FILED
July 2, 2019
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

VERIFIED DIRECT TESTIMONY
OF
DANIEL G. HANSEN

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

Petitioner's Exhibit 10

July 2, 2019

DIRECT TESTIMONY OF DANIEL G. HANSEN
VICE PRESIDENT, CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, AFFILIATION AND BUSINESS ADDRESS.

A. My name is Daniel Hansen and I am a Vice President at Christensen Associates Energy Consulting, LLC. My principal place of business is 800 University Bay Drive, Suite 400, Madison, Wisconsin 53705. My credentials are set forth in the Petitioner's Exhibit 10-A (DGH).

Q. PLEASE DESCRIBE YOUR INVOLVEMENT IN THIS PROCEEDING.

A. I have been retained by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") to assist them in developing and supporting their revenue decoupling mechanism ("RDM") proposal.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to introduce and support Duke Energy Indiana's proposed five-year RDM program.

II. THE PURPOSE OF THE COMPANY'S PROPOSED REVENUE DECOUPLING MECHANISM

Q. WHAT IS THE PURPOSE OF DUKE ENERGY INDIANA'S PROPOSED RDM?

A. The RDM is intended to complement Duke Energy Indiana's proposed dynamic pricing pilots, potential retail rate design changes, energy efficiency programs, the Company's current volt/VAR optimization project, and address other external changes contributing to reductions in electricity usage by residential and small commercial customers.

Q. HOW WOULD THE PROPOSED RDM ACCOMPLISH THESE OBJECTIVES?

A. Currently, Duke Energy Indiana's rates for residential and small commercial customers (on Rates RS and CS, respectively) consist of a fixed connection charge (*i.e.*, $/month) and declining block energy rates (*i.e.*, $/kWh), where the latter refers to rates that decrease as customer usage increases in a billing month. These rates are set periodically, typically in a base rate case, to collect a specific amount of revenue (the revenue requirements) based on an agreed-upon test-year number of customers and test year weather-normalized sales from the applicable customers. As a result, actual revenues recorded by the Company will vary as the number of customers and their usage varies from the values used to set rates. Because a portion of the energy rates collects revenue to cover fixed costs, when customers use less energy, Duke Energy Indiana experiences a reduction in revenue that is not matched by a reduction in costs.

For residential and small commercial customers, the RDM would make the Company indifferent to the effects of customer demand response to dynamic pricing pilots, modifications to the current default rate designs, implementation of volt/VAR optimization, and successful implementation of energy efficiency programs. In so doing, the RDM would ensure that Duke Energy Indiana is a partner with its customers in helping them find their best rate, helping them respond to the incentives provided by their rate, and reducing long-term costs (thus putting downward pressure on rates over time).

The RDM accomplishes these goals by creating a deferral tracking account in which the difference between allowed and actual revenue toward fixed cost recovery is recorded. Allowed fixed-cost revenue will be determined in this rate case proceeding and is reflective of each customer class's allocated cost of service. As explained in detail later in my testimony, the RDM will establish the total monthly amount of allowed fixed-cost revenue ("RDM allowed fixed-cost revenue") by multiplying the per-customer allowed fixed-cost revenue by the actual number of customers served in the current month. The difference between the RDM allowed fixed-cost revenue and actual fixed-cost revenue from customers will be booked to a RDM deferral account. Over-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is lower than actual fixed-cost revenue) results in a rate decrease in a future period. Conversely, under-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is higher than actual fixed-cost revenue) results in a rate increase in a future period. Through these rate adjustments, the RDM would make Duke Energy indifferent to its residential and small commercial customers' consumption decisions and the success of its volt/VAR optimization efforts.

Q. WHAT RATE DESIGN WOULD DUKE ENERGY IMPLEMENT IF THE PROPOSED RDM IS APPROVED?

A**.** If the proposed RDM is approved, Duke Energy Indiana would implement (subject to Commission approval) rate designs for Rates RS and CS that reflect its unit cost study. These "Scenario 1" rates (as described in the testimony of Company witness Jeffrey R. Bailey) use less steeply declining block energy rates and a somewhat lower customer charge than the "Scenario 2" rates that would be implemented in the absence of the RDM. Relative to Scenario 2 rates, the Scenario 1 rates would improve customer incentives to invest in conservation and energy efficiency, particularly for higher-use customers, as the higher per-kWh rate would increase the return on such investments. In the absence of the RDM, Duke Energy Indiana would be hesitant to implement the Scenario 1 rate designs because they increase the variability in revenue recovery. That is, a higher fixed connection charge combined with more steeply declining block rates would result in a lower rate at the margin for some customers, so that the change in revenue with respect to a change in usage is lower than it would be under the higher and less steeply declining block energy rates. Under the RDM, the utility would be willing to bear the additional variability in revenue because it would refund or recover the deviation from allowed fixed-cost revenue per customer ("RPC") in the following year.

Q. WHAT PRICING PILOT PROGRAMS IS DUKE ENERGY PROPOSING?

A. As described in Duke Energy Indiana witness Mr. Jeff Bailey's direct testimony, Duke Energy Indiana is proposing three optional rates to customers served on each of Rates RS and CS: Critical Peak Pricing ("CPP"), Variable Peak Pricing ("VPP"), and Variable Peak Pricing with Demand ("VPP-D"). Each of these rates offers an event-based component (the Critical or High price) that charges a higher peak-period price on the days with the highest energy costs. The demand charge component in the VPP-D rate provides customers with an incentive to improve their load factor (the ratio of their average demand to their highest 30-minute demand during a billing month), which can result in more efficient use of utility infrastructure. Each pilot rate is limited to approximately 500 participants during the pilot period.

