FILED
April 9, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF PETITIONER'S TDSIC PLAN FOR ELIGIBLE TRANSMISSION, DISTRIBUTION, AND STORAGE SYSTEM IMPROVEMENTS, PURSUANT TO IND. CODE § 8-1-39-10(a) INCLUDING TARGETED ECONOMIC DEVELOPMENT PROJECTS PURSUANT TO IND. CODE § 8-1-39-10(c) AND EXTENSIONS TO RURAL AREAS PURSUANT TO IND. CODE § 8-1-39-11, FOR AUTHORITY TO DEFER COSTS FOR FUTURE RECOVERY AND APPROVING INCLUSION OF NIPSCO'S TDSIC PLAN PROJECTS IN ITS RATE BASE IN ITS NEXT GENERAL RATE PROCEEDING PURSUANT TO IND. CODE § 8-1-2-23.	)	**CAUSE NO. 45330**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S

PUBLIC'S EXHIBIT NO. 2 – 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.

April 9, 2020

Respectfully submitted,

_/s/ T. Jason Haas_______________________
T. Jason Haas
Attorney No. 34983-29
Deputy Consumer Counselor

**PUBLIC (REDACTED) TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER
CAUSE NO. 45330
NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC**

NOTE: [redacted] INDICATES CONFIDENTIAL INFORMATION

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 determine if Northern Indiana Public Service Company LLC's ("NIPSCO" or "Petitioner") 6-Year Plan ("2020-2025 Gas Plan" or "Plan 2") meets Ind. Code ch. 8-1-39 requirements as an eligible Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan. I consider if Petitioner's proposed improvement projects are for purposes of safety, reliability, or system modernization with established incremental benefits and detailed project cost estimates.

Q: Please summarize the results of your analysis.

A: Petitioner presented 33 projects ("projects") in Plan 2 as eligible Transmission, Distribution, and Storage System Improvements, and eligible for recovery.

NIPSCO's first TDSIC Plan ("Plan 1"), Cause No. 44403, Final Order on April 30, 2014, was terminated on December 31, 2019 with all remaining Plan 1 cost estimates cancelled. Petitioner states Plan 2 actual costs started on January 1, 2020. I found no duplicative costs between the two Plans and did not find any Plan 2 projects contained within rate base from Petitioner's last rate case in Cause No. 44988.

As part of the 2020-2025 Gas Plan, NIPSCO reviewed transmission, distribution, and storage assets. (Petitioner's Exhibit No. 2, Verified Direct Testimony of Don Bull, page 8, lines 9-15 and page 13, lines 6-10.) NIPSCO provided a risk analysis performed by EN Engineering that evaluated transmission projects completed in Plan 1 and transmission projects NIPSCO anticipates completing in Plan 2 on reducing overall transmission risk.[1] Petitioner's confidential best estimates included detailed work order level or unit cost estimates, depending on project type.

My analysis evaluated whether the 2020-2025 Gas Plan meets the requirements of Ind. Code ch. 8-1-39. I recommend denial of NIPSCO's application. My analysis indicates NIPSCO's Plan 2 does not fully meet the requirement for Ind. Code § 8-1-39-10(b)(3). This section requires a "determination whether the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan." NIPSCO has not provided evidence to the Indiana Utility Regulatory Commission ("Commission") of

[1] Confidential Attachment 2-A, Confidential Appendix 1, page 1 – Executive Summary

quantifiable benefits for risk reduction of chosen projects versus excluded projects. While NIPSCO provides the cost of the projects and demonstrates the benefits of the plan through the reduction of risk, there is no demonstration that links or supports how or why these costs justify the anticipated benefits.

With regard to the other requirements of Ind. Code ch. 8-1-39, I determined the proposed projects are eligible transmission, distribution, and storage system improvements under Ind. Code § 8-1-39-2, and NIPSCO provided the best estimate of the eligible improvements under Ind. Code § 8-1-29-10(b)(1). However, as explained below, I recommend a 2% inflation factor be applied to NIPSCO's estimates. I determined the public convenience and necessity require or will require the eligible improvements included in the plan under Ind. Code § 8-1-39-10(b)(2). I also reviewed Petitioner's definitions of key terms from Cause No. 44403, and recommend continued use of these key terms. Additionally, if the Commission approves Plan 2, then I recommend approval of Petitioner's proposal for updating the 2020-2025 Gas Plan in future semi-annual tracker adjustment proceedings.

