STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR GAS UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, (3) APPROVAL OF A NEW TAX SAVINGS CREDIT RIDER, (4) APPROVAL OF VECTREN SOUTH'S ENERGY EFFICIENCY PORTFOLIO OF PROGRAMS AND AUTHORITY TO EXTEND PETITIONER'S ENERGY EFFICIENCY RIDER ("EER"), INCLUDING THE DECOUPLING MECHANISM EFFECTUATED THROUGH THE EER, (5) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO GAS AND COMMON PLANT IN SERVICE, (6) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, AND (7) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO WHICH VECTREN SOUTH WOULD CONTINUE ITS CUSTOMER BILL ASSISTANCE PROGRAMS.	)	FILED February 19, 2021 INDIANA UTILITY REGULATORY COMMISSION **CAUSE NO. 45447**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S

PUBLIC'S EXHIBIT NO. 7 – PUBLIC (REDACTED) TESTIMONY OF OUCC WITNESS BRIEN R. KRIEGER

With the current requirement that all staff work from home, signatures for affirmations are not available at this time.

February 19, 2021

Respectfully submitted,

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SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
CAUSE NO. 45447
PUBLIC (REDACTED) TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Brien R. Krieger and my business address is 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a utility analyst in the Natural Gas Division. For a summary of my educational and professional experience and general preparation for this case, please see Appendix BRK-1.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to discuss my review and analysis of Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc.'s ("Petitioner" or "Vectren South") cost of service study ("COSS"), proposed rate design, tariffs, and monthly customer charge.

Q: Please summarize your recommendations concerning Petitioner's COSS, rate design, monthly customer charge, and tariff.

A: My recommendations are as follows.

1. Define Transmission plant as Commodity and allocate Transmission Plant-in-Service assets with annual throughput of all rate classes.
2. Define High Pressure Distribution as Commodity and allocate High Pressure Distribution Plant-in-Service assets with annual throughput of all rate classes.

3. Redefine the Low Pressure/Medium Pressure Distribution Plant-in-Service assets of Commodity, Customer, and Demand proportions to 35%, 30%, and 35% respectively.

4. Reduce Petitioner's proposed monthly customer charges for rate classes 110, 120/125 and 145 to be approximately equal to Petitioner's total margin increase.

5. For Rate 110 - Residential Sales Service, reduce the proposed monthly customer charge from $35.00 to $16.50.

6. For Rate 120/125 - General Sales Service and Schools/Government Transportation Service, reduce the proposed monthly customer charge for the three meter groups from $35.00, $70.00 and $135.00 to $32.00, $63.00, and $125.00, respectively.

7. For Rate 145 - General Transportation, reduce the proposed monthly customer charge from $250.00 to $125.00.

8. Reduce subsidies received by Rate 170–Contract Transportation.

9. Approve Petitioner's proposed future allocation of TDSIC and compliance costs included in the CSIA.

10. Approve Petitioner's proposed tariff language changes and consolidation of meter classes within rate tariffs.

II. OVERVIEW OF ANALYSIS AND KEY TERMS

Q: Please describe the subsequent sections of your testimony and how the sections relate to each other.

A: My testimony has eight sections. The first section is a summary of recommendations, my analysis is contained within sections III through VII, and Section VIII gives the Commission specific recommendations based on sections III through VII.

Section III is an overview of Petitioner's system and the operation of the system. It is important to visualize Petitioner's entire natural gas system and understand how the various system components work together to transport or move natural gas to all customer types from interstate pipelines. For example, large industrial customers may receive gas from high pressure larger diameter pipes while residential customers may receive gas from small plastic pipes at the end of cul-de-sac in a residential neighborhood. The system design and its usage determine how costs should be shared or allocated to the various rate classes.

Section IV is a review of Petitioner's prior COSS and its relation to Petitioner's natural gas system. While my analysis is independent of Petitioner's prior COSS, my conclusions are supported by the prior COSS. The design of the Petitioner's system and the customer mix remain similar to the prior COSS presented in Cause No. 43112, Petitioner's last rate case. My analysis of Petitioner's system operation and design compares closely to cost causation as determined in Petitioner's prior COSS.

Section IV is my stand-alone analysis of Petitioner's COSS for this Cause, which draws parallels to Petitioner's prior COSS. My analysis presents Petitioner's allocation methods and why I recommend different allocation factors for Transmission assets and Distribution assets. Section V contains my recommended changes based upon the absence of Petitioner's use of the Commodity function, which typically is used to describe the usage characteristics of natural gas pipe mains. Transmission mains and Distribution mains deliver or transport natural gas through the system for use by large volume users or small residential users.

In Section VI, I recommend rate design changes because of Petitioner's COSS results. My recommendations to rate design are dependent on Petitioner's COSS methodology, because a different methodology could impact the need for subsidy or reduce the amount in monthly customer charges. Regardless of methodology, I recommend a reduced monthly customer charge more reflective of the requested margin increase and subsidy amounts tempered with gradualism that bring rate classes closer to fully allocated cost. This section focusses on the rate design that should be developed to incorporate gradual changes and reductions for subsidies between rate classes. I analyze Petitioner's proposed monthly customer charge increases compared to Petitioner's proposed increased margin revenue. Regardless of the COSS methodology used, my recommendations of lower monthly customer charges and reduced subsidies to Rate 170 will remain.

Q: Please define the key terms you use in your analysis.

A: I use a few key terms in my analysis of Petitioner's COSS, which are typical in the analysis of any COSS. I use the term "Commodity" to describe the use of Petitioner's assets for delivery or to transport natural gas to support throughput of natural gas to the customer. Annual Throughput, a Commodity allocator, is an allocation method to assign each rate class' usage characteristics of parts of the system and is viewed as each calendar month's usage contributing to that rate's total annual consumption.

The use of a "Design Day" is interchangeable with the use of peak daily consumption of a rate class but is not interchangeable with "Heating Degree Day Design Day." The Heating Degree Day peak design is a function of outdoor temperature, but not all peak design day loads are driven by outdoor temperature. In other words, a "heating" design day occurs when it is cold, thereby necessitating heat. A Heating Degree Day impacts residential customers much more than, for example, industrial customers, whose use is not weather-dependent.

III. OVERVIEW OF PETITIONER’S SYSTEM OPERATION

Q: Please describe Vectren South’s system.

A: Petitioner serves Evansville, Vincennes, Washington, and other outlying communities in southern and southwestern Indiana. In response to OUCC Data Request (“DR”) 4.3, Petitioner provided a system map including city gates (“take-points”) and indicated the approximate location of its top eleven annual volumetric customers. Confidential Attachment BRK-1-C. Five of the top eleven customers are in tariff Rate 160-Large Volume Service (“Rate 160”) and six are in Rate 170-Contract Transportation (“Rate 170”). There are approximately 55 take-points from interstate pipelines that run in a north-south direction within Petitioner’s service territory. Petitioner classifies its system in three different pressures that are assigned to different FERC accounting categories: Transmission (FERC 367), High Pressure Distribution (FERC 376), and Medium/Low Pressure Distribution (FERC 376). Petitioner has four underground storage fields and storage equipment (FERC 350-356), with two storage fields and associated equipment located in southern Indiana and two located in the northern portion of Petitioner’s service territory.

Transmission lines, including those at the storage fields, feed into some of the High Pressure distribution (“HPD”) mains. Petitioner’s southern service territory is dominated by 90% of Petitioner’s Transmission mains and is a networked system of Transmission mains and HPD mains feeding into Low Pressure/Medium Pressure Distribution (“LP/MP”) mains. Vectren South’s system map shows that the Transmission mains deliver to eight of the eleven largest industrial customers. These transmission mains also provide transmission of natural gas to the outlying smaller communities east and west of Evansville.

In the mid-section and northern region of Petitioner's service territory, many HPD mains are connected laterally into interstate pipelines. The HPD mains then connect to the LP/MP network systems to serve the remaining three large industrial customers along with cities, towns, and unincorporated areas.

Q: Please describe Petitioner's operation and how it impacts your analysis of Petitioner's COSS.

A: My analysis indicates Petitioner's system's commodity-related operation of its take-points, transmission mains and storage fields, both during the summer months and the winter months, are necessary for annual operation of Petitioner's system. I reach this conclusion based on my review of Petitioner's system map and Petitioner's response to OUCC DR 4.4. Biannually, Petitioner forecasts and develops seasonal (heating/cooling or winter/summer) take-point flow allocation tables for internal operational guidance and to determine transport customer delivery options. Petitioner's normal winter and normal summer operations utilize commodity assets of the natural gas system related to city gate, storage, and the transmission mains. Operations, especially during the summer month transmission construction period, may require changes to typical operation. See OUCC DR 4.4, Attachment BRK-2 for Petitioner's description of operations.

IV. PETITIONER'S PRIOR COSS AND RATE DESIGN – CAUSE NO. 43112

Q: When did Petitioner perform its last COSS?

A: Petitioner's most recent COSS was performed in Cause No. 43112 (Ind. Util. Regul.

Comm'n Aug. 1, 2007) with a rate base cutoff date of March 31, 2006.

Q: Please summarize your analysis of Petitioner's prior COSS in Cause No. 43112.

A: Petitioner classified costs into Commodity, Customer, and Demand to set the direction for what costs should be collected in the volumetric and monthly customer charges. Petitioner's COSS witness Kerry A. Heid stated: "[c]ommodity costs are those that vary with the volume of gas delivered to customers and are allocated based on annual volumes. Demand costs are those incurred to deliver gas to customers at certain levels and are, therefore, dependent on customer demands." Cause No. 43112, Exhibit No. KAH-1, page 6, lines 28-32.

