated damages"). That OPPD can make neither showing provides an independent reason for concluding that the Liquidated Damages Provision constitutes an unenforceable penalty.

1. The stipulated amount was *not* a reasonable estimate of OPPD's likely damages.

Whether a stipulated amount is a reasonable estimate of likely damages is to be "determined [as of] the time the contract was entered." *Aramark Uniform Services*, 2007 WL 1532329, at *3 (emphasis deleted). Here, that was August 2024, when the Second Amended EPC was executed.

First, there is no indication that Liquidated Damages Provision is an estimate at all, let alone a reasonable one. *Cf. Kealy v. Harter*, 682 F.2d 198, 200 n.2 (8th Cir. 1982) (per curiam) (applying Nebraska law and opining that the "reasonable estimation" precept "require[s] that the parties make a good faith attempt to predict damages"). To be sure, the

Original EPC recites in Article XI(a) that "both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty." But nothing in the Original EPC or in the Second Amended EPC — or any extrinsic evidence of which we are aware — provides a basis for viewing the dollar figures as an actual estimate or prediction. *Cf. Hanover Insurance Co. v. Binnacle Development, LLC*, 493 F. Supp. 3d 585, 591 (S.D. Tex. 2020) (finding no "reasonable forecast" of actual damages where the "evidence shows that no study or analysis went into setting $2,500 per diem as the delay fee"), *aff'd*, 57 F.4th 510 (5th Cir. 2023).

Second, the Original EPC and the Second Amended EPC indicate a lack of reasonableness on their face. Article XI(c)(1) and (2) originally imposed a maximum daily charge of $250,000 for failing to timely complete Standing Bear Lake Station and of $100,000 for failing to timely complete Turtle Creek Station. For the former, charges were imposed beginning May 1, 2023; for the latter, beginning August 18, 2023. *See* Exhibit C (specifying the two respective "Substantial Completion Dates"). The Second Amended EPC **doubled** the maximum daily charge for Standing Bear Lake Station (to $500,000) and **quadrupled** it for Turtle Creek Station (to $400,000). For the former, the higher charges were imposed beginning December 30, 2024; for the latter, beginning December 16, 2024.

We are aware of no explanation for these massive increases except to impose a hefty penalty for delay. Certainly, the increases cannot be justified by seasonal variation. To the contrary, it is conceivable that delays would be more costly to OPPD in the summer (when peak demand for electricity is greater, and spot-market electricity costs are correspondingly

higher) than in the winter (when peak demand is lesser, and such costs are correspondingly lower). *See* Exhibit I, at 11, ¶ 31. But the change from the Original to the Second Amended EPC reflects **precisely the opposite**: lower estimated electricity costs in summer and higher estimated electricity costs in winter. On its face, therefore, this is simply not a **reasonable** estimate. *See id.* at 18–19, ¶ 44(2) (opinion of Zachry's expert that this change is "counter-intuitive to the summer peaking nature of the SPP market" and is thus "not reasonable").

Third, as described above (p. 9), just 30 days after the Substantial Completion Date for each Station, the daily charge for that Station "ratchets up" by $100,000. Together with other features of the Liquidated Damages Provision, such a "round-numbered increase . . . completely disconnects the Liquidated Damages provisions from economic harm actually incurred by OPPD." Exhibit I, at 13, ¶ 35. This is yet another reason why the Provision is, on its face, "an unreasonable way to estimate economic damages." *Id.*

Fourth, as detailed in Section B above (pp. 5–8), using publicly available historical data and prices from robust futures markets, it was feasible **in August 2024** to make reasonable estimates of both Actual Purchase Costs and Estimated Generation Costs rather than merely fabricate large round numbers. Zachry's experts did just that, yielding estimates of total Damages of between $6.7 and $17.0 million. *See* Exhibit I, at 34, ¶ 90. Compare that to the Liquidated Damages Provision's "estimate" of $64.3 million — a sum that is between four and nine times too high!

For these many reasons, the amount stipulated in the Second Amended EPC was not a reasonable estimate of OPPD's likely damages.

2. The stipulated amount is *not* reasonably proportionate to OPPD's actual damages.

Nor was that amount reasonably proportionate to OPPD's actual damages. Based on a model using assumptions favorable to OPPD (and without regard to any available defenses), Zachry's experts have calculated that OPPD theoretically sustained actual damages though April 15, 2025 of just under $8.7 million. *See* Exhibit I, at 29, ¶ 77. Yet the amount yielded by the Liquidated Damages Provision tops $64.3 million, a multiple of **roughly 7.4** and a windfall to OPPD of **more than $55 million**. Almost by definition, that multiple is not reasonably proportionate, and that windfall is not reasonable. The caselaw addressing this prong of the test accords with that conclusion:

- **2.2 multiple**, *see Computer Support Services, Inc. v. Vaccination Services of America, Inc.*, 2017 WL 2399486, at *5 (Neb. Ct. App. May 23, 2017) (not reasonably proportionate where liquidated damages of $45,500 exceeded actual damages of only $21,045);

- **$71K windfall**, *see Papio Keno Club*, 247 B.R. at 461 (not reasonably proportionate where liquidated damages of $71,340 are contrasted with no actual damages);

- **$65K windfall**, *see Kealy*, 682 F.2d at 199–200 (not reasonably proportionate where liquidated damages of $65,000 are contrasted with no actual damages).

- **$900K windfall**, *see Hanover Insurance*, 493 F. Supp. 3d at 591 (finding an "ultimate disproportionality between the damages imposed by the liquidated-damages clauses and the actual damages" where "actual damages are $0 and liquidated damages are $900,000").[4]

[4] Decisions from other jurisdictions applying essentially the same test are in accord. *See, e.g., Trustees of Columbia University v. D'Agostino Supermarkets, Inc.*, 36 N.Y.3d 69, 80 (2020) (concluding that because a liquidated damages provision "calls for a sum **more than sevenfold** the amount due if defendant had complied fully with the [contract]," the court "cannot enforce such an obviously and grossly disproportionate award" (emphasis added)); *Newark Shopping Center Owner, L.L.C. v. Saudades Group, LLC*, 2025 WL 655063, at *9 (Del. Super. Ct. Feb. 26, 2025) (finding a violation of the "reasonably proportionate" standard where the liquidated sum was "**more than four times** higher than the maximum" supported by testimonial evidence (emphasis added)); *Garden Ridge, L.P. v. Advance International, Inc.*, 403 S.W.3d 432, 441 (Tex. App.—Houston [14th Dist.] 2013, pet. denied) (holding that defendant had proved that the liquidated sum of $79,457 was "unreasonably large when compared to [plaintiff's] actual damages of zero").

For all these reasons, the amount stipulated in the Second Amended EPC was not reasonably proportionate to OPPD's actual damages, if any. Because that amount was likewise not a reasonable estimate of OPPD's likely damages, OPPD cannot satisfy the second independent requirement for establishing that the Liquidated Damages Provision is enforceable. Accordingly, the provision constitutes an unenforceable penalty.

C. OPPD's contrary argument lacks merit.

OPPD has previously contended that the "liquidated damages provision in the [EPC] Contract is enforceable." Motion to Dismiss at 7 (section heading). In so contending, OPPD advances essentially a single argument: the Liquidated Damages Provision is enforceable **simply and solely** because the Original EPC provides that the parties "acknowledge that actual damages incurred by [OPPD] . . . would be difficult to determine and that both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty." *Id.* at 10 (quoting Exhibit A, at 14, art. XI(a)).

That is not the law. OPPD urges that, as "stated in *Lund-Ross*, Zachy should not be 'let off the hook' by this Court by its attempt to ignore the explicit provisions it agreed to be bound by in the Contract, including the Second Amendment." *Id.* at 11 (quoting *Lund-Ross*, 2021 WL 6202667 at *5). But *Lund-Ross* actually held that when "the parties are experienced in business, the damages are economic, and the parties had fair opportunity to consider the agreement, Nebraska courts have been **reluctant** to let them off the hook." 2021 WL 6202667 at *5 (emphasis added; cleaned up). Perhaps **reluctant**, but given the above-cited caselaw, obviously **not categorically opposed**.

Therefore, as *Lund-Ross* observed, the Nebraska Supreme Court has "upheld awards of liquidated damages" **not** in every case but rather in those cases "where the damages were uncertain, and the parties' stipulated damages were reasonable." *Id.* As that court itself has repeatedly opined, it has "consistently upheld the right of contracting parties to privately bargain for the amount of damages to be paid in the event of a breach of contract, **provided the stipulated sum is reasonable in light of the circumstances**." *Berens & Tate*, 275 Neb. at 430–31 (emphasis altered; quoting *Reichert v. Rubloff Hammond, L.L.C.*, 264 Neb. 16, 24 (2002), in turn quoting *Kozlik*, 240 Neb. at 535).

Lund-Ross also observed that the "Nebraska Supreme Court has been **pretty clear** about how to determine whether a stipulated amount is liquidated damages or a penalty," namely, the two-part test quoted on Page 11 above and applied herein. 2021 WL 6202667, at *4 (emphasis added). The numerous decisions discussed above, including one from the Bankruptcy Appellate Panel of the Eighth Circuit, make clear that courts applying Nebraska law do not hesitate to nullify liquidated damage clauses when they fail the governing two-part test — as the Liquidated Damages Provision fails here.

Finally, we note OPPD's assertion — unsupported either conceptually or with an offer of proof — that "OPPD's damages are enormous." Motion to Dismiss at 11. But we have shown that, at least in proportion to the charges imposed by Article XI of the Second Amended EPC, that is simply false. We have also shown that, whatever their magnitude, OPPD's actual damages were **not** difficult to ascertain or measure — an independent reason to declare the charges to be unenforceable penalty.

CONCLUSION

For these reasons, the Liquidated Damages Provision of the Second Amended EPC is an unenforceable penalty under governing Nebraska law, and the Court should grant the Reorganized Debtors partial summary judgment so declaring.

Dated: April 28, 2025

Respectfully submitted,

/s/ *John B. Thomas*

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CERTIFICATE OF SERVICE

I certify that on this day, a copy of the foregoing pleading was filed electronically with the Clerk of Court using the CM/ECF system. Notice of this filing will be sent to all counsel of record by operation of the court's electronic filing system.

Dated: April 28, 2025

/s/ *John B. Thomas*
John B. Thomas

EXHIBITS

A. Excerpts of EPC Contract (Sept. 2021).

B. Excerpts of Exhibit B to EPC Contract.

C. Excerpts of Exhibit E to EPC Contract.

D. Change Order No. 1 (Nov. 9, 2023).

E. Amendment No. 2 to EPC Contract (Aug. 2024).

F. Excerpts of OPPD 2025 Corporate Operating Plan (Dec. 19, 2024), https://bit.ly/3GDMfF3.

G. Excerpts of OPPD Rate Fundamentals Report (Jan. 9, 2025), https://bit.ly/4cQe6hp.

H. Letter from OPPD's counsel to Zachry's counsel (Apr. 22, 2025).

I. Declaration of Tanya Bodell (Apr. 28, 2025).

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FOR EXECUTION

ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE CREEK GENERATING STATIONS

CONTRACT NO. 263406

September 21, 2021

EXHIBIT
A

ARTICLE XI - LIQUIDATED DAMAGES.

(a) The Contractor and the District acknowledge that actual damages incurred by the District as a result of the Contractor's failure to meet the Guaranteed Substantial Completion Dates and Performance Guarantees would be difficult to determine and that both parties agree that the liquidated damages provisions in this Article XI are reasonable and appropriate measures of the damages for such completion and performance shortfalls, and are not a penalty. Total liquidated damages in the aggregate for both sites shall not exceed Fifteen percent (15%) of the Contract Price.

(b) On or before March 31, 2023, EPC Contractor, OFE Suppliers and OPPD shall meet and confer regarding the status of Acceptance Tests and progress toward meeting the Guaranteed Substantial Completion Date(s), and EPC Contractor and Suppliers shall commit in writing that the Work will be completed by the Guaranteed Substantial Completion Date(s). Failure to meet the Guaranteed Substantial Completion Date(s) shall be subject to the provisions of subsection (c)(1) below. Such provisions shall be the sole and exclusive remedy for any such failure.

(c) Contractor's failure to meet the Guaranteed Substantial Completion Date(s) and/or Performance Guarantees shall result in the following liquidated damages; provided, however, if the Work is delayed by the District or other contractors, Contractor shall nevertheless continue to perform the Work in accordance with the Project Schedule, however Contractor may be entitled to a Change Order if price and schedule are impacted. Acceptance by the District of ongoing monthly liquidated damage payment shall in no event constitute a waiver of the District's right to future liquidated damage payments or operate as an accord and satisfaction of the District's right to future liquidated damage payments or in any other manner prejudice the District's right to future liquidated damage payments. The District's damages arising from claims or causes other than failure to achieve the Guaranteed Substantial Completion Date(s) and/or Performance Guarantees shall be limited only by Section 33 (Limitation of Liability) of the General Conditions.

(1) Delay in Completion of Work

(i) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for SBLS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed Substantial Completion Date for SBLS that the Work is not completed, $125,000 per calendar day through May 15, 2023, and $250,000 per calendar day, from May 16, 2023, until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price.

(ii) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for TCS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day

beyond the Guaranteed Substantial Completion Date for TCS that the Work is not completed, $50,000 per calendar day, through September 1, 2023, and $100,000 per calendar day, from September 2, 2023, until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price.

(2) Performance Guarantees. The Contractor shall have reasonable access to the Sites as mutually agreed between the parties, to implement corrective action in order to demonstrate Performance Guarantees. Any release of retainage will be in accordance with Article IV, Section (b). With respect to Performance Guarantees, should the District and the Contractor agree that any remedy is impractical, uneconomic or inexpedient, or should Contractor not make any such remedy, or should Contractor still fail to satisfy such Performance Guarantees following all attempts to remedy, it is agreed that the District's loss would be difficult to determine. Accordingly, after successful completion of all of the tests and retests specified, the District and Contractor agree that, as a predetermined reasonable and sole and exclusive remedy for any such loss, Contractor will pay to the District, as liquidated damages and not as a penalty, the liquidated damages, if any, determined in accordance with the following provisions.

If the Contractor cannot demonstrate conformance with the Thermal Performance Guarantees by passing the Acceptance Tests on or before the Guaranteed Substantial Completion Date, for either or both SBLS or TCS, the Contractor shall pay daily liquidated damages as follows:

Thermal Performance Guarantee	Liquidated Damages
Balance of Plant Auxiliary Power – Natural Gas – SBLS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Fuel Oil – SBLS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Natural Gas – TCS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.
Balance of Plant Auxiliary Power – Fuel Oil – TCS	One Thousand Five Hundred Dollars ($1,500) for each kW (or prorated fraction thereof) by which the auxiliary power is greater than the guaranteed value.

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(d) Liquidated damages shall be paid to the District by the Contractor at the end of each month in which any liquidated damages accrue, or the District may, at its option, offset any accrued liquidated damages against amounts due and payable to the Contractor under the Contract Documents.

(e) Specific Performance. It is hereby agreed by the District and Contractor that the Work to be performed under the Contract Documents is unique in nature. Consequently, except as to breaches for which a remedy is specified in the Agreement, if Contractor breaches the Contract Documents, the District shall have the right to require specific performance at the District's option. Such option by the District shall not limit the District's right to any and all damages recoverable under the Agreement.



2023 GENERATION ADDITION

ENGINEER, PROCURE, CONSTRUCT

EXHIBIT B - TECHNICAL SPECIFICATION

EXHIBIT

B

OMAHA PUBLIC POWER DISTRICT
2023 GENERATION ADDITION

ENGINEER, PROCURE, CONSTRUCT
EXHIBIT B – TECHNICAL SPECIFICATION

OPPD Contract No.:	263406
Document No.:	10214444-ZP-M0102
Issue:	For Contract
Revision:	1

Prepared By

HDR

SECTION 01 – OVERVIEW

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1 OVERVIEW

1.1 INTRODUCTION

Owner: Omaha Public Power District – OPPD

The Owner's project consists of two power plant Sites. The northern Site, hereafter referred to as the "Standing Bear Lake Station" (SBLS), will use reciprocating internal combustion engine (RICE) generator sets as the generation technology; the southern Site, hereafter referred to as the "Turtle Creek Station" (TCS), will use combustion turbine generators as the generation technology.

Further description of the two project Sites follows.

1.2 STANDING BEAR LAKE SITE

Facility Name: Standing Bear Lake Station

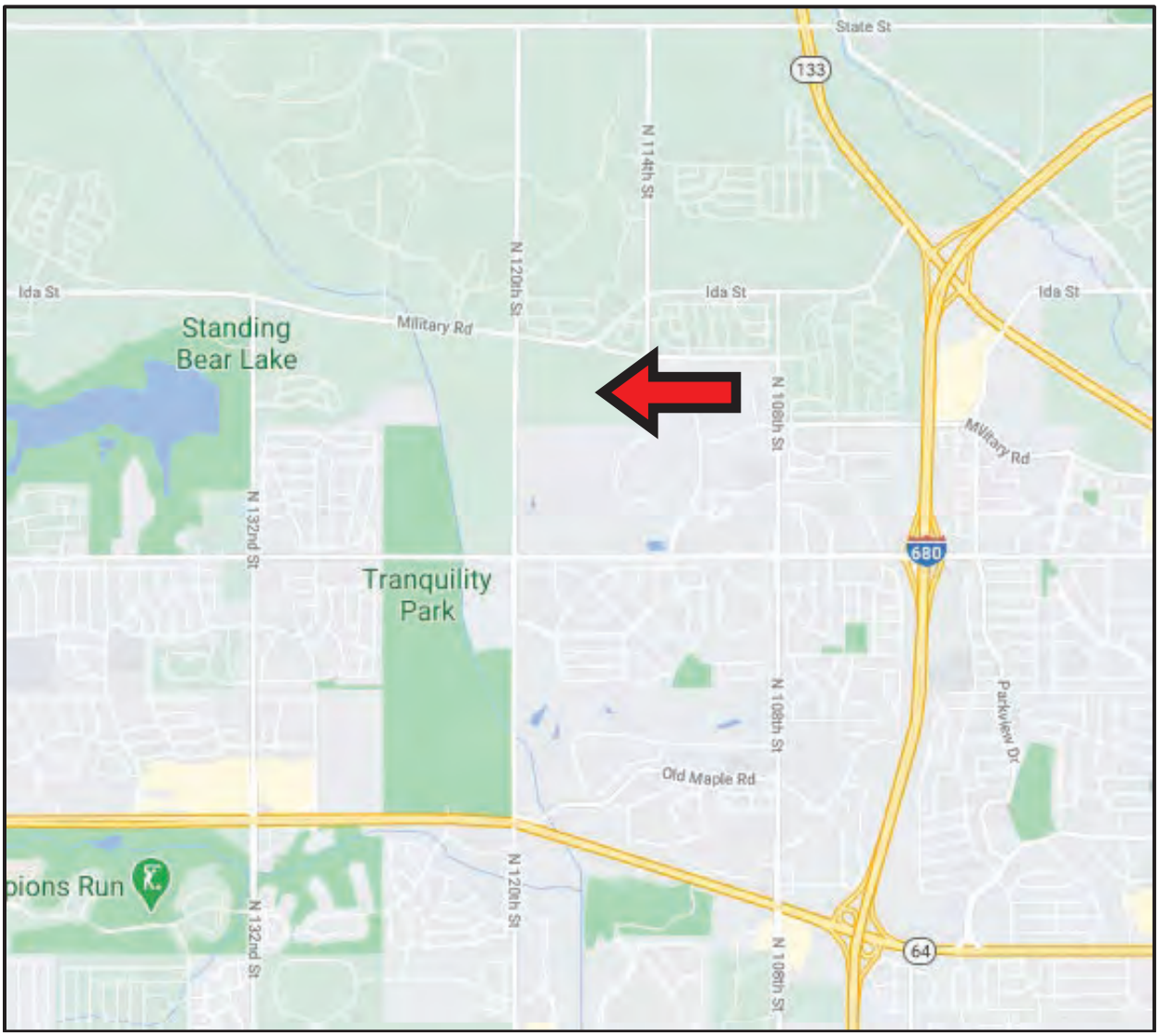
Project Location: State of Nebraska, County of Douglas, NW Omaha

Project Address: Military Rd Omaha, NE 68164

Approximate GPS: 41.315741, -96.094803

The Facility is located southeast of the intersection of Military Road and North 120th Street. Interstate 680 exit 5 (Fort Street) is the closest highway access point.