Q: Are there any further recommendations based upon your analysis?

A: Yes. Again, if the Commission approves Plan 2, then in future updates, Petitioner should provide work order level detail cost estimates for all projects, including rural extensions, now lacking site specific engineering based upon site investigations completed for final design, material/labor procurement and scheduling. At that time, the update of approved Plan projects should include work order level estimates for Plan 2 projects originally based upon unit cost, parametrically derived costs, or preliminary design only projects.

The OUCC requests Petitioner continue informal communication and continue to improve the update process. If Plan 2 is approved, the OUCC requests Petitioner include "costs tied to reasons" in the update process if best estimates or actual expenditures exceed a prior best estimate by 20% or $100,000. "Costs tied to reasons" means Petitioner will need to explicitly name the portion of work order detail causing the overage and the associated cost for the unplanned work order item. The OUCC recommends Petitioner file detailed work order level estimates, based on completed engineering with site visits, if Petitioner requests a new project to be added.

II. OVERVIEW OF TDSIC STATUTE AND NIPSCO'S PLAN

Q: What are the main conditions of Indiana's TDSIC statute, Ind. Code ch. 8-1-39, under which NIPSCO requests approval of Plan 2?

A: NIPSCO requests approval of its Plan 2 for a CPCN to implement TDSIC eligible projects meeting requirements of Ind. Code ch. 8-1-39, and if approved, requests cost recovery through a semi-annual cost adjustment mechanism ("TDSIC tracker"). (Petition, paragraph 4, pages 3-5.)

Petitioner's proposed TDSIC Plan of 33 projects includes one rural extension project ("RE1") with RE1 having multiple main extensions and services projected on an annual basis to provide service in rural areas (Ind. Code § 8-1-39-11). All projects within the Plan must meet the requirements of Ind. Code § 8-1-39-2 to be eligible transmission, distribution, and storage system improvements, and the Commission must determine if the Plan is reasonable in accordance with Ind. Code § 8-1-39-10.

If the Plan is approved, the Commission shall issue an order as described as in Ind. Code § 8-1-39-10(b) that includes:

- A finding of the best estimate of the cost of the eligible improvements;
- A determination the plan projects meet public convenience and necessity; and,
- A determination the estimated costs of the eligible improvements are justified by incremental benefits attributable to the plan.

Q: Please provide an overview of NIPSCO's 6-Year TDSIC Plan.

A: NIPSCO proposes 33 projects for the Plan period of 2020 to 2025 and characterizes the 33 projects into three broad categories: Gas System Deliverability, Gas System Integrity, and Rural Gas Extensions. The total costs for each of these categories is included in Table 1.

TABLE 1 - Investment by Segment[2]

Investment Segment	Projected Direct Capital
Gas System Deliverability	$92,656,660
Gas System Integrity	$531,495,088
Rural Gas Extensions	$183,421,531
Plan Total	$807,573,279

Gas System Deliverability is to "…add new gas mains and add or upgrade regulator stations to improve NIPSCO's ability to meet customers' deliverability demands." (Bull Direct, page 8, lines 5-6.) The Gas System Integrity investments are to "…replace certain segments of NIPSCO's gas transmission, distribution, and storage facilities to ensure public safety." (Bull Direct, page 8, lines 9-11.) The Rural Extensions are "…the costs associated with designing and installing gas main and service projects to reach rural areas." (Bull Direct, page 103, lines 16-17.)

[2] Bull Direct, page 8.

Petitioner provided confidential best estimates for each of the 33 projects (Table 2), and also by FERC account in Petitioner's Exhibit No. 2, Confidential Attachment 2-A. The projects have an annual 3% escalation factor applied to the years after the cost estimates originated ("base estimate" or "base year"), not including contingency, through the planned last year of construction. (Bull Direct, page 32, footnote 13.) The base year estimates range from 2017 to 2020 with storage and liquefied natural gas representing the majority with a base year of 2017.