Petitioner used three major cost causation allocators for Transmission and Distribution: Annual Throughput, Number of Bills, and Design Day. In the present COSS, Petitioner's annual throughput and number of customers are similar in magnitude to the same allocators in Cause No. 43112. Rate 170 has greater Annual Throughput, thus resulting in a greater causation for costs for Transmission. Rate 170 has a lower Design Day demand in this Cause because Petitioner used a different method which only includes one cold weather driven load, not peak production loads. A Design Day is not only concerned with theoretical weather driven loads but needs to be analyzed against actual peak demands for the various rate classes.

Q: What theory did Petitioner use for cost causation when it allocated Commodity, Demand, and Customer classifications in its COSS for Cause No. 43112?

A: The following is an excerpt from Petitioner's COSS Witness Heid's testimony describing cost allocation. Petitioner's Exhibit No. KAH-1, page 6, line 27 – page 7, line 1.

> For example, investment and cost items were identified as being commodity, demand, or customer related. Commodity costs are those that

> vary with the volume of gas delivered to customers and are allocated based on annual volumes. Demand costs are those incurred to deliver gas to customers at certain levels and are, therefore, dependent on customer demands. These costs are allocated based on peak day demands. Customer costs are those that vary with the number of customers served and are allocated based on number of customers.

Mr. Heid stated variable costs should be recovered through volumetric rates. *Id*. at 12, lines 6-7. I agree with Mr. Heid's assessment because more or less consumption is the cause for the variable costs and these variable costs should be assigned to the user's quantity of natural gas consumed.

Q: How did Petitioner treat the allocation of the large Plant-in-Service FERC accounts in Cause No. 43112?

A: For FERC 350, 352, 354 – Underground Storage, Petitioner allocated approximately 20% of Underground Storage as Commodity and all rate classes were allocated their percentage of Commodity costs based upon Annual Throughput. The remaining 80% was divided equally into two winter Sales allocators (Design Day Sales and Winter Sales as found in Petitioner's COSS). Winter Sales do not include the Rate classes for large transport customers (Rates 160, and 170), only sales for residential and general classes (Rates 110 and 120/125 and Rate 145). Petitioner's "Incremental Winter" allocator has no sales attached, and therefore applies to all rates.

For FERC 367-Transmission Mains, Petitioner used all three classifications – Demand, Commodity, and Customer. Demand represented 35% of the costs in FERC 367 and was allocated with design day derived from heating degree days. Commodity was 35% of costs and was allocated with annual throughput. Customer represented 30% and was allocated by the number of customers.

For FERC 376 – Distribution Mains, Petitioner again used all three classifications, but did not allocate any distribution mains cost to Rate 170. Demand represented 35% of the costs and was allocated with design day. Commodity was 35% of costs and was allocated with annual throughput. Customer represented 30% and was allocated with number of customers. There were other large Plant-in-Service accounts such as meters, services, and house regulators that were allocated directly to the rate class that the devices served.

Q: Did Petitioner use a zero-intercept method to determine the percentages used for the cost classifications: Demand, Commodity, and Customer?

A: Yes. A zero-intercept study was used to determine the customer component of distribution mains cost, regardless of peak volume or annual throughput. In Cause No. 43112, the minimum system cost was 30% of the total, representing the Customer function allocated with the number of customers. The remaining cost of FERC 376 was allocated as Commodity with annual throughputs and Demand allocated with design day.

In the Commission Order (August 1, 2007), Section D. Petitioner's Rebuttal laid out the use of a minimum system method of functionalization and allocation. On page 13 of the Order, regarding Petitioner's COSS witness' allocation method while using the minimum system or zero-inch method, the Commission Order included Petitioner's rebuttal, stating:

> Mr. Heid responded to the testimony of Mr. Galligan and Mr. Baudino regarding Petitioner's cost of service study, proposed revenue distribution by rate class and proposed rate design. He testified that Petitioner properly allocated the customer-related component of mains based on a conventional zero-inch study, i.e., a linear regression that determines the portion of mains costs that are not related to pipe diameter or customer demands. He testified that this is a widely used method for reflecting the fact that the length of mains is a function of the number of customers. He said Petitioner allocated

50% of the remaining mains costs based on peak day demand and 50% based on annual demand.

Q: What differences exist between the COSS in the present Cause and Cause No. 43112?

A: There are major differences between the COSS in the prior Cause performed by Petitioner's witness Kerry A. Heid, Exhibit KAH in Cause No. 43112, and the COSS performed by Petitioner's witness Russell A. Feingold, Exhibit No. 16 in this Cause. My analysis indicates not all of Mr. Feingold's changes should be implemented. My analysis focusses on the major differences, and specifically why the allocation of Plant-in-Service assets classified as Commodity, Customer, and Demand should closely follow the COSS methodology used in Cause No. 43112. For an overview of the prior method, please refer to Cause No. 43112, Exhibit KAH-2, Schedule 2, Attachment BRK-3.

Q: Are there similarities between the COSS in Cause No. 43112 and the study conducted in the present Cause?

A: Yes, there are several similarities, but for my analysis I reviewed the three major cost causation allocators. Both studies define three major cost causation allocators (Annual Throughput, Number of Bills, and Design Day), however their use is not consistent within the three Classification groupings (Commodity, Customer, and Demand) of Cause No. 43112 and this Cause. The magnitude and minor differentials between the rate class characteristics indicated by the allocators indicate cost causation remains similar.

Q: How do the three major allocators compare in magnitude and use?

A: Annual Throughput, one of the major class characteristics, has increased, which indicates Transmission assets provide essential delivery to all users. Annual Throughput for Rate 170-Contract Transportation has increased its annual consumption by 35%, while Rate

110-Residential has decreased annual consumption by 10%. The increase to Annual Throughput indicates that Rate 170 is the primary user of bulk delivery Commodity assets.

The Numbers of Customers as a percentage of total remains relatively unchanged and therefore warrants no changes to its use. The Design Day is reduced for Rate 170 but my analysis indicates the Design Day allocator is calculated differently in this Cause. The use of any Design Day, derived from heating degree days, for allocating all rate class peak loads instead of Annual Throughput shifts large cost burdens to Rate 110, which is not the only rate class driving peak demand. Additionally, short term peak demands do not cause the majority of natural gas main costs as I discuss later in my testimony. Tables 1, 2, and 3 compare these three major allocators.

Table 1: Annual Throughput – Therms

	Rate 110	Rate 120/125/(145)	Rate 145	Rate 160	Rate 170	Total
Cause No. 43112	74,935,944	47,463,034	0	50,066,930	112,675,194	285,141,102
% of Total	26.3%	16.6%	0.00%	17.6%	39.5%	
Cause No. 45447	66,972,421	36,862,371	19,026,719	55,393,325	152,333,310	330,588,146
% of Total	20.25%	11.15%	5.76%	16.76%	46.08%	

Table 2: Number of Customers

	Rate 110	Rate 120/125/(145)	Rate 145	Rate 160	Rate 170	Total
Cause No. 43112	100,724	10,327	0	35	4	111,090
% of Total	90.6%	9.3%	0.00%	0.03%	.0036%	
Cause No. 45447	102,723	10,367	75	26	6	113,197
% of Total	90.75%	9.15%	0.07%	0.02%	0.01%	

Table 3: Design Day Therms

	Rate 110	Rate 120/125/(145)	Rate 145	Rate 160	Rate 170	Total
Cause No. 43112	1,246,684	614,923	0	162,119	594,381	2,616,106
% of Total	47.6%	23.5%	0.00%	6.2%	22.7%	
Cause No. 45447	1,061,072	496,929	113,198	189,142	367,164	2,227,505
% of Total	47.64%	22.31%	5.08%	8.49%	16.48%	

Q: Please describe why rates were combined in the prior COSS and your derivation of the Number of Customer Allocator used in Table 2.

A: In Cause No. 43112, Rates 120, 125, and 145 were combined in the COSS because Rate 120 included both General Service and General Transportation in one rate. Petitioner proposed to separate Rate 145 General Transportation in Cause No. 43112, and after the Commission's approval, Rate 145 became an independent rate class.

In Cause No. 43112, the Number of Annual Bills was used as the number of customers allocator. In this Cause, I needed to divide the annual bills count by 12 to arrive at a comparison for Number of Customers for Table 2.

Q: Please describe the derivation of the Design Day Allocator in Table 3.

A: Both the prior Cause and this Cause use a method to derive Design Day based upon outdoor temperature, or the heating degree day method. In my analysis I refer to this outdoor temperature derived Design Day as Heating Degree Day Design Day ("HDD Design Day") to clarify not all Design Day peaks are driven by outdoor temperature.

In Cause No. 45447, the HDD Design Day allocator is lower for Rate 170 and higher for Rates 120, 125, 145, and 160 as compared to Cause No. 43112. The HDD Design Day for Cause No. 45447 was not derived from the 12-month consumption per rate class as was done in Cause No. 43112. Rather, Petitioner first calculated rate class heat sensitive loads (through an Incremental Winter Allocator) and then corrected these heat sensitive or winter loads to a 70 HDD Design Day. *See* Attachment BRK-4, OUCC DR 4.9.

Q: What is your analysis of Petitioner's use of the Design Day?