The Site location is indicated on the map below and a satellite view of the Site is shown in the aerial map that follows.





The Facility will be in a suburban area in northwest Omaha, on a primarily greenfield site. The Site is co-located on a Metropolitan Utilities District site. The Facility will consist of nine RICE generator sets installed inside an engine hall exhausting outdoors to emission reduction catalysts, exhaust silencers, and exhaust stacks.

Primary fuel for the engines will be pipeline quality natural gas, with backup fuel being ultra-low sulfur diesel. The engines will be capable of blending hydrogen into the natural gas in the future when hydrogen fuel becomes available.

Power from the Facility will be directed to a substation located on the site that also serves as a power delivery substation for the area.

The Facility is anticipated to be operated as a regulating and peaking power Facility, with the engines operating in a cyclic manner to support grid demands.

Refer to the preliminary site plan located in Appendix 10.

1.3 TURTLE CREEK SITE

Facility Name: Turtle Creek Station

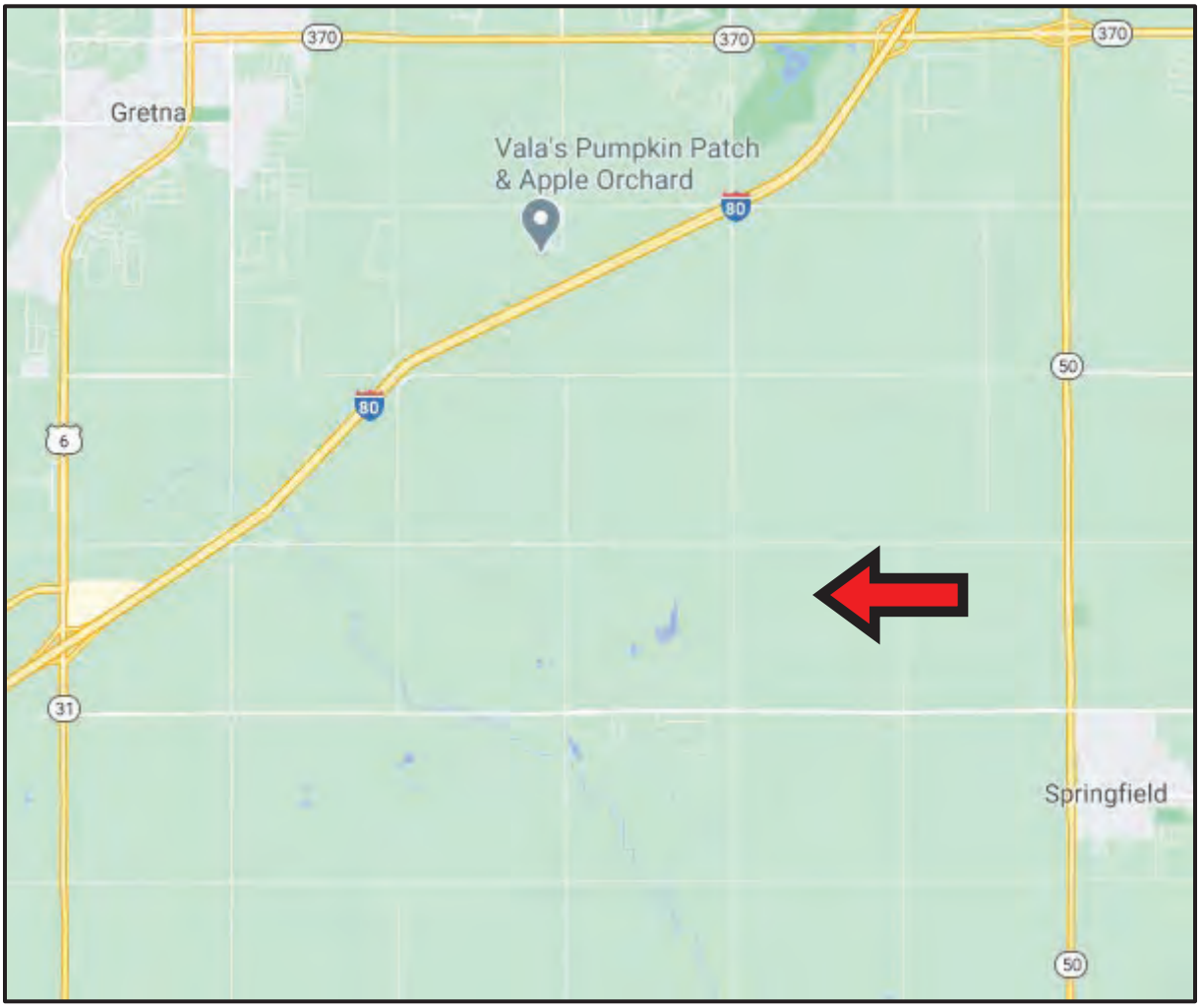
Project Location: State of Nebraska, County of Sarpy

Project Address: 14601 South 168th Street, Gretna, NE 68028

Approximate GPS: 41.095489, -96.170071

The Facility is located southeast of the intersection of Fairview Road and S 168th Street. Interstate 80 exit 432 (NE-31 or S216th Street) is a nearby Interstate highway access point.

The Site location is indicated on the map below and a satellite view of the Site is shown in the aerial map that follows.





The Facility is in a rural area approximately 15 miles southwest of downtown Omaha on agricultural land and adjacent to the Sarpy County landfill. The Facility will consist of two combustion turbine generator sets installed outdoors and exhausting to emission reduction modules.

Primary fuel for the CTG's will be pipeline quality natural gas, with backup fuel being ultra-low sulfur diesel. The CTG's should be capable of blending hydrogen into the natural gas in the future when hydrogen fuel becomes available.

Power from the Facility will be directed to a substation located on the site.

The Facility is anticipated to be operated as a regulating and peaking power Facility, with the CTG's operating in a cyclic manner to support grid demands.

Refer to the preliminary site plan located in Appendix 10.

EXHIBIT E

GUARANTEED COMPLETION DATES AND PROJECT SCHEDULES

GUARANTEED SUBSTANTIAL COMPLETION DATES

Standing Bear Lake Station Guaranteed Substantial Completion Date	May 1, 2023
Turtle Creek Station Guaranteed Substantial Completion Date	August 18, 2023

EXHIBIT
C

CHANGE ORDER NO. 1

Date: November 9, 2023

Project: Omaha Public Power District-Turtle Creek Station/Standing Bear Lake Station (the "Project")

Parties: Omaha Public Power District, a public corporation and political subdivision of the State of Nebraska ("OPPD" or "District") and Zachry Industrial, Inc. ("Contractor") (together, the "Parties").

Contract: Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations, Dated September 21, 2021 (OPPD Contract No. 263406) (the "EPC Contract").

This Change Order No. 1 ("Change Order") amends the EPC Contract and is entered into between OPPD and Contractor effective November 9, 2023 (the "Change Order Effective Date").

WHEREAS, the EPC Contract defines the terms "Contract Change Request (CCR)" and "Change Order" and those definitions shall apply to this Change Order;

WHEREAS all other capitalized terms used in this Change Order shall have the meaning set forth in the EPC Contract, unless otherwise stated herein;

WHEREAS, Contractor has submitted CCRs and supporting information, OPPD has considered the CCRs and supporting information, and OPPD issues this Change Order;

WHEREAS, for purposes of this Change Order, the Parties shall refer to the subject CCRs described herein and set forth on Exhibit "A" hereto as "Potential Change Notices" ("PCNs"); and

WHEREAS, the Parties entered into a Memorandum of Agreement on October 11, 2023, setting forth their agreement regarding certain PCNs ("MOA"); and

WHEREAS, contemporaneously with the execution of this Change Order, OPPD and Contractor have executed Amendment No. 1 to the EPC Contract, which, among other terms and consistent with the MOA, sets forth Revised Guaranteed Substantial Completion Dates for Standing Bear Lake Station ("SBLS") of August 8, 2024, and for Turtle Creek Station ("TCS") of August 30, 2024.

NOW THEREFORE, in consideration of the foregoing recitals (which are incorporated herein by this reference) and the covenants and agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties further agree as follows:

1. **Defined Terms.** Unless otherwise defined herein, all capitalized terms used herein shall have the meanings ascribed thereto in the EPC Contract.

2. **Change Order and Amount.**

EXHIBIT D

Exhibit "A" sets forth the PCNs that are the subject of this Change Order. The Parties agree to the amounts set forth on Exhibit "A" as satisfaction for such PCNs and accept the cancellation of those PCNs described to be canceled. Payment for the PCNs identified with Invoice Month of November 2023 shall be paid Net 10 days from receipt of invoice. Payment for the PCNs identified with any other Invoice Month set forth on Exhibit "A" shall be paid in accordance with the EPC Contract. Withholding of retainage will be pursuant to the terms of the EPC Contract.

3. **ProlecGE Transformers**

As set forth in the MOA, OPPD agrees to accept the derated ProlecGE transformers for TCS. All other performance obligations relating to the GSU Transformers referenced in the EPC Contract shall remain in full force and effect. In exchange for OPPD's acceptance of the derated transformers, Contractor will credit OPPD $3,902,000. The credit shall be applied against the amount invoiced by Contractor for PCNs identified with Invoice Month of November 2023.

4. **Siemens Commissioning Schedule.**

Siemens Energy ("Siemens") has supplied Owner Furnished Equipment ("OFE") to TCS under a separate contract with OPPD. Upon successful completion of commissioning at TCS, OPPD agrees to provide, and Contractor agrees to accept, the lump sum payment of $2,250,000, to cover an additional thirty-six (36) days in connection with Contractor's Work for an expanded Siemens' OFE commissioning schedule. Contractor shall remain responsible for commissioning of TCS and SBLS in accordance with the terms of the EPC Contract.

5. **Soil Compaction.**

As set forth in the MOA, based on Contractor's third-party geotechnical report, OPPD accepts any site erosion, settlement, foundation movements, and other impacts that occur after the two (2) year EPC Contract Warranty (beginning with Substantial Completion).

6. **Low Voltage Switch Gear at SBLS.**

As set forth in the MOA, all issues related to the Low Voltage Switchgear are the sole responsibility of Contractor.

7. **Change to Contract Price.**

The Contract Price is as detailed below:

The original Contract Price was: $366,207,836.00.

The Contract Price shall be increased by this Change Order in the amount of $64,185,282 for the accepted PCNs detailed on Exhibit "A."

Additionally, the Contract Price shall be decreased in the amount of $3,902,000 to reflect the credit referenced in Section 3 above.

Additionally, the Contract Price shall be increased for the Siemens Commissioning Schedule work described in Section 4 of this Change Order in the amount of $2,250,000.

The adjusted Contract Price, including the price of this Change Order, is: $428,741,118.00.

8. **Effect of Change Order**.

Contractor agrees to perform the above-described Work in accordance with the above terms and in compliance with the Contract Documents. The adjustment in the Contract Price set out in this Change Order (and the adjustment in the Guaranteed Substantial Completion Dates made in Amendment No. 1) shall constitute the entire compensation and/or adjustment in the Contract Price and contract time due Contractor arising out of the changes for the Work covered by this Change Order. Contractor forever waives, relinquishes, releases, and discharges OPPD from any and all present or future claim of any kind for additional compensation or payment, whether known or unknown, or which may arise in the future, of or relating to Contractor's alleged "cumulative impact" claim initially set forth in its letter to OPPD dated May 12, 2023, whether such claim is described as a "cumulative impact" claim or by any other description or name, and whether such claim is asserted under the terms of the EPC Contract or of any other agreement or legal document, or pursuant to any statute or legal or equitable theory, doctrine, rule, or common law principle. No additions or deletions to this Change Order shall be allowed, except with written permission of the District.

9. **Miscellaneous.**

Except as specifically modified in this Change Order, the terms of the EPC Contract shall remain unchanged and in full force and effect. This Change Order may be executed in separate counterparts, and delivered via email, which shall be sufficient to bind the parties to the terms and conditions of this Change Order.

IN WITNESS WHEREOF, the Parties have caused this Change Order No. 1 to be executed by their duly authorized representatives as of the date set forth above.

OMAHA PUBLIC POWER DISTRICT

By: DocuSigned by: 80AC33D8E87A4D3...

Title: Contract Specialist

ZACHRY INDUSTRIAL, INC.

By: DocuSigned by: Ralph Biediger 4E061F33D33B4DA...

Title: President, Projects Group

CONFIDENTIAL SETTLEMENT COMMUNICATION
SUBJECT TO FRE 408 & ALL SIMILAR PROTECTIONS

AMENDMENT NO. 2 TO
ENGINEER, PROCURE, AND CONSTRUCT CONTRACT FOR OMAHA PUBLIC POWER DISTRICT STANDING BEAR LAKE AND TURTLE CREEK GENERATING STATIONS (CONTRACT NO. 263406)

This AMENDMENT NO. 2 to Contract No. 263406 ("**Amendment No. 2**") is entered into as of this 13 day of August ("**Effective Date**"), by and between Omaha Public Power District, a public corporation and political subdivision of the State of Nebraska ("**OPPD**"), and Zachry Industrial, Inc., a Texas corporation ("**Contractor**") (together with OPPD, the "**Parties**" or individually, a "**Party**").

WHEREAS, OPPD and Contractor are parties to that certain *Engineer, Procure, and Construct Contract for Omaha Public Power District Standing Bear Lake and Turtle Creek Generating Stations* (Contract No. 263406) dated 21 of September, 2021 (the "EPC Contract");

WHEREAS, pursuant to Article IV, Subsection (b) of the EPC Contract, OPPD withholds five percent (5%) of each Milestone Payment owed to Contractor as retainage and as of the Effective Date, OPPD is holding approximately [$20,220,446] in retainage (the "**Retainage**");

WHEREAS, Contractor and certain of its affiliates (collectively, the "**Debtors**") filed voluntary petitions for relief under chapter 11 of the United States Bankruptcy Code (the "**Bankruptcy Code**") in the United States Bankruptcy Court for the Southern District of Texas ("**Bankruptcy Court**") on May 21, 2024 (the "**Petition Date**"), which initiated the chapter 11 cases (the "**Chapter 11 Cases**") now jointly administered under lead case number 24-90377 (MI); and

WHEREAS, OPPD and Contractor desire to amend the EPC Contract as described herein.

NOW, THEREFORE, in consideration of the mutual covenants set forth below, the Parties agree as follows:

1. Defined Terms. Unless otherwise defined herein, all capitalized terms used herein shall have the meanings ascribed thereto in the EPC Contract.

2. Amendment of Article IV – Contract Price, Payment. Article IV, Subsection (b) of the EPC Contract is hereby deleted in its entirety and replaced in its entirety with the following:

(b) Milestone Payments. Contractor shall submit an invoice, on the tenth (10th) day of each month, showing milestones completed and payments due for those milestones in accordance with the Milestone Payment Schedule set forth in Exhibit G. After review and approval of the invoice by OPPD, milestone payments shall be made to the Contractor in the amount of 100% of approved invoice, without withholding of retainage. Such payment shall be made approximately fifteen (15) days from receipt of the invoice. Payment of such

EXHIBIT
E

monthly milestone payments by the District shall not be construed or deemed to be an acceptance of the Work covered thereby.

3. Amendment of Article IV – Contract Price, Payment. Article IV of the EPC Contract is hereby amended to add the following Section (i):

(i) Contractor warrants and agrees that it has the necessary work force and resources to complete the Work, including achieving the Guaranteed Substantial Completion Dates. In an effort to expedite completion of the Work, and provided that Contractor shall assume the EPC Contract (as amended) as specified in Section 10 hereof and recommend approval of this Amendment by the Bankruptcy Court of the Southern District of Texas, the District shall remit certain "Milestone Final Completion" payments to the Contractor. These Milestone Final Completion payments are contingent on the Contractor meeting the lesser of ninety days (90) from Substantial Completion or the dates for the respective Sites listed in subsections (a) and (b) below. Failure of Contractor to meet the scheduled dates below for each individual site will result in Contractor forfeiting the additional Two Million Dollar ($2,000,000.00) payment for the respective Site set forth in this Amendment No. 2. Subject to the terms of the EPC Contract, including this Amendment No. 2, the Milestone Final Completion payments shall be adjusted as follows:

On Final Completion, the Milestone Final Completion payment shall increase by Two Million Dollars ($2,000,000.00) per site from the allotted amount set forth in the EPC Contract:

(a) SBLS will be a payment of Three Million Dollars ($3,000,000.00) if the current schedule date of March 30, 2025 is met.

(b) TCS will be a payment of Three Million Dollars ($3,000,000.00) if the current schedule date of March 16, 2025 is met.

4. Amendment of Article IV – Contract Price, Payment. Article IV of the EPC Contract is hereby amended to add Section (j), as set forth below:

(j) Release of Retainage. The following procedures shall apply to the release of the Retainage:

(i) SurTec Information Systems, Inc. shall serve as Contractor's designated third-party administrator (the "**Agent**");
(ii) Contractor shall direct Agent to establish an escrow account (the "**OPPD Escrow Account**");
(iii) Upon execution of this Amendment No. 2, OPPD shall promptly deposit the entirety of the Retainage into the OPPD Escrow Account; and
(iv) The Agent shall directly pay Subcontractors, associated with the funds held in the OPPD Escrow Account; *provided that*, OPPD shall receive

contemporaneous notice of all payments made from the OPPD Escrow Account.