Petitioner's Exhibit No. 2, Confidential Attachment 2-B presents the annual capital estimate breakdown per project, 3% escalation on the base estimate, and the project specific contingency applied to the base estimate. I confirmed the 3% escalation factor is not applied to the contingency dollar estimates.

TABLE 2 - NIPSCO TDSIC PLAN PROJECTS (2020-2025)

1	TP7	Transmission Pipeline Replacement	Hessen Cassel to Hanna St.
2	TP8	Transmission Pipeline Replacement	Highland Junction to Grant St.
3	TP10	Transmission Pipeline Replacement	Aetna to Tassinong
4	TP11	Transmission Pipeline Replacement	Aetna to 483# Loop
5	TP12	Transmission Pipeline Replacement	Aetna to LaPorte Pressure Reduction
6	TP13	Transmission Pipeline Replacement	Aetna to Tassinong Pressure Reduction
7	TP14	Transmission Pipeline Replacement	Colfax and Cline Station Rebuilds
8	IM24	Inspect & Mitigate - Transmission	Corrosion Rectifiers Install/Replace
9	IM25	Inspect & Mitigate - Transmission	Corrosion Moisture Monitoring
10	IM27	Inspect & Mitigate - Transmission	Engineering and Preconstruction - Inspect and Mitigate Transmission
11	IM33	Inspect & Mitigate - Transmission	Station Equipment Upgrades/Replacements
12	IM35	Inspect & Mitigate - Transmission	Transmission Communications Instrumentation Replacement
13	IM36	Inspect & Mitigate - Transmission	2G/3G Cellular Modem Replacement
14	IM37	Inspect & Mitigate - Transmission	Royal Center to Laketon Corrosion Remediation and Pipe Repair
15	IM38	Inspect & Mitigate - Transmission	Trunkline-Goodland Station Heater & Odorizer Replacement
16	IM39	Inspect & Mitigate - Transmission	Wakarusa Station Replacement
17	IM40	Inspect & Mitigate - Transmission	Michigan City ANR Rebuild
18	SD15	System Deliverability - Transmission	Churubusco HP System Improvement
19	SD16	System Deliverability - Transmission	Shipshewana to Howe
20	DSD10	System Deliverability - Distribution	System Deliverability Projects - Distribution
21	DSD13	System Deliverability - Distribution	Shipshewana Distribution Headers
22	RE1	Rural Extensions - Distribution	Rural Extensions
23	S41	Storage Projects	Engineering and Preconstruction - Storage
24	SLNG1	Storage Projects	LNG - Replace Air Actuated Control Valves
25	SLNG2	Storage Projects	LNG - Install Travel Limit Switches on Purification System Valves
26	SLNG3	Storage Projects	LNG - Replace Unit #2 Tank Foundation Heating System
27	SLNG4	Storage Projects	LNG - Replace Unit #2 Purification Sys. Regen. Gas Heater
28	SLNG5	Storage Projects	LNG - Water Mist Fire Protection System for Purification Building
29	SRC1	Storage Projects	RCUGS - Dehydrator #4 Reboiler
30	SRC2	Storage Projects	RCUGS - Replace Injection Flow Control Valve
31	SRC3	Storage Projects	RCUGS - Isolation Valves
32	SRC4	Storage Projects	RCUGS - Replace Desulf #2 Regeneration System
33	SRC5	Storage Projects	RCUGS - Replace Desulf #2 Absorber Towers

Q: Did NIPSCO previously file a second TDSIC plan in Cause No. 45074?

A: Yes. However, NIPSCO requested Cause No. 45074 be dismissed without prejudice. The Commission granted NIPSCO's request in an Order dated September 4, 2018.

