ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. FOR APPROVAL OF PETITIONER'S 7-YEAR PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE 8-1-39-10 AND APPROVAL OF A TRANSMISSION AND DISTRIBUTION INFRASTRUCTURE IMPROVEMENT COST RATE ADJUSTMENT AND DEFERRALS, PURSUANT TO IND. CODE 8-1-39-9, AND APPROVAL OF CERTAIN REGULATORY ASSETS	)	CAUSE NO. 44526 APPROVED: MAY 08 2015

ORDER OF THE COMMISSION

Presiding Officers:
Angela Rapp Weber, Commissioner
Jeffery A. Earl, Administrative Law Judge

On August 29, 2014, Duke Energy Indiana, Inc. ("Duke") filed its Verified Petition in this Cause. Duke also prefiled the testimony and exhibits constituting its case-in-chief.

The following parties intervened in this Cause:

- Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor");
- Citizens Action Coalition of Indiana, Inc. ("CAC");
- Duke Energy Indiana Industrial Group ("Industrial Group");
- Steel Dynamics, Inc. ("SDI");
- Indiana Municipal Power Agency ("IMPA");
- Wabash Valley Power Association, Inc. ("WVPA");
- The Kroger Co. ("Kroger");
- The Environmental Defense Fund ("EDF");
- Companhia Siderurgica Nacional, LLC a/k/a CSN, LLC ("CSN"); and
- The Indiana Telecommunications Association ("ITA").

The Commission held a field hearing in this Cause at 6:00 p.m. on November 12, 2014, at the Bloomington/Monroe County Convention Center, 302 S. College Avenue, Bloomington, Indiana.

On November 13, 2014, EDF prefiled its testimony and exhibits with the Commission. On November 14, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC"), CAC,

Industrial Group, SDI, WVPA, and CSN prefiled their respective testimony with the Commission. On December 12, 2014, Duke prefiled its rebuttal testimony.

The Commission held an evidentiary hearing in this Cause at 9:30 a.m. on January 26, 2015, in Hearing Room 222, 101 West Washington Street, Indianapolis, Indiana. Duke, the OUCC, Nucor, CAC, Industrial Group, SDI, IMPA, WVPA, Kroger, EDF, and CSN appeared at and participated in the hearing.

Prior to the evidentiary hearing, the OUCC, CAC, Industrial Group, CSN, Kroger, Nucor and SDI (collectively "Joint Movants") filed a motion to strike portions of Duke's rebuttal evidence on the grounds that it constituted improper supplemental direct evidence. The presiding officers denied the Motion on the record during the evidentiary hearing. At the conclusion of Duke's presentation of its case-in-chief during the evidentiary hearing, the Joint Movants orally moved to dismiss Duke's Petition under Ind. Trial Rule 41(B). The Presiding Officers denied the motion, and the denial was affirmed by a majority of the full Commission on appeal. The Industrial Group, SDI, EDF, and WVPA proceeded to offer their respective cases-in-chief. The OUCC, CAC, Nucor, Kroger, IMPA, ITA, and CSN did not offer any evidence at the hearing. Duke then offered revised rebuttal testimony limited to evidence responsive to the evidence presented by the Industrial Group, SDI, EDF, and WVPA.

Because not all parties who prefiled evidence in this Cause offered evidence at the hearing, our consideration of the issues in this Order is limited to the following evidence, which was admitted into the record at the hearing:

(1) Duke's case-in-chief, which consists of the testimony and exhibits of the following witnesses:

- Melody Birmingham-Byrd, Senior Vice President, Midwest Delivery Operations, at Duke Energy Business Services LLC ("DEBS");
- Russell Lee Atkins, Vice President Design Engineering and Construction Planning – Midwest, at DEBS;
- Theodore H. Kramer, Director, Transmission Engineering at DEBS;
- Donald L. Schneider, Jr., Director, Advanced Metering, at DEBS;
- William D. Williams, Director, Asset Management, Finance and Markets Business Line, Management Consulting Division, of Black & Veatch Corporation; and
- Brian P. Davey, Director, Rates and Regulatory Strategy – Indiana, at DEBS.

(2) WVPA's case-in-chief, which consists of the direct testimony and exhibits of Gregory E. Wagoner, Vice President, Transmission Operations and Development at WVPA

(3) EDF's case-in-chief, which consists of the direct testimony and exhibits of Dick Munson, Midwest Director, Clean Energy, at EDF

(4) SDI's case-in-chief, which consists of the direct testimony and exhibits of Kevin C. Higgins, Principal in the firm of Energy Strategies, LLC

(5) The Industrial Group's case-in-chief, which consists of the direct testimony and exhibits of the following witnesses:

- Michael P. Gorman, Managing Principal of Brubaker & Associates, Inc.; and
- Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc.

(6) Duke's rebuttal evidence, which consists of the testimony and exhibits of Ms. Birmingham-Byrd, Mr. Davey, and Robert B. Hevert, Managing Partner of Sussex Economic Advisors, LLC.[1]

Based on the applicable law and the evidence presented at the hearing, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the hearings in this Cause was given and published by the Commission as required by law. Duke is a public utility as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-39-10, the Commission has jurisdiction over a public utility's request for approval of a seven-year plan for eligible transmission, distribution, and storage improvements. Under Ind. Code § 8-1-39-9, the Commission has jurisdiction over a public utility's request to recover eligible transmission, distribution, and storage system costs through a periodic rate adjustment. Therefore, the Commission has jurisdiction over Duke and the subject matter of this proceeding.

2. **Duke's Characteristics.** Duke is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana. Duke is a second-tier, wholly owned subsidiary of Duke Energy Corporation. Duke renders retail electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such service to the public.