5. Amendment of Article XI – Liquidated Damages. Article XI Section (f) of Amendment No. 1 to the EPC Contract is hereby deleted in its entirety, such that Article XI, Section (f) now provides in its entirety, the following:

(f) Payments for Early Completion. Provided that Zachry has successfully completed commissioning requirements per the EPC Contract, as determined by OPPD, Zachry shall be entitled to receive the following payments, to be paid within fifteen (15) days of receipt of an invoice:

(1) For SBLS, $193,548.00 per day for each calendar day before the Guaranteed Substantial Completion Date that the Work is completed. There shall be an overall cap on this compensation of $5,999,988, reflecting up to 31 calendar days.

(2) For TCS, $352,941.00 per day for each calendar day before the Guaranteed Substantial Completion Date that the Work is completed. There shall be an overall cap on this compensation of $5,999,997, reflecting up to 17 calendar days.

6. Amendment of Article XI – Liquidated Damages. Article XI, Section (b) of Amendment No. 1 to the EPC Contract, is hereby deleted in its entirety, such that Article XI, Section (b) of the Agreement now provides, in its entirety, the following:

(b) On or before August 31, 2024, EPC Contractor, OFE Suppliers and OPPD shall meet and confer regarding the status of Acceptance Tests and progress toward meeting the Guaranteed Substantial Completion Date(s), and EPC Contractor and Suppliers shall commit in writing that the Work will be completed by the Guaranteed Substantial Completion Date(s). Failure to meet the Guaranteed Substantial Completion Date(s) shall be subject to the provisions of subsection (c)(1) below. Such provisions shall be the sole and exclusive remedy for any such failure.

7. Amendment of Article XI – Liquidated Damages. Article XI, Section (c), Subsection (1) (i) and (ii) of the EPC Contract is hereby deleted in its entirety, such that Article XI, Section (c), Subsection (1) (i) and (ii) of the EPC Contract now provides, in its entirety, the following:

(1) Delay in Completion of Work

(i) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for SBLS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed

Substantial Completion Date for SBLS that the Work is not completed, $350,000 per calendar day through January 29, 2025, and $500,000 per calendar day until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price. If Substantial Completion has not been achieved by February 28, 2025, then on March 1, 2025, Contractor shall pay the remainder of such maximum liquidated damages applicable to SBLS.

(ii) If the Contractor fails to complete the Work on or before the Guaranteed Substantial Completion Date, for TCS, as a predetermined reasonable and sole and exclusive remedy for such delay, the Contractor shall be subject to liquidated damages as follows: For each calendar day beyond the Guaranteed Substantial Completion Date for TCS that the Work is not completed, $250,000 per calendar day, through January 15, 2025, and $400,000 per calendar day until the Work is accepted as complete. There shall be an overall sub-cap on this liability equal to ten percent (10%) of the Contract Price. If Substantial Completion has not been achieved by February 14, 2025, then on February 15, 2025, Contractor shall pay the remainder of such maximum liquidated damages applicable to TCS.

8. Revised Schedule. The Guaranteed Substantial Completion Date for SBLS shall be December 30, 2024, and the Guaranteed Substantial Completion Date for the TCS will now be December 16, 2024.

9. Waiver. Upon execution of this Amendment No. 2 and approval of the Bankruptcy Court, all OPPD's current and future Owner Furnished Equipment (OFE) backcharges will be waived and dismissed and all of Contractor's current and future Potential Change Notices (PCN's) will be waived and dismissed.

10. Assumption. Contractor shall seek Court approval to assume the Agreement (as amended by this Amendment) pursuant to Section 365 of the Bankruptcy Code. The Parties agree that all requirements for assumption of this Agreement (as amended by this Amendment) under section 365(b)(1) of the Bankruptcy Code shall be satisfied upon the Parties' entry into this Amendment No. 2. Contractor acknowledges and agrees that it shall continue to perform all obligations under the EPC Contract (as amended by Amendment No. 1 and Amendment No. 2), including achieving Substantial Completion of the SBLS and the TCS as specified in Section 8 of this Amendment No. 2.

11. Bankruptcy Court Approval and Effectiveness. This Amendment No. 2 shall be effective only upon entry of an order by the Bankruptcy Court of the Southern District of Texas approving Contractor's assumption of the EPC Contract (as amended) pursuant to section 365 of the Bankruptcy Code. Upon entry of such order by the Bankruptcy Court of the Southern District of Texas, Sections 6 and 7 of this Amendment shall take effect retroactively to the date of execution of this Amendment.

12. Effect of Amendment. Except as provided in Amendment No. 1 and this Amendment No. 2, all other terms and conditions of the EPC Contract shall remain the same and in full force and effect.

13. Counterparts. This Amendment may be executed and delivered by facsimile or other electronic means and upon such delivery the facsimile or electronic signature will be deemed to have the same effect as if the original signature had been delivered to the other Party. This Amendment may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument.

[*Signature Page to Follow*]

IN WITNESS WHEREOF, the Parties have caused this Amendment to be executed by their duly authorized representatives as of the date set forth above.

OMAHA PUBLIC POWER DISTRICT

By: _____

Title: _____

Date: _____

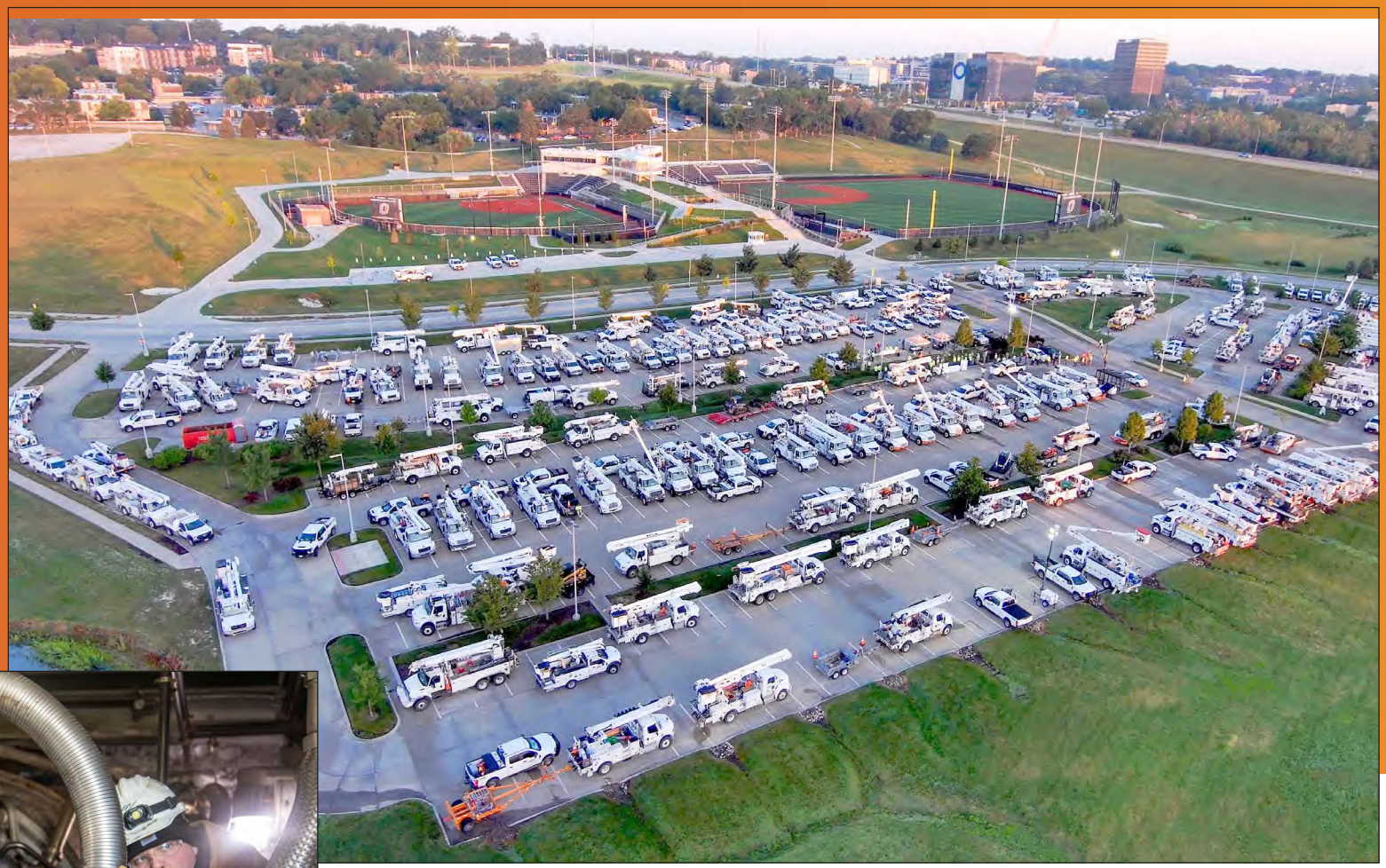
ZACHRY INDUSTRIAL, INC.

By: _____

Title: President, EPC

Date: 8/14/2024

2025 CORPORATE OPERATING PLAN





EXHIBIT

F

Omaha Public Power District

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MANAGEMENT LETTER

Management Letter



Every day in 2024, Omaha Public Power District (OPPD) worked tirelessly to overcome challenges and prepare for a bright future.

We diversified our portfolio with energy sources that will enhance our reliability during extreme weather, reduce our carbon output and help us meet fast-growing customer demand for electricity.

We're forging ahead with plans for advanced metering infrastructure (AMI) technology, which will help us assess and restore outages with greater speed and precision.

We also powered through major challenges this year, including extreme cold and low river levels in January that affected generation plants on the Missouri River, an April tornado that devastated Elkhorn and Bennington, major flooding near our Fort Calhoun Station site and a July 31 storm with hurricane-force winds that caused the biggest outage in OPPD history.

Above all, our public power mission kept us focused on reliability, affordability and environmental sustainability. Our locally elected Board of Directors continued to guide us with forward-looking directives to serve the community.

Our 2025 Corporate Operating Plan recommends a 6.3% rate increase, composed of a 4.9% average general rate increase and a 1.4% increase from the Fuel and Purchased Power Adjustment (FPPA) factor and replenishment of the Rate Stabilization Account (RSA). The general rate increase is driven by rising net power costs from increasing load and a growing capital portfolio, leading to additional debt issuances. The FPPA and RSA impact is driven by outages and storm restoration costs. FPPA is the mechanism OPPD uses to collect price fluctuations from year to year.

For context, OPPD's rates are still far lower, on average, than other utilities. Residential rates are 25.2% below the national average, according to the U.S. Energy Information Administration's final 2023 report, the most recent data available.

As the energy landscape changes, OPPD is working on multiple fronts to adapt and thrive – and our future is bright.



L. Javier Fernandez
President and Chief Executive Officer



STRATEGIC PLANNING AND ENTERPRISE RISK



Strategic Direction

To provide clear and transparent direction on behalf of OPPD's customer owners OPPD's publicly elected Board of Directors established fifteen strategic direction (SD) policies in 2015 to which OPPD is accountable. The policies guide OPPD's planning efforts to address current and future trends, mitigate risks, pursue strategic opportunities, and prioritize resources to efficiently and effectively provide energy services to our customer owners. The SD policies leverage industry benchmarks to drive performance as a top utility and provide the basis for a scorecard to which the organization manages its performance. The Board monitors OPPD's compliance with these policies and updates the policies, when determined appropriate, to clarify strategic direction.

Our Strategic Foundation (SD-1)

Mission: To provide affordable, reliable and environmentally sensitive energy services to our customers.

Vision: "Leading the Way We Power the Future"

In implementing this vision, OPPD shall adhere to these principles:

- Strengthen the public power advantage of affordable and reliable electricity;
- Exemplify fiscal, social and environmental responsibility to optimize value to our customer-owners;
- Proactively engage and communicate with our stakeholders;
- Act transparently and with accountability for the best interest of our customer-owners;
- Collaborate, when appropriate, with partners; and
- Leverage OPPD's leadership to achieve these goals

Core Values

- We have a PASSION to serve
- We HONOR our community
- We CARE about each other

Board Strategic Direction Policies & Strategic Goals

Policy	Measure	Definition	Strategic Goal
Rates (SD-2)	% Below Regional Retail Average	Retail rate target of North Central Regional average published rates on a system average basis.	10%
Access to Credit Markets (SD-3)	Debt Coverage Ratio	Revenues less expenses divided by total annual senior and subordinate lien debt interest and principal payments.	2.0
Reliability (SD-4)	SAIDI	System Average Interruption Duration Index	< 90 mins
	SAIFI	System Average interruption Frequency Index	< 0.9 incidents
	EFOR	Equivalent Forced Outage Rate	< or = 8.0%
Customer Satisfaction (SD-5)	Absolute Satisfaction Score	Customer satisfaction for similar-sized utilities in the region across residential and business customers.	Top quartile
Safety (SD-6)	DART	Days Away, Restricted or Transferred	< or = 0.50
	PVIR	Preventable Vehicle Incident Rate	< or = 4.00
Environmental Stewardship (SD-7)	% Net reduction in CO2e	Strive to achieve net zero carbon equivalent (CO2e) emissions by 2050 relative to OPPD's 2013 benchmark with the following interim targets, 2027-41-51% net reduction. Future interim targets to be informed by and determined following the completion of the 2026 integrated resource plan.	Achieve net zero CO2e by 2050
Employee Relations (SD-8)	Employee Engagement	Composite score of employee engagement	Top quartile

For a full listing of the 15 Strategic Directives, which includes Integrated System Planning (SD-9), Ethics (SD-10), Economic Development (SD-11), Information Management & Security (SD-12), Stakeholder Outreach & Engagement (SD-13), Retirement Plan Funding (SD-14), Enterprise Risk Management (SD-15), please access the following link to the OPPD Board Policy document https://www.oppd.com/media/317205/oppd-board-policy-binder.pdf

Powering the Future to 2050



At OPPD, we've imagined the future. Powering the Future to 2050 (PF2050) is a strategic vision to make OPPD cleaner, more sustainable, and more innovative than you can believe. While others have been wondering about what's next, we've been hard at work, nights and weekends, planning out what the future of power looks like and how to bring it to life. The vision is clear – **Perfect Power**, **Customer Freedom**, and a **Cleaner World** enabled through a **Digitally Driven**, **Purpose-Driven Culture**, and **Future-Ready Posture** mindset.

In November of 2019, the Board of Directors revised SD-7 (Environmental Stewardship) and established the goal to conduct all operations in a manner that strives for the goal of net-zero-carbon production by 2050. In consideration of this revision, other SD policies, and transformational changes within and outside the industry, the Executive Leadership Team (ELT) created PF2050, which provides a strategic vision for the organization through the year 2050. PF2050 outlines a transformational journey and was developed with the expressed intent to meet or exceed the fifteen SD policies. This vision will transform OPPD to a digital utility with two-way and multi-directional power and communication flows, build a proactive grid, give customer-owners multiple options, minimize environmental impact, and reduce carbon emissions. The future is coming, and we want to make sure it is illuminated.

Acknowledging the rapidly evolving and increasingly complex environment we operate in, OPPD adopted a future-ready posture mindset. This means we are taking a thoughtful approach to investing in both core work ('keeping the lights on today') and in the efforts to power our next generation. This deliberate and agile approach resulted in the establishment of the enterprise-level resourcing priorities. These enterprise priorities are aligned under PF2050 and influence the current year's budget. The process ensures OPPD's finite resources are being used to facilitate the right work to get us closer to our objectives of Perfect Power, Customer Freedom, and a Cleaner World by 2050.

The 2025-2030 enterprise priorities (listed in priority order below) were established to provide this life essential energy service to our customer-owners and employees. Their requirements and aspirational futures are woven into the very DNA of these priorities and are the underpinnings of everything we do.

1. Resource Adequacy
2. Technology Transformation
3. Next Generation Grid
4. Master Facilities Plan

Powering the Future to 2050

OPPD leveraged PF2050 and the enterprise priorities to guide planning, prioritization, and resourcing decisions for this Corporate Operating Plan. The vision to meet the growing demands of the service territory is becoming a reality as we transition from strategic planning to resourcing the execution in service of our customer-owner requirements in 2030 and beyond. We will continue to build upon our resource prioritization & capacity management framework and strategic STEER trends and risk scanning capabilities that will result in new and better ways to deliver affordable, reliable, and environmentally sensitive energy services to our customers. Additional information regarding PF2050 can be found on https://www.oppdcommunityconnect.com/pf2050.







Enterprise Risk Management (SD-15)

Fundamental to effective planning is an understanding of the District's enterprise level risks and the development and implementation of initiatives and mitigation plans to respond to those risks. The District's Enterprise Risk Management (ERM) program specifies risk management standards, management responsibilities, and controls to help ensure risk exposures are properly identified and managed within agreed upon risk tolerance levels. Specific risk mitigation plans and procedures are maintained and reviewed periodically to provide focused and consistent efforts to mitigate various risk exposures. An increased focus on emerging risks, such as disruptive technology, was launched in 2023. This process will continue to strengthen executive leadership's understanding of these risks to ensure an optimal future-ready posture for the organization. In support of its 2025 corporate planning efforts, OPPD leveraged risk assessments and mitigation plans to help prioritize resource allocation. The ELT will continue to expand this effort by incorporating those critical trends identified and associated with PF 2050.

Theme	OPPD's Risk Management Focus
Retail Revenues & Wholesale Revenues	Persistently pursue customer and economic development to achieve economies of scale and strengthen the affordability of our rates. Optimize wholesale revenues and purchases to further benefit our customer-owners.
Resource Adequacy and Reliability	Acquire and maintain a high availability and diverse generation portfolio to serve a significantly growing customer demand.
Environmental Sensitivity	Ensure the District is compliant with all environmental regulations, well-positioned to respond to new regulations, and able to minimize our environmental impact.
Fuel Costs	Effectively manage the District's fuel portfolio through numerous mitigation strategies to continue to ensure low cost and resilient generation.
AMI & Tech Transformation Execution	Deliver world-class execution of priority initiatives that will create a future-ready posture to deliver increased value to our customer-owners.
Cyber & Physical Security	Vigorously defend customer information and District assets from all potential cyber and physical security threats inherent with national critical infrastructure.
Infrastructure Investment	Optimally invest in transmission, distribution, substation, facility, and technology assets to ensure reliable and resilient energy services and supporting functions will meet the demands of our customer-owners.
Workplace Safety	Continue promoting safety as a top priority to ensure every employee and contractor goes home as healthy as they came into work.
Community Partnership	Honor and support the communities in which we operate and fulfill the promise of public power.