Q: Are any of NIPSCO's projects from Cause No. 44403 (Plan 1) or dismissed Cause No. 45074 contained as Plan 2 projects?[3]

A: Yes. However, there is no project cost overlap. There are on-going projects from Cause No. 44403, which have been moved into Plan 2. Also, NIPSCO has re-engineered specific projects from Cause No. 45074. Petitioner uses similar or the same names from Cause No. 44403 or Cause No. 45074 because of pipe connectivity in the same geographical area, parallel existing pipe, or a prior Plan project which was cancelled and re-engineered for Plan 2.

The OUCC and NIPSCO discussed potential project cost overlap during informal meetings on February 4 and February 11, 2020. The OUCC specifically asked NIPSCO about projects that share similar project names, or may be a continuance of a Plan 1 project. At that time, Petitioner provided a table correlating Plan 1 projects to Plan 2 projects with similar names.[4] Distinct line segments with mileage were included for each project, along with the planned work: new or modified, retired, or reduced pressure. Concerning planning costs, Petitioner's witness Donald Bull states that Engineering and Preconstruction estimated costs are included in specific Plan 2 projects whenever possible. (Bull Direct, page 46,

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[3] See attachment BRK-1 containing Petitioner's response to OUCC DR 2-001, and confidential attachment BRK-2, containing Petitioner's confidential responses to Industrial Group DR 1-015 and DR 1-016.

[4] See attachment BRK-3.

lines 13-15.)

In Petitioner's Cause No. 44403 TDSIC-11 (filed 2/25/2020), I found all Plan 1 projects for year 2020 with prior cost estimates set to zero dollars.[5] I have found no duplicative costs or projects between Plan 1 and Plan 2.

Q: What are the specific projects from Plan 1 continued in Plan 2?

A: The OUCC and Petitioner discussed six projects from Cause No. 44403, which are continued in Plan 2. These Plan 1 project numbers are TP2, TP7, TP8, TP9, IM33-DIM14, and IM34-DIM40. During these discussions, NIPSCO clarified the separation of Plan 2 from Plan 1 project scope, and agreed further clarification will continue as requested. NIPSCO stated it is open to accounting schedule revisions, and further discussion to ensure accounting information is understood.

Plan 1 Project No. TP2, Aetna to LaPorte, is renumbered as Plan 2 TP 12 Aetna to LaPorte. Plan 1 (TP2 - Aetna to LaPorte) had zero dollars estimated in Plan 1 for years 2019 and 2020, and the corresponding Plan 2 TP 12 is a continuation of retirements of some 22" pipeline segments, reduced operating pressure of the remaining 22" pipeline, and some additional regulating stations to tie in existing distribution. (Bull Direct, page 76, line 9 through page 78, line 10.) Plan 1 TP2 was completed and placed into rate base as of December 31, 2018.[6] I did not find duplicate costs between the two Plan projects – Aetna to LaPorte.

Plan 1 TP7 Hessen Cassel to Hanna remains as Plan 2 TP7 Hessen Cassel to Hanna, a City of Fort Wayne project. All costs for Plan 1 Hessen Cassel to Hanna

[5] Cause No. 44403 TDSIC-11, Audit Package 1-001 (Plan Update-11).
[6] Cause No. 44403 TDSIC-10, Petitioner's Confidential Exhibit No. 3, page 44, lines 3-9.

were estimated to occur in year 2020 and removed from Plan 1. Hessen Cassel to Hanna has a new best estimate approximately doubling the Plan 1 estimate because TP7 now has the site specific engineering estimate.

Similarly, TP8 Highland to Grant is in both Plans, but the Plan 2 best estimate is about 1/3 of Plan 1’s 2020 estimate of <Confidential [redacted] Confidential> as found in Cause No. 44403 TDSIC-10, but removed in Cause No. 44403 TDSIC-11.

The Aetna to Tassinong project (Plan 1 TP9 to Plan 2 TP10) is a redesigned project for Plan 2 replacing 16” main in most sections with 24” main and adding redundancy. The Plan 1 TP9 total was <Confidential [redacted] Confidential>. Approximately <Confidential [redacted] Confidential> was removed from Plan 1 TP9 year 2020. Approximately <Confidential [redacted] Confidential> was spent in Plan 1 on integrating 16” pipe with a regulating station to remain operating at lower pressure along with land and permit acquisitions.[7] NIPSCO is now planning on installing 26 miles of 24” pipeline, compared to Aetna to Tassinong as proposed in Plan 1 TP10. (Bull Direct, page 68, line 6 – page 69, line 5.)