A: The use of Petitioner's HDD Design Day method to determine the peak Design Day reduces the peak for Rate 170 as compared to the Design Day method used in Cause No. 43112. Most industrial processes are not a function of HDD, as industrial spaces need less space heating, and industrial peaks are set by operational demands. The low demand periods for industrials are typically set during annual maintenance periods.

Petitioner's HDD method to arrive at the Design Day allocator reduces the peak for Rate 170 proportionally less than that of Rate 110 as compared to January 2021 consumption of each rate class. Both rates set annual monthly peak consumption during January and these monthly consumption peaks are equal. While the peak day for Rate 110 is estimated by the Petitioner with HDD, the peak day for Rate 170 is a function of production – not weather - which Petitioner does not address. Petitioner's method to formulate the Design Day allocator and Petitioner's use of Design Day are incorrect as compared to January's peak month consumption because Petitioner assigns 47.64% of Transmission costs to Rate 110 and 16.48% to Rate 170 based upon the Design Day allocator.

Annual Throughput is a better indicator of cost causation because the peak month consumption of Rate 110 and Rate 170 are approximately equal, about 15,000,000 therms. The total of the remaining four rates for the peak month is also equal to about 15,000,000 therms. There is not one dominant rate class driving peak demand. However, Rate 170 is the dominant annual throughput user. The annual throughput of Rate 170 is approximately 2.25 times Rate 110 and requires many delivery points, system support from storage, transmission mains, and use of HP Distribution mains.

V. PETITIONER'S COST OF SERVICE STUDY

Q: Please explain the COSS allocation process Petitioner uses in this Cause.

A: Petitioner's COSS method functionalized costs by using FERC accounts, and then classified those costs as Demand, Commodity, and Customer costs to be allocated with Petitioner's specific rate class characteristics. See Petitioner's Exhibit No. 16 Attachment RAF-2, page 4. The use of the Commodity function is drastically reduced as compared to the prior COSS.

Petitioner's Plant-in-Service, allocated with rate class characteristics, is predominantly Underground Storage Plant (FERC 350-356), Transmission Mains (FERC 367), and Distribution Mains (FERC 376). The Distribution Mains are separated into two pressure classes: HP Distribution, and LP/MP Distribution.

Petitioner uses allocators to represent characteristics such as: annual throughput, peak winter demand, number of customers, incremental winter throughput, internal records data, or internal labor accounts. Specific FERC accounts such as meters or services were directly assigned to the responsible rate class. In this Cause, Petitioner substantially eliminates the use of Commodity, which is one of three functions used in Petitioner's prior COSS.

Q: What revenue increase and Non-Gas margin increase does Petitioner propose?

A: Petitioner is requesting a total operating revenue increase of 27.8% with the total Non-Gas ("margin") increase of 42.8%. Petitioner's Exhibit No. 16, page 44, Table 4 and page 43, Table 2, respectively. The final cost allocations per rate class are also in these tables with Rate 120/125 General Sales and Government/Schools Transport having the largest margin increase of 48.6% and the Rate 110 Residential proposed increase being 47.1%. The three remaining transportation rates have lower increases with the Rate 170 Contract Transmission proposed margin increase being the largest at 40.6%.

Q: Please describe the importance of using the Commodity classification for cost causation analysis.

A: Commodity is typically allocated with annual throughput. Commodity allows for the bulk of costs attributable to the installation and maintenance of mains to be allocated for the moving of natural gas to customers. Commodity is especially important for allocation of transmission mains because transmission mains operationally serve all customers. The annual throughput allocator distributes the bulk costs and the operational costs to those customers that use the system the most.

In the prior COSS, Commodity represented 20% of Underground Storage, 35% of Transmission, and 35% of Distribution. In this Cause, Petitioner did not use Commodity in Transmission or Distribution. In Transmission, the lack of Commodity, supplanted by Demand allocated with the peak demand allocator Design Day ("DESDAY"), causes an unwarranted shift of cost to Rate 110 – Residential Service.

My analysis and the prior COSS both determine that the causation of Transmission cost is Annual Throughput. In Distribution, the elimination of Commodity costs causes Petitioner to lump more costs into the Customer classification and collect more costs through a Monthly Service Charge, while those costs were collected in volumetric rates in the prior Cause.

Q: What Transmission allocators did Petitioner use?

A: Petitioner's COSS allocated Transmission as Demand using only the Design Day allocator. The Annual Throughput allocator was not used. Annual Throughput would assign cost based upon annual usage for the bulk of the cost of mains. Demand allocation, if there is a dominant peak demand, should only allocate those incremental costs of larger pipe material – pipe diameter. Petitioner's choice not to use Annual Throughput is in stark contrast to the COSS from Cause No. 43112, where Transmission was allocated to all rate classes with Annual Throughput. OUCC DR 9.6. Attachment BRK-5, page 1.

Q: Please provide a comparison between the annual throughput and monthly throughput for Rate 170 and Rate 110.

A: In this Cause, Rate 170 Annual Throughput is 2.3 times that of Rate 110. See Table 1 above. On a monthly basis, Petitioner's 2021 consumption estimates for Rate 110 and Rate 170 are approximately equal for December, January, and February. The other nine months, March through November, Rate 110 monthly volumes are less than one-tenth (1/10) of the monthly volumes of Rate 170. See Tab Incr, Winter Throughput on Petitioner's workpaper - 45447 Vectren South No 16 Workpaper VEDS COSS External Allocators.xls.

Annual Throughput is a better indicator of cost causation because it is connected to the cause of the total cost of mains. In other words, those using the most volumes are responsible for most of the costs. In this Cause, for nine months of the year, the consumption magnitude is dominated by Rate 170 - Contract Transportation.

Q: Please explain why operations, pipe size, and construction of mains make Annual Throughput a better allocator than Design Day in predicting cost causation for transmission mains.

A: The transmission system is a pressure and volumetric flow system dependent on interstate pipelines and underground storage. The network design ensures natural gas supply to all geographical areas through a network of interconnected pipes before delivery to the distribution system. Not all available pipe is used at the same time, but at some point all transmission pipe will be used over a range of different operating strategies. This gives the operator flexibility during different times of year and different coincident loads. Petitioner's transmission mains are particularly important in southern Indiana, as they supply 9 of Petitioner's 11 largest industrial customers (Rate 160 and Rate 170) that are located west and east of Evansville.

Q: How does pipe size impact allocation costs?

A: The volumetric delivery of natural gas is a function of the area of the circular cross section of the pipe, or the equation "pi multiplied by radius squared." For example, doubling the internal radius of a pipe increases its capacity by four times. A larger pipe diameter ensures adequate peak flow at a given pressure. When pressure increases, more natural gas volumes can be delivered. Larger pipe diameters also allow for more peak demands at an incrementally smaller cost of the total cost of the main, since the total costs do not vary much with increased pipe size.

Q: What costs are not related to pipe size?

A: Construction costs not related to pipe size include planning, surveying, excavation, hauling, pipe bed preparation, unloading and stringing of pipe, inspections, and backfill. These costs are required regardless of pipe diameter so those customers using the largest volumetric throughput should pay for the majority of construction costs. The additional minor cost of a pipe main is the additional size or pipe diameter to handle the peak coincident demands based upon Petitioner's design parameters and operation for customer requirements.

Q: How does throughput represent cost causation more accurately?

A: Throughput represents all costs of transmission mains, not just the incremental design day volumes available through larger pipe diameters. The extra costs of providing additional peak capacity are lower than the average costs of providing baseline throughput capacity. Annual throughput is the most accurate measure of cost causation for the transmission system.

Q: Please explain why Annual Throughput replicates cost causation for Transmission.

A: The operational and design requirements for volumetric throughput for nine months is a direct function of natural gas volumes delivered to the Rate 170 customers. Seventy-five percent (75%) of the time Rate 170 is using approximately 50% of the throughput of all rate classes.

A gas distribution system would not exist if only short duration peak demand related costs were collected, and Vectren South could not provide service to all customers if the Transmission system were not built for annual throughput. The use of Design Day as the sole allocator for Transmission only allocates responsibility of costs to peak demands, does not represent the use of the whole system and shifts costs away from the dominant users of the transmission system. The allocation of costs only on peak demands is not consistent with the principle of cost-causality because it does not take into account the use of the system year-round. The allocation of transmission cost on Annual Throughput is the monthly cost causation for transmission, essential to the collection of monthly revenue requirements, and the economic feasibility of the gas delivery system.

Q: Do you have concerns about any of the peak demand or design day allocators?

A: Yes. I find the Design Day ("DESDAY") allocator flawed in its definition of peak demand as well as the use of other allocators associated with DESDAY. These associated allocators are Incremental Winter ("INCWTR"), DESDAY_HP, and DESDAY_LowMed. Design Day is calculated as a function of outside temperature or heating degree days ("HDD"), but not all system peaks are driven by outside temperature. Petitioner calculates DESDAY allocation as 47.64% for Rate 110 – Residential and 16.48% for Rate 170 – Contract Transportation as shown in Table 3, Design Day Therms.

Setting a peak for residential customers based upon cold days or HDD is reasonable but does not apply to industrial customers because their peak may or may not be a function of outdoor temperature. The transportation rates Rate 145, Rate 160, and Rate 170 industrials typically have flat monthly loads driven by production. These rates do set peak daily demands, but their peak demand is not a strong function of HDD and is more closely related to production.

Q: Please provide your analysis of the use and derivation of Design Day.