ASSUMPTIONS

Assumptions

2025 Proposed Rate Action

Effective January 1, 2025, OPPD's 2025 Corporate Operating Plan assumes an average total rate increase of 6.3% across all customer classes, composed of a 4.9% average general rate increase and a 1.4% increase from the FPPA factor and replenishment of the RSA. The general rate increase is largely driven by rising net power costs and a growing capital portfolio which leads to additional debt issuances. The FPPA and replenishment of the RSA is driven by outages and storm restoration costs.

General

2024 Projected

Revenues, operations and maintenance (O&M), capital and deferred expenditures reflect the 2024 actual values and forecast submitted through September 30, 2024.

Financing/Investing

Financing

Revenue bonds with net proceeds of $460.0 million are included in the 2025 budget. The proceeds of these bonds are expected to be used for capital expenditures.

Average Earnings Rates on Funds

The average earnings rate used for all funds (including special purpose) for 2025 is 3.6% which is a decrease of 0.5% from the prior year's rate of 4.1%.

Energy Sales/Revenues

Load Forecast

The plan assumes a 12.5% increase in retail energy sales (MWh) and a 2.1% increase in the number of customers in 2025, as compared to the 2024 budget.

Assumptions

Generation and Purchased Power

Outages have been scheduled for the following base-load units in 2025:

1. Nebraska City Station Unit Number 2
2. North Omaha Station Units 4 & 5

Additionally, there are several shorter outages scheduled for other units. The purchased power budget includes generation supplied from 1,272 megawatts of wind capability, 80 megawatts of hydropower from the Western Area Power Administration, as well as 86 megawatts of solar capability.

Department Operations and Maintenance Budget

Department and division level budgets were proposed, and these plans were reviewed with the ELT for alignment with the strategic and operational objectives before submitting them in the 2025 Corporate Operating Plan for Board final approval.

Capital Budget Expenditures

The capital portfolio prioritization and allocation process continues to improve capital planning. The process enables better alignment with the strategic directives and provides more transparency of capital spending through improved project review and approval processes. The size of the capital budget continues to grow as the District undergoes system expansion to provide reliable electric service to a growing community.

Total 2025 Budget

The total 2025 Budget is $2.3 billion.

BUDGET SUMMARY
(DOLLARS IN THOUSANDS)

Total Budget

	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Capital Expenditures*	$ 727,000	$ 788,000	$ 61,000	8.4
Non-Fuel Operations & Maintenance	528,335	582,729	54,394	10.3
Fuel and Purchased Power	492,691	567,138	74,447	15.1
Total Debt Service and Other Expenses	189,242	216,317	27,075	14.3
Decommissioning Expenditures**	112,918	102,596	(10,322)	(9.1)
Payments in Lieu of Taxes	45,599	53,532	7,933	17.4
Reserves	11,939	13,269	1,330	11.1
TOTAL BUDGET	**$ 2,107,724**	**$ 2,323,581**	**$ 215,857**	**10.2**

*Capital Expenditures are shown net of Contributions in Aid of Construction

**Decommissioning Expenditures represent expenditures related to Decommissioning activity, which differs from Decommissioning Funding ($10.7 million) which is an expense and is reflected on the income statement.

Budget Component Comparison

	BUDGET 2024	BUDGET 2025	CHANGE
Capital Expenditures*	34.5%	33.9%	(0.6)
Non-Fuel Operations & Maintenance	25.1%	25.1%	0.0
Fuel and Purchased Power	23.4%	24.4%	1.0
Total Debt Service and Other Expenses	9.0%	9.3%	0.3
Decommissioning Expenditures**	5.4%	4.4%	(1.0)
Payments in Lieu of Taxes	2.2%	2.3%	0.1
Reserves	0.6%	0.6%	0.0
TOTAL BUDGET	**100.0%**	**100.0%**	**-**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

FINANCIAL STATEMENTS



Financial Statements

Income Statement

The District uses a 2.0 debt service coverage ratio as the basis of annual budgets, which is based on SD-3 Access to Credit Markets. It should be noted that OPPD does not set budgets or other forward-looking plans on the basis of net income. Net income for 2025 is budgeted to be $203.1 million, which is $41.7 million or 25.9% higher than the 2024 budget.

Major Factors Contributing to the Change in Budgeted Operating and Net Income:

Operating revenues are $1,671.2 million, which is $238.8 million or 16.7% higher than the 2024 budget. As the District anticipates load growth across all customer classes, retail revenues are expected to increase $208.7 million or 17.0% from the 2024 budget. The increase in operating revenue was also impacted by higher wholesale revenue of $25.6 million or 15.6%. The wholesale revenue increase is largely driven by higher congestion hedging revenue. The 2024 budget took a very conservative approach to congestion hedging revenues, leading to an increase in 2025 to more closely reflect actual performance.

Operations and maintenance expenses are $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget. Fuel and purchased power account for an increase of $74.4 million, or 15.1%, when compared to 2024 budget. Other O&M increases are driven by costs and headcount growth associated with the District's strategic priorities as well as additional investment in vegetation management.

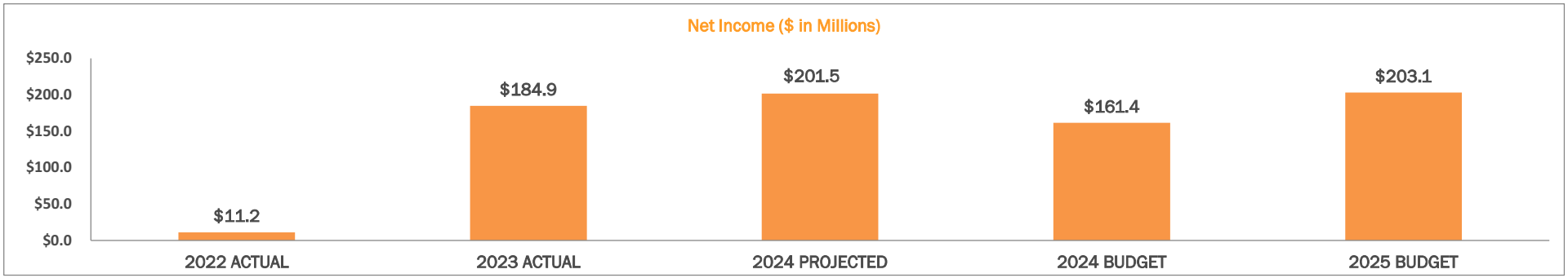
Other income is $88.8 million, which is $2.8 million or 3.2% higher than the 2024 budget amount due to largely offsetting impacts. Allowance for funds used during construction (AFUDC) is budgeted to increase by $13.1 million due to a growing capital portfolio, offset by decreased interest income of $11.9 million due to a lower earnings rate for funds on deposit.

Interest expense is $174.3 million in 2025 which is $22.6 million or 14.9% higher than the 2024 budget due to additional planned debt issuances required to execute a large capital portfolio.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

INCOME STATEMENT
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
OPERATING REVENUES	$ 1,400,784	$ 1,428,905	$ 1,516,446	$ 1,432,358	$ 84,088	$ 1,671,191	$ 238,833	16.7
OPERATING EXPENSES								
O&M EXPENSE	962,458	1,036,164	1,090,192	1,021,028	69,163	1,149,867	128,839	12.6
DEPRECIATION EXPENSE	150,074	124,980	143,871	138,448	5,423	183,433	44,985	32.5
PAYMENTS IN LIEU OF TAXES	40,462	42,498	45,827	45,599	228	53,532	7,934	17.4
DECOMMISSIONING EXPENSE	141,918	33,320	16,148	15,298	850	10,694	(4,604)	(30.1)
REGULATORY AMORTIZATION	14,835	13,600	-	-	-	-	-	-
TOTAL OPERATING EXPENSE	**$ 1,309,747**	**$ 1,250,562**	**$ 1,296,037**	**$ 1,220,373**	**$ 75,664**	**$ 1,397,526**	**$ 177,154**	**14.5**
OPERATING INCOME	**$ 91,037**	**$ 178,343**	**$ 220,409**	**$ 211,985**	**$ 8,423**	**$ 273,665**	**$ 61,680**	**29.1**
INTEREST INCOME	20,481	35,412	61,646	54,211	7,434	42,355	(11,856)	(21.9)
ALLOWANCE FOR FUNDS USED	16,427	33,079	39,504	26,332	13,173	39,481	13,149	49.9
PRODUCTS AND SERVICES - NET	2,868	2,092	1,772	2,484	(712)	3,952	1,469	59.1
MISC. NON OPERATING INCOME	25,917	4,718	1,008	3,000	(1,992)	3,000	-	-
MARK TO MARKET	(60,693)	38,747	11,204	-	11,204	-	-	-
TOTAL OTHER INCOME	**$ 5,000**	**$ 114,048**	**$ 115,134**	**$ 86,027**	**$ 29,108**	**$ 88,788**	**$ 2,761**	**3.2**
TOTAL INCOME LESS OPERATING EXPENSE	**$ 96,037**	**$ 292,391**	**$ 335,543**	**$ 298,012**	**$ 37,531**	**$ 362,453**	**$ 64,441**	**21.6**
INCOME DEDUCT. & INT. CHARGES								
INTEREST EXPENSE	97,739	120,168	147,203	151,720	(4,517)	174,319	22,599	14.9
OTHER INCOME DEDUCTIONS	1,787	3,091	3,917	1,205	2,712	1,205	-	-
AMORTIZATION	(14,694)	(15,767)	(17,030)	(16,271)	(759)	(16,157)	114	(0.7)
TOTAL INCOME DEDUCT. & INT. CHARGES	**$ 84,832**	**$ 107,491**	**$ 134,090**	**$ 136,654**	**$ (2,564)**	**$ 159,367**	**$ 22,713**	**16.6**
NET INCOME	**$ 11,205**	**$ 184,900**	**$ 201,453**	**$ 161,358**	**$ 40,095**	**$ 203,086**	**$ 41,728**	**25.9**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Financial Statements

Coverage Ratios

The Total Debt Service Coverage ratio, which is the key metric viewed by credit rating agencies, is budgeted to be 2.00 times in 2025, as directed by SD-3 Access to Credit Markets.

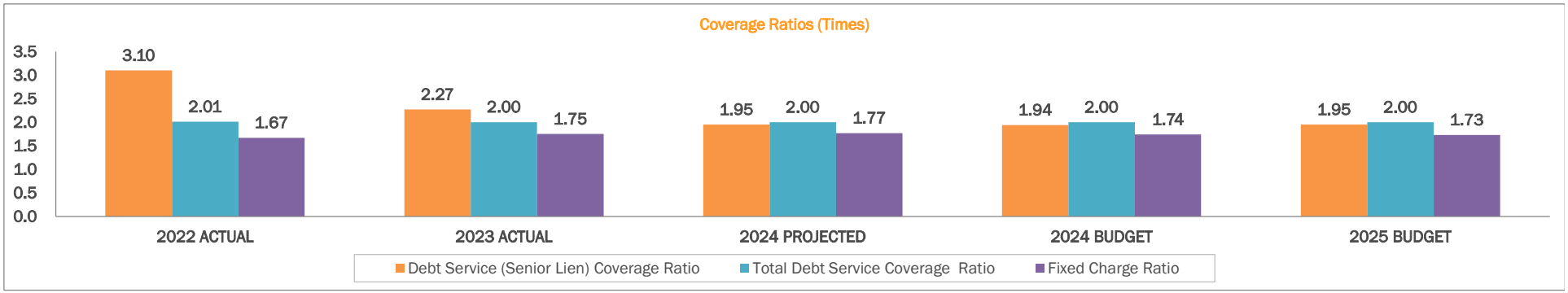
The Fixed Charge ratio is budgeted at 1.73 times in 2025, as compared to the budgeted 2024 value of 1.74 times.

The Senior Lien Debt Service Coverage ratio is budgeted to slightly increase to 1.95 compared to the 2024 metric of 1.94 times as increases in net receipts are offset by additional debt service requirements from additional borrowings. The additional debt issuances for senior lien revenue bonds are expected to be used to support a growing capital portfolio. Senior lien debt service requirements are expected to increase by $36.2 million or 19.6% from the 2024 budget amount.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

COVERAGE RATIOS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
OPERATING REVENUES (EXCL. NC2)	$ 1,331,698	$ 1,354,221	$ 1,448,671	$ 1,368,804	$ 79,867	$ 1,600,681	$ 231,877	16.9
INTEREST INCOME - BONDS RESERVE ACCOUNT	1,357	3,229	5,354	3,491	1,863	4,383	892	25.6
PAYMENTS IN LIEU OF TAXES	(40,462)	(42,498)	(45,827)	(45,599)	(228)	(53,532)	(7,934)	17.4
O&M EXPENSE (EXCL. NC2 PARTICIPANT SHARE)	(930,054)	(1,000,481)	(1,055,662)	(966,215)	(89,447)	(1,118,677)	(152,462)	15.8
NET RECEIPTS	**$ 362,539**	**$ 314,471**	**$ 352,536**	**$ 360,481**	**$ (7,945)**	**$ 432,854**	**$ 72,373**	**20.1**
TOTAL DEBT SERVICE COVERAGE RATIO (DSC)	**2.01**	**2.00**	**2.00**	**2.00**	**-**	**2.00**	**$0**	**-**
DEBT SERVICE REQUIREMENTS (SENIOR LIEN)	$ 116,947	$ 138,251	$ 180,755	$ 185,183	$ (4,428)	$ 221,392	$36,209	19.6
DEBT SERVICE (SENIOR LIEN) COVERAGE RATIO	3.10	2.27	1.95	1.94		1.95		
FIXED CHARGE RATIO	1.67	1.75	1.77	1.74		1.73		



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding. Total DSC as defined in OPPD's published Strategic Directive-3: Access to Credit Markets.

Financial Statements

Debt and Financing Data

Total senior lien revenue bonds outstanding at year-end 2025 are budgeted to equal $3,480 million. The 2025 budget anticipates the issuance of approximately $460.0 million of new senior lien revenue bonds and also includes senior lien revenue bond maturities and retirements of $52.5 million.

The 2025 budget does not anticipate the issuance of new subordinated bonds as all will mature or be retired during 2024.

Total commercial paper outstanding at year-end 2025 is budgeted to remain at the 2024 level of $250.0 million. The 2025 budget does anticipate the net impact of both an issuance and retirement of $100.0 million in new commercial paper.

Total separate system (Nebraska City Unit 2 (NC2)) revenue bonds outstanding at year-end 2025 are budgeted to equal $185.1 million. The 2025 budget does not anticipate the issuance of new NC2 revenue bonds but does have NC2 revenue bond maturities and retirements of $4.4 million.

The total average interest rate on existing debt is budgeted at 4.45% at the end of 2025 and the debt to capitalization ratio is budgeted to be 65.6% for 2025.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

DEBT AND FINANCING DATA
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
SENIOR LIEN REVENUE BONDS								
BALANCE - BEGINNING OF YEAR	$ 1,524,630	$ 1,935,320	$ 2,439,775	$ 2,439,775	$ -	$ 3,072,490	$ 632,715	25.9
NEW ISSUES	420,565	549,760	906,755	448,657	458,098	460,000	11,343	2.5
MATURITIES / RETIREMENTS	(9,875)	(45,305)	(274,040)	(45,895)	(228,145)	(52,535)	(6,640)	14.5
BALANCE - END OF YEAR	**$ 1,935,320**	**$ 2,439,775**	**$ 3,072,490**	**$ 2,842,537**	**$ 229,953**	**$ 3,479,955**	**$ 637,418**	**22.4**
AVERAGE INTEREST RATE (END OF YEAR)	3.85%	3.79%	4.13%	4.47%		4.44%		
SUBORDINATED								
BALANCE - BEGINNING OF YEAR	229,775	227,225	134,745	134,745	-	-	(134,745)	(100.0)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(2,550)	(92,480)	(134,745)	(2,560)	(132,185)	-	2,560	(100.0)
BALANCE - END OF YEAR	**$ 227,225**	**$ 134,745**	**$ -**	**$ 132,185**	**$ (132,185)**	**$ -**	**$ (132,185)**	**(100.0)**
AVERAGE INTEREST RATE (END OF YEAR)	4.23%	6.54%		4.01%				
COMMERCIAL PAPER								
BALANCE - BEGINNING OF YEAR	325,000	250,000	250,000	250,000	-	250,000	-	-
NEW ISSUES	-	100,000	100,000	-	100,000	100,000	100,000	-
MATURITIES / RETIREMENTS	(75,000)	(100,000)	(100,000)	-	(100,000)	(100,000)	(100,000)	-
BALANCE - END OF YEAR	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ -**	**$ 250,000**	**$ -**	**-**
AVERAGE INTEREST RATE (END OF YEAR)	1.50%	3.72%	4.00%	4.00%		4.27%		
SEPARATE SYSTEM REVENUE BONDS (NC2)								
BALANCE - BEGINNING OF YEAR	201,495	197,680	193,680	193,680	-	189,480	(4,200)	(2.2)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(3,815)	(4,000)	(4,200)	(4,200)	-	(4,415)	(215)	5.1
BALANCE - END OF YEAR	**$ 197,680**	**$ 193,680**	**$ 189,480**	**$ 189,480**	**$ -**	**$ 185,065**	**$ (4,415)**	**(2.3)**
AVERAGE INTEREST RATE (END OF YEAR)	4.95%	4.95%	4.95%	4.95%		4.95%		
TOTAL AVERAGE INTEREST RATE (END OF YEAR)	**3.74%**	**3.98%**	**4.32%**	**4.44%**		**4.45%**		
TOTAL INTEREST EXPENSE (ON DEBT)	**$ 84,832**	**$ 107,491**	**$ 134,090**	**$ 136,654**	**$ (2,564)**	**$ 159,367**	**$ 25,277**	**18.9**
DEBT TO CAPITALIZATION RATIO	**64.00%**	**64.00%**	**65.60%**	**66.00%**		**65.60%**		

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Financial Statements

Cash Flow Analysis

2025 Budget Compared to 2024 Budget

Cash Receipts

2025 cash receipts are budgeted to increase by $221.5 million to $1,714.3 million, a 14.8% change. This increase is primarily due to increased retail revenue from projected load growth and the general rate increase to customers.

Cash Disbursements

2025 cash disbursements are budgeted to increase by $221.5 million to $2,251.4 million, a 10.9% shift. Increases in cash disbursements relate to capital expenditures from a growing capital portfolio that also impacts increased debt service to support the capital portfolio. In addition, purchased power is expected to increase by $66.6 million due to higher purchase volumes to support customer load growth.