The Plan 1 Projects IM33-DIM14 and IM34-DIM40 are now combined into Plan 2 IM 33, Station Equipment Upgrades/Replacements. Plan 1 IM33-DIM14 had no estimates and no expenditures, while IM34-DIM40 had no estimates in Plan 1 years 2018, 2019, and 2020. Essentially, Plan 2 IM33 includes projects, some defined in Plan 1, now in Plan 2, and is defined with two subprojects: Odorizers

[7] Petitioner Confidential Attachment 2-A Confidential Appendix 1, page 11, Table 2 Completed Projects

and Pipeline Buildings/Heaters. Project ID IM33 best estimates are based on a per unit basis and will need additional definition, location, and detailed work order level estimates provided in the update process.

Q: Are there any 2020-2025 Gas Plan projects in NIPSCO's current base rates or other tracking mechanisms?

A: No. Petitioner states there are no Plan 2 projects in base rates. (Bull Direct, page 111, lines 4-6.) Petitioner has four associated cost recovery petitions: Cause Nos. 44403, TDSIC Plan 1; 44988, base rates; 45007, FMCA Plan 1; and 45330, TDSIC Plan 2.

The OUCC reviewed projects at the time of each filing, and found separation of projects in each individual petition. The OUCC and Petitioner have discussed the issue of overlapping or duplicate projects in the various cost recovery mechanisms. NIPSCO and the OUCC agree, at this point, there are no overlapping or duplicate projects.

Q: In your opinion, are the proposed projects eligible transmission, distribution and storage improvements as used in Ind. Code § 8-1-39-2?

A: Yes. The projects are undertaken for the purposes of safety, reliability, and system modernization, including the extension of gas service to rural areas, and were not included in NIPSCO's most recent rate case. Therefore, the proposed projects are eligible transmission, distribution and storage improvements as used in Ind. Code § 8-1-39-2.

Q: In your opinion, are the projects included in Petitioner's Gas Plan 2 required or will be required for public convenience and necessity?

A: Yes. The risk analysis indicates these projects will improve NIPSCO's system for reliable natural gas delivery during the Plan installation and into the future. On some pipelines, vintage year alone suggests replacement is required. However, NIPSCO did not provide a dollar quantification or demonstrate that the incremental benefit for the proposed Plan 2 projects justify the costs. With dollar quantified benefits, the Commission would have one metric to aid in deciding if NIPSCO is providing the best use of rate payer dollars and ascertain the worth of selected projects compared to non-selected competing projects.

III. ANALYSIS OF NIPSCO'S SUPPORT FOR SAFETY, RELIABILITY, AND SYSTEM MODERNIZATION IMPROVEMENTS OF PLAN 2

Q: Did Petitioner demonstrate that the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan?

A: No. NIPSCO provides conclusory testimony that merely states the estimated costs are justified by the incremental benefits, and the 2020-2025 Gas Plan provides incremental benefit by significantly decreasing the potential risk. (Bull Direct, page 112, line 15 – page 113, line 5.) NIPSCO did not provide quantifiable incremental benefits for the Plan 2 projects' risk reductions. (Bull Direct, page 113, lines 13-14.) Finally, it is not apparent how selected Plan 2 projects were chosen over alternative projects. Furthermore, my analysis indicates NIPSCO provided a general explanation of its review of projects for the 2020-2025 Gas Plan, but does not provide the exact methodology that shows how a specific project was or was not included in the plan.

Q: Did Petitioner select Plan 2 projects based upon a benefit-cost analysis ensuring best use of dollars for risk reduction?

A: No. It appears Petitioner selected projects based on the EN Engineering risk analysis, and chose the highest transmission risk projects. Mr. Bull states, "[a] broader portfolio of projects was prioritized to develop the specific improvements included in the Plan." (Bull Direct, page 11, lines 16-17.) I did not find evidence Petitioner prioritized projects based upon deploying capital to maximize risk reduction per dollar invested, or reasons for rejecting the other risk evaluated projects.