3. **Relief Requested.** Duke requests approval of its proposed seven-year plan for eligible transmission, distribution, and storage system improvements ("T&D Plan") under Ind. Code § 8-1-39-10. Specifically, Duke requests: (1) a finding that the projects contained in its T&D Plan are "eligible transmission, distribution, and storage system improvements" within the meaning of Ind. Code § 8-1-39-2; (2) a finding that the best estimate of the cost of the eligible improvements was included in the T&D Plan; (3) a determination that the public convenience and necessity require or will require the eligible improvements included in the T&D Plan; and (4) a determination that the estimated costs of the eligible improvements included in the T&D Plan are justified by incremental benefits attributable to the T&D Plan.

Assuming the Commission approves the T&D Plan, Duke also requests a finding that the eligible transmission, distribution, and storage system improvements included in the T&D Plan are eligible for recovery as a transmission, distribution, and storage system improvement charge ("TDSIC") under Ind. Code § 8-1-39-9. Finally, Duke requests approval of its proposed process for updating the T&D Plan in future semi-annual proceedings.

---

[1] Although we considered all of the evidence listed, our ultimate decision in this case rendered the issues raised in the direct testimony of Mssrs. Davey, Phillips, Gorman, and Higgins, and the rebuttal testimony of Ms. Birmingham-Byrd and Mssrs. Davey and Hevert moot because that evidence addressed issues related to the recovery of T&D Plan costs through the TDSIC mechanism and ongoing reporting requirements. Therefore, we have not summarized that evidence in this order.

4. **Summary of the Evidence.**

A. **Duke's Direct Evidence.** Ms. Birmingham-Byrd testified that in developing the T&D Plan, Duke focused on improvements that maintain reliability and modernize the T&D grid to enable additional value-added customer services and options now and in the future. Ms. Birmingham-Byrd testified that system reliability is a core value that will be maintained by the T&D Plan. Replacing aging infrastructure, targeting degrading components, upgrading equipment, and improving poor performing circuits will help to maintain a safe, reliable T&D system. The modernization components of the T&D Plan will enable the deployment of enhanced equipment providing more timely and accurate information about outages to customers. Customer outages can be pinpointed and restored more efficiently through the distribution automation and advanced metering investments. Near-term customer benefits include hourly interval usage data (next day) through a unique website portal, allowing customers to better understand their energy usage and save energy, and the convenience of remote turn off / turn on for customer moves. Future, advanced-metering benefits could include time-differentiated peak pricing rates, pay as you go billing options, pick your own due date options, and customer usage alerts.

Ms. Birmingham-Byrd testified that the T&D Plan cost estimates are Duke's best estimates of the costs at this time; however, these estimates are preliminary and high-level until project parameters can be identified with more specificity and detailed engineering work completed to enable a better cost estimate. Even the more detailed year-one estimated costs provided in Mr. Atkins' Confidential Exhibit B-4 are subject to change on a project or component basis as the T&D Plan develops, engineering progresses, and contracts are entered into for labor, materials, and construction. Duke will provide updated projects and cost estimates annually in one of its semi-annual filings, so stakeholders and the Commission are aware of any changes. Ms. Birmingham-Byrd also provided testimony concerning the reasonableness of the overall rate impact of the T&D Plan. Duke is aware of the need to balance rate impacts with the need and value of the T&D Plan. As a result, the average annual rate impact is approximately 1%, below the 2% annual cap imposed by Ind. Code § 8-1-39-14(a).

Ms. Birmingham-Byrd provided testimony regarding the economic development impacts on the State of Indiana. Duke's T&D Plan focuses on economic development in two ways. First, the T&D Plan includes an economic development plan component that is focused on providing needed site improvements for new or existing customers. In turn, these new or existing customers will be providing new jobs or investment to the State of Indiana. Second, Duke has estimated the economic development impact of the investments contained in the T&D Plan. The proposed T&D Plan is estimated to create or support an estimated average of 2,700 jobs per year for each of the seven years of the plan (or 840 jobs per year in Indiana). These jobs include both direct jobs and indirect or induced jobs that are created or supported by the T&D Plan investment. The T&D Plan is also estimated to produce about $184 million in additional state and local tax revenue. The direct jobs created from this investment will be a mix of contractor and direct employee hires, and could include construction and maintenance, engineering, project management, operating, and other technical support positions.

Mr. Atkins provided an overview of Duke's transmission and distribution system, explained in detail the overall goals of the T&D Plan, summarized the Distribution and Other T&D projects, provided cost estimates for those projects, and explained the final results of the Black & Veatch risk profile analysis. Duke owns and operates approximately 5,800 miles of transmission lines, 12,000 miles of distribution lines, and 400 substations in Indiana. Duke has approximately 810,000 customers in Indiana, most of whom have electro-mechanical meters. A significant portion of Duke's transmission and distribution system was constructed in the 1960s, 1970s, and 1980s, and is nearing or has exceeded its original life expectancy. Duke hired Black & Veatch to conduct a system risk analysis that enabled Duke to prioritize projects that would strategically lower the risk profile of the T&D system.

Mr. Atkins provided Petitioner's Exh. B-1, which has summaries of each project included in the T&D Plan, including the seven-year budget for the project, the first year budget for the project, a description of the project scope, the current and desired state of the project, the project benefits, and the risks associated with not doing the project. Mr. Atkins divided the four categories of the T&D Plan into 40 project types or categories in Petitioner's Exh. B-3. Mr. Atkins also provided Petitioner's Exh. B-4 (confidential), which includes more information on the project scope for the project categories included in year one of the T&D Plan including the number and location of individual planned projects. Duke will further refine the cost estimates for each year of the T&D Plan in its semi-annual T&D Rider No. 65 filings.

Mr. Atkins testified that the seven-year estimated cost of the T&D Plan is $1,868,050,000. He testified that Duke has significant estimating experience with projects such as these. Many of the projects are accelerations of existing programs or projects Duke performs annually. Others are new technologies for Duke, but Duke relied on similar investments in other Duke Energy jurisdictions for its cost estimating. Mr. Atkins testified that the estimates reflect a reasonable view of the expected costs at this time. Duke also engaged Black & Veatch to review its cost estimates for reasonableness, and this independent review confirmed Duke's estimates. He explained that Duke would expect changes and refinements to the cost estimates contained in the T&D Plan and its proposed semi-annual Rider review process will allow Duke to timely inform the Commission and stakeholders of any significant changes.