The budgeted values of cash receipts and disbursements result in a year-end cash balance of $688.3 million in 2025, a 30.1% or $159.4 million increase over 2024 budget.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

CASH FLOW ANALYSIS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
CASH BEGINNING OF PERIOD	$ 636,681	$ 667,880	$ 693,066	$ 642,041	$ 51,025	$ 765,405	$ 123,364	19.2
RECEIPTS								
RETAIL REVENUES	1,126,285	1,109,853	1,266,898	1,222,054	44,844	1,423,890	201,836	16.5
WHOLESALE REVENUES (INCL. NC2)	248,490	239,797	229,419	168,881	60,538	194,677	25,796	15.3
INTEREST INCOME	50,004	53,081	59,235	57,211	2,024	45,034	(12,177)	(21.3)
OTHER ELECTRIC REVENUES	42,940	46,205	46,437	42,234	4,203	46,776	4,542	10.8
PRODUCTS & SERVICES	2,086	2,978	2,696	2,484	212	3,953	1,469	59.1
USE OF RESERVE ACCOUNTS	-	-	13,269	-	13,269	-	-	-
TOTAL RECEIPTS	**$ 1,469,805**	**$ 1,451,914**	**$ 1,617,954**	**$ 1,492,864**	**$ 125,090**	**$ 1,714,329**	**$ 221,465**	**14.8**
DISBURSEMENTS								
CAPITAL EXPENDITURES	551,032	574,608	762,355	727,000	35,355	788,000	61,000	8.4
O&M EXPENSE (W/O FUEL & PURCHASED POWER)	409,119	497,369	523,309	540,396	(17,087)	581,882	41,486	7.7
PURCHASED POWER	357,276	337,969	406,935	310,416	96,519	377,052	66,636	21.5
DEBT SERVICE	146,457	272,569	209,453	215,568	(6,115)	244,632	29,064	13.5
FUEL	188,414	157,894	147,135	178,358	(31,223)	187,841	9,483	5.3
PAYMENTS IN LIEU OF TAXES	38,605	40,494	42,281	42,882	(601)	48,044	5,162	12.0
CONTRIBUTIONS TO RESERVE ACCOUNTS	-	-	-	-	-	13,269	13,269	-
DECOMMISSIONING EXPENSE	141,918	33,320	16,303	15,298	1,005	10,694	(4,604)	(30.1)
CHANGES IN OTHER NET ASSETS	(17,420)	(36,663)	40	-	40	-	-	-
TOTAL DISBURSEMENTS	**$ 1,815,401**	**$ 1,877,560**	**$ 2,107,810**	**$ 2,029,918**	**$ 77,892**	**$ 2,251,415**	**$ 221,497**	**10.9**
NET OPERATING CASH FLOW	**$ (345,596)**	**$ (425,646)**	**$ (489,856)**	**$ (537,054)**	**$ 47,198**	**$ (537,086)**	**$ (32)**	**0.0**
FINANCING	474,385	477,870	968,651	448,657	519,994	483,000	34,343	7.7
FINANCING COST / RESERVE AMOUNT	(22,590)	(27,038)	(46,126)	(24,676)	(21,450)	(23,000)	1,676	(6.8)
COMMERCIAL PAPER - NET	(75,000)	-	-	-	-	-	-	-
OTHER	-	-	(360,330)	-	(360,330)	-	-	-
TOTAL FINANCING	**$ 376,795**	**$ 450,832**	**$ 562,195**	**$ 423,981**	**$ 138,214**	**$ 460,000**	**$ 36,019**	**8.5**
TOTAL CHANGE IN CASH	31,199	25,186	72,339	(113,073)	185,412	(77,086)	35,987	(31.8)
CASH END OF PERIOD	**$667,880**	**$693,066**	**$765,405**	**$528,968**	**$236,437**	**$688,319**	**$159,351**	**30.1**
DECOMMISSIONING FUND	**$534,901**	**$479,964**	**$406,731**	**$346,768**	**$59,963**	**$288,684**	**($58,084)**	**(16.8)**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.


ENERGY SALES

Energy Sales

Electric Energy Sales & Electric Customers

Total electric energy sales are budgeted to be 18,878,664 MWh, which is 8.5% or 1,479,981 MWh more than the 2024 budget. Retail energy sales are budgeted to be 15,355,048 MWh, or 12.5%, greater when compared to 2024 budget. This increase is driven by load growth across all customer classes. Wholesale energy sales (including NC2 participation sales) are budgeted to decrease by 226,624 MWh or 6.0% from 2024 budget as volumes are expected to decrease due to load growth consuming owned generation and leaving less energy available to sell into the marketplace.

In 2025, the average number of retail customers is budgeted to increase by 8,762, a 2.1% increase from 2024 budget.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

ELECTRIC ENERGY SALES AND CUSTOMERS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET. MWh CHANGE	% CHANGE
ELECTRIC ENERGY SALES (MWh)								
RESIDENTIAL	3,937,046	3,947,870	3,857,951	3,995,295	(137,344)	4,044,941	49,646	1.2
COMMERCIAL	3,763,330	3,796,608	3,800,810	3,891,422	(90,613)	3,927,174	35,752	0.9
INDUSTRIAL	4,293,784	4,683,632	5,812,465	5,703,474	108,990	7,318,775	1,615,301	28.3
UNBILLED SALES	111,815	(56,155)	83,552	58,252	25,301	64,158	5,906	10.1
RETAIL ENERGY SALES	**12,105,976**	**12,371,955**	**13,554,778**	**13,648,443**	**(93,666)**	**15,355,048**	**1,706,604**	**12.5**
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
TOTAL MWh SALES	**16,516,668**	**15,697,593**	**17,120,459**	**17,398,684**	**(278,224)**	**18,878,664**	**1,479,981**	**8.5**
ELECTRIC CUSTOMERS (12 MONTH AVG.)								
RESIDENTIAL	351,712	357,528	363,042	361,464	1,578	369,548	8,084	2.2
COMMERCIAL	49,550	49,782	50,320	49,987	333	50,665	678	1.4
INDUSTRIAL	135	133	135	149	(14)	149	-	-
TOTAL RETAIL CUSTOMERS	**401,397**	**407,443**	**413,497**	**411,600**	**1,897**	**420,362**	**8,762**	**2.1**
kWh / CUSTOMER								
RESIDENTIAL	11,194	11,042	10,627	11,053	(426)	10,946	(107)	(1.0)
COMMERCIAL	75,950	76,265	75,533	77,849	(2,316)	77,513	(336)	(0.4)
INDUSTRIAL	31,805,809	35,215,275	43,055,293	38,278,351	4,776,942	49,119,296	10,840,944	28.3
AVERAGE kWh / CUSTOMER	**29,881**	**30,503**	**32,579**	**33,018**	**(439)**	**36,376**	**3,358**	**10.2**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Energy Sales

Operating Revenues

Total electric operating revenues for 2025 are budgeted to be $1,671.2 million, which is $238.8 million or 16.7% above the 2024 budgeted operating revenues. Retail revenues are $208.7 million or 17.0% greater than 2024 budget due to load growth across all customer classes. Wholesale revenues are $25.6 million or 15.6% higher when compared to the 2024 budget primarily due to increased congestion hedging revenue.

OPERATING REVENUES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
ELECTRIC OPERATING REVENUES								
RESIDENTIAL	$ 460,848	$ 472,633	$ 479,045	$ 490,025	$ (10,980)	$ 539,712	$ 49,687	10.1
COMMERCIAL	336,360	350,956	371,319	378,580	(7,261)	402,565	23,985	6.3
INDUSTRIAL	291,343	317,828	378,704	363,789	14,915	504,432	140,642	38.7
UNBILLED REVENUES/ADJUSTMENTS	10,556	(2,354)	4,267	5,185	(918)	5,677	492	9.5
FPPA RECEIVABLE AMORTIZATION	7,400	(7,400)	4,766	-	4,766	(4,766)	(4,766)	-
USE OF (CONTRIBUTION TO) RESERVE	(6,000)	7,000	13,269	(11,939)	25,208	(13,269)	(1,330)	11.1
TOTAL RETAIL SALES	**$ 1,100,507**	**$ 1,138,663**	**$ 1,251,370**	**$ 1,225,640**	**$ 25,730**	**$ 1,434,351**	**$ 208,711**	**17.0**
NC2 PARTICIPANTS	69,086	74,684	67,775	63,554	4,221	70,511	6,956	10.9
OTHER	187,392	168,896	150,753	100,930	49,823	119,554	18,624	18.5
TOTAL WHOLESALE REVENUES	**$ 256,478**	**$ 243,580**	**$ 218,528**	**$ 164,484**	**$ 54,044**	**$ 190,065**	**$ 25,580**	**15.6**
TOTAL SALES OF ELECTRIC ENERGY	**$ 1,356,985**	**$ 1,382,243**	**$ 1,469,899**	**$ 1,390,125**	**$ 79,774**	**$ 1,624,416**	**$ 234,291**	**16.9**
OTHER ELECTRIC REVENUES	43,799	46,662	46,547	42,233	4,314	46,776	4,542	10.8
TOTAL ELECTRIC OPERATING REVENUES	**$1,400,784**	**$1,428,905**	**$1,516,446**	**$1,432,358**	**$84,088**	**$1,671,191**	**$238,833**	**16.7**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

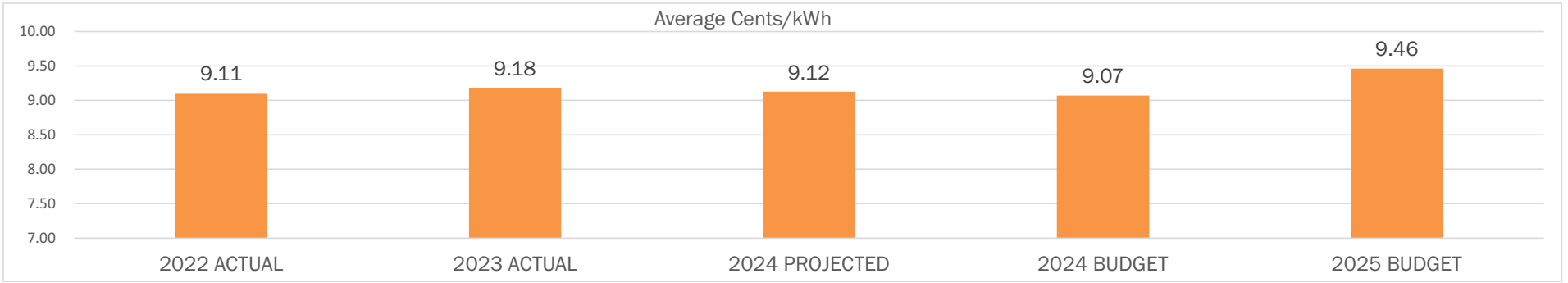
Energy Sales

Average Cents/kWh

The 2025 average price per kWh for retail customers is budgeted to be 9.46 cents. This is 0.39 cents, or a 4.3% increase, from the 2024 budget. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used as a baseline to determine the appropriate rate increase for each class. Individual customer impacts will vary based on their specific rate class and usage patterns.

AVERAGE CENTS/kWh

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
RESIDENTIAL	11.73	11.97	12.42	12.27	0.15	13.34	1.07	8.7
COMMERCIAL	8.95	9.24	9.77	9.73	0.04	10.25	0.52	5.4
INDUSTRIAL	6.88	6.79	6.52	6.38	0.14	6.89	0.51	8.0
RETAIL AVERAGE *	**9.11**	**9.18**	**9.12**	**9.07**	**0.06**	**9.46**	**0.39**	**4.3**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.
* Average rates are from the revenue recognized on the Income Statement and do not incorporate accrued unbilled. These rates differ from customer billed rates and are calculated for benchmarking and illustrative purposes only.



NET SYSTEM REQUIREMENTS

Net System Requirements

Net system requirements (total retail sales as shown on the next page) for 2025 are budgeted to be 16,096,875 MWh, an increase of 1,731,308 MWh or 12.1% from the 2024 budget. The major components of net system requirements are below by sales and supply components.

Total sales are budgeted to increase 1,479,981 MWh or 8.5% from the 2024 budget, an increase largely driven by retail sales with an increase of 1,706,605 or 12.5% when compared to the 2024 budget.

For supply components, firm/participation purchases are the largest change with a budgeted increase of 1,143,962 MWh or 27.5% from the 2024 budget due to Platteview Solar and Milligan Wind being in service for the entirety of 2025.

Net System Requirements
Sales and Supply Components (MWh)

	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Sales Components				
Retail Sales	13,648,443	15,355,048	1,706,604	12.5
NC2 Participation Sales	2,096,963	1,894,840	(202,123)	(9.6)
Wholesale Energy Sales	1,653,278	1,628,777	(24,501)	(1.5)
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**
Supply Components				
Generation	10,147,180	10,252,594	105,414	1.0
Purchased Power Agreements	4,158,744	5,302,706	1,143,962	27.5
Wholesale Purchases	3,809,884	4,065,192	255,308	6.7
Lost or Unaccounted For	(717,124)	(741,828)	(24,703)	3.4
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

NET SYSTEM REQUIREMENTS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET MWh CHANGE	% CHANGE
GENERATION (MWh)								
GENERATION	**9,335,878**	**7,959,596**	**7,595,771**	**10,147,180**	**(2,551,408)**	**10,252,594**	**105,414**	**1.0**
FIRM/PARTICIPATION PURCHASES	4,473,672	3,514,769	4,484,291	4,158,744	325,547	5,302,706	1,143,962	27.5
WHOLESALE PURCHASES	3,198,414	4,655,118	5,544,605	3,809,884	1,734,721	4,065,192	255,308	6.7
TOTAL PURCHASES	**7,672,086**	**8,169,888**	**10,028,896**	**7,968,628**	**2,060,268**	**9,367,898**	**1,399,270**	**17.6**
TOTAL INPUT	**17,007,963**	**16,129,483**	**17,624,668**	**18,115,808**	**(491,140)**	**19,620,492**	**1,504,684**	**8.3**
WHOLESALE ENERGY SALES								
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
TOTAL WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
NET SYSTEM REQUIREMENTS	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**
TOTAL RETAIL SALES	12,105,976	12,371,955	13,554,778	13,648,443	(93,666)	15,355,048	1,706,604	12.5
ENERGY LOST OR UNACCOUNTED FOR	491,295	431,890	504,208	717,124	(212,916)	741,828	24,703	3.4
TOTAL RETAIL SALES	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**

PEAK LOAD (MW)								
PEAK LOAD EXCLUDING DEMAND RESPONSE	2,680	2,928	2,959	3,009	(50)	3,164	155	5.2
DEMAND RESPONSE*	126	129	140	140	(0)	128	(12)	(8.6)
PEAK LOAD INCLUDING DEMAND RESPONSE	2,554	2,799	2,819	2,869	(50)	3,036	167	5.8
LOAD FACTOR (%) - REFLECTS DEMAND RESPONSE	56.3	52.2	56.9	57.2	(0.2)	60.5	3.4	5.9

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

* Does not include voluntary demand response

OPERATIONS AND MAINTENANCE EXPENSE



Operations and Maintenance Expense

The District's 2025 total budgeted O&M expense is $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget.

2025 Budget Compared to 2024 Budget

Purchased power, including wind purchases, represents 33.0% of total O&M expense and is budgeted at $379.7 million. This represents an increase of $67.2 million or 21.5% above the 2024 budget amount. The increase from the 2024 budget is primarily due to higher purchase volumes to serve anticipated customer load growth. As load growth outpaces owned generation, purchased power volumes are expected to increase.

Fuel expense is budgeted at $187.4 million, an increase of $7.3 million or 4.0% more than the 2024 budgeted amount primarily due to a full year of generation from Standing Bear Lake and Turtle Creek stations.

Transmission and distribution expense is budgeted at $192.7 million, which is $26.2 million or 15.7% more than the 2024 budgeted amount. The increase over the budget amount is attributable to additional external services, including tree trimming and cable locating, as well as increased headcount supporting growth at the utility.

Administrative and general expense is budgeted at $178.9 million. This category reflects an increase of $12.0 million or 7.2% more than the 2024 budget. The increase in 2025 is primarily related to rising costs associated with salary and benefits driven by both higher rates and an increase in the number of covered employees.

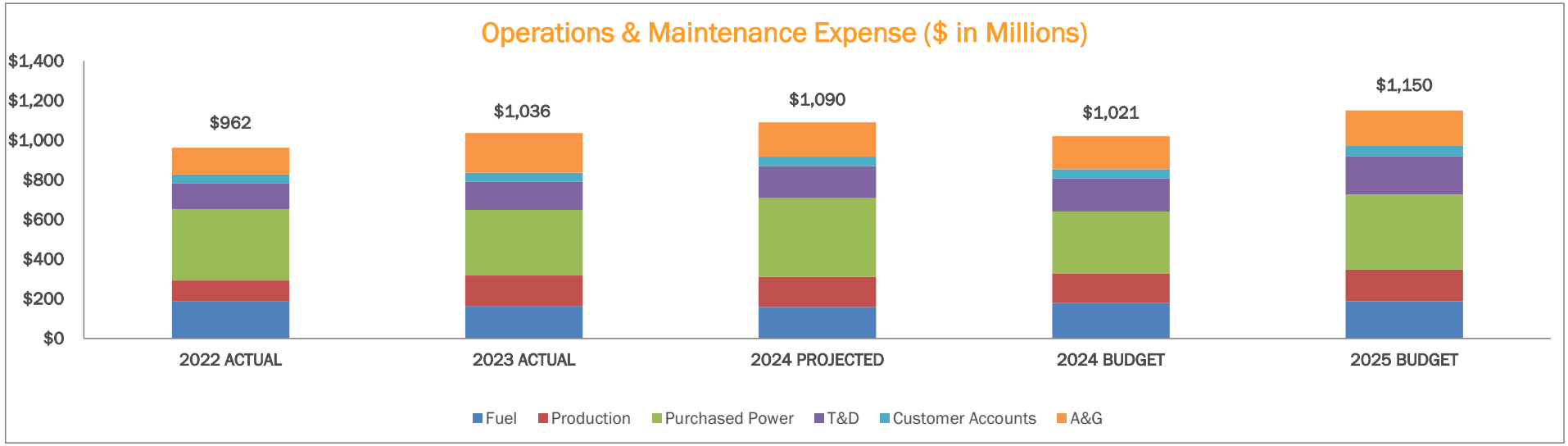
Production expense is budgeted to be $159.7 million, which is $12.0 million or 8.1% above the 2024 budgeted amount and is also impacted by a full year of operation at two new generating facilities, Standing Bear Lake and Turtle Creek as well as headcount growth.