A: A Design Day allocator is intended to indicate the variance between base loads and peak loads so the utility can design its system to handle maximum, short duration loads. For residential customers, this variance is produced because of heating load requirements during winter months. This is also typical of general service loads. This base load and winter load variance may not be as great for industrial loads because their consumption is usually production related and there may not be much need for additional space heating.

Q: How is Petitioner's Design Day calculation derived?

A: Petitioner's Design Day load calculation per rate class is derived from separation of base summer loads and incremental winter loads from winter peak month data. Petitioner's theoretical Design Day peak consumption is calculated by escalating only the remainder of base summer and incremental winter loads. The remainder for all rate classes is assumed to be driven by outdoor temperature or space heating requirements.

The theoretical heating requirement is based upon the 70 Degree Day factor, which is a measurement of space heating requirements when the outside temperature is below 65 degrees Fahrenheit. The magnitude of DESDAY for Rate 110 is 1,061,072 therms and for Rate 170 is 367,164 therms. See Tab External on Petitioner's workpaper - 45447 Vectren South No 16 Workpaper VEDS COSS External Allocators.xls.

Q: How did you calculate the number of design days for Rate 110?

A: I calculated the number of design days that could occur for Rate 110 by dividing Petitioner's January forecast by the design day magnitude. Mathematically, the Residential DESDAY quantity could occur 15 days in January to equal the 2021 January forecast of 15,256,079 therms. See Tab External on Petitioner's workpaper - 45447 Vectren South No. 16 Workpaper VEDS COSS External Allocators.xls. This calculation then means the remaining days of January would need no heating or no cooling.

I further analyzed the DESDAY by doing the following. DESDAY is the theoretical maximum daily consumption which occurs for heat sensitive loads in a cold month, January. This daily peak day needs to be compared to the total monthly consumption, 31 days, for January to see if it makes sense. I assumed the peak load occurs in January. I multiplied each rate tariff DESDAY consumption by the number of days in January and compared that number to the forecasted January 2021 consumption.

If these peak loads occurred every day of the month, which is not expected and is not the design intent of HDD, Rate 110 would consume 31,832,160 therms and Rate 170 would consume 11,014,920 therms in a peak month. Comparing this improbable condition to actual monthly winter consumption gives insight into the Petitioner's incorrect use of DESDAY. Petitioner's peak day for Rate 170 multiplied by 31 days is only 73% of its predicted January consumption. At a minimum, the peak day for Rate 170 should be the monthly consumption divided by 31 days.

For January 2021, Rate 110 is forecast to use 15,256,079 therms. Because the theoretically improbable monthly consumption of 31 days at peak is greater than the forecast monthly consumption, the DESDAY represents a potential peak day for that rate class.

For Rate 170 the exact opposite occurs. For January 2021, Rate 170 is forecast to use 15,374,227 therms. Because the theoretically improbable peak month, 31 days of daily peak, is LESS than the monthly consumption, the DESDAY does not represent a potential peak.

Again, DESDAY for Rate 170 is not a function of outdoor temperature. For Rate 170, DESDAY is largely inaccurate when using HDD to derive the design day, compared to actual metered months that set Rate 170 peak demand. A design day for the Rate 170 customers would be a minimum of the peak monthly consumption divided by the number of days. A more accurate method to determine the industrial Design Day would be to use actual metered peak days, which should be available from Petitioner's meter records for the large consumption users – Rate 170.

Q: Is it appropriate to use 70 Heating Degree Days to determine the DESDAY allocator for all rate classes?

A: No. Using 70 HDDs, driven by cold outside temperatures for the distribution mains and services that are located close to the peak load does not make sense. For customer peak loads not driven by outside temperature, HDD does not make sense, but using actual metered load adjusted for growth does make sense. Upstream of the max HDD areas or the predominant residential loads, the flows may be accommodated operationally by optimizing the interconnected network of the HPD, Transmission, and Storage.

Q: Has Vectren South's outdoor temperatures caused it to reach the 70 HDDs?

A: No, not in the past 10 years. I asked Vectren South for its actual HDD, a daily peak quantity, for the past 10 years. The highest HDD was experienced on 2/19/2015 recording 62 HDDs with a base of 65 degrees Fahrenheit. OUCC DR 12.4 Attachment BRK-6. Additionally, I looked up data for Evansville, Indiana compiled by the National Oceanic and Atmospheric Administration ("NOAA"). NOAA reports the 30-year average (1981-2010) for Evansville with January being the coldest month with an average of 1007 HDDs for the month, or the total heating degree day measurements for the month.

Q: Does Commodity and the associated allocation affect Distribution Accounts?

A: Yes. In the prior Cause, Distribution – Commodity was allocated with Annual Throughput using only the non-transportation rate classes. Additionally, distribution mains were separated into Demand and Customer, with the associated percentages divided among Commodity, Demand, and Customer based upon a minimum distribution study.

In this Cause, Petitioner changed the allocation of distribution mains (FERC 376) to include some HP Distribution costs to Rate 170 and some LP/MP Distribution costs to transportation Rates 160 and 145, but used design day, not annual throughput. Specifically, design day allocators were separated into distribution pressure classes: Demand – DESDAY_HP and DESDAY_LowMed along with similar pressure separation for customer allocators and Customer – CUST_HP and CUST_LowMed were used.

Q: Is Petitioner's switch of allocator for Transmission and Distribution appropriate?

A: No. The utility is designed for use and operation every day of the year. Ignoring Commodity or annual throughput ignores Petitioner's system design and operation. Using Peak demand or Petitioner's DESDAY allocator, which seldom occurs, presumes the entirety of Plant-in-Service costs associated with Transmission and Distribution are a direct function of increased pipe diameter. Assigning the costs to those users that represent approximately one-half of the peak demand when another rate class dominates peak use for 9 months of the year does not accurately represent cost causation and is not appropriate. I do not recommend using DESDAY as a Demand allocator.

VI. OUCC ADJUSTMENTS TO PETITIONER'S COSS

Q: What are your changes to Petitioner's COSS?

A: I recommend replacing the Demand classification with the Commodity classification for all Transmission Plant-in-Service FERC accounts in Petitioner's COSS. For this classification change, all Transmission Plant-in-Service FERC accounts should be allocated with the Annual Throughput allocator by replacing the Design Day allocator. This change has the effect of placing cost causation on the transmission network design, operation, and the large volume users that dominate peak demands for 9 months of the year.

Petitioner did not include Commodity cost for Distribution (FERC 376). Commodity – Annual Throughput should supplant Demand-Peak Demand. Like Transmission, the Design Day allocator should be changed to Annual Throughput to establish allocated costs from annual larger volume users and the network design of HP Distribution Plant-in-Service.

For the LP/MP Distribution, I agree with Petitioner's removal of customers that are not served from the LP/MP Distribution. I do not agree with Petitioner only using Demand and not using the Commodity classification. I recommend inclusion of the Commodity classification as discussed in this question below. Petitioner also only uses Demand cost in the volumetric rates and lumps all other costs into the Customer classification. Petitioner takes this one step further, without explanation, and puts all the Rate 110- Residential Customer costs into the Rate 110 Monthly Customer Charge.

Weather dependency becomes more prevalent for the residential and general service rate customers, both of which are the predominant users of LP/MP Distribution. The LP/MP Distribution mains (FERC 376) serve specific customer peak load and annual load. The LP/MP Distribution mains do not have as much diversity in peak load and network design as the transmission system.

The distribution customer benefits by being connected to the pipe for potential use but should not be subject to only Demand costs and Customer costs. Allocating costs for highest demand and allocating the remainder of the costs based solely as a Monthly Customer Charge ignores associated Commodity costs to establish network design, future growth, and basic installation costs regardless of pipe size.

For all these reasons, I recommend the addition of Commodity – Throughput in conjunction with Petitioner's zero-intercept method and I recommend allocating the LP/MP Distribution portion of FERC 376 in the same manner established in Petitioner's previous rate case. Demand should be 35% of the costs in FERC 376 LP/MP Distribution and allocated with Design Day. Commodity should be 35% of the costs in FERC 376 LP/MP Distribution and allocated with Annual Throughput. Customer should be 30% of the costs in FERC 376 LP/MP Distribution and allocated with Number of Customers.

Q: What adjustments to Plant-in-Service Transmission are you recommending?

A: I recommend all FERC accounts contained in Plant-in-Service Transmission be allocated with the Annual Throughput allocator. Table 4 below contains the accounts extracted from Petitioner's COSS. See 45447_Vectren South_CONFIDENTIAL VEDS COSS_10302020.xlsm, Tab-Classification.

Table 4: Transmission FERC Accounts Allocated from Petitioner's Design Day to OUCC Recommended Annual Throughput ($000)

FERC ACCOUNT	Name	Total Plant-in-Service
365.1	Land and Land Rights	$744,000
365.2	Rights-of-Way	$1,753 ,000
366.2	Measuring & Reg Station Structures	$254,000
367	Mains	$104,878,000
368	Compressor Station Equip	$28,000
369	Measure & Regulating Station Equip.	$15,147,000
371	Other Equipment	$5,000,000
Total		$122,809,000

A comparison of Petitioner's Allocation using Design Day and the OUCC's allocation using Annual Throughput is reflected in Table 5 below.

Table 5: OUCC Transmission Allocation Using Annual Throughput Compared to Petitioner's Method Using Design Day

($000)

	Rate 110	Rate 120/125	Rate 145	Rate 160	Rate 170	Total
Petitioner	$58,500	$27,397	$6,241	$10,428	$20,243	$122,809
OUCC	$24,869	$13,693	$7,074	$20,583	$56,590	$122,809
Difference	$33,631	$13,704	$(833)	$(10,155)	$(36,348)	

Q: How does Petitioner allocate the HP and LP/MP Distribution of FERC 376?