Q. HOW WILL THE PROPOSED RDM COMPLEMENT DUKE ENERGY INDIANA'S PROPOSED PRICING PILOTS?

A. Duke Energy Indiana's proposed pilot rates include dynamic rates, which change with system conditions (as forecast on a day-ahead basis) and a demand-based rate. As customers respond to these rates, the resulting change in utility revenue is likely to be larger than the change in its short-term costs. For example, while reducing billed demand (thus improving load factor) can reduce long-term capacity-related costs, the Company may resist assisting customers in promoting such response due to the near-term reduction in net margin. With the proposed RDM, the Company can fully engage with its customers in promoting and encouraging demand response.

Q. HOW WOULD THE PROPOSED RDM COMPLEMENT THE COMPANY'S VOLT/VAR OPTIMIZATION?

A. As described in Duke Energy Indiana witness Ms. Cicely Hart's direct testimony, Duke Energy Indiana is implementing a volt/VAR optimization program as part of its Transmission, Distribution, and Storage System Infrastructure Charge ("TDSIC") plan. This program would result in a reduction in billed sales in the range of 1 to 2 percent. The RDM would make Duke Energy Indiana whole for the resulting reduction in RPC, potentially avoiding the need for an additional rate case to re-align test-year billing determinants with current billed energy.

Q. HOW WOULD THE PROPOSED RDM COMPLEMENT DUKE ENERGY INDIANA'S ELECTRIC TRANSPORTATION PILOT, DISCUSSED IN DUKE ENERGY INDIANA WITNESS MR. LANG REYNOLD'S DIRECT TESTIMONY?

A. Assuming the Electric Transportation Pilot results in more energy sales during an annual RDM period, those additional sales would result in the RDM crediting customers (*i.e.*, reducing their energy rate), with all other variables held equal. This prevents customers from overpaying their share of fixed costs due to increased adoption of an energy-intensive end use.

Q. HOW WOULD THE PROPOSED RDM COMPLEMENT THE COMPANY'S EXISTING ENERGY EFFICIENCY PROGRAM AND THE LOST REVENUE MECHANISM INCLUDED IN THE COMPANY'S ENERGY EFFICIENCY ADJUSTMENT RIDER ("EE RIDER")?

A. The Company's existing energy efficiency program has resulted in cost-effective sales reductions for its customers and is expected to continue to do so in the future. Although the Company's EE Rider currently includes a lost revenue adjustment mechanism ("LRAM") for residential and small commercial customers, as well as for other customers, LRAMs only adjust for the fixed-cost portion of revenues that are lost as the result of Company-sponsored energy efficiency programs, as measured by an Evaluation, Measurement and Verification "EM&V" process. They do not address the recovery of fixed costs that result from other sources of reductions, such as naturally occurring energy efficiency, increased distributed generation, the Company's volt/VAR optimization program, and proposed customer pricing alternatives. As discussed in my testimony, the proposed RDM accounts for all of these factors. In contrast to the LRAM, which can only lead to rate increases, the proposed RDM may result in either an increase or decrease in utility revenue, as it accounts for programs such as the Company's proposed electric transportation pilot that may increase customer usage. The fact that the RDM is not limited to specific Company-sponsored energy efficiency programs addresses Duke Energy Indiana's disincentive to promote other programs that reduce customer use. The RDM simply results in the Company recovering an amount of revenue per customer toward fixed costs that is approved by the Commission in a base rate case regardless of the actual level of sales.

Q. HOW WOULD ADOPTING THE RDM FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS AFFECT THE RECOVERY OF LOST REVENUES IN THE COMPANY'S EE RIDER?

A. The RDM would completely replace the recovery of lost revenues in the Company's EE Rider for residential and small commercial customers. The LRAM in the Company's EE Rider would still be used to recover lost revenues associated with the successful implementation of Company-sponsored energy efficiency programs for other customer groups. The direct testimony of Company witness Diana L. Douglas explains in more detail the impacts of RDM approval on the EE Rider.

Q. WOULD ADOPTING THE RDM FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS IN LIEU OF RECOVERING LOST REVENUES IN THE COMPANY'S EE RIDER AFFECT THE AMOUNT OF COST-EFFECTIVE ENERGY EFFICIENCY OFFERED BY THE COMPANY?

A. No. Adopting the RDM in lieu of the LRAM would in no way affect the amount of cost-effective energy efficiency programs that Duke Energy Indiana would offer to its customers. (However, as noted elsewhere in my testimony, it removes the Company's disincentives to support third-party EE efforts.) The process for determining the target amount of energy efficiency savings and the offered programs will not change, and the Company will still receive program cost recovery and performance incentives for these customer groups, as well as others, within the EE Rider. As with the LRAM that is currently used in the EE Rider, the RDM would effectively eliminate the volumetric throughput disincentive associated with utility-offered energy efficiency programs for these customer groups, while the LRAM will be continued within the EE Rider to eliminate the volumetric throughput disincentive for other customer groups.

Q. WHY DO YOU BELIEVE IT IS REASONABLE FOR DUKE ENERGY INDIANA AND OTHER UTILITIES TO MOVE FROM AN ENERGY EFFICIENCY LRAM TO A BROADER MECHANISM SUCH AS THE COMPANY'S PROPOSED RDM?

A. While an LRAM can be an effective method of removing utility disincentives to effectively administer its EE programs, the RDM would lead to several improvements. First, the RDM embeds a more comprehensive view of customer usage than an LRAM. That is, the RDM can lead to rate increases or decreases. For example, suppose the Company successfully promotes an EE program and at the same time its sales are higher than expected due to hotter than normal summer weather. If the weather-induced sales increase exceeds the EE savings, customer rates would be reduced through the RDM but increased through the LRAM. Second, the RDM may reduce the complexity associated EM&V. That is, under the RDM, parties would only need to know that energy savings are sufficiently high to pass a cost-benefit test. Third, the RDM would remove the Company's disincentive to support third-party conservation programs or Company-sponsored programs for which the benefits are difficult to track.