Decommissioning expense represents the annual funding of the decommissioning liability. Decommissioning funding for 2025 is budgeted to be $10.7 million, which is $4.6 million or 30.1% less than the 2024 budget. Contributions to decommissioning represent investment earnings on balances in the decommissioning trust.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

OPERATIONS AND MAINTENANCE EXPENSE
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
PURCHASED POWER	$ 360,420	$ 332,382	$ 397,566	$ 312,527	$ 85,039	$ 379,716	$ 67,189	21.5
FUEL	186,359	164,240	157,857	180,164	(22,307)	187,422	7,258	4.0
SUBTOTAL	**546,779**	**496,622**	**555,423**	**492,691**	**62,732**	**567,138**	**74,447**	**15.1**
TRANSMISSION AND DISTRIBUTION	130,856	141,390	160,558	166,553	(5,995)	192,708	26,155	15.7
ADMINISTRATIVE AND GENERAL	135,402	199,820	173,038	166,938	6,100	178,926	11,988	7.2
PRODUCTION	105,534	152,812	152,976	147,748	5,228	159,699	11,951	8.1
CUSTOMER	43,887	45,520	48,196	47,096	1,100	51,396	4,300	9.1
TOTAL O&M EXPENSE	**$ 962,458**	**$ 1,036,164**	**$ 1,090,192**	**$ 1,021,028**	**$ 69,166**	**$ 1,149,867**	**$ 128,841**	**12.6**
DECOMMISSIONING EXPENSE	**$ 141,918**	**$ 33,320**	**$ 16,148**	**$ 15,298**	**$ 850**	**$ 10,694**	**$ (4,604)**	**(30.1)**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.



CAPITAL EXPENDITURE PLAN

Capital Expenditure Plan

Capital Expenditures

The 2025 capital budget was derived by breaking investments into three categories, sustain, enterprise priority and expand. This categorization ensures the District invests at appropriate levels to maintain existing assets but also invests in the continuing expansion of the utility.

Sustain - capital projects aimed at maintaining and improving existing assets

Expand - new assets, increasing the District's asset base

Enterprise Priority - projects directly related to Resource Adequacy, Technology Transformation, Next Generation Grid and the Master Facilities Plan

Capital expenditures represent 33.9% of the total 2025 budget. Capital expenditures are budgeted at $788.0 million, which is $61.0 million or 8.4% more than the 2024 budget.

The year over year growth is primarily related to investments in District expansion and enterprise priorities. Enterprise priority projects are budgeted at $474.1 million, which is a $70.6 million increase over the 2024 budget of $403.5 million, primarily related to investments in new generation. Expand, which includes projects related to load growth and economic development, are budgeted at $120.7 million, an increase of $15.4 million from the 2024 budget. Partially offsetting the budget growth in expand and enterprise priority is a decrease in sustain assets, which have a 2025 budget of $193.3 million, a decrease of $24.9 million from the 2024 budget of $218.2 million. While the District invests a larger percentage of the capital portfolio on enterprise priority and expand projects, the level of investment in sustain assets is decreasing but is still approximately $7.4 million greater than the historical investment rate.

Transmission and Distribution is budgeted at $338.6 million, a decrease of $17.6 million or 4.9% from the 2024 budget. The decrease is largely due to 2024 budgeted investments in owned solar generation that did not materialize, partially offset by additional investment in enterprise priorities, particularly Resource Adequacy and Master Facilities Plan as the District builds out transmission and distribution infrastructure to support new generation and invests in improved facilities.

Production increased to $330.6 million from the 2024 budget spend of $261.3 million. The change of $69.3 million or 26.5% is primarily related to the net impact of decreased spending on Power with Purpose projects as those units are expected to come online in 2024, offset by investments in new combustion turbines that is ramping up in 2025.

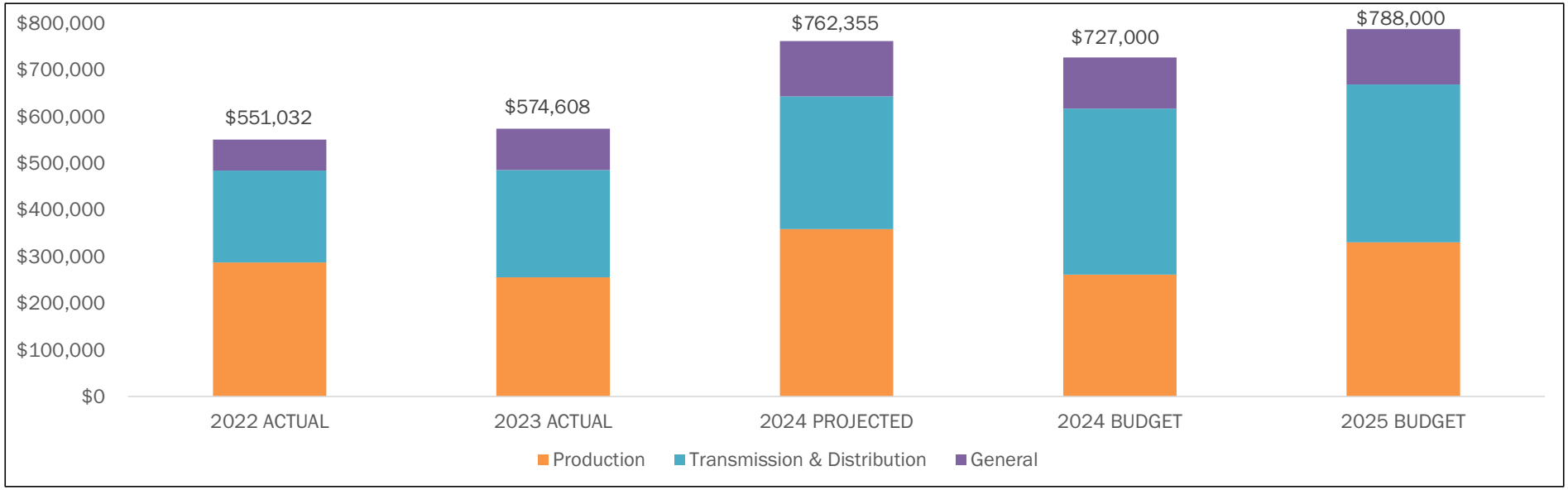
General for 2024 is budgeted to be $118.8 million, which is $9.2 million or 8.4% higher than the 2024 budget. The increase is the result of investment in Next Generation Grid as the District prepares to implement advanced metering infrastructure technology.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

CAPITAL EXPENDITURES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
TRANSMISSION AND DISTRIBUTION	$ 197,344	$ 230,381	$ 284,302	$ 356,176	$ (71,874)	$ 338,625	$ (17,551)	(4.9)
PRODUCTION	287,260	255,580	359,190	261,259	97,931	330,586	69,327	26.5
GENERAL	66,428	88,647	118,862	109,565	9,297	118,789	9,224	8.4
TOTAL	**$ 551,032**	**$ 574,608**	**$ 762,355**	**$ 727,000**	**$ 35,355**	**$ 788,000**	**$ 61,000**	**8.4**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.



CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Near Term Generation Support generation and transmission & distribution for Board Resolution No. 6582 approved on August 15, 2023	$ 149,360	$ 269,671
Master Facilities Plan Investment and upgrades to various OPPD facilities, which are all over 30 years old with only minor enhancements throughout their life	45,785	107,150
Circuit and Substation Upgrades Upgrade and replace multiple circuits and substations due to the expansion of our transmission and distribution infrastructure	61,951	82,076
AMI - Smart Grid Technology to support AMI	34,830	66,265
Transformer Purchases and Replacements Procure transformers to replace aging equipment and support load growth	31,522	30,777
Power with Purpose Support generation and transmission & distribution for Board Resolution No. 6351 approved on November 14, 2019	147,228	21,816

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Customer Service Residential Project Purchase and installation of underground or overhead infrastructure to new residential developments	$ 18,934	$ 18,432
Transportation Fleet Replacement Routine replacement of OPPD-owned transportation equipment, including light, medium and heavy duty trucks and construction equipment	16,383	18,007
Transmission Distribution Improvement Program-Cable Replacement Replace the worst performing underground distribution cable on a performance driven basis	16,548	15,645
North Omaha Extension Supports continued operation of North Omaha Station	10,690	13,292
Customer Service Commercial and Industrial Project Purchase and installation of underground or overhead infrastructure for commercial and industrial customers	13,182	13,157
Ground Line Inspection and Treatment Pole Replacement Replace degraded wood poles and structures used for transmission and distribution	7,945	11,019

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Subscription Software Renewals Renew subscription based software used by the district to conduct business	$ 4,767	$ 10,631
Transmission Distribution Improvement Program-Conductors Replace junk conductors on a performance driven basis	6,893	10,088
Transmission and Distribution Street & Highway Project Relocation of OPPD transmission and distribution facilities that are located in public road right-of-way	10,501	10,000
Coal Handling Upgrade Update Nebraska City coal handling system to reduce single point failure possibility	1,258	7,149
Expansion of Computing Storage Allows for real time expansion of computing capacity to allow for growth and support OPPD strategic initiatives	-	5,859
Energy Marketing Trade System OPPD will migrate the Energy Marketing and Trading processes to an industry standard	-	5,075
Substations and Control Centers Security Upgrades Security modifications required to address identified threats and vulnerabilities at various substation and control centers	12,887	4,946

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Arbor Railroad Line Improvements Repair and replace bridges, ties, ballast, rail, and crossings along the OPPD owned Arbor Rail line	$ 18,021	$ 4,832
Transmission and Distribution Street Light Project Relocation of OPPD street lights facilities that are located in public road right-of-way	3,500	3,500
Nebraska City Common Intake Vacuum Lift System Supports continued operation of Nebraska City at low river levels	-	3,150
Cass County Combustion Inspection Perform manufacturer recommended inpsection and repairs	-	2,950
Bellevue Transmission Redesign Improve the reliability and resiliency of the Bellevue transmission system	876	2,860
Large Motor Capital Repairs Support planned and emergent motor rewinds and replacements	-	2,800
Generation Station Intake Structure Environmental Upgrade Replace existing traveling screens (circulating water intake structure) at North Omaha and Nebraska City Fossil locations for renewal of the environmental permit	2,462	2,405

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Omaha Public Power District

Rate Fundamentals Report

EXHIBIT
G

Disclaimer

The statements made reflect OPPD's opinion and are intended strictly for educational purposes. The materials are intended to provide transparency in rate design and fundamental cost-of-service principles utilized in rate setting by OPPD. Some examples have been simplified for accessibility.

Agenda

I. Introduction
II. Total Cost Determination
III. Cost of Service Study
IV. Rate Design

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I. Introduction

Introduction

Report Goal

OPPD wants our customers to have foundational knowledge of how their rates are structured. This report provides information on how rates are calculated, set annually, and designed to align customer expectations and OPPD's strategic vision. This report connects the Corporate Operating Plan (COP), Strategic Initiatives, and Cost of Service Study (COSS) to help customers understand how these work together in establishing rates.

The following represents the goals of the information contained within this report:

- Introduce electricity basics
- Provide information on OPPD's Total Cost Determination (also referred to as the Revenue Requirement)
- Illustrate the steps performed in an embedded COSS with visibility to key modeling decisions
- Discuss alignment of costs with the fundamental rate elements – demand, energy, and service charges
- Bring visibility to OPPD's strategic vision for rate design

Introduction

Overview of the Rate Process



How large is the pie?

Total Cost Determination

- Determine the total costs required to provide service to our customers.



How to slice the pie?

Cost of Service Study

- Assign the total costs based on the relative contribution of each customer class to the cost drivers.



How to serve the pie?

Rate Design

- Recover the costs with rates that adhere to generally-accepted rate principles.

Introduction
Key Terms and Definitions

Generation	The production of energy via coal, natural gas, and renewables to satisfy peak demand and energy needs of our customers.
Transmission	Transmission of energy via high-voltage supply facilities, power lines, and substations that bring power from the generation source into our service territory.
Distribution	Distribution of energy via facilities and wires that connect the supply of energy to our customers.
Customer Services	Support services for all customers regardless of energy consumption (i.e. billing, metering, data management, customer service, etc.).

Introduction
Key Terms and Definitions

Cost of Service	The process of fairly apportioning the total costs to each customer class based on the relative proportion of their contribution to the costs.
Total Cost Determination	The total cost determination ensures that revenues cover the total costs to serve our customers and support our operations. This is also referred to as the Revenue Requirement.

Introduction
Key Terms and Definitions

Demand Costs	Costs based on the customer's highest amount of power (demand), measured in kilowatts (kW).
Energy Costs	Costs based on the customer's cumulative energy needs, measured in kilowatt-hours (kWh).
Customer Costs	Costs based on the number of customers on the system, measured in customer-months.

Introduction

The Electric Delivery System

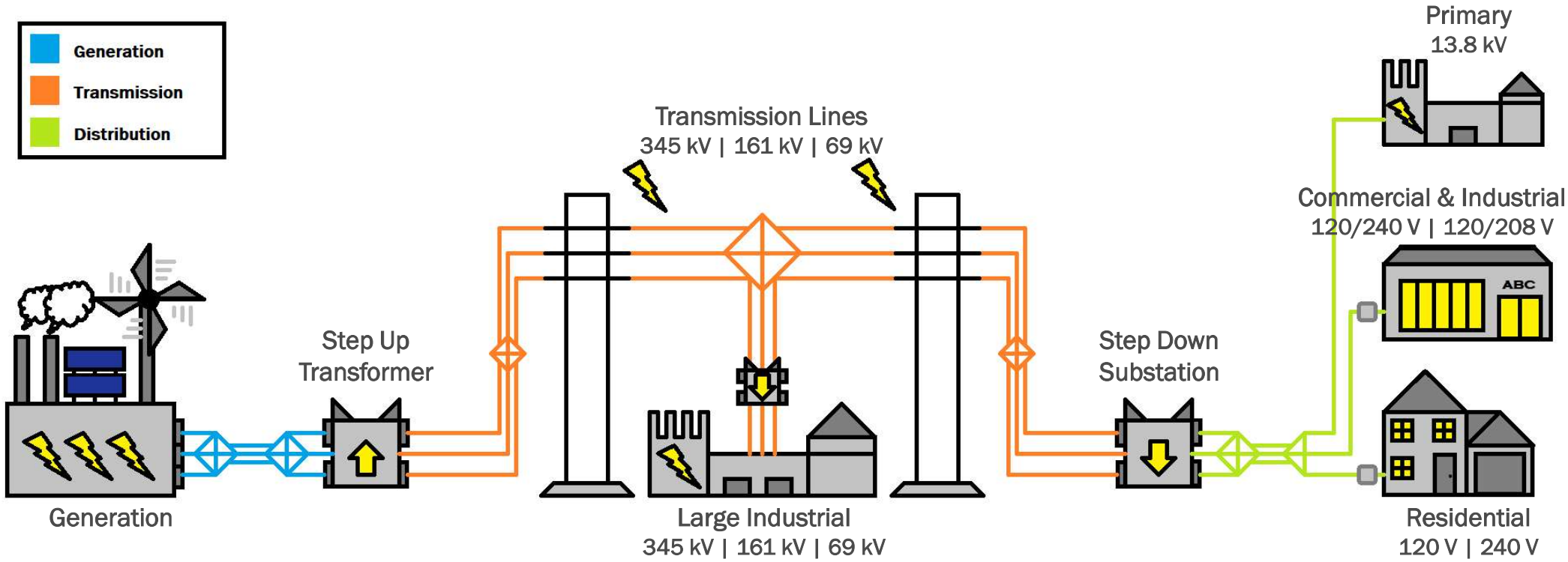


Illustration based off of the following source:

Office of Electricity Delivery and Energy Reliability. (2015, July). *United States Electricity Industry Primer*. U.S. Department of Energy. Retrieved January 2023, from https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf

Introduction

Electricity Basics: Generation

- Generation is the conversion of energy resources into electricity.
- Energy resources include coal, gas, renewables, and other forms.
- Each energy resource has a different ability to meet various energy needs and usage.
- Resource planning decisions include evaluating load growth expectations, resource adequacy, system resiliency, and cost effectiveness, while also taking into consideration OPPD's Pathways to Decarbonization.



Introduction

Electricity Basics: Generation by Source

- Fuel source is an important factor in generation.
- Fuel sources are typically categorized as renewable vs non-renewable.
- As outlined in the strategic visions of the *Powering the Future to 2050*, OPPD has a net carbon zero goal for 2050.
- By the end of 2024, OPPD's nameplate capacity consisted of 32.4% wind resources, up 5% year over year.

Introduction

Electricity Basics: Generation by Flexibility

- Dispatchable refers to the ability for a generation resource to change its output based on demand (within its generation potential).
- Dispatchable firm resources include technologies like conventional coal thermal, gas-fired combined cycle and combustion turbine, nuclear, geothermal, biomass, and others.
- Some renewable technologies are fully dispatchable such as nuclear and geothermal, while others such as wind and solar are dispatchable but limited to their variable fuel supply (referred to as variable energy resources).
- The ability to control generation output is critical for resiliency as severe weather, localized grid emergencies, and other extreme events can impact customers.
- OPPD's resource planning mix balances the ability to withstand and recover from localized and regional events with securing energy resources and maintaining a diverse portfolio of assets.

Introduction

Electricity Basics: Generation by Usage

- Generation facilities are often categorized by their intended purpose and utilization into the following usage categories:
- **Baseload** refers to facilities that are intended to run around the clock. Baseload units serve the minimum level of demand on the electrical grid over all hours of the day. Typically, these facilities have low fuel costs, but are less flexible to variations in demand.
- **Intermediate** refers to units that run a substantial portion of the year, but not the whole year. Combined-cycle gas units have historically filled this role.
- **Peaker** refers to units that are only utilized during peak hours. Typically, these units have higher fuel costs or economic costs, such as demand response.

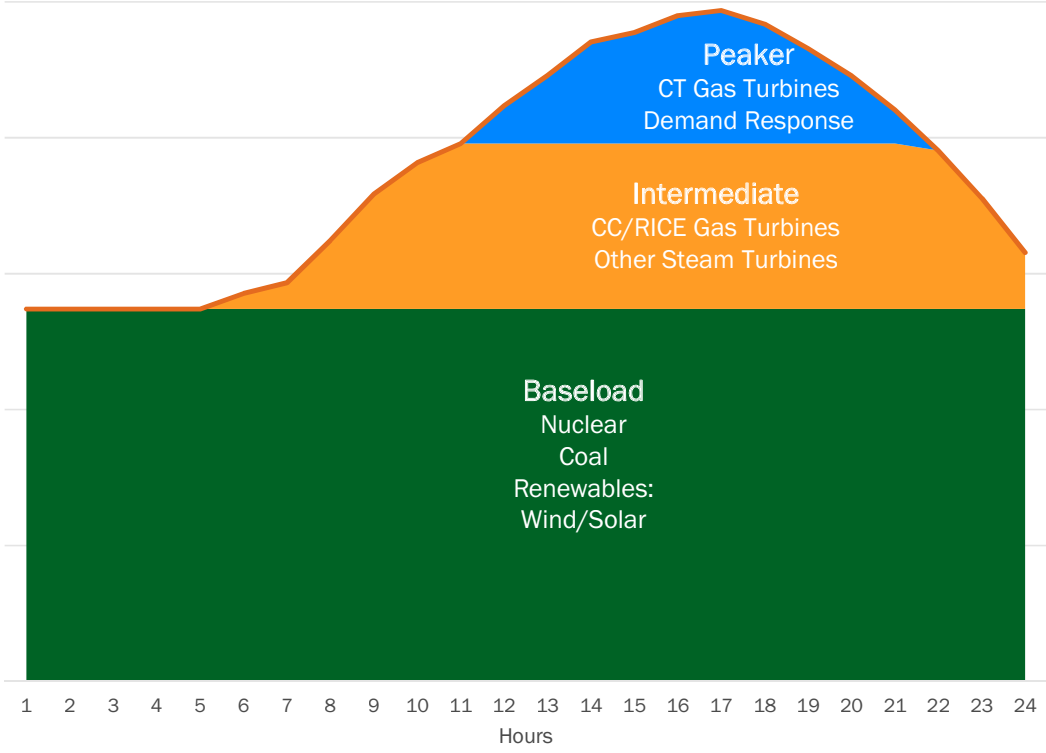


*Chart pictured is for illustrative purposes

Disclaimer on Peaker Resources:
Peaker Resources have historically operated as strictly serving peak load as the name would suggest. However, Peaker Resources currently operate as both serving peak load and balancing renewable resources.