Mr. Bull states later in testimony, "…most of the Plan's investments positively impact public safety. Safety drivers focus on risk reduction related to gas system leaks, pipeline ruptures, or incidents of pressure excursion." (Bull Direct, page 22, lines 14-16.) For example, Petitioner avoids potential pipeline events by replacing vintage pipe, but did not contrast risks and costs against repairing pipe in a "repair vs. replace" study. (Bull Direct, page 113, line 11.)

Mr. Bull further states, "NIPSCO also evaluated several alternatives to the pipe size for the Aetna to Tassinong pipeline to balance the cost of construction with required capacity." (Bull Direct, page 63, lines 6-8.) Mr. Bull goes on to state, "NIPSCO evaluated alternative projects through the process of updating the Aetna – Tassinong pipeline replacement." (Bull Direct, page 68, lines 15-17.) However, Petitioner did not provide this or any other competitive analysis comparison of possible projects in its case-in-chief that could provide service at a lower cost.

Mr. Bull discussed redundant feed and additional interstate pipeline take points when discussing Projects TP10 and TP11, Aetna to Tassinong and Aetna to

483# Loop, respectively. (Bull Direct, page 67, line 9 – page 73, line 18.) However, Petitioner has not substantiated the necessity or benefits to customers for redundancy or additional capacity by providing an assessment of operational or customer benefits with the natural gas loop flow analysis ("hydraulic model") in its case-in-chief. (Bull Direct, page 72, line 13.)

Q: Did the OUCC try to determine if Petitioner's ranking methodology of potential projects included quantification of risks, or if a comparative analysis of included versus excluded projects was performed?

A: Yes. The OUCC's Data Request No. 2-001 asked Petitioner for a prioritized portfolio of projects, but quantification and rank ratings were not included. The OUCC also asked NIPSCO how it determined priorities for potential projects, but quantification of risks was not included in Petitioner's response. See Attachment BRK-1 with Petitioner's responses.

Q: Did Petitioner quantify the incremental benefits of the Plan 2 projects?

A: No. Mr. Bull discusses the difficulty in quantifying incremental monetary benefits. (Bull Direct, page 112, line 15 – page 114, line 9.) Mr. Bull explicitly states that the "benefit to NIPSCO's customers from these investments cannot be calculated in an actuarial calculation." (Bull Direct, p. 113, lines 13-14.)

Petitioner suggests it has met its burden of proof relying on the Commission's Order in Cause No. 44403, where the Order discusses that Gas Plan 1 provided incremental benefits through risk reduction. In this regard, Mr. Bull explains that "[t]he same is true for the projects proposed in the 2020-2025 Plan." (Bull Direct, p. 114, lines 8-9.) A comparison of cost and risk reduction for Plan projects versus potential alternatives of competing projects was not provided by

Petitioner. A comparison is necessary to ascertain if ratepayer dollars are used judiciously.

Q: Has the Commission recently recognized the importance of prioritizing projects and monetizing incremental benefits associated with risk reduction?

A: Yes, in the final order in the petition for Indianapolis Power and Light for approval of its TDSIC plan, Cause No. 45264, issued on March 4, 2020. On page 23, addressing public convenience and necessity, the Commission stated:

> IPL has used a risk-informed prioritization process that scored and ranked projects. The Risk Model estimated the reduction in the likelihood of failure, as well as the consequences of asset failure and prioritized projects so as to deploy capital in a way that maximizes risk reduction benefit per dollar invested.

On page 24, addressing incremental benefits attributable to the TDSIC plan, the Commission stated:

> IPL's analysis did not attempt to quantify all project benefits, but rather focused on projects that lend themselves to monetization. This supplemental monetization analysis showed that the projects analyzed, when viewed as part of a total portfolio, will provide a net benefit that exceeds the cost of the eligible improvements whether considered on a nominal or a present value basis.

Q: Did NIPSCO attempt to focus on any projects that lend themselves to monetization in order to show a net benefit that exceeds the cost of the eligible improvements?