Mr. Atkins testified that the communication replacement project included in this category is a high-level estimate because a technology solution has not been selected. Over the next two years the radio replacement plan will be continually reviewed and updated to reflect the most current state of the program and the best technological solution for the communication needs of the business. This project is targeted for 2017/2018 and updates will be provided annually in one of Duke's semi-annual T&D Rider filings.

Mr. Atkins testified that the mobile deployment and innovation project involves deployment of mobile data terminals to all distribution field workers to improve real-time dispatch, outage status, and event support. It will allow real-time two-way communication with first responders and T&D field workers. This improved information flow between dispatch and field workers will allow for more efficient customer order work and outage restoration.

Mr. Atkins testified that the distribution operation center renovations program is directed to modify Duke's current multifunction facilities to be more purpose-designed and to support a much more technologically dependent distribution system work force. The transmission and distribution control center upgrade project will advance these facilities to current state-of-the-art support centers that complement the capabilities of the modern electric grid. This project will enable fault location, mobile data and dispatch, and increased customer information about distribution grid performance. The development of a Transmission & Substation Asset Performance Center would allow enhanced analysis and monitoring of outages and events on the delivery system. This will provide for a more efficient system and should reduce outage restoration time.

Mr. Atkins testified that the Envision Center would be an educational center used for community outreach so that Duke can engage the public, schools, universities, community groups, local governmental officials, and others about the benefits of its grid modernization efforts. He stated that this is a unique opportunity for Duke because this will be the first full-scale rollout of distribution automation and advanced metering infrastructure technology in the State of Indiana by a large electricity supplier. Duke currently plans to locate the Envision Center on or near the Duke Energy campus in Plainfield, Indiana to allow centralized access for much of its service territory.

Mr. Atkins described the economic development site readiness program. The project would be used to fund facility modifications, alternate source needs, or other T&D system improvements that would be beneficial to the promotion of economic growth in the State of Indiana. Mr. Atkins testified that this proactive approach to site-readiness capacity upgrades and a redundant, networked system will help draw customers to Indiana. These funds will be used as new customer sites or expansions are identified and will be limited to investments in the T&D system.

Mr. Atkins testified that the real-time customer Personal Mobile Device communication project includes the installation of a customer communications software system designed to provide customers information relevant to the T&D systems, such as outage notifications, estimated time of restoration, and outage causation. This system will connect with systems such as outage management and customer billing and proactively communicate with customers based on what they have requested and their preferred method of communication.

Mr. Atkins testified that the vegetation management components of the T&D Plan will increase the reliability of Duke's transmission and distribution system. The components include a capital program directed at the removal of hazard trees that pose a risk of striking electric facilities, facility relocation, and right-of-way acquisition for facilities experiencing high-frequency, vegetation-related outages, and incremental O&M required to bring the vegetation management program in line with an industry-standard, five-year trim cycle. The first two programs are existing capital projects that will be accelerated as part of the T&D Plan. The O&M vegetation management project is also an existing project. However, the project size was determined by comparing vegetation management expense in the last rate case relative to the current annual spend required to implement the five-year trim plan.

Mr. Atkins testified that the Integrated Volt-VAR Controls ("IVVC") project provides real-time monitoring and the ability to make voltage adjustments to the distribution system, which is estimated to ultimately reduce overall system voltage by approximately 2% on impacted circuits. This results in a 1% load reduction on average for impacted circuits, providing cost savings to customers. In addition, IVVC can be used for peak reduction during high-use conditions. Duke completed a business case cost / benefit analysis which demonstrated that the IVVC project is estimated to provide a benefit of $240 million over a 20-year life.

Mr. Atkins also described how Duke will update the Commission and intervenors if there are changes to the T&D Plan. Duke plans to make updates to its 7-year transmission plan annually. Duke will also update its risk analysis with completed projects and an updated assessment of the future needs for upcoming years. This risk model will be used to produce future year capital plans and will be submitted for review to the Commission, OUCC, and intervening parties annually in one of its semi-annual T&D Rider proceedings.

Mr. Atkins testified that public convenience and necessity require each component of the T&D Plan. The plan reduces operational risk through replacement of aging infrastructure, improves the operational efficiency of Duke's transmission and distribution system, improves the overall customer experience, and will enable a number of customer benefits and programs in this filing and in future years. Mr. Atkins further testified that the estimated costs of the T&D Plan justify the incremental benefits of the Plan. He stated that the projects and programs included in the T&D Plan are reasonable, necessary, and justified by significant reliability and modernization benefits.

Mr. Kramer provided testimony on the transmission projects included in the T&D Plan. Duke operates a transmission system consisting of approximately 5,800 miles of transmission lines operated at 69 kV to 345 kV and about 400 transmission substations, which include distribution assets. Duke has a significant number of transmission assets that are approaching or have exceeded their estimated physical service lives. There are 12 transmission categories within Duke's T&D Plan targeted at replacing, rebuilding, and modernizing these assets. Improvements made to the transmission system will improve reliability and telemetry through relay replacement and two-way communication. Investments in the 69 kV transmission system will reduce the number of system faults, improving reliability through a reduction of the frequency and duration of service interruptions and voltage sags.

Mr. Kramer described the planned transmission projects for the first year of the Plan. He stated that these projects were selected from lists of candidate equipment or projects based on a combination of factors including identified condition or age of the equipment, feedback from maintenance personnel, project efficiencies and savings from combining engineering or labor from several projects, coordinating project schedules to correspond with planned outages or other planned work, and the individual risk assessment scores from the Black & Veatch risk study. The most significant first-year projects in the Plan are:

(1) Transmission Relay Upgrade—Tiers I and II: installation of new microprocessor-based relays with additional functionality including full two-way communication and the

ability to provide distance to fault, which will allow improved restoration following an outage and increased immunity to geomagnetic-induced currents.