Q. WOULD THE RDM AFFECT THE COMPANY'S INCENTIVE TO OPERATE EFFICIENTLY?

A. No, the RDM would not affect Duke Energy Indiana's incentive to operate efficiently. The RDM affects only the revenue collected from applicable customers. It does not affect cost levels or guarantee a rate of return. The benefits the Company can expect to realize from operating efficiently are not changed by implementing the RDM.

Q. WOULD THE RDM REDUCE A CUSTOMER'S INCENTIVE TO CONSERVE?

A. No. Because the Company is proposing to modify its retail rate design if the RDM is approved, the customer-level incentive to conserve will *increase* under the RDM (as described earlier in my testimony). Furthermore, the recovery of deferrals through rates will have no effect on the customer-level incentive to conserve. That is, with the RDM in place, the customer will experience a bill reduction in the amount of the full volumetric rate, including all riders and fees, multiplied by the amount of saved energy (*i.e.*, kWh). The portion of this bill reduction that is associated with the fixed-cost portion of the Rate RS or CS base energy rates is then placed in the RDM deferral account for the utility to recover in the following year. Because each customer uses a very small percentage of the total group-level usage, a conserving customer pays back essentially none of its own lost revenues. Therefore, a customer's decision to conserve should not be affected by the presence of the RDM because the customer cannot conserve enough energy to affect the rate it pays in the following year. Because the energy rates will be higher (and the fixed connection charge lower) if the RDM is approved, customer incentives to conserve will be increased.

Q. HAVE OTHER REGULATORS ACKNOWLEDGED THAT THE RECOVERY OF DEFERRALS THROUGH A DECOUPLING MECHANISM DOES NOT AFFECT A CUSTOMER'S INCENTIVE TO CONSERVE?

A. Yes. The Oregon Public Utility Commission concluded that decoupling does not affect customer incentive to conserve in Order No. 09-020 for Docket UE-197,[1] which approved the Sales Normalization Adjustment, or SNA, for Portland General Electric. The order stated the following:

> Staff also argues that the SNA would create a disincentive for customers to improve their energy efficiency because the SNA would increase rates and reduce the bill savings. We believe that the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient. (Page 28)

Q. HAVE OTHER ORGANIZATIONS PREFERRED DECOUPLING TO ALTERNATIVES BECAUSE IT DOES NOT REDUCE A CUSTOMER'S INCENTIVE TO CONSERVE?

A. Yes. The Natural Resources Defense Council ("NRDC") has supported revenue decoupling as a means of addressing utility disincentives to promote conservation because decoupling preserves the customer's incentive to conserve.[2]

Q. HAS THE INDIANA UTILITY REGULATORY COMMISSION ("THE COMMISSION") PREVIOUSLY APPROVED A MECHANISM LIKE THE RDM?

A. Yes, the Commission has approved revenue decoupling mechanisms for four natural gas utilities: Citizens Gas, Indiana Natural Gas, Vectren Southern Indiana Gas, and Vectren Indiana Gas. In each case, the decoupling mechanism is contained within an Energy

[1] http://apps.puc.state.or.us/orders/2009ords/09-020.pdf.
[2] Energy Facts: Removing Disincentives to Utility Energy Efficiency Efforts. https://www.nrdc.org/sites/default/files/decoupling-utility-energy.pdf.

Efficiency Rider[3] and called the Sales Reconciliation Component ("SRC"). The SRC, which is the same at each utility, is structured in a similar way as the Company's proposed RDM, in that it compares actual revenue (referred to as "margin" in the tariff) to allowed revenue that is adjusted for the number of customers currently served. As with the proposed RDM, the SRC passes cumulative deferrals through to rates once per year.

Q. HAS REVENUE DECOUPLING BEEN APPROVED FOR OTHER FULLY INTEGRATED ELECTRIC UTILITIES?

A**.** Yes, a number of fully integrated electric utilities (i.e., those responsible for transmission, distribution, and generation services) have revenue decoupling, including (with the state or states in which a mechanism has been approved in parentheses): Avista Utilities (Idaho and Washington), Hawaiian Electric Company (Hawaii), Idaho Power Company (Idaho), Pacific Gas and Electric Company (PG&E, in California), Pacific Power (Washington), Portland General Electric (Oregon), Puget Sound Energy (Washington), San Diego Gas and Electric Company (SDG&E, in California), Southern California Edison (SCE, in California), and Xcel Energy (Minnesota). Some of these mechanisms have been in place for a number of years. Idaho Power Company's decoupling mechanism was initially approved in 2006 as a three-year pilot program and is still in place. The three California investor-owned utilities (PG&E, SCE, and SDG&E) had decoupling implemented in 1982, removed due to market restructuring in the late 1990s, then reintroduced in the early 2000s after the California energy crisis. Note that many

[3] The Energy Efficiency Rider is listed as Rider E at Citizens Gas; Appendix D at Indiana Natural Gas; and Appendix I at Vectren Southern Indiana Gas and Vectren Indiana Gas.

additional "wires only" electric utilities (*i.e.*, those that deliver electricity but do not provide generation services) have revenue decoupling.