A: No. NIPSCO does not monetize any risks avoided or improved with its proposed Plan 2 projects. Petitioner has not provided supplemental benefit analysis to evaluate best use of ratepayer dollars for the projects, and Petitioner has the capabilities to do such analysis by utilizing existing operation and maintenance data, commodity cost comparisons, or land/easement procurement costs.

Q: Is it NIPSCO's burden to provide sufficient proof in its case-in-chief to support its request?

A: Yes. In two recent orders, the Commission discussed the necessity of the Petitioner providing a complete case-in-chief and that this burden is the Petitioner's responsibility. An excerpt from the final order in *City of Evansville, Indiana*, Cause No. 45073, Order of the Commission, at p. 8 (December 19, 2018) says, "Evansville is reminded that it bears the burden of proof in demonstrating it is entitled to its requested relief. The OUCC should not have to request or otherwise seek basic supporting documentation that should have been provided with Petitioner's case-in chief to support its requested relief. Further, even if the OUCC is able to ascertain through discovery the information necessary to support Petitioner's requested relief, the Commission, which is the entity that must ultimately render a decision on the matter, would still lack the necessary information to make its determination because it is not privy to the parties' discovery."

The second excerpt is from *Application of Indiana Michigan Power Company*, Cause No. 45245, Order of the Commission, at p. 10 (February 19, 2020) says, "Thus, we also remind I&M of the importance of submitting a complete case-in-chief to facilitate OUCC and Commission review and to avoid unnecessary discovery and motion practice."

Q: Please summarize your analysis of project selection and the net benefit to ratepayers.

A: The reasons for project selection were not quantified with dollars. I did not find risks mapped to dollar savings or a quantification of the benefits other than risk reduction. I consider the following examples quantifiable: operational dollars saved through better natural gas flow management, reduced gas commodity cost with multiple take-points, reduced inspection dollars because older pipe is replaced, reduced reactive manpower for leak identification, or substantiated difficulties with alternative corridors.

Additionally, Mr. Bull characterized two Plan project routes (TP10 and TP11) as complex, congested, or with multiple railroad or highway crossings. (Bull Direct, page 69, line 6 – page 70, line 16, and page 73, line 19 – page 75, line 3.) These projects may warrant special attention on risks avoided, potential risks increased, and incremental benefits.

In summary, Petitioner's Plan 2 projects appear to be chosen based upon a hierarchy of risk, but without a cost benefit analysis, which demonstrates the estimated costs of the Plan 2 improvements are justified by the incremental benefits attributable to Plan 2. It is not apparent any monetization is embedded in any risk characteristic applied in the EN Engineering risk analysis. I find it presumptive to infer Petitioner has chosen the best use of ratepayer money because there is no comparative analysis of risk reduction versus dollars spent for the selected Plan 2 projects. Additionally, I did not find quantifiable risk evaluation for distribution or storage projects similar to what was performed for NIPSCO transmission assets.

My analysis of incremental benefits indicates Petitioner has not met the requirement of Ind. Code § 8-1-39-10(b)(3) for proving the estimated costs of the eligible improvements are justified by the incremental benefits. Petitioner has not provided in its case-in-chief, validation that Plan 2 projects maximize risk reduction, while maximizing the incremental benefits of the dollars invested.

Q: What information should have been provided to demonstrate that project costs justify the incremental benefits?

A: NIPSCO should have provided project information quantifying the value of individual avoided risks for all selected projects. Various methods for quantifying benefits in dollars can be used such as dollars relating to improved customer experience or dollars per risk characteristic avoided. The additional information would allow the Commission to demonstrate, as required in Ind. Code § 8-1-39-10(b)(3), that the estimated costs of the eligible improvements included in the plan are justified by incremental benefits attributable to the plan. Petitioner's methods should explicitly quantify attributes with incremental beneficial dollars on a per project basis to justify the cost of the projects. Additionally, Petitioner should submit a comprehensive list of included projects, alternative projects it considered, but excluded, with reasons for exclusion, the alternative projects' potential costs, and the incremental value of reduced risk of the alternative projects. From this comprehensive list, a determination could be made whether NIPSCO had chosen the best of competing projects which provide the lowest cost for the highest risk reduction.