(2) Transmission Breaker Replacement: replacement of obsolete oil breakers, high-volume SF6 gas breakers, and other high-maintenance gas breakers with new gas breakers that have greater interrupting capability, improved reliability, and reduced environmental issues from oil spills and SF6 gas discharge.

(3) 69 kV Circuit Integrity Improvement: rebuilding selected transmission lines or line sections that contain aged or deteriorating components such as wood poles and cross-arms, insulators, conductors, and static wires to improve the overall reliability of the 69 kV circuits.

(4) Aluminum H Structure Replacement: replacing self-supporting 345 kV aluminum H-frame structures with new steel poles to decrease exposure to failures.

Mr. Kramer testified that these selected projects constitute $580.5 million of the overall approximate $753 million transmission category seven-year expenditures of the T&D Plan. The cost estimates were developed from internal estimating procedures and validated by Black & Veatch. He testified that the cost estimates are reasonable and will evolve as more information becomes available on the specific project being constructed in any given year. Duke needs flexibility within its T&D Plan to identify new or changing needs of the delivery system as the program progresses. Duke will update the transmission plan on an annual basis defining future years based on risk reduction and system performance improvement providing the best utilization of future capital.

Mr. Schneider provided a detailed overview of the Advanced Metering Infrastructure ("AMI") proposal. Duke proposes the implementation of an advanced metering solution across its Indiana service territory, which is estimated to include approximately 817,000 advanced meters and associated communications and IT infrastructure. The project consists of a four-year phased deployment for most of Duke's residential and commercial customers. This will not include meter replacement for larger commercial and industrial customers that already have an advanced metering solution. Duke plans to collect interval kilowatt-hour usage on all meters for billing purposes and time-tagged event and alert data such as tamper alerts for more efficient theft detection.

Mr. Schneider testified that the AMI plan includes advanced meters, a two-way communication network, and central computer systems. Duke will install a neighborhood area network ("NAN") to create the two-way communications path to the advanced meters. The NAN will use flexible mesh networks to establish an optimized communication path. Collection point devices aggregate the communications from all advanced meters with a NAN and communicate the information over a wide area network ("WAN") to the central computer systems. Collection point devices also communicate commands, firmware/program updates, and instructions from the central computer systems out to the advanced meters. Duke will utilize a virtual private network over a public cellular network in Indiana as the WAN.

Mr. Schneider described the changes customers will see in their service after the new metering is installed, including: (1) the ability to view the previous day's hourly interval usage data via Duke's web portal; (2) meter reads through the AMI communication network rather than walk-by meter reads or estimated bills; (3) remote activation and deactivation of service; and (4) the ability for Duke to better identify isolated outages more readily and restore service more efficiently. AMI could also enable such future offerings as dynamic pricing, flexible billing, and alternative payment options.

Mr. Schneider testified that Duke issued a request for quotes to the leading AMI vendors within the United States for bid proposals. After evaluation of the proposals, Duke concluded Itron was best aligned with Duke's overarching grid strategy and architectural guidance. The estimated cost for deploying the AMI is about $181 million over the first four years of the 7-Year T&D Plan, which includes the cost of technology components and the installation labor for the AMI meters, communication devices/grid routers, and IT systems.

Mr. Schneider testified that Duke looked at the proposed costs of AMI and compared those costs to quantifiable benefits, such as savings from meter reading. He testified that the main quantifiable benefits arise from the elimination of monthly manual meter reads, enhanced theft detection that can be conducted without a truck roll, and the ability to conduct customer-requested service disconnects and reconnects remotely. Based on the business case, over a 20-year period, the net present value of the AMI solution is estimated to be approximately $38 million. Essentially, the analysis demonstrates that over 10.4 years the investment in the advanced metering solution pays for itself. Mr. Schneider testified that the business case cost/benefit analysis demonstrates that there are quantifiable benefits that outweigh the costs of the AMI project. Additionally, there are qualitative benefits and future functionality that will result in further benefits.

Mr. Williams testified that Black & Veatch prepared the following analyses: (1) a risk model to identify the investment required to replace aging T&D infrastructure; (2) an independent review of capital cost estimates to evaluate the reasonableness of Duke's unit cost assumptions; and (3) an economic impact analysis to estimate the economic impacts that would result from the T&D Plan.

Mr. Williams testified that the risk modeling was performed by analyzing and quantifying the risk reduction Duke may achieve through its T&D Plan. It utilizes a risk-based planning approach in which the majority of the T&D Plan investments are evaluated with respect to how they reduce asset risk on Duke's T&D system. This approach allows Duke to prioritize and optimize its T&D Plan to focus investment on high-risk assets. The results of the analysis showed that the proposed T&D Plan would reduce the total T&D system risk by 21% over the seven-year period, driven by significant substation- and circuit-risk reduction (18% and 27%, respectively). Mr. Williams testified that Duke's T&D Plan is a balanced, optimized plan that prioritizes investment for eligible transmission, distribution, and storage system improvements using risk reduction as a primary objective.

Mr. Williams testified that Black & Veatch conducted an independent cost review of Duke's T&D planning capital cost estimates and estimating process, based on their knowledge

and experience with similar T&D project capital cost estimates. Black & Veatch concluded that the project cost estimates and unit cost estimates reviewed were reasonable and within the typical band of uncertainty seen across the industry for capital planning and cost forecasting purposes. Mr. Williams said that Duke's cost estimating process was reasonable.