Introduction

Electricity Basics: Transmission

- The transmission system is comprised of high-voltage lines (69kV, 161kV, & 345kV) that transfer bulk electricity between generation facilities and the end customer.
- Transmission lines are typically above ground with large support towers.
  - Air acts as the insulator with higher voltages requiring larger clearance.
  - Higher voltages reduce line losses.
- Some of the largest customers interconnect at the transmission level.
- For resiliency, each load point on the system generally has at least two alternate supply sources.



Introduction

Electricity Basics: Transmission (Cont.)

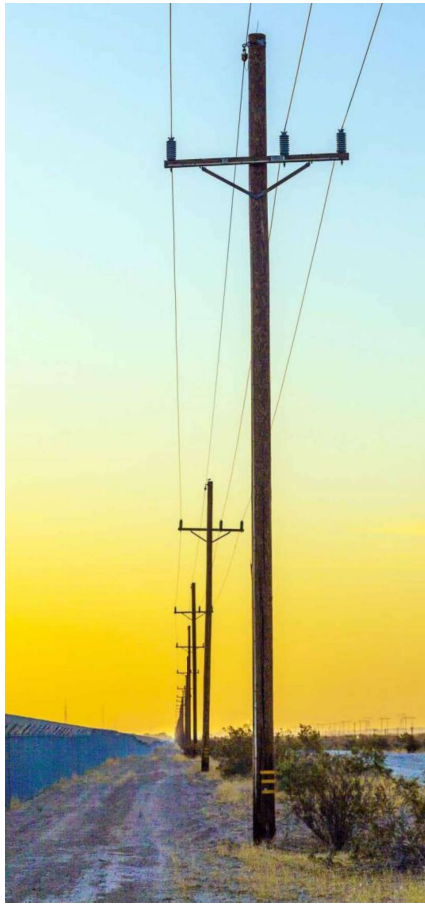
- OPPD's transmission system interconnects both to its generating stations and to neighboring utilities.
- OPPD's transmission system is part of the Eastern Interconnection and is a part of the Southwest Power Pool (SPP).
- SPP oversees regional transmission expansion for the OPPD region and guides the transmission service processes within our service territory.
- Altogether, the interchange of power over the transmission system has oversight by several national and regional entities that help ensure the reliability of the transmission system.



Introduction

Electricity Basics: Distribution

- The distribution system receives power from the transmission system.
- This power is brought down from high-voltage levels through distribution substations to a level that can be used by households and businesses.
- Most customers take service at the distribution level.
  - Primary Level – e.g. 13.8 kV (Three Phase) & 8 kV (Single Phase)
  - Secondary Level – e.g. 120V/240V or less than 600V
- The distribution system consists of the poles, transformers, substations, meters, service drops, and other assets needed to connect service to customers.



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II. Total Cost Determination

Total Cost Determination

Covering our Costs to Serve

- The total cost determination ensures that revenues cover the costs to serve our customers and support our operations, which is commonly referred to as the **Revenue Requirement**.
- The total cost determination is established by Strategic Directive 3 (SD-3), which provides the guiding principles to maintaining a low-cost, flexible structure to support the operation of the utility.
- The main principle established in SD-3 is maintaining a minimum 2.0 Debt Service Coverage Ratio.

$$\text{Debt Service Coverage Ratio} = \frac{\text{Revenues} - \text{Expenses}}{\text{Debt Interest} + \text{Principal Payments}}$$

Total Cost Determination

Capital Expenditure Philosophy

- The Debt Service Coverage Ratio is an important metric in evaluating the health of the utility.
- Maintaining the 2.0 Debt Service Coverage Ratio contributes to OPPD preserving a AA credit rating with the credit rating agencies.
- It ensures that new debt will be issued at competitive bond rates, which lead to lower long-term electricity rates for our customers.
- While Debt Service Coverage is an important consideration, there are other metrics that credit rating agencies consider when evaluating the bond rating. Likewise, OPPD's capital expenditure philosophy and investment decisions extend beyond credit rating agency evaluations.
- When making resource decisions, OPPD considers many factors such as reliability, economic development, competitive rate position, cost, etc.

Total Cost Determination

Return on Investments

- While OPPD does not set a minimum return on its investments on behalf of its customers, OPPD is required by state statute to set rates sufficient to establish and maintain a successful operation that does not incur operating losses (Nebraska Revised Statute 70-655).
- As a publicly-owned utility, any earnings above operating costs are strictly to ensure debt obligations are sustainably funded and investments are not deferred to future customers. Thus, returns are utilized to meet the needs of current customer-owners and support of operations.

Total Cost Determination
Strategic Investments

- OPPD is entering one of the most transformative resource planning eras in its 75-year history as capacity and energy needs grow and the industry evolves.
- OPPD's service territory is experiencing rapid growth in energy needs due to our competitive rates and economic development.
  - For example, peak load increased from 2,545 MW in 2022 to 2,811 MW in 2024
- OPPD remains committed to deliver on its Power with Purpose initiative:
  - 81 MWs of solar added in May 2024 (Platteview Solar Facility)
  - In Q1 2025, OPPD will add ~600 MWs of gas generation (Turtle Creek and Standing Bear Stations)
  - The utility also remains committed to planned North Omaha Station units 4 & 5 conversion from coal to natural gas, and retirement of units 1-3.
- OPPD's Near Term Resource Planning Goals support:
  - 1,000 – 1,500 MW of wind and solar (including 300 MW Milligan Wind Facility added Fall 2024)
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 320 MW of added fuel capacity and fuel oil storage

Total Cost Determination

Planning Process Considerations

While the Integrated Resource Plan (IRP) details the comprehensive work in determining the resource planning strategy, several key considerations are listed below.

- Access to Credit Markets
- Reliability and Resiliency
- Cost Minimization
- Environmental Sensitivity
- Competitive Rate Position
- Economic Development
- Customer Experience
- Strategic Alignment

Total Cost Determination

Putting It All Together

- The total cost determination supports the overall needs of our system and ensures OPPD's operations remain favorable to credit rating agencies for the issuance of debt to finance investments.
- The total cost determination is driven by the standard established in SD-3 to maintain a minimum 2.0 Debt Service Coverage Ratio.
- OPPD's capital expenditure philosophy ensures that a balanced approach is taken regarding resource decisions to secure access to credit markets, maintain competitive rates, and support the overall health of the system.

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III. Cost of Service

Cost of Service

Embedded Cost of Service Study

- After the Total Cost Determination is complete, we move to the Cost of Service Study (COSS).
  - Total Cost Determination – *How large is the pie?*
  - Cost of Service Study (COSS) – *How do we slice the pie?*
- OPPD utilizes an embedded-cost approach, which is the most common approach in the industry.
- An embedded-cost approach utilizes accounting costs associated with assets and expenses as they occur to provide service.

Cost of Service

Study Goals

- Nebraska Revised Statute 70-655 requires the Board to establish rates that are fair, reasonable, and non-discriminatory.
- The goal of the COSS is to fairly apportion the total costs to each customer class based on the relative proportion of their contribution to those costs.
- There are three fundamental steps in performing an embedded COSS:
  - Functionalization
  - Classification
  - Allocation
- For each fundamental step, the COSS seeks to determine cost causation to appropriately assign costs to each rate class.
  - i.e. What was the cost driver?

Cost of Service
Overview

- The COSS goes through functionalization, classification, and allocation to ensure the costs of providing service are fairly and reasonably apportioned.
- Functionalization separates the utility's assets according to how they are used – generating electricity to meet demand and energy needs, transferring electricity from the power source to the distribution system, and distributing the power to OPPD's customers' premises. Billing and metering is included in distribution.
- Classification provides measures for the service level of each of the functionalized components.
  - Customer demand is measured in kilowatts (kW),
  - Customer energy is measured in kilowatt-hours (kWh)
  - Customer counts are measured in the number of customers (can be a weighted measure)
- Allocation then applies the classification metrics to each rate class.

Cost of Service

Step 1: Functionalization

- **Functionalization** refers to the process of dividing the total costs into three components:
  - Generation
  - Transmission
  - Distribution
- Functionalization is an important step as customers have various electrical service needs:
  - Distribution assets are primarily utilized by residential and commercial customers.
  - Large industrial customers interconnect at the transmission level.
- Proper functionalization ensures that rates are appropriately assigned based on cost causation and characteristics.

Cost of Service

Functionalization FERC Standards

- The process of functionalizing the total costs is straightforward as it typically follows the assignment according to the accounting treatment as set forth in the Uniform System of Accounts (USOA) from the Federal Energy Regulatory Commission (FERC).

Functionalization According to FERC USOA		
Asset Account Number	Item	Expense Account Numbers
300s - 340s	Generation	500s - 550s
350s	Transmission	560s - 570s
360s - 370s	Distribution	580s - 590s

Cost of Service

Functionalization General Categories

Generation

- Fuel, purchased power, and generation assets

Transmission

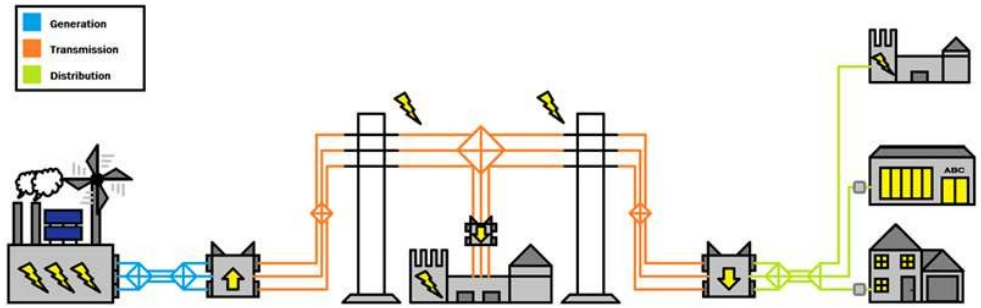
- High-voltage transmission lines (69kV, 161 kV, 345 kV)
- Transmission substations

Distribution

- Distribution substations
- Distribution lines (primary and secondary)
- Overhead and underground services
- Poles
- Meters, service drops, feeders
- Streetlights
- Customer service

General

- General plant and administrative and other general (Needs to be distributed to generation, transmission and distribution)



Cost of Service
Functionalization Transformation

- OPPD is undergoing a transformative period:
  - 1,000 – 1,500 MW of wind and solar
  - 125 MW of battery storage
  - 32+ MW of demand response
  - 600 – 950 MW of combustion turbines
  - 320 MW of added fuel capacity and fuel oil storage
- Changes in our generation mix, growing energy resource needs, and expansion in our residential, commercial, and industrial classes will result in the functionalized total costs evolving over time.
- OPPD will continue to monitor anticipated changes, economic changes, and other factors to maintain gradualism and rate stability.

Cost of Service

Step 2: Classification

- **Classification** identifies the drivers of the costs.
- Costs are generally split into three categories:
  - **Demand Costs**
    - Costs based on the customer's maximum demand
    - Measured in kilowatts (kW)
  - **Energy Costs**
    - Costs based on the customer's energy needs
    - Measured in kilowatt-hours (kWh)
  - **Customer Costs**
    - Costs based on the number of customers on the system
    - Measured using customer-months
- Portions of general plant and administration and general expenses are each categorized as energy-related, demand-related, and customer-related.

Cost of Service

Classification Demand-Related Costs

- Demand-related costs are costs that vary based on the size-related needs to serve a customer's maximum demand.
- All three functionalization categories have size-related needs.
  - Generation costs are the capacity built to meet maximum expected demand and the additional planning reserve margin.
  - Transmission costs are mainly size-related demand costs as transmission facilities transmit bulk power to load centers to meet maximum expected demand.
  - Distribution costs also have size-related demand costs including transformers and conductors to meet maximum expected demand. Customer classes do not have their maximum demands at the same times on the distribution system.

Cost of Service

Classification Energy-Related Costs

- The majority of energy-related costs are generation costs. While some generation assets are built for resiliency and peak demand, generation is also built to serve the energy needs of customers and portions are assigned to energy.
  - The split for generation assets between energy and demand will be discussed in detail below.
- Costs that vary with energy production are categorized as energy-related. Two major cost categories:
  - Fuel is classified entirely as energy-related as energy needs require the consumption on fuel.
  - Purchased power is generally classified as energy-related because power is purchased on the integrated marketplace when OPPD is short energy resources or when market prices are lower than OPPD's variable fuel costs.

Cost of Service

Classification Customer-Related Costs

- The majority of customer-related costs are distribution costs.
- Customer-related costs includes meters, customer billing, and portions of the distribution plant.
- The split between demand-related and customer-related distribution costs is determined by OPPD's minimum system approach.
- In 2022, OPPD reviewed the classification of its distribution system and enacted the minimum system methodology for its planning system. More information will be discussed in detail below.

Cost of Service

Classification Important Considerations

- Two important classification factor decisions are:
  - The split between demand-related and energy-related generation assets.
  - The split between customer-related and demand-related distribution assets.
- The best strategy for determining the classification approach in an embedded-cost approach is identifying cost causation and system planning.
- OPPD utilizes a load factor approach (a derivative of the “average and excess” approach) for the classification of generation assets.
  - OPPD performed a study considering 14 different demand classification approaches when determining the classification of generation assets.
- The load factor approach uses the system wide load factor to determine the proportion assigned to energy-related costs and the remaining portion is assigned to demand-related costs.
  - Rather than the traditional “excess demand” derivation for the demand-related allocation, the 4CP measure is used (more information provided in allocation section below).
- As previously mentioned, OPPD’s generation fleet will change considerably in the future. Additionally, the Inflation Reduction Act of 2022 has significantly impacted the business decisions regarding the owning of utility-scale renewable resources. OPPD will ensure that the classification of generation assets matches the transformation of the generation portfolio.

Cost of Service

Classification Important Considerations (Cont.)

- The classification of the distribution plant is another important consideration (particularly FERC accounts 364–370).
- OPPD has previously used the zero-intercept, but adopted the minimum system approach in 2022 determining it best represented OPPD's system planning.
  - The minimum system approach provides a more intuitive approach to determining the customer-related distribution costs as it assigns a minimum-sized unit cost as the customer-related portion and the remaining costs are assigned as demand-related.
- The minimum system approach was one of many classification, functionalization, and allocation refinements OPPD recently implemented in collaboration with our rate consultant Brattle.
  - These adjustments resulted in greater precision of cost recovery matching cost incurrence for demand, energy, and customer costs.

Cost of Service

Step 3: Allocation

- **Allocation** is the assignment of the classified costs to customer classes based on the relative proportion of their contribution to those costs.
- Allocation is the most critical step of a COSS as it determines the cost allocations for each customer class.
  - It is essential to understand the characteristics of each customer class, such as the number of customers, energy consumed, voltage-level, and their contribution to both coincident peak (CP) and non-coincident peak (NCP) demand.
- Each allocation method represents a set of relative proportions that total to 100% across all customer classes.
- There are multiple allocations used for the various classified costs:
  - Demand-related allocations
  - Energy-related allocations
  - Customer-related allocations

Cost of Service

Allocation Approaches

- Before discussing allocation approaches, it is worth noting certain customer classes will view some allocation approaches more favorably than others.
- OPPD's allocation approach is based on a set of measurable criteria that are universally adopted for determining the appropriateness of an allocation method.
- Some of these criteria include:
  - Measuring the precision of the method compared to the actual planning and operating of facilities.
  - Measuring the accuracy of the method to cost causation.
  - Assessing the ability of the method to recognize specific customer class characteristics, such as energy usage, peak demand, number of customers, etc.
  - Assessing the accuracy of the method to produce consistent results.
  - Reviewing the modernity of the method to reflect best practices across the industry.
- Adhering to these criteria, several methods can be appropriate. OPPD partners with Brattle to provide a balanced approach in selection of allocation methods.
- OPPD does not seek to influence a particular set of results when determining allocation factors.

Cost of Service
Allocation Methods

- Demand-related allocation methods:
  - Coincident peak demand (CP)
    - Also referred to as system peak demand (kW)
    - Depending on the nature of the CP, there are different measures of CP (4CP vs. 12CP)
  - Non-coincident peak demand (NCP)
- Energy-related allocation methods
  - Aggregate energy (kWh)
  - Considered both at point of generation and point of use to account for energy losses
- Customer-related allocation methods
  - Number of customers
  - Weighted customer measures:
    - Relative cost – meters, transformers, service lines, etc.
    - Effort required – customer service, billing, etc.
    - Ratio of service – transformers, connections, streetlights, etc.