III. DUKE ENERGY INDIANA'S PROPOSED REVENUE DECOUPLING MECHANISM

Q. WHAT TOPICS WILL YOU ADDRESS IN THIS SECTION?

A. In this section of my testimony, I provide a detailed description of Duke Energy Indiana's proposed RDM.

Q. AT A CONCEPTUAL LEVEL, HOW WOULD THE PROPOSED RDM FUNCTION?

A. In the proposed RDM, Duke Energy Indiana records the monthly difference between the RDM allowed fixed-cost revenue and actual fixed-cost revenue for each of the applicable customer classes. This difference is called the "RDM deferral." These deferrals are accumulated for 12 consecutive months, at which point the annual total is divided by forecast sales to the customer class for the following year to calculate the RDM Charge or Credit. When RDM allowed fixed-cost revenue is *less than* actual fixed-cost revenue, customers receive a rate decrease or credit in the following year. When RDM allowed fixed-cost revenue *exceeds* actual fixed-cost revenue, customers receive a rate increase or charge in the following year. The RDM deferral will include the effects of weather (*i.e.*, RDM allowed fixed-cost revenue is based on weather-normalized test-year revenues while actual fixed-cost revenue fluctuates with weather conditions). As described below, total RDM allowed fixed-cost revenue scales with the number of customers served.

Q. HOW WOULD THE PROPOSED RDM AFFECT THE TOTAL AMOUNT OF REVENUE FROM RATES?

A. Through regulatory proceedings, Duke Energy Indiana establishes rates to collect a specific amount of revenue from customers (the utility's revenue requirement) based on the test-year number of customers and energy usage by those customers (referred to as "billing determinants"). Currently, the actual revenue Duke Energy Indiana records varies from the revenue requirement set in the last rate case proceeding due to both changes in the number of customers served and their energy use. Changes in energy use may be due to variability in weather, increases in appliance and home energy efficiency, customer-owned generation, and variations in economic conditions in and around Duke Energy Indiana's service territory. The Company's RDM proposal is to record the difference between actual revenues and allowed revenues toward fixed-cost recovery, which are a product of allowed fixed-cost revenue per customer (to be established in this rate case proceeding and adjusted in future rate proceedings) and the number of customers served in the current month. By recovering or refunding the difference between RDM allowed fixed-cost revenue and actual fixed-cost revenue, the RDM eliminates the variability in revenue toward fixed-cost recovery due to variations in customer usage levels, regardless of the cause, but retains variability in fixed-cost revenue due to the number of customers served.

Q. HOW WILL RDM DEFERRALS BE CALCULATED?

A. Each month, the Company will compare RDM allowed fixed-cost revenue to actual fixed-cost revenue from Rate RS and CS tariff rates, with the difference entered in the RDM deferral account. The calculation of the deferral for customer group *g* in month *m* ($Deferral_{m,g}$) is shown in Equation 1. The equation has the same form regardless of the customer class to which it is applied; only the parameter values (*e.g.*, the fixed revenue per customer) change when the RDM is applied to different customer classes.

Equation 1: $Deferral_{m,g} = C_{m,g} \text{ x } FRC_{m,g} - kWh_{m,g} \text{ x } FEC_g$

where

$C_{m,g}$ = The number of customers served for customer class g served during month m.

$FRC_{m,g}$ = Fixed revenue per customer for customer class g served during month m, which represents the allowed weather-normalized revenue per customer toward fixed costs, as determined each time base rates change based on the revenue requirements and billing determinants established in each proceeding.

$kWh_{m,g}$ = Billed sales during month m for customer class g.

FEC_g = The fixed energy charge for customer class g, which represents the fixed-cost component of base rates for customer class g.

The first term of Equation 1, $C_{m,g}$ x $FRC_{m,g}$, represents the total allowed fixed-cost revenue under the RDM, calculated as the allowed fixed-cost revenue per customer multiplied by the number of customers currently served. This term shows that total allowed fixed-cost revenue changes with the number of customers served. The second term of Equation 1 ($kWh_{m,g}$ x FEC_g) represents the actual fixed-cost revenue collected from customer class g during month m, calculated as the product of the billed sales to the class and the fixed-cost component of the per-kWh rates. RDM deferrals (whether positive or negative) will not earn interest. Because the $kWh_{m,g}$ values are based on billed usage that is not weather-normalized, the resulting RDM deferral will include the effect of weather on fixed-cost revenue. That is, the RDM weather normalizes Duke Energy

Indiana's fixed-cost revenue and adjusts for any other factors that result in a change in usage per customer versus the test-year usage per customer used in setting the base rates.

Q. HOW WILL THE COMPANY DETERMINE THE VALUE OF $C_{m,g}$, OR THE NUMBER OF CUSTOMERS SERVED?

A. The value of $C_{m,g}$ is based on the number of customers billable, which is calculated as the connection charge revenue divided by the connection charge rate. This definition is used in place of the number of customers billed, which can include more than one customer for the same meter in a given month due to move outs/move ins. Customers that move out/move in during a billing cycle receive a prorated connection charge, which is reflected in Duke Energy Indiana's connection charge revenues. Therefore, the Company's proposal to use the number of customers billable provides an accurate number of meters receiving service for the month and prevents double counting of customer premises in the calculation of allowed revenue.