A: Petitioner splits Distribution mains (FERC 376) into HP and LP/MP so that some large volume users can be allocated to the HP distribution but excluded from the LP/MP distribution based upon which pressure system the customer is connected. The HP distribution mains represents 15% of FERC 376 and the LP/MP distribution mains are the remaining 85%.

Both distribution pressures are classified and allocated in the same manner with the allocations derived from the Mains zero-inch study: 52% Demand and 48% Customer. Demand was then allocated on Design Day Demand and Customer using Number of Customers. Both Classifications excluded customers not served by the respective pressure systems.

Q: What adjustments to the Distribution function are you recommending?

A: For the HP portion of distribution mains, I recommend Petitioner change the classification of Demand to Commodity and allocate Commodity on Annual Throughput of all rate classes. My reasons for changing Demand to Commodity – Annual Throughput is the same as my reasons for Transmission. See Table 6. The Customer portion of HP distribution does not need to be changed so Table 7 shows the OUCC's new total allocation for FERC 376.

Table 6: OUCC COSS Adjustments to HP Distribution of FERC 376: Petitioner's Demand - Design Day vs. OUCC Commodity- Annual Throughput ($000)

	Rate 110	Rate 120/125	Rate 145	Rate 160	Rate 170	Total
Petitioner: Demand	$9,031.70	$4,229.79	$963.52	$1,609.95	$2,532.14	$18,367
OUCC: Commodity	$3,719	$2,048	$1,058	$3,078	$8,464	$18,367
Difference	$5,312	$2,182	$(94)	$(1,468)	$(5,931)	

Table 7: Total HP Distribution Allocation Comparison of FERC 376

($000)

	Rate 110	Rate 120/125	Rate 145	Rate 160	Rate 170	Total
Petitioner	$24,506	$5,792	$975	$1,614	$2,533	$35,419
OUCC	$19,194	$3,610	$1,069	$3,082	$8,464	$35,419
Difference	$5,312	$2,182	$(94)	$(1,468)	$(5,931)	

For the LP/MP portion of distribution mains, I recommend Petitioner follow the COSS allocation method for FERC 376 used in Cause No. 43112. Specifically, I recommend Customer classification should be 30% of distribution mains classified as Customer allocated on customer count, 35% should be classified as Demand allocated on Design Day, and 35% should be classified as Commodity – annual throughput. This is the same allocation used in Cause No. 43112 and the Demand and Commodity should be used to separate costs attributed to pipe diameter and for costs attributed to putting pipe in the ground. See Tables 8 and 9. In the current Cause Petitioner did not allocate distribution mains based on Commodity as was done in Cause No. 43112. Adding Commodity is appropriate because not all customers are HDD sensitive and adding some Commodity allocated with throughput more closely replicates the majority of costs associated with installing mains.

Table 8: OUCC COSS Adjustments to LP/MP Distribution of FERC 376 ($000)

	Rate 110	Rate 120/125	Rate 145	Rate 160	Rate 170	Total
Demand (35%) – LP/MP Design Day	$41,400	$19,389	$3,500	$5,997	0	$70,286
Commodity (35%) – LP/MP Annual Throughput	$26,407	$14,535	$7,502	$21,842	0	$70,286
Customer (30%) – LP/MP Customer Count	$54,678	$5,518	$35	$13	0	$60,245
Total	$122,486	$39,442	$11,038	$27,852	0	$200,817

Table 9: Total LP/MP Distribution Allocation Comparison of FERC 376 ($000)

	Rate 110	Rate 120/125	Rate 145	Rate 160	Rate 170	Total
Petitioner	$149,086	$37,583	$5,242	$8,906	$0	$200,817
OUCC	$122,486	$39,442	$11,038	$27,852	$0	$200,817
Difference	$26,600	$(1,860)	$(5,795)	$(18,946)	$0	$0

Q: Do you recommend Petitioner update the proposed COSS?

A: Yes. Petitioner's COSS software operates with interdependent data and calculations embedded in the software, and other data from Petitioner is not included in that software. My COSS recommendations change the allocations for a few Plant-in-Service FERC accounts. These allocation changes affect downstream allocators because of the hierarchy and interdependency of allocators in the COSS software.

For Phase 1, Petitioner proposes updates to rate base and capital structure through June 30, 2021 that are both actual and as a consequence of the Commission's Final Order. The OUCC's case-in-chief recommends changes, other than those in my testimony, that are inputs to the COSS model such as return on equity, depreciation, capital assets, and expenses. If any of the OUCC's adjustments to accounting, depreciation, authorized return, or COSS allocations are approved in the Commission's Order for this Cause, then I recommend Vectren South rerun the COSS using the outcome of the Final Order in this Cause.

In Phase 2 Petitioner proposes updates to the entire revenue requirement based upon actual revenues and expenses through December 31, 2021 with the Phase 2 implementation of rates. The OUCC recommends a revenue proof including all billing determinants be provided prior to implementation of Phase 2.

VII. RATE DESIGN: SUBSIDIES, MONTHLY CUSTOMER CHARGES, TARIFF CHANGES, AND FUTURE TDSIC AND CSIA ALLOCATIONS

A. Subsidies

Q: Does Petitioner propose to mitigate subsidies for all rate classes through its proposed rate design?

A: No. Petitioner mitigates subsidies to all rate classes except Rate 170. See Table 10 below. The other rate classes approach a 25% reduction of subsidies received or subsidies paid but Rate 170 is a 66.7% change from the existing subsidy. Petitioner's Exhibit No. 16, page 43, line 13 – Table 3 Comparison of Revenue (Subsidy/Excess by Rate Class ($000)).

Table 10: Petitioner's Proposed Subsidy Changes ($000)

Rate Class	Current (Subsidy)/Excess	Petitioner (Subsidy)/Excess	Percent Change
Rate 110	($3,098)	($2,286)	(26.2%)
Rate 120/125	($969)	($613)	(36.7%)
Rate 145	$1,622	$1,250	(23.0%)
Rate 160	$2,620	$1,941	(25.9%)
Rate 170	($176)	($293)	66.7%

Q: What changes do you recommend to Petitioner's subsidy proposal?

A: I propose reducing the amount Rate 170 receives by $44,000 from its existing subsidy of $176,000, as shown in Table 11 below. This reduces the subsidy received to a 25% change for Rate 170, which is of similar magnitude to the subsidy changes for the other rate classes.

Table 11: OUCC's Proposed Subsidy Changes ($000)

Rate Class	Current (Subsidy)/Excess	OUCC (Subsidy)/Excess	Percent Change
Rate 110	($3,098)	($2,286)	(26.2%)
Rate 120/125	($969)	($773)	(20.1%)
Rate 145	$1,622	$1,250	(23.0%)
Rate 160	$2,620	$1,941	(25.9%)
Rate 170	($176)	($132)	(25.0%)

The difference in dollars for Rate 170 between Petitioner's subsidy recommendation of $293,000 (Table 10) and my recommendation of $132,000 (Table 11) is $161,000. The $161,000 needs to be allocated to other rate classes to retain a net zero subsidy between all rate classes. I chose to place all of this subsidy in Rate 120/125 to decrease the amount of subsidy received. My change reduces the subsidy received by Rate 170 and increases the subsidy received by Rate 120/125. Both subsidy changes are gradual and approach the desired change of 25%. This continues to reduce the subsidy gradually and moves all rate classes closer to the COSS results.

B. Monthly Customer Charges

1. Rate 110 – Residential Sales Service

Q: What monthly customer charge does Petitioner propose for Rate 110 – Residential Service?

A: Petitioner proposes to increase the residential customer charge from $11.00 to $35.00.

Q: Is the proposed residential monthly customer charge reasonable as compared to Petitioner's proposed margin increase?

A: No. The proposed monthly customer charge increase is 218% as compared to a proposed total margin increase for all rate classes of 42.8%. The proposed monthly customer charge of $35.00 represents approximately 47% of the total revenue requirement for Rate 110. Petitioner's Exhibit No. 16, Attachment RAF-2, page 4, line 28 and Attachment RAF-4, page 10, line 308. The $35.00 monthly customer charge also represents 63% of Petitioner's proposed total Non-Gas revenues. Petitioner's Exhibit No. 16, Attachment RAF-3, line 7 and Attachment RAF-4, line 308. Petitioner's proposed monthly customer charge for any residential customer using 50 therms per month or less is approximately 50% of the total bill including the GCA. Petitioner's Exhibit No. 19, Schedule E-5, page 1, Typical Bill Comparison – Residential.

These comparisons indicate residential customers would lose the ability to control costs based upon their usage, while Petitioner's risk of not meeting the Rate 110 revenue requirement would be substantially reduced.