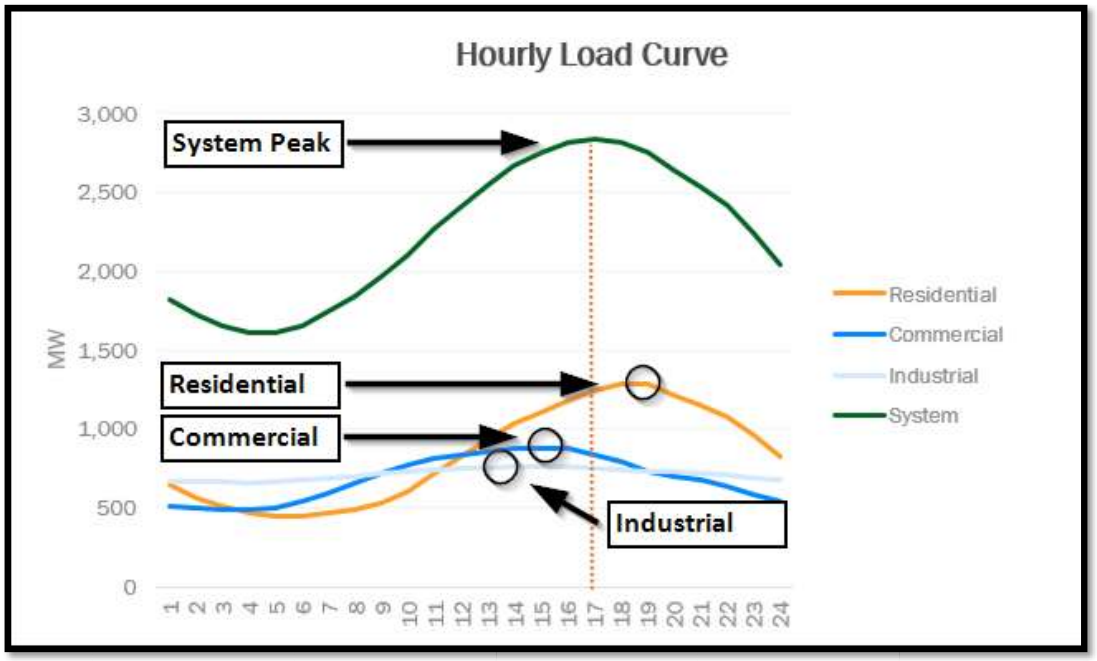
Cost of Service
Demand-Related Allocations

- Coincident Peak (CP) is the demand placed on the system by a customer class at the system peak.
- 4CP measures the CP contribution during the 4 highest months of the year.
  - These are the summer months of June – September for OPPD.
  - This method is used to allocate the demand-related production costs as our capacity and OPPD's resource adequacy requirement is currently driven by the summer peak. Note: resource adequacy requirements may change as SPP examines system resiliency requirements and may cause a need to reevaluate the 4CP allocation for demand-related production costs.
- 12CP measures the contribution during the system peak hour of each of the 12 months of the year.
  - These are averaged together to provide the 12CP measure.
  - 12CP is widely accepted in allocating transmission costs as it strikes a balance in reflecting the way the system has been planned and is used. This helps to maintain reliability and serve load accordingly.
- Non-coincident peak (NCP) refers to the demand placed on the system by each customer class at the point in time when that class reaches its individual peak demand (regardless of the system peak).
  - This measure is utilized for the allocation of distribution demand-related costs such as substations, which are built to meet the highest instantaneous peak demand regardless of the time of day.

Cost of Service

Load Curve

- The following graph provides an example of a daily load curve cycle and visually illustrates the concept of CP and NCP.
- The **circled points** for each class indicate the **NCP** for each class, while the intersection of each class line with the **dotted line** illustrates their contribution to the **CP** (system peak).
- None of the NCP's align with the CP. However, load variability is distinct between classes. In summer months, generally:
  - Residential peaks in the evening
  - Commercial peaks middle afternoon
  - Industrial peaks early afternoon
    - Industrial is relatively constant throughout the day
- Variability translates to different levels of utilization of system capacity. Load Factor measures utilization efficiency and is important for determining allocation of costs for each class.



Cost of Service
Load Factor

- Load Factor is a measure that captures variation in load.
- It is calculated as the ratio of average load by peak load:
  - $\text{Load Factor} = \frac{\text{Average Load}}{\text{Peak Load}}, [0,1]$
- Higher load factors indicate higher utilization over all hours of the day and year, which aligns well with baseload generation.
- Baseload generation typically has lower energy costs and higher load factor customers align well with baseload generation (leading to lower rate offerings).
- Differences in load factors can occur within rate classes and can merit different rate offerings based on different levels of utilization of the system.

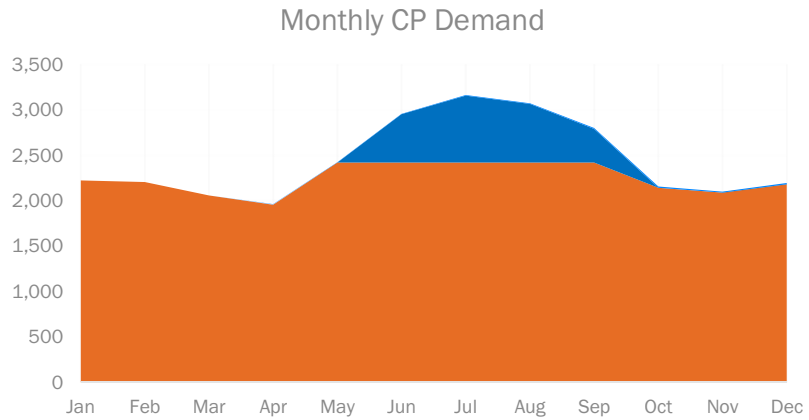
Cost of Service

Load Factor Impacts on Rates

- Rate 110 (Standard) and Rate 115 (Heat Pump) are both residential rates, but with different load profiles due to Rate 115 requiring an electric heat pump.
  - Rate 115 uses electricity both in heating and cooling of the household, yearly load factors are typically 35% higher than Rate 110 customers.
  - With more load used throughout the year, rates are lower and the average Rate 115 pays approximately 2.2 cents/kWh less than the average Rate 110 customer.
- Electrification of households will allow more efficient recovery of costs and illustrates how load factor is correlated with rates.
- Electrification of transportation can be utilized to increase load factors. Rate offerings will be evaluated to incentive recharging over night (off-peak periods), which would be beneficial to the system. However, if left unaddressed, customer load factors may worsen if charging occurs during on-peak periods.

Cost of Service

Generation Demand-Related Allocations



- OPPD utilizes a derivative of the average and excess approach for classification with the “excess demand” allocation method being 4CP.
- The rationale for utilizing 4CP is illustrated in the monthly peak load graph above.
  - The blue area represents the summer peak demand in excess of the non-summer peak demand (orange area).
  - Therefore, generation capacity and OPPD’s resource adequacy requirement is currently driven by the summer peak.

Cost of Service

Transmission Demand-Related Allocations

- Transmission costs are classified as entirely demand-related using the 12CP allocation.
- The 12CP allocation method is widely accepted as the most appropriate approach for allocation of transmission costs. This is due to the majority of utilities planning their systems to meet their 12 monthly peaks.
  - FERC uses 12CP in allocation of transmission costs.
  - SPP also relies on 12CP for allocation of fees from its members.

Cost of Service

Distribution Demand-Related Allocations

- The 1NCP allocation method is widely accepted and utilized as the distribution demand-related allocator.
  - Transformers, substations and other size-related distribution investments are generally designed for customer's maximum demand needs regardless of the system peak.

Cost of Service
Energy-Related Allocations

- There are several substantial cost categories allocated strictly on energy-related usage including:
  - Fuel
  - Purchased power
  - Portions of generation assets
- Energy is measured in usage at the meter, production at the facility, and adjusted for losses on the system (line, substation, transformer, etc.).
- OPPD captures where customers are located on the system and determines load losses at each interconnection level.
  - Customers interconnected at higher voltage levels have lower energy losses (industrial).
  - Customers interconnected at lower voltage levels have higher energy losses (residential).

Cost of Service

Energy-Related Allocations (Cont.)

- When customers use power is another important factor.
  - Fuel costs are different for different generation types.
  - Purchased power is higher during specific time intervals and seasons.
- Seasonality (summer vs non-summer) for residential and commercial classes provide a means of capturing time of consumption impacts.
- Advanced Metering Infrastructure (AMI) will further enable the ability to provide time-varying rates and better match cost recovery with incurrence.

Cost of Service
Customer-Related Allocations

- Customer-related allocation methods typically involve a weighted-measurement of the number of customers, which controls for variation in customer attributes.
- Customer-related allocation methods include measures such as:
  - Relative cost – meters, transformers, service lines, etc.
  - Effort required – customer service, billing, etc.
  - Ratio of service – transformers, connections, streetlights, etc.
- Customer-related costs are the smallest classified cost category.
- Distribution systems represent the most diverse functional component and require special attention to ensure proper classification and allocation.

Cost of Service

Transmission Level Market Access Rate Allocations

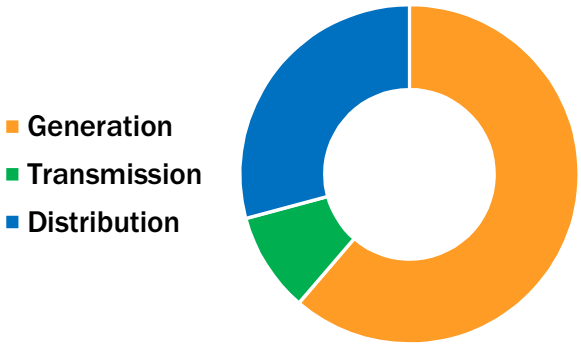
- Large Power – High-Voltage Transmission Level – Market Energy, Rate 261M, reflects a unique customer class and offering.
  - As required, customers are supplied at transmission level voltage 161kv or 345kV and own their own electric substation for the delivery of service.
  - In addition, customer's energy charge is equal to wholesale market prices for energy from the SPP for each hour and these prices are directly passed through to the customer.
- Rate 261M customers have unique allocation factor assignment in the energy components:
  - Each customer receives a direct assignment of the purchased energy costs at the market price.
- The interconnection level is considered in the allocation of functional components.
  - Interconnection at the transmission level avoids much of the distributional investments.
- This unique offering provides a shared risk and investment between the customer and the utility that requires specific allocation considerations.

Cost of Service

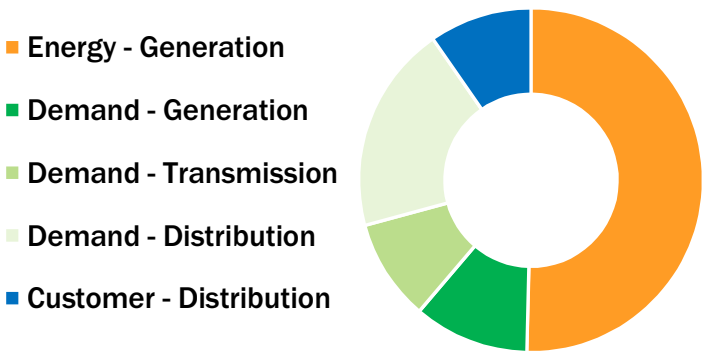
Summary of OPPD Cost of Service Allocations

- The following charts are examples of the proportion of the total costs to serve by functionalization, classification, and main allocation method.

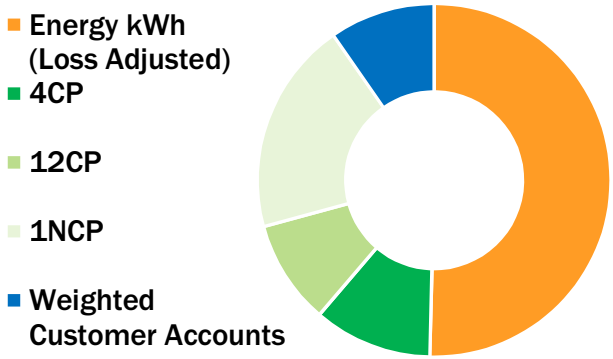
Functionalization



Classification



Allocation



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Omaha Public Power District

IV. Rate Design

Rate Design

Step 4: Rate Design

- The ultimate goal of the COSS is to fairly apportion costs among customer classes based on their proportionate contribution to the costs.
- After determining the total costs for each customer class, cost recovery is aligned with the fundamental rate elements/charges:
  - Demand Costs (Demand Charges)
    - Costs based on the customer's maximum demand
    - Measured in kilowatts (kW)
  - Energy Costs (Energy Charges)
    - Costs based on the customer's cumulative energy needs
    - Measured in kilowatt-hours (kWh)
  - Customer Costs (Service Charges)
    - Costs based on the number of customers on the system
    - Measured using customer-months

Rate Design

Demand Charges

- Demand charges are determined through dividing the demand-related costs by the billing demand (measured in kW).
- Demand charges include the size-related capacity costs of generation, transmission, and distribution.
  - Demand charges must be consistent with the collection method of demand meter data to ensure over/under collection does not occur.
- Demand charges seek to provide price signals to customers regarding instantaneous use costs and serve to more effectively recover demand-related costs based on peak contributions.
- When a class does not have demand metering technology, demand-related costs must be recovered either through:
  - The energy charge or
  - The service charge
- This is discussed below regarding 2-Part Rates vs. 3-Part Rates.

Rate Design
Energy Charges

- Energy charges reflect recovery of energy costs.
- Energy charges can take the form of both **Base Rates** and **Riders**.
  - **Base Rates** are charges set within the service regulations and approved by the Board.
  - **Riders** (sometimes referred to as "trackers") are additional charges, not included in the base rates, that are designed to recover specific costs that the rider is "tracking,"
    - **Rider 461** - OPPD utilizes a Fuel and Purchased Power Adjustment Rider (FPPA) that recovers fluctuations in net power costs (fuel, purchased power, and off-system sales) outside of OPPD's control. This rider ensures the base rates remain stable during volatility in the integrated marketplace while also providing an effective price signal to customers.
  - Energy charges can be structured in several different ways:
    - Seasonally – based on the time of year
    - Temporally – based on the time of day or week (AMI-enabled)
    - Volumetrically – based on the volume consumed (e.g. declining-block structures)

Rate Design

Service Charges

- Service charges are used to recover the costs of being a customer.
- Service charges are uniform for all customers taking service on a rate and do not vary based on size-related demand or energy needs.
  - Includes costs such as billing, customer service, meters, etc.
- Service charges are calculated as follows:
  - $$\text{Service Charge} = \frac{\text{Customer Costs Allocated to Customer Class}}{\text{Number of Customers in Class} \times 12 \text{ Billing Months}}$$

Rate Design

2-Part Rates vs 3-Part Rates

- OPPD's residential and small commercial classes lack the supporting infrastructure for demand charges. Therefore, demand-related costs are recovered through service charges and energy charges.
  - Rate offerings with only service charge and energy charges are referred to as **2-Part Rates.**
  - Rate offerings with an additional demand charge component are referred to as **3-Part Rates.**
- For these classes, the energy charge must recover not only energy costs but also generation, transmission, and distribution costs. Increasing diversity of customer needs has made it challenging to effectively recover fixed costs in the absence of time-of-use volumetric energy charges.
  - Customer class divergence includes:
    - Various forms of energy efficiency
    - Electrification of heating
    - Electrification of transportation
    - Customer-owned generation
- OPPD's 2-Part rate structures recovers portions of distribution demand-related costs and the customer-related costs within the service charge while demand-related generation, transmission, and part of distribution costs along with energy costs are recovered through the energy charges.
- OPPD's transition towards more effective price signaling will take a balanced approach over time.
  - In the interim, as we transition to AMI technology, OPPD will seek to align legacy rates with future price signals.
  - This will allow for stability and behavioral shifts in energy consumption that will mitigate transitional challenges.

Rate Design

Generally-Accepted Rate Principles

- There are some generally-accepted rate principles utilized within the electric industry, which include:
  - Customer bill stability
  - Simplicity, understandability, and transparency of rates
  - Rates that support healthy utility operations
  - Rates that promote efficient use and investments
  - Fairness in allocation among classes
- These principles must be properly understood to remain effective in the shifting landscape of energy, which includes:
  - Ongoing technological advancements
  - Growth in distributed energy resources (DER)

Rate Design

Transition Toward Effective Price Signals

- Utility planning has become increasingly sophisticated, and the ability to capture allocators based on more granular load and equipment data has enabled greater precision when determining class-level costs to serve.
- It is also important to adhere to the Efficient-Use Principle, which is defined as providing customers with effective price signals and information to manage their energy costs.
  - Appropriate changes in energy usage will result in a reduction in the costs allocated to them. For example, in the future with AMI-enabled technology, customer interactions will increase in app-based communications, which provide real-time cost savings estimates to encourage more efficient consumption.
- While high-load factor customers have historically matched baseline generation, as the industry moves increasingly towards intermittent renewable generation, customers with flexible demand will be key to the minimization of costs and therefore benefit from incentives and rate offerings.

Rate Design

Transition Toward Effective Price Signals (Cont.)

- AMI technology will be initiated over the next several years and will help OPPD to build more advanced and dynamic rate structures.
- Enabled by this technology, customers will have greater understanding of the drivers of their bill and better ability to respond to price-signals.
  - OPPD will be able to utilize data from AMI-metering to better serve our customers by coordination of customer profiles and usage data allowing for strategic engagement that address customer's needs and preferences.

Rate Design
Conclusion

- Rate design aligns cost recovery with the fundamental rate element – demand charges, energy charges, and service charges.
- Rate principles provide the guiding vision and long-term strategy to provide customers with greater flexibility, choice, transparency, gradualism, affordability, and fairness when determining rate offerings.
- The utility industry is experiencing rapid developments. Rate structures will need to be able to evolve to be more adaptable to the increasingly dynamic environment and leverage technology that will become available to better serve our diverse customer needs.
- OPPD will continue its partnership with both external entities and our customer-owners to provide affordable, reliable, and environmentally sensitive energy services to our customers.

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April 22, 2025

White & Case, LLP,
609 Main Street, Suite 2900
Houston, Texas 77002

RE: ***First Requests for Production of Documents in Connection with Zachry Holdings, Inc. et al. v. Omaha Public Power District (Adv. Pro. No. 25-03025 (MI))***

Dear Ms. Garr:

I am writing in response to your letter dated April 18, 2025, regarding Zachry's Voluntary Requests for Production of Documents.

As the Court has made clear, discovery is not currently open. OPPD does not believe that it is appropriate for Zachry to serve discovery requests while a motion to transfer venue remains pending and as we prepare to file an amended motion to dismiss. Attempting to initiate discovery at this stage is not only premature—it disregards the procedural posture of this case.

Even assuming the Court ultimately denies our forthcoming motion to dismiss, discovery would still be improper in this forum. The Southern District of Texas Bankruptcy Court is not the appropriate venue for this dispute, and OPPD will not voluntarily engage in discovery in this Court. Doing so would risk waiving significant objections to this venue.

Furthermore, Zachry's attempt to carve out limited discovery tailored solely to its own objectives is plainly self-serving. Discovery—when appropriate and in the proper forum—must encompass all relevant issues, not just those Zachry selectively identifies. The effort to control the scope and timing of discovery undermines the fairness of this process.

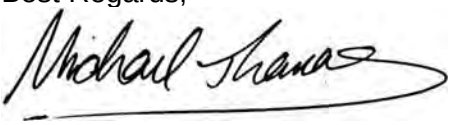
Zachry has repeatedly represented to the Court that the liquidated damages issue involves a straightforward legal issue suitable for early resolution via summary judgment. If that were truly the case, discovery would be unnecessary. The fact that Zachry is now seeking to open discovery only undercuts its own narrative and confirms that its claims are not as clear-cut as it has led the Court to believe.

We trust that this matter is now clear. Should you wish to discuss this further, please feel free to reach out.

EXHIBIT
H

FOLEY & LARDNER LLP

Best Regards,



Jonathan Michael Thomas