Q. HOW WILL THE COMPANY DETERMINE THE VALUES FOR THE FIXED REVENUE CHARGE, OR $FRC_{m,g}$?

A. The $FRC_{m,g}$ values will be based on the test-year fixed-cost revenue and number of customer bills in each customer class. That is, the same inputs used to calculate the per-kWh energy charges and connection charges through this proceeding will be used to calculate the FRC values. Prior to calculating the FRC values, the Company removes variable costs included in base rates. This process is described in the testimony of Company witness Ms. Maria T. Diaz and is illustrated on Schedule 1 of Petitioner's Exhibit 7-H (MTD). Each month's FRC is calculated by multiplying the annual FRC (calculated from the full test year) by the test-year monthly shares of sales (in kWh) for the applicable customers. For example, if each month had the same amount of usage, the monthly FRC values would all be one twelfth of the annual FRC. The resulting values will reflect the seasonal pattern of sales and revenue per customer, such as the fact that Rate RS customers have lower revenue per customer during spring and fall months than in summer and winter months. For those customers, if the RDM used a single FRC value across the entire year in place of the proposed month-specific values, it would tend to produce refunds during summer and winter months (when RDM allowed fixed-cost revenue would tend to be less than actual fixed-cost revenue) and surcharges during spring and fall months (when RDM allowed fixed-cost revenue would tend to exceed actual fixed-cost revenue). The use of monthly FRC values results in RDM allowed fixed-cost revenue values that better reflect the actual fixed-cost revenue for Duke Energy Indiana each month. Schedule 2 of Petitioner's Exhibit 7-H (MTD) contains the Company's proposed FRC values for each customer class and month of year. The data submitted is based on proposed rates and billing determinants. Note that the FRC values will be updated whenever base rates change.

Q. HOW WILL THE COMPANY DETERMINE THE VALUES FOR THE FIXED ENERGY CHARGE, OR FEC_g?

A. The FEC_g value will be calculated using the same fixed-cost revenue value used in the annual FRC calculation described above, but divided through by total test-year sales for the applicable customers rather than the test-year number of customer bills (as is done for the FRC calculation). A single FEC value will be used for every month of the year and customer class (RS and CS). Schedule 1 of Petitioner's Exhibit 7-H (MTD) contains the Company's proposed FEC values for each customer class, including the underlying data.

The data submitted is based on proposed rates and billing determinants. As with the FRC, the FEC values will be updated whenever base rates change.

Q. CAN YOU PROVIDE SIMPLE EXAMPLES OF HOW THE CALCULATIONS OUTLINED ABOVE WOULD WORK?

A. Yes. Let's assume that through this rate case Duke Energy Indiana will establish that it needs to collect $1,300 toward fixed costs from 10 customers with a fixed connection charge of $10 per customer per year, or $100 in total per year. The remaining $1,200 will be collected from sales volumes, or $120 per customer. Assuming sales to each customer is 2,400 kWh during the test year, the flat energy rate to collect the $1,200 will be $0.05 per kWh ($1,200 / (10 customers x 2,400 kWh)). The annual FRC in this example is $120 ($1,200 from sales volumes / 10 customers). The FEC in this example is $0.05 ($1,200 from sales volumes / 2,400 kWh).

Suppose that in the year after the rate case, the number of customers stays at 10 and use per customer increases to 2,500 kWh. Actual fixed-cost revenues for the year will be $1,250 (2,500 kWh/customer x $0.05/kWh FEC x 10 customers). Under current ratemaking methods (in the absence of the RDM), Duke Energy Indiana would gain $50 compared to the revenues set in the rate case due to the increase in sales.

In contrast, under the RDM the $50 gain would be refunded to customers in the following year. That is, actual fixed-cost revenue would still be $1,250, but the RDM allowed fixed-cost revenue would be $1,200 (the $120 FRC multiplied by the 10 customers served). Duke Energy Indiana would record a deferral of negative $50 for the year and give it back to customers in the following year through a rate decrease (of $50 divided by the expected sales during the year).

The previous example shows what happens when sales increase but the number of customers served stays the same. Now suppose that the number of customers served increases but use per customer remains the same. Specifically, suppose the number of customers served increases by 1 and use per customer remains 2,400 kWh. Actual fixed-cost revenue would be $1,320 (2,400 kWh/customer x $0.05/kWh FEC x 11 customers). Without the RDM, Duke Energy Indiana would gain $120 compared to the rate case. With the RDM in place, RDM allowed fixed-cost revenue would be $1,320 (11 customers times $120 FRC), which exactly matches the actual fixed-cost revenue. Thus, there would be no RDM deferral for that year. The general point from these examples is that the RDM will only affect Company revenue due to changes in use per customer. If the only thing that changes relative to the test year is the number of customers served (i.e., use per customer remains at the test-year level), the RDM will have no effect.

Q. HOW WOULD THE PROPOSED RDM DEFERRAL BE CONVERTED TO A CHARGE OR CREDIT?

A. Every twelve months, the cumulative RDM deferral for each customer group would be converted to a dollar-per-kWh charge or credit by dividing the deferral amount by the forecast sales to the customer group. A positive cumulative deferral would result in a charge while a negative cumulative deferral would result in a credit. Separate calculations will be made for each affected customer class (*e.g.*, Rate RS and Rate CS), which prevents the RDM from causing inter-class cross-subsidies. Schedule 3 of Petitioner's Exhibit 7-H (MTD) provides an example of the deferral calculation when use per customer decreases by 0.5 percent.

Q. WHAT ADMINISTRATIVE SCHEDULE DOES DUKE ENERGY INDIANA PROPOSE FOR THE RDM?

A**.** The RDM administrative schedule is described in the testimony of Company witness Ms. Maria T. Diaz.

Q. WHAT PORTION OF THE ELECTRIC RATES WILL BE INCLUDED IN THE RDM?

A**.** The RDM only applies to revenue collected from the portion of RS and CS tariffed base energy charges that recover fixed costs. It does not apply to the connection charge (which is already fixed on a per-customer basis) or any rate adjustment riders. As discussed previously, the EE Rider will be modified during the RDM pilot period to exclude energy efficiency lost revenue for these residential and small commercial rate groups.