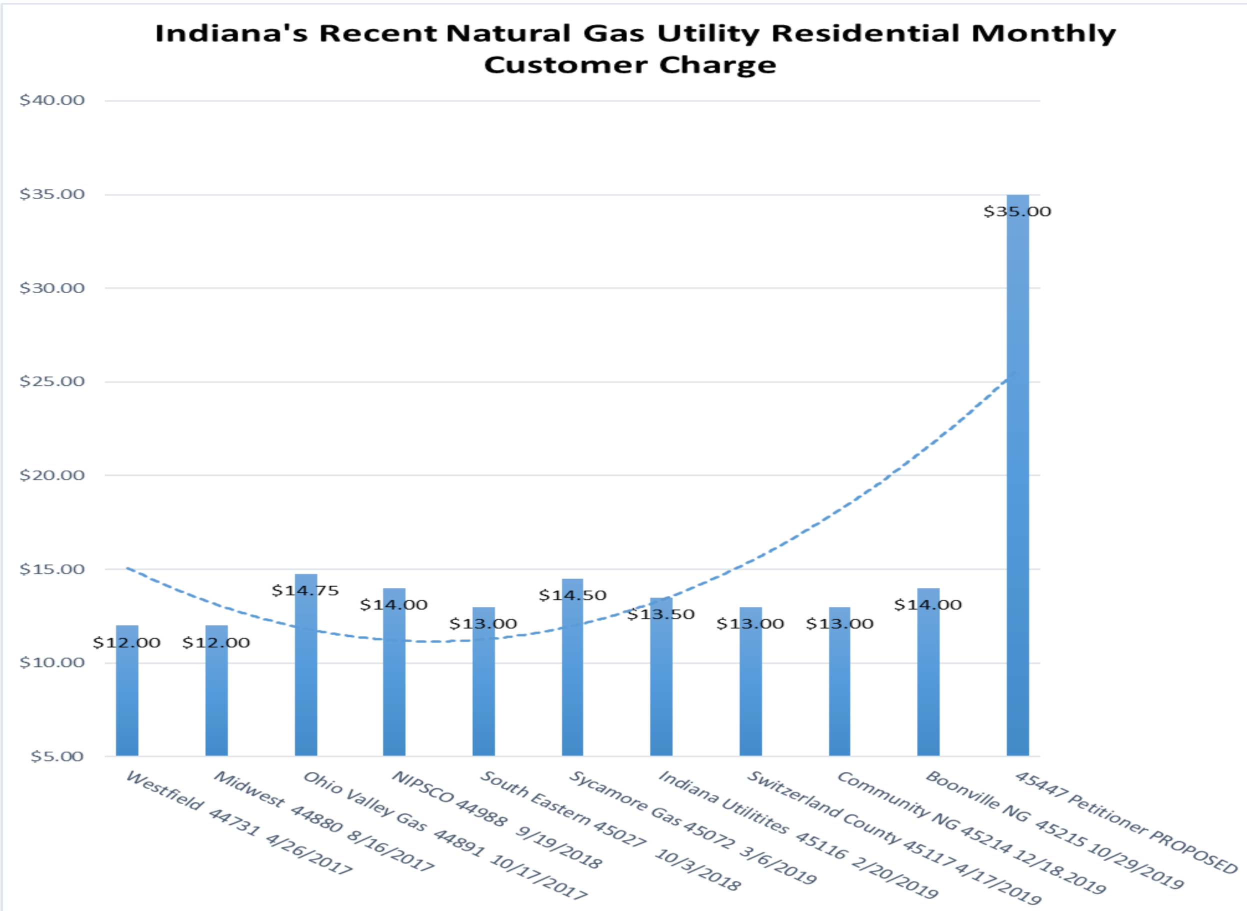
Q: Are there other monthly charges related to increases in rate base?

A: Yes. Petitioner has a Compliance and System Improvement Adjustment ("CSIA") and expects to file additional CSIA trackers starting in 2022. These additional charges have the potential not to be reflected in volumetric rates, and therefore would further reduce Petitioner's financial risk, and conversely, reduce customers' ability to control costs related to gas usage. Petitioner also has a decoupling mechanism which reduces Petitioner's financial risk and ensures collection of all margin costs. Low volume customers are affected the most by the imposition of a high monthly customer charge because they have less financial control over a larger percentage of their bill. Margin costs are best collected through volume consumption with the monthly customer charge reflecting the least cost possible to remain connected. Lumping more costs in the monthly customer charge assures Petitioner quick collection of any reduced revenues due to lower consumption in volumetric rates that would ultimately be collected through the SRC reconciliation.

Q: How does Petitioner' s proposed residential monthly customer charge compare to other Indiana natural gas utilities?

The proposed residential monthly charge of $35.00 would be the highest of Indiana natural gas utilities, as I have illustrated in Chart A. If a $35.00 monthly customer charge is approved the monthly customer charge would be more than double other recently approved residential monthly customer charges for a Commission regulated natural gas utility.

Chart A – Indiana Natural Gas Utility Residential Customer Charges



Q: How does Petitioner's request to increase its residential customer charge five times more than its requested margin compare to requests by other Indiana natural gas utilities?

A: Petitioner's proposed Rate 110 residential monthly customer charge increase is 5.0 times the percentage of the requested total margin increase. The customer charge should reflect an amount similar to increased margin because the increased margin is the additional revenue requirement for all depreciated assets and expenses providing service to the customer since the prior rate case.

The monthly customer charge is supposed to represent the cost of being connected to the distribution system, but not all system assets. Substantially altering the collection method of total revenue requirements by moving more costs into the customer charge substantially reduces Petitioner's financial risk. Too large of an increase in the customer charge, along with Petitioner's future CSIA filings, has the potential for an even higher percentage of a customer's bill to be beyond their cost control.

In other Indiana natural gas Orders (Table 12), most residential monthly charge increases are less than half of the total margin increase. I recommend the residential monthly charge increases should not exceed the total requested margin increase.

Table 12: Indiana Utilities Residential Customer Charge Increase versus Total Margin Increase

Natural Gas Utility	Cause No.	Order	Requested Margin Increase	Prior Customer Charge	Approved Customer Charge	Approved Customer Charge (Percentage Increase)
Midwest	44880	8/16/2017	17.0%	$12.00	$12.00	0.0%
Ohio Valley Gas	44891	10/17/2017	17.8%	$14.50	$14.75	1.7%
NIPSCO	44988	9/19/2018	46.5%	$11.00	$14.00	27.3%
South Eastern	45027	10/3/2018	32.5%	$11.00	$13.00	18.2%
Sycamore Gas	45072	3/6/2019	16.4%	$12.00	$14.50	20.8%
Indiana Utilities	45116	2/20/2019	11.1%	$11.67	$13.50	15.7%
Switzerland County	45117	4/17/2019	15.5%	$10.86	$13.00	19.7%
Community NG	45214	12/18.2019	24.1%	$13.00	$13.00	0.0%
Boonville NG	45215	10/29/2019	14.8%	$12.00	$14.00	16.7%

Q: What monthly residential customer charge is appropriate in this Cause?

A: I recommend Vectren South's monthly residential customer charge (Rate 110) be set at $16.50/month, which more closely aligns with recent Commission-approved residential customer charges for Indiana natural gas utilities. Also, an increase from $11.00 to $16.50 is a 50% increase, which is very close to the requested total margin increase.

There are additional reasons to keep the monthly customer charge at a reasonable amount. Petitioner's TDSIC (Cause No. 44429) will end with Petitioner's upcoming TDSIC-14 filing. After a Final Order is issued in this Cause, those costs will be put into rate base, and the TDSIC charges, which are currently recovered through a fixed monthly charge for Rate 110, will be reset to zero.

The most recent TDSIC charge in TDSIC-13 was $14.10 per month on top of the Monthly Customer Charge from Petitioner's last rate case. The OUCC anticipates Petitioner will file future petitions for Compliance or TDSIC recovery, and these charges, if approved, would be a further increase to customers' bills.

2. Rate 120/125 General Sales Service and Schools/Government Transportation Service

Q: What Monthly Service Charge do you recommend for these two rates?

A: I recommend monthly service charge increases similar in magnitude to Petitioner's proposed margin increase percentage, which is 42.8%. A comparison of Petitioner's present monthly charges with the OUCC's recommendation per meter size is in Table 13.

Table 13: Rate 120/125 Monthly Customer Charge

Meter Group	Existing	Petitioner Proposed	OUCC Proposed
Group 1	$22.00	$35.00	$32.00
Group 2	$44.00	$70.00	$63.00
Group 3	$88.00	$135.00	$125.00

3. Rate 145 General Transportation Service

Q: What Monthly Service Charge do you recommend for Rate 145?

A: I recommend monthly service charge increases similar in magnitude to Petitioner's proposed margin increase percentage, which is 42.8%. A comparison of Petitioner's present monthly charges with the OUCC's recommendation is in Table 14.

Table 14: Rate 145 Monthly Customer Charge

	Existing	Petitioner Proposed	OUCC Proposed
Rate 145 – General Transportation	$88.00	$250.00	$125.00

C. Tariff Changes

Q: Does Petitioner have any Rate Changes or Tariff language changes other than the monthly customer charges you do not agree with?

A: No. For Rate 145-General Transportation Service, Petitioner proposes to eliminate the three separate Customer Facility Charges (i.e., for Groups 1, 2 and 3) and to combine them into one Customer Facility Charge applicable to all customers served under this rate schedule. Currently, all 75 customers in this rate class are charged the Customer Facility Charge for Group 3 because they are all larger customers. This proposal recognizes that the load characteristics and size of the customers is consistent. Petitioner's Exhibit No. 17, Page 10 line 21 - page 11, line 20. I agree with this change.