Mr. Williams testified that Black & Veatch performed a study to evaluate the economic impact of the T&D Plan. Black & Veatch performed this analysis using the Impact Analysis for Planning Modeling application, which is widely used in the energy industry to measure such impacts. The results show that the total economic impacts to the State of Indiana include 5,882 jobs created or supported, over $400 million in labor income, and $1.11 billion in value-added gross domestic product. The analysis considered possible job losses associated with Duke's move to AMI metering. The results estimate that while there may be some job reductions due to the AMI investments, other job increases will occur to offset the losses and create an overall job gain in Indiana.

B. WVPA's Direct Evidence. Mr. Wagoner testified that WVPA is supportive of Duke's T&D Plan. WVPA is a transmission customer that provides electric service to approximately 335,000 retail customers. WVPA, Duke, and IMPA jointly own, operate, and maintain their transmission facilities in Duke's Balancing Authority Area in Indiana (the "Joint Transmission System"). WVPA has substantial rights to use the Joint Transmission System and substantial obligations for investment in the Joint Transmission System.

Mr. Wagoner testified that WVPA and its members have experienced an increasing trend in the number and duration of transmission-related outages due to aging transmission infrastructure. On average over the past five years transmission-related outages account for 35% to 40% of total outage duration on distribution cooperatives' systems. Increased investment in the Joint Transmission System will reduce the number and duration of transmission-related outages thus improving overall reliability to WVPA's distribution cooperative members and their retail customers.

Mr. Wagoner testified that, in connection with Duke's T&D Plan, WVPA estimates that it will invest approximately $100 million in the Joint Transmission System over the next seven years. Mr. Wagoner testified that WVPA and its members have invested millions of dollars in distribution automation and self-healing on the members' distribution-system circuits over the past several years. Twenty-two of WVPA's members currently have AMI deployed.

C. EDF's Direct Evidence. Mr. Munson testified that any data relating to demand, power quality, availability, voltage, frequency, current, power factor, or other information generated by the AMI meters should be made available to both the customer and the utility. Customers should have access to their retail electric consumption data in the shortest intervals possible—he recommended 15-minute intervals—but never in intervals greater than one hour.

Mr. Munson recommended that Duke supplement its filing to include cost-benefit analyses for the following: (1) providing data access directly from the meter so customers could connect in-home devices to see, understand, and take charge of their electricity usage

immediately; (2) providing data access to customers and their designated third-parties through standards-based data protocols so that customers can use third-party web or mobile applications or join innovative new business models that require quick and easy access to metering data; and (3) providing smart thermostats and in-home monitors to customers, which would allow them to see their energy usage in real time: Mr. Munson testified that if the study shows that it would be cost-effective to do so, Duke should include smart thermostats, in-home monitors, and Green Button-Connect My Data features in its deployment plan. Mr. Munson also recommended that Duke (through the collaborative stakeholder process) file a proposal with the Commission within six months of the Commission's order, in which Duke sets forth a proposal for access to energy usage data by customers and third parties. Mr. Munson also recommended that the Commission require Duke to implement time-variant pricing plans within six months from the Commission's order approving the T&D Plan. He stated that without requiring time-variant pricing, the customers would be forced to pay for the improvement plan but would not receive the plan's full benefits.

D. <u>Duke's Rebuttal Evidence</u>. Mr. Schneider testified that Duke does not believe its business case should assume some benefits of AMI, such as energy efficiency savings based upon customer behavior, given they are more difficult to quantify due to the dependence on customer behavior. He stated that Duke built its business case based on readily identifiable and uncontroversial benefits, but it does not dispute the existence of other potential benefits of AMI, such as energy savings due to more enhanced energy usage data. Instead, those benefits would be provided directly to customers based on the customers' actions, which underscores Duke's position that customers can benefit from the AMI deployment prior to Duke's rate case filing.

Mr. Schneider testified that Duke's proposed collaborative approach to developing customer pricing options enabled by AMI is a reasonable means to gain agreement on the detailed parameters of time of use rates and peak rebate pricing pilot programs. Duke proposes to meet with interested stakeholders within 60 days of the Commission's order approving AMI, where Duke will propose a pilot time-of-use option and a pilot peak time rebate or critical peak pricing option for residential and small commercial customers. Duke is willing to work with interested stakeholders on the design of the initial pilot programs with the goal of filing for pilot program approval within six months of the first collaborative meeting. Such a schedule would allow potential customer participation in pilot pricing offerings while the AMI rollout occurs over the planned 4.5-year period. Duke is also willing to discuss a smart thermostat program and is willing to commit to an investigation in 2015 of a smart thermostat energy efficiency and demand response program.

Mr. Schneider testified that Mr. Munson's recommendation for Duke to utilize "Green Button" to share data with customers and third parties is not prudent at this time. The more prudent course of action is scaling up its existing customer web portal functionality to make interval data available to customers. This will allow Duke to use existing company resources to share data with customers. The customer web portal will enable customers to download their energy usage data, at which point they can decide whether and how to share their own data with third parties.

5. **Commission Discussion and Findings.** Ind. Code § 8-1-39-10(a) says: "A public utility shall petition the commission for approval of the public utility's seven (7) year plan for eligible transmission, distribution, and storage improvements." A plan submitted under Ind. Code § 8-1-39-10 may include a "targeted economic development project described in [Ind. Code § 8-1-39-11] . . . ." *Id.* In order to approve a seven-year plan, the Commission must first make the following specific findings:

> (1) A finding of the best estimate of the cost of the eligible improvements included in the plan.
> (2) A determination whether public convenience and necessity require or will require the eligible improvements included in the plan.
> (3) A determination whether the estimated costs of the eligible improvements included in the plan are justified by the incremental benefits attributable to the plan.

Ind. Code § 8-1-39-10(b).

A. **Eligible Transmission, Distribution, and Storage System Improvements and Public Convenience and Necessity.** Ind. Code § 8-1-39-2 defines "eligible transmission, distribution, and storage system improvements" as new or replacement electric or gas transmission, distribution, or storage utility projects that:

> (1) a public utility undertakes for the purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas;
> (2) were not included in the public utility's rate base in its most recent general rate case; and
> (3) either were:
> (A) designated in the public utility's seven (7) year plan and approved by the [C]ommission under [Ind. Code § 8-1-39-10] as eligible for TDSIC treatment; or
> (B) approved as a targeted economic development project under [Ind. Code § 8-1-39-11].