Q. WHAT ARE THE APPLICABLE ELECTRIC SERVICE CLASSES FOR THE RDM?

A**.** The RDM will apply to customers served on the Rate RS (Schedule for Residential and Farm Electric Service), Riders 6.3 (Optional High Efficiency Residential Service, and Rate CS (Schedule for Commercial Electric Service). The RDM excludes customers served on all other rates, including Rider 7.1 (Optional High Efficiency Total Electric Commercial Service) and Rider 20 (*Your FixedBill*). For purposes of the initial program, Duke Energy Indiana would like to focus on the mass-market residential and commercial customers served on Rates RS and CS. Larger customers, including those served on Rates LLF and HLF are excluded from the RDM. As noted below, Duke Energy Indiana will be providing an evaluation of the RDM and may recommend at that time to maintain, expand, or discontinue the program.

Q. HOW LONG WOULD THE RDM BE IN EFFECT?

A. Duke Energy Indiana is proposing to implement the RDM as a five-year program. Duke Energy Indiana will provide an evaluation of the program prior to expiration and recommend whether the program should be maintained, expanded, or discontinued in a separately filed proceeding. At the end of the five years, the RDM would expire unless the Commission approves its continued use as proposed in a separately filed proceeding. The Company's evaluation of the RDM will include documentation of the annual deferrals and resulting rate changes and an estimate of the extent to which each year's deferral was caused by weather vs. non-weather factors.

Q. IS THE COMPANY FILING A TARIFF FOR THE RDM FOR COMMISSION APPROVAL?

A. Yes. The proposed tariff, Standard Contract Rider No. 99, is attached as Petitioner's Exhibit 7-H (MTD), sponsored by Company witness Ms. Maria T. Diaz, who will also describe the proposed implementation and mechanics in more detail in her direct testimony.

IV. <u>SUMMARY OF RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have described Duke Energy Indiana's proposed Revenue Decoupling Mechanism (RDM), which would complement the Company's proposed dynamic pricing pilots and support rate design changes that would increase customer incentives to conserve energy and self-generate. The RDM accomplishes this task through a tracking account that removes the link between customer usage decisions and Company revenue toward fixed costs, with the resulting deferrals being collected from (or refunded to) customers through a dollar-per-kWh charge (or credit) in the following year. The RDM aligns Company and customer interests, ensuring Duke Energy Indiana's presence as a partner in helping its customers make best use of their rate options and in promoting conservation and energy efficiency. In addition, the RDM maintains the Company's incentive to promote economic growth and operate efficiently.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Indiana Utility Regulatory Commission approves the RDM five-year program as described in my testimony.

Q. WAS PETITIONER'S EXHIBIT 10-A (DGH) PREPARED BY YOUR OR AT YOUR DIRECTION?

A. Yes, it was.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Daniel G. Hansen

RESUME

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Academic Background:

PhD, Michigan State University, 1997, Economics
MA, Michigan State University, 1993, Economics
BA, Trinity University, 1991, Economics and History

Positions Held:

Vice President, Laurits R. Christensen Associates, Inc. 2006–present
Senior Economist, Laurits R. Christensen Associates, Inc., 1999–2005
Economist, Laurits R. Christensen Associates, Inc., 1997–1999

Professional Experience:

I work in a variety of areas related to retail and wholesale pricing in electricity and natural gas markets. I have used statistical models to forecast customer usage, estimate customer load response to changing prices, and estimate customer preferences for product attributes. I have developed and priced new product options; evaluated existing pricing programs; evaluated the risks associated with individual products and product portfolios; and developed cost-of-service studies. I have conducted evaluations and provided testimony regarding revenue decoupling and weather adjustment mechanisms.

Major Projects:

Assisted a utility in forecasting the load impacts from a new residential peak-time rebate program.

Evaluated residential demand response pilot programs with programmable-controllable thermostats.

Developed long-term forecasting models for an electric utility.

Conducted a review of an electric utility's load forecasting methods.

Conducted an independent evaluation of a revenue decoupling mechanism for an electric utility.

Estimated load impacts for commercial and industrial demand response programs.

Evaluated a straight-fixed variable rate design for a natural gas utility.

Estimated the load impacts from a residential peak-time rebate program.

Worked with a state's regulatory staff to evaluate alternative electricity pricing structures for residential, commercial, and industrial customers.

Assisted a utility in meeting regulatory requirements regarding the allocation of distribution services.

Evaluated a residential electricity pricing pilot program.

Evaluated the cost effectiveness of automated demand response technologies.

Evaluated and modified short- and long-term electricity sales and demand forecasting models.

Created a short-term electricity demand forecasting model.

Prepared testimony regarding the return on equity effects associated with natural gas revenue decoupling mechanisms.

Conducted an independent evaluation of two natural gas revenue decoupling mechanisms

Created forecasts of load impacts from electricity demand response programs.

Estimated historical the load impacts from electricity demand response programs.

Prepared testimony regarding a proposed natural gas decoupling mechanism.

Prepared testimony regarding the weather normalization of test year sales and revenues.

Participated on a regulatory proceeding panel to discuss decoupling mechanisms.

Prepared testimony regarding a proposed electricity decoupling mechanism.

Prepared a report and testimony regarding a natural gas decoupling mechanism.

Evaluated a model that estimated the costs associated with removing and relicensing hydroelectric facilities.

Assisted an electric utility in evaluating new rate options for commercial and industrial customers.

Designed and evaluated time-of-use and critical-peak pricing rates for an electric utility.

Reviewed cost-of-service study for a municipal electric utility.

Produced a report on rate design methods that provide appropriate incentives for demand response and energy efficiency.

Assisted in wholesale power procurement process.

Evaluated a weather-adjustment mechanism for a natural gas utility.

Assessed weather-related fixed cost recovery risk for an electric utility.