Petitioner proposes the following other changes the OUCC does not oppose:

- Changes to the current locations served.
- Changes to tariff definitions.
- Rate 145 has a change to the volumetric breakpoint between the two rate blocks.
- Petitioner removed the contract language from general sales service Rate 120.
- The contract language for Rates 145, 160, 170, 180, 185 and 190 was revised.
- Rates 145, 160 and 170 under gas transportation provisions have been revised.
- The Gas Transportation Provisions for Rates 145, 160 and 170 were revised.
- Pooling services for Rates 180 and 185 have been revised.

D. Future TDSIC and CSIA Allocation

Q: Do you agree with Petitioner's proposal to use non-gas revenues for any future TDSIC allocations?

A: Yes. The OUCC asked a clarifying question concerning Petitioner's plans to use non-gas revenues, or each rate's margin revenues, to allocate future TDSIC recovery. Petitioner responded it plans on using non-gas revenues for both TDSIC and CSIA recovery. OUCC DR 15.6, Attachment BRK-7. My analysis indicates Petitioner's investments are system improvements to benefit Petitioner's delivery system regardless of whether the natural gas is purchased from Petitioner or from a third party, which can occur for transportation customers. Using margin revenue for allocation of TDSIC and Compliance costs allocates infrastructure costs to all customers regardless of their consumption. This is equitable, so all customers are treated equally whether they purchase gas from Petitioner or purchase gas from a third party as a transportation customer.

VIII. RECOMMENDATIONS

Q: What are your COSS recommendations?

A: I recommend adjustments to the allocation of Transmission Plant-in-Service and Distribution Plant-in-Service. I recommend Petitioner rerun the COSS model including changes to allocation and other OUCC adjustments to revenue requirements based upon accounting expense adjustments, depreciation, and rate of return approved in this Cause during Petitioner’s Phase 1 update. For Phase 1, I recommend:

- Petitioner rerun the COSS based upon the following allocations.

  1. Transmission Plant-in-Service (FERC 367) allocated 100% to Commodity – Annual Throughput.
  2. High Pressure Distribution Plant-in-Service (FERC 376) change Demand – Design Day allocation to Commodity – Annual Throughput allocation.
  3. Low/Medium Pressure Distribution Plant-in-Service (FERC 376) allocated 35% to Commodity – LP/MP Annual Throughput, 30% to Customer – LP/MP Number of Customers, and 35% to Demand – LP/MP Design Day. These allocations exclude Rate 170 as Petitioner proposes.

Petitioner proposes to make revenue requirement changes based upon actual revenues and expenses with the Phase 2 implementation of rates. OUCC witness Mark Grosskopf opposes this proposal. However, if Petitioner’s Phase 2 proposal is approved, then I recommend:

- Petitioner use the COSS design from the Commission's Final Order for this Cause and provide a revenue proof with updated billing determinants for any revenues adjusted in Phase 2.

Q: What are your rate design recommendations?

A: I recommend rate classes approach a 25% reduction of subsidies paid or subsidies received. Petitioner should reduce the subsidy received by Rate 170 and place the equal amount to reduce the subsidies received by Rate 120 and Rate 125.

- Remove $44,000 of the subsidy currently received by Rate 170 – Contract Transportation and balance the subsidy differential by decreasing the subsidy received by Rate 120/125 General Service – School/Government Transportation Service by $160,000 from Petitioner's proposed subsidy.

Rate 110, Rate 120, Rate 125, and Rate 145 increases to monthly customer charges should be similar in magnitude to the Petitioner's total margin increase. I recommend the following:

- Set the Rate 110 – Residential Service monthly customer charge to $16.50/month.
- Set the Rate 120 – General Sales Service monthly customer charge and Rate 125 – School/Government Transportation Service monthly customer charge to $32/month for Group 1 Meters, $63/month for Group 2 Meters, and $125/month for Group 3 Meters.
- Set the Rate 145 – General Transportation Service monthly customer charge to $125.00/month.

I also recommend the Commission accept Petitioner's proposed future TDSIC and CSIA allocation based upon margin rates.

Q: What are your Tariff language recommendations?

A: I recommend approval of Petitioner's changes as discussed in Petitioner's Exhibit No. 17. Specifically, I support the consolidation of three meter groups into one meter group in Rate

145 – General Transportation Service. I also recommend approval of the following tariff revisions proposed by Petitioner:

- Changes to the current locations served;
- Changes to tariff definitions;
- Change to Rate 145 regarding the volumetric breakpoint between the two rate blocks;
- Removal of the contract language from general sales service Rate 120;
- Revisions to the contract language for Rates 145, 160, 170, 180, 185 and 190;
- Revisions to Rate 145, 160 and 170 gas transportation provisions;
- Revisions to the Gas Transportation Provisions for Rates 145, 160 and 170; and
- Revisions to pooling services for Rates 180 and 185.

Q: Does this conclude your testimony?

A: Yes, it does.

APPENDIX BRK-1 TO THE TESTIMONY OF OUCC WITNESS BRIEN R. KRIEGER

Q: Please describe your educational background and experience.

A: I graduated from Purdue University in West Lafayette, Indiana with a Bachelor of Science Degree in Mechanical Engineering in May 1986, and a Master of Science Degree in Mechanical Engineering in August 2001 from Purdue University at the IUPUI campus.

From 1986 through mid-1997, I worked for PSI Energy and Cinergy, progressing to a Senior Engineer. After the initial four years as a field engineer and industrial representative in Terre Haute, Indiana, I accepted a transfer to corporate offices in Plainfield, Indiana where my focus changed to industrial energy efficiency implementation and power quality. Early Demand Side Management ("DSM") projects included ice storage for Indiana State University, Time of Use rates for industrials, and DSM Verification and Validation reporting to the IURC. I was an Electric Power Research Institute committee member on forums concerning electric vehicle batteries/charging, municipal water/wastewater, and adjustable speed drives. I left Cinergy and worked approximately two years for the energy consultant ESG, and then worked for the OUCC from mid-1999 to mid-2001.

I completed my Master's in Engineering in 2001, with a focus on power generation, including aerospace turbines, and left the OUCC to gain experience and practice in turbines. I was employed by Rolls-Royce (2001-2008) in Indianapolis working in an engineering capacity for military engines. This work included: fuel-flight regime performance, component failure mode analysis, and military program control account management.

From 2008 to 2016 my employment included substitute teaching in the Plainfield, Indiana school district, grades 3 through 12. I passed the math Praxis exam requirement for teaching secondary school. During this period, I also performed contract engineering work for Duke Energy and Air Analysis. I started working again with the OUCC in 2016.

Over my career I have attended various continuing education workshops at the University of Wisconsin and written technical papers. While previously employed at the OUCC, I completed Week 1 of NARUC's Utility Rate School hosted by the Institute of Public Utilities at Michigan State University. In 2016, I attended two cost of service/rate-making courses: Ratemaking Workshop (ISBA Utility Law Section) and Financial Management: Cost of Service Ratemaking (AWWA).

In 2017, I attended the AGA Rate School sponsored by the Center for Business and Regulation in the College of Business & Management at the University of Illinois Springfield and attended Camp NARUC Week 2, Intermediate Course held at Michigan State University. I completed the Fundamentals of Gas Distribution on-line course developed and administered by Gas Technology Institute in 2018. In October 2019, I attended Camp NARUC Week 3, Advanced Regulatory Studies Program held at Michigan State University by the Institute of Public Utilities.

My current responsibilities include reviewing and analyzing Cost of Service Studies ("COSS") relating to cases filed with the Commission by natural gas, electric and water utilities. Additionally, I have taken on engineering responsibilities within the

OUCC's Natural Gas Division, including participation in "Call Before You Dig-811" incident review and natural gas emergency response training.

Q: Have you previously filed testimony with the Commission?

A: Yes. I have provided written testimony concerning COSS in Cause Nos. 44731, 44768, 44880, 44988, 45027, 45072, 45116, 45117, 45214, and 45215. Additionally, I have provided written testimony for Targeted Economic Development ("TED") projects in 2017/2018/2020 and various Federal Mandate Cost Adjustment ("FMCA") and Transmission, Distribution, and Storage System Improvement Charges ("TDSIC") petitions. I filed testimony or provided analysis in the following FMCA or TDSIC 7-Year Plan or Tracker petitions: Cause Nos. 44003, 44429, 44430, 44942, 45131, 45007, 45264, 45330 and 45400.

While previously employed by the OUCC, I wrote testimony concerning the Commission's investigation into merchant power plants, power quality, Midwest Independent System Operator and other procedures. Additionally, I prepared testimony and position papers supporting the OUCC's position on various electric and water rate cases during those same years.

Q: Please describe the general review you conducted to prepare this testimony.

A: I reviewed Vectren South's Petition, Testimony, COSS, and Tariffs for this Cause, Cause No. 45447. I focused on Petitioner's testimony necessary for my COSS, rate design, and tariff analysis. I primarily used the testimony, attachments, exhibits, and workpapers of Russell A. Feingold, Petitioner's Exhibit No.16, and Katie J. Tieken, Petitioner's Exhibit No. 17.

I also reviewed Petitioner's prior Petition (Cause No. 43112), Testimony, Stipulation and Settlement Agreement, and the Commission Order. I participated in OUCC case team meetings concerning Petitioner's case. On December 17, 2020, I participated in an informal discussion on the COSS with Petitioner's COSS witness, Mr. Russell Feingold.

Note: Attachment BRK-1, Page 1 is Confidential.

Q 4.4: Please provide an explanation of normal winter and normal summer operation of the natural gas system related to city gate usage, storage usage, and the transmission mains.