In construing a statute, our primary goal is to determine and give effect to the intent of the Legislature. *Ind. Civil Rights Comm'n v. Adler*, 714 N.E.2d 632, 637 (Ind. 1999). When the statute is clear and unambiguous, we need not apply any rules of construction other than to require that words and phrases be given their plain, ordinary, and usual meanings. *City of Carmel v. Steele*, 865 N.E.2d 612, 618 (Ind. 2007).

Black's Law Dictionary defines an improvement as an "addition to real property, whether permanent or not; esp., one that increases its value or utility . . . ." 773 (8th Ed. 2004). This definition is consistent with the use of the term improvement throughout Ind. Code ch. 8-1-39. For example, Ind. Code § 8-1-39-7, in defining TDSIC costs, refers to costs incurred both while the improvements are under construction and post in service. Ind. Code § 8-1-39-9(a) and (b)

allow a utility to recover capital expenditures and TDSIC costs. Our definition excludes other types of expenses such as operations and maintenance expenses or labor expenses that are not associated with the construction of an improvement. This definition raises a threshold question of what is the real property to which eligible improvements may be made.

Ind. Code § 8-1-39-2 requires eligible projects to be improvements to Duke's transmission, distribution, or storage "system." Ind. Code ch. 8-1-39, which addresses TDSIC recovery, is similar to Ind. Code ch. 8-1-31, which addresses recovery of distribution system improvement charges by a water utility ("DSIC") and predates Ind. Code ch. 8-1-39. 170 IAC 6-1.1-1(c) defines a distribution system for purposes of a DSIC proceeding as distribution mains, valves, hydrants, service lines, meters, meter installation, and other appurtenances "necessary to transport treated water from . . . the treatment facility to . . . the customer." In *Ind.-American Water Co.*, we distinguished a water utility's distribution system from other parts of its utility infrastructure, such as its source of supply, treatment plant, and storage facilities. 2003 Ind. Cause No. 42351 DSIC 1, 2003 Ind. PUC LEXIS 362, at *46-47 (IURC Feb. 27, 2003).

Similarly, within the context of electric utility service, the plain meaning of a transmission and distribution system is the infrastructure necessary to transmit electricity from the generation facility to the customer. This includes, at a minimum, power lines and poles, substations, transformers, and meters.[2] It does not include projects that are not necessary to transmit electricity to the customer or projects that, though they may be tangentially related to the transmission and distribution of electricity, are not part of the transmission and distribution system.

B. <u>Ineligible Projects</u>. Our analysis of Ind. Code § 8-1-39-2 and our definitions of transmission and distribution system improvements call into question whether several of the projects in Duke's proposed T&D Plan are eligible transmission, distribution, and storage system improvements.

1. <u>Other T&D Projects</u>. The collection of projects listed under "Other T&D" in Duke's T&D Plan includes expenses for some projects that do not replace existing transmission or distribution system infrastructure and are not new transmission and distribution projects. These projects include the following:

- replacing a vehicle radio communications system ($30M);
- a separate real-time, two-way communication and dispatch system ($2.5M);
- a customer contact software system for cell phones and other mobile devices ($1.5M); and
- the Envision Center, a $3M "energy learning center" used to demonstrate to the public, schools, universities, community groups and local governmental officials how energy infrastructure is changing.

Duke argues that improved communications between repair crews and with the dispatch center will reduce outage time and improve system reliability and safety. Duke also argues that

[2] Duke did not include any storage system projects in its seven-year plan. Therefore, we need not address the definition of a storage system improvement.

the customer communication software and Envision Center will allow it to provide relevant information to customers such as outage notifications and estimated restoration times and to educate customers and the community about new energy technologies. Even accepting that as true, however, we find that the projects are well beyond the scope of the system improvements contemplated by Ind. Code § 8-1-39-2. The projects are not part of an existing or new transmission or distribution system. The projects are not infrastructure improvements necessary to transmit electricity from generation to the customer. Our finding does not prevent Duke from seeking recovery for the projects through some other statutory mechanism or as part of a traditional base rate case, but they may not be included in Duke's T&D Plan.

2. **Vegetation Management.** Similarly, Duke's proposed vegetation management projects ($48.5M categorized as Transmission or Distribution O&M, plus nearly $74M categorized as "Capital Investment") do not fall within the meaning of "eligible transmission, distribution, and storage system improvements" under Ind. Code § 8-1-39-2. The only reference to O&M in Ind. Code ch. 8-1-39 is in Ind. Code § 8-1-39-7, which includes "[o]peration and maintenance expenses" in the definition of TDSIC costs. But the statute qualifies the definition to mean costs "incurred with respect to eligible transmission, distribution, and storage system improvements incurred both while the improvements are under construction and post in service." Thus, O&M expenses are only recoverable if they are related to a system improvement project—otherwise, they do not qualify as a system improvement project. This is confirmed by Ind. Code § 8-1-39-9, which authorizes recovery only of capital expenditures and TDSIC costs.

We recognize that reduced outages, operational benefits, and improved facilities integrity are potential vegetation management benefits. For this reason, the Commission routinely includes the recovery of vegetation management expenses in a utility's base rates. Mr. Atkins testified that Duke already recovers vegetation management expense through the rates authorized in its last case, but that Duke proposed to use the TDSIC statute to accelerate its vegetation management program and bring it in line with industry standards. That is simply not the purpose of the TDSIC statute. Therefore, Duke may not include vegetation management O&M in its T&D Plan.