Evaluated a revenue decoupling mechanism for a natural gas utility.

Estimated price responsiveness of real-time pricing customers.

Evaluated the need for electricity transmission and distribution standby rates for a utility.

Developed a market share simulation model using conjoint survey results of electricity distributors.

Conducted conjoint surveyed of electricity distributors regarding rate structure preferences.

Developed a method to calculate a retail forward contract risk premium.

Prepared a report on the performance of Financial Transmission Rights (FTRs) in the PJM electricity market.

Reviewed a retail pricing model for use in a competitive electricity market.

Provided support in a natural gas rate case filing.

Simulated outcomes associated with alternative wholesale rate offers to electricity distributors.

Developed a business case to support a natural gas fixed bill product.

Assessed the accuracy of a natural gas fixed bill pricing algorithm.

Audited an evaluation of the costs associated with implementing a renewable portfolio standard.

Developed a model to value interruptible provisions in a long-term customer contract.

Performed a study on the determinants of electricity price differences across utilities and regions.

Developed long-term demand and energy forecasts.

Conducted market research to assess customer interest in new product options.

Recommended new retail pricing products for commercial and industrial customers.

Prepared a report on the fundamentals of retail electricity risk management.

Prepared a report that presented a taxonomy of retail electricity pricing products.

Presented at a workshop in Africa regarding deregulated electricity markets.

Prepared a report on the effectiveness of distributed resources in mitigating price risk.

Performed a valuation of energy derivatives consistent with FAS 133.

Created an electricity market share forecasting model.

Developed standby rates for an electric utility.

Developed an electricity wholesale price forecast.

Forecasted retail customer loads for an electric utility.

Assisted in mediating a new product development process with a utility and its industrial customers.

Developed a model that simulates wholesale market price changes due to retail load response.

Developed a pricing model for an innovative financial product.

Estimated changes in wholesale electricity prices due to customer load response.

Oversaw creation of software that estimates customer satisfaction with utilities.

Developed a model to economically evaluate a capital addition to a generator.

Developed a wholesale version of the Product Mix Model.

Evaluate Risk Implications of New Product Offering.

Mixed Logit Estimation of Customer Preferences.

Estimation of Customer Price Responsiveness.

Product Mix Model Workshops.

Unbundling and Rate Design.

Development of a Computer Program.

Large Commercial and Industrial Customer Rate Analysis.

Residential Customer Rate Analysis.

Survey of Power Marketers.

Development of Multi-Period Analysis Tool.

Evaluating the Effect of Alternative Rates on System Load.

Estimating the Persistence of Weather Patterns.

Electricity Customer Survey Data Analysis.

Product Mix Analysis for Small Customers.

Survey of Postal Facilities.

Professional Papers:

"2018 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates: *Ex-post* and *Ex-ante* Report," with David Armstrong, 2019.

"2018 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark and David Armstrong, 2019.

"2018 Load Impact Evaluation for Pacific Gas & Electric Company's SmartAC™ Program," with Corey Lott, 2019.

"2018 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates," with Michael Ty Clark and Nick Crowley, 2019.

"2017 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates: *Ex-post* and *Ex-ante* Report," with David Armstrong, 2018.

"2017 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Nick Crowley, 2018.

"2017 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark and Nick Crowley, 2018.

"2017 Load Impact Evaluation of Non-Residential Critical Peak Pricing (CPP) Rates," with Michael Ty Clark, Corey Lott, and Nick Crowley, 2018.

"2017 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates," with Michael Ty Clark and Nick Crowley, 2018.

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2017.

"2016 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark and Nick Crowley, 2017.

"2016 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2017.

"2016 Load Impact Evaluation of San Diego Gas and Electric's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates," with Steven D. Braithwait and Michael Ty Clark, 2017.

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-Based Pricing Programs: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2016.

"2015 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small, Medium, and Agricultural Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2016.

"2015 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Michael Ty Clark, 2016.

"2015 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2016.

"Statewide Time-of-Use Scenario Modeling for 2015 California Energy Commission Integrated Energy Policy Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Statewide Load Impact Evaluation of California Aggregator Demand Response Programs: *Ex-post* and *Ex-ante* Load Impacts," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Steven Braithwait and David Armstrong, 2015.

"2014 Load Impact Evaluation of California Statewide Base Interruptible Programs (BIP) for Non-Residential Customers: *Ex-post* and *Ex-ante* Report," with Tim Huegerich, 2015.

"2014 Load Impact Evaluation of Southern California Edison's Mandatory Time-of-Use Rates for Small and Medium-Sized Business and Agricultural Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"2014 Load Impact Evaluation of Pacific Gas and Electric Company's Mandatory Time-of-Use Rates for Small and Medium Non-residential Customers: *Ex-post* and *Ex-ante* Report," with Marlies Patton, 2015.

"FirstEnergy's Smart Grid Investment Grant Consumer Behavior Study," with EPRI (B. Neenan) and Marlies Patton, 2015.

"An Evaluation of Portland General Electric's Decoupling Adjustment, Schedule 123," with Robert J. Camfield and Marlies C. Hilbrink, 2013.

"Evaluation of the Straight-Fixed Variable Rate Design Implemented at Columbia Gas of Ohio," with Marlies C. Hilbrink, 2012.

"The Effect on Electricity Consumption of the Commonwealth Edison Customer Application Program Pilot," with EPRI and CA Energy Consulting staff, 2012.

"The Effects of Critical Peak Pricing for Commercial and Industrial Customers for the Kansas Corporation Commission," with David A. Armstrong, 2012.

"Meeting Commonwealth Edison's Distribution Allocation Requirements from Illinois Commerce Commission Order 10-0467," with Michael O'Sheasy, A. Thomas Bozzo, and Bruce Chapman, 2011.