Objection:

Vectren South objects to the request on the grounds and to the extent it is overbroad and unduly burdensome and not reasonably calculated to lead to the discovery of admissible evidence and on the separate and independent grounds and to the extent it is vague and ambiguous and provides no basis from which Vectren South can determine what information is sought. Vectren South is unable to determine from the Request what an "explanation of normal winter and normal summer operation..." is meant to include nor what the term "normal" means for purposes of the Request.

Subject to and without waiver of the foregoing objections, Vectren South responds as follows:

Response:

Petitioner provides the following high-level description of the gas system operation:

- Using forecasted customer demand, Vectren Gas Supply acquires sufficient gas from interstate pipelines at Vectren South's city gate stations to combine with available storage field capacities to meet customer demand on a daily basis.
- Biannually, Gas Control and Gas Supply develop seasonal (heating/cooling) city gate flow allocation tables to provide guidelines on typical gas flow capabilities for internal operational guidance and to determine transport customer delivery options.
- Transmission pipelines are primarily used to move gas from the city gate stations to distribution systems or to/from storage fields.
- Generally, the primary differences between winter and summer Vectren South system operation are related to storage field operation and system impact due to transmission line projects. Gas is purchased and injected into the storage fields in the summer months and withdrawn during the winter months to meet a portion of customer demand. Certain large transmission line projects may require changes to typical city gate and storage field operation during the summer months.

VECTREN ENERGY DELIVERY OF INDIANA - SOUTH (GAS)
IURC CAUSE NO. 43112
COST OF SERVICE STUDY
ALLOCATION OF RATE BASE

DATA: 12 MONTHS ENDED MARCH 31, 2006
TYPE OF FILING: CASE-IN-CHIEF
WITNESS: HEID

PETITIONER'S EXHIBIT NO. KAH-2
SCHEDULE 2
PAGE 1 OF 3

		No.	Allocation Method	Total	Rate 110	Rate 120/125/145	Rate 160	Rate 170
	GROSS PLANT							
(1)	Total Manufactured Gas Production	5	Design Day Sales	$0	$0	$0	$0	$0
(2)	Total Natural Gas Production Plant	2	Annual Sales	$54,245	$35,185	$19,059	$0	$0
	Total Underground Storage Plant							
(3)	Commodity	1	Annual Throughput	$2,505,930	$658,566	$417,124	$440,008	$990,233
(4)	Demand	5	Design Day Sales	$5,011,861	$3,455,063	$1,556,798	$0	$0
(5)	Winter	14	Winter Sales	$5,011,861	$3,317,781	$1,694,079	$0	$0
	Total Transmission Plant							
	Mains							
(6)	Customer	3	Number of Bills	$7,069,534	$6,409,892	$657,160	$2,227	$255
(7)	Commodity	1	Annual Throughput	$8,317,446	$2,185,850	$1,384,477	$1,460,431	$3,286,688
(8)	Demand	4	Design Day Throughput	$8,317,446	$3,960,582	$1,953,545	$515,034	$1,888,285
(9)	Land and Land Rights	131	Total Component of Transmission Mains	$1,509,516	$799,596	$254,416	$125,941	$329,562
(10)	Compressor Station Equipment	1	Annual Throughput	$27,708	$7,282	$4,612	$4,865	$10,949
(11)	Structures and Improvements	131	Total Component of Transmission Mains	$223,698	$118,494	$37,702	$18,663	$48,838
(12)	Measuring and Regulating Equipment	131	Total Component of Transmission Mains	$4,009,488	$2,123,841	$675,766	$334,517	$875,365
(13)	Other Transmission Equipment	132	Subtotal Transmission Plant	$6,426	$3,402	$1,083	$537	$1,404
	Total Distribution Plant							
(14)	Mains							
(15)	Customer	23	Number of Bills-Rates 110 thru 160	$21,435,236	$19,435,864	$1,992,618	$6,754	$0
(16)	Commodity	21	Annual Throughput-Rates 110 thru 160	$25,218,978	$10,957,574	$6,940,323	$7,321,080	$0
(17)	Demand	22	Design Day Throughput-Rates 110 thru 160	$25,218,978	$15,535,747	$7,662,960	$2,020,270	$0
(18)	Land and Land Rights	103	Total Component of Distribution Mains	$119,160	$76,147	$27,515	$15,498	$0
(19)	Compressor Station Equipment	21	Annual Throughput-Rates 110 thru 160	$0	$0	$0	$0	$0
(20)	Structures and Improvements	103	Total Component of Distribution Mains	$115,596	$73,870	$26,692	$15,035	$0
(21)	Measuring and Regulating Equipment	103	Total Component of Distribution Mains	$2,605,566	$1,665,037	$601,639	$338,890	$0
(22)	Services	8	Services Study	$49,173,868	$42,967,198	$5,754,006	$301,863	$150,801
(23)	Meters - Account 381 & 385	7	Meters Study	$12,310,204	$7,992,921	$3,769,231	$470,006	$78,045
(24)	Meter Installations - Account 381 & 385	7	Meters Study	$449,304	$291,730	$137,571	$17,155	$2,849
(25)	House Regulators - Account 381 & 385	7	Meters Study	$538,051	$349,352	$164,744	$20,543	$3,411
(26)	Measuring and Regulating Equipment - Industrial	18	Direct to Rate 170	$14,986	$0	$0	$0	$14,986
(27)	Other Distribution Equipment	109	Subtotal Distribution Plant	$30,285	$19,353	$6,993	$3,939	$0
(28)	Total General and Intangible Plant	110	Subtotal Gross Plant	$11,835,161	$8,082,200	$2,359,180	$886,720	$507,062
(29)	Total Gross Plant			$191,130,529	$130,522,527	$38,099,294	$14,319,977	$8,188,732

Q 4.9: In Exhibit No. 16, Confidential Workpaper VEDS COSS External Allocators.xls, on the Design Day tab, there is data listed for the months: July, August, January, and February. Please explain the reasons why only these four months were chosen for use in this excel spreadsheet and what is the use of this data in this spreadsheet.

Response:

The purpose of the Design Day Study is to attribute the overall system's volumetric supply plan to satisfy a Design Day (one number for a single day) to the Company's six tariff rate schedules. The Design Day volumes are based on a day with 70 Heating Degree Days (HDD). The months of January and February were selected as the basis for the heat sensitive portion of the analysis because of their greater level of actual and normal HDDs and the fact that the Company's peak days typically occur during those winter months. Only the heat sensitive portion of customers' gas consumption in January and February are adjusted upward to a day with 70 HDD (the Company's Design Day). Therefore, July and August are used as baseload months (without HDD-impacted volumes) to represent a baseload level of gas consumption for January and February.

The Company filed supplemental workpapers on November 25, 2020; please see "45447_Vectren South No 16 Supplemental Workpaper VEDS COSS External Allocators Design Day study_112520.xlsx" which was provided to parties on November 25, 2020.

Q 9.6: Referring to Petitioner's Exhibit No. 16 Workpaper VEDS COSS External Allocators, two allocators, Totvols and Salesvols, are included on Tab "External" in the Commodity and Revenue Allocators section. For each allocator:

a. Describe where and why these allocators were used.
b. Provide the name of the Functionalized and Classified using the allocator.
c. Provide the FERC account being allocated with the allocator name.
d. Provide the allocated amounts for each rate class.

Response:

a. The Salesvols allocation factor was used to assign Production-Related Plant, Accumulated Depreciation Reserve and Depreciation Expense to the Company's rate classes. The Totvols allocation factor was created in the COSS, but this external allocation factor was not used based on the specific cost allocation methodologies that were chosen to conduct the Company's COSS.

b. Production – Commodity.

c. FERC Account Nos. 330, 331 and 332 used the Salesvols allocation factor.

d. Please refer to the file, VEDS COSS Model MFSR 15 CONFIDENTIAL.xlsm under the tab entitled, F1E.

Q 12.4: Please provide the actual largest Heating Degree Day ("HDD") for Evansville, Indiana for each year for the years 2010 to 2019.

Response:

Climatic Data Center:					
USW00093817	EVANSVILLE AIRPORT	Heating Degree Day	Date	Fahrenheit Temperature	Fahrenheit Temperature
	Year, June 30	Max Base 65		MAX	MIN
	2011	55	1/21/2011	16	4
	2012	46	1/13/2012	23	14
	2013	47	2/1/2013	25	10
	2014	61	1/6/2014	10	-3
	2015	62	2/19/2015	11	-6
	2016	49	1/18/2016	22	10
	2017	52	1/7/2017	20	5
	2018	58	1/16/2018	11	2
	2019	57	1/30/2019	14	1
	2020	48	11/12/2019	22	11

Q 15.6: On page 45, lines 2-4 of his testimony, Mr. Feingold states, "the last column of Table 5 provides the class revenue allocation factors based on the Company's proposed non-gas rates to be used in future CSIA or Transmission, Distribution and Storage Improvement Charge ("TDSIC") proceedings."

a. Does Petitioner expect to use the same allocation factors for the Compliance Component of Petitioner's future CSIA filings as is currently used in Cause No. 44429?
b. If not, please explain what allocation factors Petitioner is proposing to use for the Compliance Component of Petitioner's future CSIA filings.

Response:

a. No. Petitioner proposes to use allocation factors based upon the Company's proposed non-gas revenues by rate class.

b. See part a.

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing ***OUCC'S PUBLIC (REDACTED) TESTIMONY OF BRIEN R. KRIEGER*** has been served upon the following counsel of record in the captioned proceeding by electronic service on February 19, 2021.

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