As part of its vegetation management category, Duke included capital clearing of vegetation associated with the installation of transmission and distribution system infrastructure. While we find that, in general, vegetation management O&M expense is not an eligible system improvement project under Ind. Code § 8-1-39-2, it is possible that capital clearing of vegetation associated with the installation or replacement of transmission or distribution system infrastructure would be a recoverable TDSIC cost under Ind. Code § 8-1-39-7(2).

3. **Economic Development.** As part of its T&D Plan, Duke proposed an economic development site readiness fund that could be used to fund facility modifications, alternate source needs, or other T&D system improvements that would be beneficial to the promotion of economic growth in Indiana.

Duke's proposed economic development fund is not a system improvement project at all. Duke has not identified any specific or even general system improvement project related to

economic development. Rather, Duke requests the creation of an economic development fund that it could utilize for future projects as the need arises. Absent any detail whatsoever about the proposed economic development projects, it is impossible for us to make the required findings under Ind. Code § 8-1-39-10—the best cost estimate, whether public convenience and necessity require or will require the improvements, and whether the benefits justify the estimated costs. Therefore, the proposed economic development site readiness fund may not be included in Duke's T&D Plan.

C. **Insufficiency of the Cost Estimates.** Ind. Code § 8-1-39-10(b)(1) requires the Commission to make a finding of the best estimate of the cost of the eligible improvements included in a T&D plan. The term "best estimate" is not defined in Ind. Code ch. 8-1-39. But we have addressed a best estimate finding in the context of new construction. Ind. Code § 8-1-8.5-5(b)(1) requires the Commission to make a best estimate of costs finding in the context of granting a certificate of public convenience and necessity for the construction of a new powerplant. In *Indianapolis Power & Light Co.*, we found that IPL had provided a best estimate of the costs of constructing a new generation facility. Cause No. 44339, 2014 Ind. PUC LEXIS 132, at *70 (IURC May 14, 2014). We noted that IPL had taken "substantial steps to firm up the cost estimate presented in this case," including detailed engineering analysis and discussions with turbine manufacturers and contractors. *Id.*, at *67. IPL's cost estimate was based on a "detailed 600+ line item cost build-up." *Id.*, at *65.

Similarly, in *N. Ind. Pub. Serv. Co.*, we considered cost estimates in the context of a request for a CPCN for the construction of Clean Coal Technology under Ind. Code ch. 8-1-8.7. Cause No. 44012, 2011 Ind. PUC LEXIS 387 (IURC Dec. 28, 2011). Ind. Code § 8-1-8.7-4(a) requires a utility to file an estimate of the costs of its proposed projects "in as much detail as the [C]ommission requires." In that case we discussed the level of detail we expect in cost estimates.

> We believe that a one-size-fits-all approach to a standardized cost estimate accuracy and/or a standardized level of engineering to be done before filing [a case for project approval] is not a reasonable or appropriate expectation because the circumstances surrounding the utility's need for the project may dictate differently.

Id., at *50-51. Utilities must balance the unique factors of each project or filing and determine the appropriate amount of engineering to be performed up front. *Id.* at *51. This is especially true in a case like this one that involves projects spread over the next seven years—we would not necessarily expect the same level of estimate accuracy in a year-seven project as we would in a year-one project.

While the new generation project in Cause No. 44339 was more complex than most of the projects proposed in Duke's T&D Plan, the difference in the quality of the evidence presented in the two cases is striking. Petitioner's Exh. B-1 includes one-page summaries of each of the proposed projects in the T&D Plan. Each page includes the estimated first-year and 7-year costs; a projected timeframe for completion, expressed as a series of years; a project description; a description of the current and desired state of the equipment; a summary of the projected benefits of the project; and a list of risks of not doing the project. Petitioner's Exh. B-2 is a 7-

year summary of the proposed T&D Plan and includes a total estimated cost for each of the four project categories. Petitioner's Exh. B-3 shows the estimated capital investments, by year, and the total estimated 7-year cost for each of the projects included in Petitioner's Exh. B-1. Petitioner's Exh. B-4 (Confidential) shows the first-year estimated cost for each of the projects included in Petitioner's Exh. B-1, and provides slightly more specific detail about the first-year projects.

Mr. Atkins said that Duke focused on providing more detailed estimates for the first year of the T&D Plan. As such, Duke provided little specific information about any of the projects for years two through seven, aside from an annual estimated cost. Duke did not provide any detail or workpapers showing how the cost estimates were derived. Duke did not provide line-item breakdowns of the estimated costs, for example, for materials and labor. Although Ind. Code § 8-1-39-7 defines five specific elements of TDSIC costs, depreciation, O&M, extensions and replacements, property taxes, and pretax returns, Duke did not breakdown its cost estimates into even these basic categories. Further, Duke's own evidence shows that such information was available to it prior to filing its case-in-chief. Mr. Williams testified that Duke provided Black & Veatch "detailed material and labor estimates for specific planned projects that provide a line item breakdown of costs that include quantities, materials, and labor costs." Petitioner's Exh. E, at 15. Duke also provided Black & Veatch with regularly updated bids from a variety of material vendors that supply [Duke] with equipment and services." *Id.* But this information was not provided to the Commission or the other parties.

In support of its cost estimates, Mr. Atkins testified that Duke has significant estimating experience with these projects and that many of the projects are accelerations of existing programs or projects. With respect to new technologies, Mr. Atkins testified that Duke relied on similar investments by other Duke Energy Corporation subsidiaries. Mr. Kramer testified only that the cost estimates "were developed from internal estimating procedures developed by the transmission scope and estimating team." Petitioner's Exh. C, at 8. But Duke did not provide any documentation to support these claims. Duke did not provide any historical cost information or detailed testimony about its internal estimation procedures. Nor did Duke provide any technical workpapers to demonstrate how the costs were derived.