"Residential Rate Study for the Kansas Corporation Commission," with Michael T. O'Sheasy, 2011.

"An Evaluation of the Conservation Incentive Program Implemented for New Jersey Natural Gas and South Jersey Gas," with Bruce R. Chapman, 2009.

"A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation," June 2007.

"Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

"Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

"A Review of the Weather Adjusted Rate Mechanism as Approved by the Oregon Public Utility Commission for Northwest Natural," October 2005, with Steven D. Braithwait.

"A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 2005, with Steven D. Braithwait.

"Analysis of PJM's Transmission Rights Market," EPRI Report #1008523, December 2004, with Laurence Kirsch.

"Using Distributed Resources to Manage Price Risk," EPRI Report #1003972, November 2001, with Michael Welsh.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, Vol. 14, number 5, pp. 33–38, June 2001, with A. Faruqui, C. Holmes and B. Chapman.

"Weather Hedges for Retail Electricity Customers," with C. Holmes, B. Chapman and D. Glyer. In papers for EPRI International Pricing Conference 2000.

"Worker Performance and Group Incentives: A Case Study," *Industrial and Labor Relations Review,* Vol. 51, No. 1, pp. 37–49, October 1997.

"Worker Quality and Profit Sharing: Does Unobserved Worker Quality Bias Firm-Level Estimates of the Productivity Effect of Profit Sharing?" Working Paper, May 1996.

"Supervision, Efficiency Wages, and Incentive Plans: How Are Monitoring Problems Solved?" Working Paper, November 1996, presented at the Western Economics Association Meetings, 1997.

"Has Job Stability Declined Yet? New Evidence for the 1990's," with David Neumark and Daniel Polsky, *The Journal of Labor Economics*, 1999.

Testimony and Reports before Regulatory Agencies:

Public Service Electric & Gas Company, New Jersey Board of Public Utilities Docket Nos. G018101112 and E018101113: Testimony supporting electric and natural gas revenue decoupling mechanisms on behalf of PSE&G as part of the CEF-EE filing, 2018.

Public Service Electric & Gas Company, New Jersey Board of Public Utilities Docket Nos. ER18010029 and GR18010030: Testimony supporting electric and natural gas revenue decoupling mechanisms on behalf of PSE&G as part of a rate case filing, 2018.

Arizona Public Service Company, Arizona Docket No. E–01345A–16–0036: Testimony supporting residential demand charges and a revenue decoupling mechanism on behalf of the Arizona Investment Council, 2017.

Black Hills/Colorado Electric Utility Company, Colorado Docket No. 16A-0436E: Testimony supporting energy and demand forecasting models on behalf of Black Hills/Colorado Electric Utility Company, 2016.

UNS Electric, Inc., Arizona Docket No. E–04204A-15-0142: Testimony supporting a residential demand charge proposed by UNS Electric on behalf of the Arizona Investment Council, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 15-00261-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2015.

Public Service Company of New Mexico (PNM), New Mexico Case No. 14-00332-UT: Testimony supporting a revenue decoupling mechanism on behalf of PNM, 2014.

Xcel Energy, Inc., Minnesota E002/GR-13-868: Testimony supporting a revenue decoupling mechanism on behalf of Xcel Energy, 2013.

Arizona Public Service Company, Arizona Docket No. E–01345A–11–0224: Testimony supporting a revenue decoupling mechanism proposed by APS on behalf of the Arizona Investment Council, 2011.

Southwest Gas Corporation, Arizona Docket No. G–01551A–10–0458: Testimony supporting a revenue decoupling mechanism contained in a settlement agreement on behalf of the Arizona Investment Council, 2011.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–10–239: Testimony regarding the weather normalization of test year sales in a general rate case on behalf of Otter Tail Power Company, 2010.

Southwest Gas Corporation, Nevada Docket No. 09–04003: Testimony regarding the return on equity effects associated with a proposed revenue decoupling mechanism on behalf of Southwest Gas Corporation, 2009.

Southwest Gas Corporation, Arizona Docket No. G–01551A–07–0504: Testimony regarding a proposed revenue decoupling mechanism on behalf of the Arizona Investment Council, 2008.

Otter Tail Power Company, Minnesota Docket No. E–017/GR–07–1178: Testimony regarding the weather normalization of test year sales and revenues in a general rate case on behalf of Otter Tail Power Company, 2008.

Massachusetts Department of Public Utilities, Docket No. DPU 07–50: Participation in a panel regarding an "Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources", on behalf of Environment Northeast, 2007.

Connecticut Light & Power Company, Docket No. 07–07–01: Testimony regarding a proposed electricity revenue decoupling mechanism on behalf of Environment Northeast, 2007.

Questar Gas Company, Docket No. 05–057–T01: Testimony regarding the effectiveness of a natural gas revenue decoupling mechanism on behalf of the Utah Division of Public Utilities, 2007.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model: Reply to Addendum A of the Consultant Report Prepared for the California Energy Commission Dated March 2007," May 2007, with Laurence D. Kirsch and Michael P. Welsh.

PacifiCorp, FERC Docket No. 2082: "Evaluation of the Klamath Project Alternatives Analysis Model," March 2007, with Laurence D. Kirsch and Michael P. Welsh.

Northwest Natural Gas Company, Oregon Docket UG 163: Testimony relating to an investigation regarding possible continuation of Distribution Margin Normalization, May 2005.

Northwest Natural Gas Company, Oregon Docket UG 152: Submitted a report in compliance with a requirement to evaluate the functioning of the Weather Adjusted Rate Mechanism, October 2005.

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________
Daniel G. Hansen

Dated: 7/2/2019