Duke also argues that its estimates are supported by an independent review by Black & Veatch. Mr. Williams described the Black & Veatch estimates as AACE Class 5 estimates as defined by the American Association of Cost Engineers ("AACE"). He explained that a Class 5 estimate is a basic cost estimate used for feasibility analysis and long-range capital planning. A Class 5 estimate is the least detailed level of estimate and carries the widest range of variance. AACE International Recommended Practice No. 17R-97: Cost Estimate Classification System, at 2 (August 12, 1997). A Class estimate 5 is defined as a screening or feasibility level and is characterized by a level of project definition of 0% to 2%. *Id.*

We recognize that the circumstances of a project dictate the appropriate range of accuracy, and the estimate of a project that is six or seven years in the future will not have the same accuracy as a first-year project. But Duke provided only Class 5 estimates for all projects in the T&D Plan. In the absence of any sufficient evidence to support Duke's cost estimates, even for the first-year projects in the T&D Plan, we cannot find that the estimated costs are the

best estimate of the costs of the eligible improvements as required by Ind. Code § 8-1-39-10. It is not enough for Duke, or even Black & Veatch, to simply assure us that the costs estimates are reasonable or best estimates. Duke must estimate its costs with a sufficient level of accuracy and supply evidence to allow the other parties and the Commission to conduct their own independent analysis of the estimated costs.

D. Insufficiency of the T&D Plan. On February 17, 2014, the Commission issued an order in *N. Ind. Pub. Serv. Co.*, Cause No. 44370, approving a seven-year plan for eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-10(a). 2014 Ind. PUC LEXIS 38 ("NIPSCO Order"). In that case, NIPSCO presented a seven-year plan in a manner similar to Duke's T&D Plan. That is, NIPSCO presented more detail for its first-year projects, and summarized the projects and estimated costs for years two through seven of the plan. The Commission approved NIPSCO's seven-year plan, specifically approving the year-one projects and created a rebuttal presumption that the projects in years two through seven were reasonable. *Id.*, at *41.

The court of appeals reversed the NIPSCO Order in part and remanded the case for further proceedings. *NIPSCO Industrial Group v. N. Ind. Pub. Serv. Co.*, 2015 Ind. App. LEXIS 292, at *39. The court determined that NIPSCO's seven-year plan did not contain enough detail for the Commission to determine whether the plan for years two through seven was reasonable or to determine a best estimate of the cost of the improvements. *Id.*, at *14. The court also reversed the Commission's creation of a presumption of eligibility for projects in years two through seven of NIPSCO's plan without any statutory authority to do so. *Id.*, at *17.

Duke's proposed T&D Plan includes 40 distinct projects within four broad categories over seven years beginning with calendar year 2015. The broad categories are: Transmission, Distribution, Other T&D, and Vegetation Management O&M Investments. At most, Duke's T&D Plan contains a comparable level of detail to that submitted by NIPSCO in Cause No. 44370. In light of the court's analysis and the numerous issues with Duke's T&D Plan that we discussed specifically above, we find that Duke's proposed T&D Plan does not contain sufficient detail for us to make the findings required by Ind. Code § 8-1-39-10. Therefore, we deny Duke's request for approval of the T&D Plan. In light of our denial of the T&D Plan, the remaining issues raised by Duke and the other parties are moot.

6. Confidentiality. Duke filed motions for protection of confidential and proprietary information on August 29, 2014, and December 16, 2014. In the motions and supporting affidavits, Duke demonstrated a need for confidential treatment for: (i) information related to Duke's prospective transmission and distribution projects specific to the identity of transmission and distribution system assets; (ii) detailed cost information for the T&D projects; and (iii) information independently compiled and developed by third-parties used in measuring the financial risk of companies. On September 10, 2014, and January 8, 2015, respectively, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Duke's request for approval of its T&D Plan is denied for the reasons set forth above.

2. All other requests for relief are denied as moot.

3. The confidential information filed by Duke in this Cause pursuant to preliminary determinations of confidentiality by the Presiding Officers is deemed confidential under Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana Law, and shall be held confidential and protected from public access and disclosure by the Commission.

4. This Order shall be effective on and after the date of its approval.

HUSTON, WEBER, AND ZIEGNER CONCUR; MAYS-MEDLEY CONCURS WITH SEPARATE OPINION; STEPHAN ABSENT:

APPROVED: MAY 08 2015

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission

MAYS CONCURRING SEPARATELY

I concur with the majority in the denial of Duke's T&D Plan. But I write separately to address the issue of economic development projects.

Ind. Code § 8-1-39-2(1) defines eligible system improvements to include projects that a public utility undertakes for purposes of economic development. This is the only unqualified use of the term economic development in Ind. Code ch. 8-1-39. Ind. Code § 8-1-39-2(3)(B) defines an eligible system improvement to include "targeted economic development" projects that are approved under Ind. Code § 8-1-39-11. In addition, Ind. Code §§ 8-1-39-5, 8-1-39-7, 8-1-39-9(a), 8-1-39-10, and 8-1-39-11 all refer specifically to "targeted economic development" projects. Ind. Code § 8-1-39-5 defines a "targeted economic development project" as a project approved by the Commission under Ind. Code § 8-1-39-10(c), which applies only to a utility that provides gas service. Similarly, Ind. Code § 8-1-39-11 applies only to equipment installed to provide gas service to a targeted economic development project. Nowhere in Ind. Code ch. 8-1-39 does a statute refer specifically to an economic development project associated with the provision of electric utility service.

I had concerns previously regarding the interpretation of an economic development project in Ind. Code ch. 39. Now that the issue is before the Commission again, there is an opportunity to voice my opinion regarding the intent of the TDSIC statute. I closely followed this legislation during the 2013 legislative session, and it was clear to me that the discussions included only gas economic development. In light of this and the analysis of the plain language of the statute above, it is clear that the Legislature intended the economic development provisions of the Ind. Code ch. 39 to apply only to gas utilities. Therefore, I believe that the targeted economic development projects contemplated by Ind. Code ch. 8-1-39 are limited to eligible system improvement projects to provide gas service and exclude projects for general economic development.