Q: Did Petitioner's transmission risk analysis of proposed Plan 2 projects indicate Plan 2 transmission projects reduce risk?

A: Yes. The risk analysis performed by EN Engineering demonstrated the improvements to the baseline transmission risk for year 2013, the reduction in risk for completed Plan 1 projects, and anticipated Plan 2 projects ending in year 2025. The Plan 2 transmission projects, which are modeled in the study, include replacing vintage pipe, adding parallel pipe for improved loop flow, retirement of mains, pressure reductions on existing pipe, and retrofitting existing line segments for in-line-inspection tools.

The EN Engineering risk analysis, page 10, Section 5.0 Effect of Pipeline Projects, discusses the Plan 2 projects and primary methods for risk reduction. For Plan 2 projects, page 15, Table 5: Risk Score Trend for Projects Identified indicates risk reduction for Plan 2 transmission projects compared to an increasing risk from the original projected 2018 risk. On page 23, this study predicts an overall system wide relative risk improvement from 2013 to 2025 of <Confidential [redacted] Confidential>.

My analysis of the EN Engineering study indicates the proposed Plan 2 risk reduction methods are similar to the methods in Plan 1: vintage pipeline retirement, pressure reduction, and pipeline reconfiguration for in-line-inspection.

The OUCC and Petitioner discussed projects and risk in a meeting on February 4, 2020. Additional evidence of risk is contained in Mr. Bull's testimony, pages 12 through 17. As a result of these discussions, my review of Mr. Bull's testimony, and the EN Engineering risk analysis, I am satisfied the EN Engineering report is supported by the evaluation of comprehensive risk magnitudes applied to those risks evaluated.

IV. NIPSCO'S SUPPORT OF PROJECT BEST ESTIMATES

Q: What cost estimate information did NIPSCO provide for its proposed Plan 2 projects?

A: NIPSCO describes developing costs with PFES, LLC and internal stakeholder review. (Bull Direct, page 27, line 18 – page 31, line 14.) Petitioner uses the AACE

International cost engineering estimating method for contingency evaluation. (Bull Direct, page 31, lines 17-19.) Petitioner provided work order level estimates for its projects in Confidential Attachment 2-A, Confidential Appendix 2, and also submitted work papers.

I reviewed work order estimates and found the estimates to include detail such as labor hours and hourly rates with detailed material lists. The OUCC and Petitioner discussed specific questions concerning the embedded formulas. The OUCC confirmed Petitioner’s method developed and presented work order level estimates. Also, Petitioner addressed specific questions regarding special order material taxes and above ground regulator painting/coatings.

There are some Inspect and Mitigate (“IM”) Project estimates that will require updating. Although some locations were identified, the material and labor cost estimates are not as detailed as compared to other projects. Petitioner’s case-in-chief project per unit cost basis, and to be determined (“TBD”) scheduling will need further refinement with field inspection. Specifically, I have identified IM24-Corrosion Rectifiers Install/Replace, IM25-Corrosion Moisture Monitoring, IM33-Station Equipment Upgrades/Replacements, IM35-Transmission Communications Instrumentation Replacement, and IM36-2G/3G Cellular Modem Replacement will need updates.

Petitioner recognizes the necessity for meeting with the OUCC during the update process as Mr. Bull explains. (Bull Direct, page 24, line 16 – page 25, line 2.) I am satisfied Petitioner has provided best estimates in Plan 2 and will solidify estimates, in the update process, when the later year projects become imminent.

Q: Does NIPSCO have specific economic development projects or rural extension projects in Plan 2?

A: NIPSCO does not have any specific economic development projects. NIPSCO anticipates rural extension projects. The Petition has estimates of services and costs on an annual basis in the RE1 summary. (Confidential Attachment 2-A, Confidential Appendix 2, page 74 of 98.) This table contains no specific rural extension projects, but rather an annual estimate of the number of main extensions, service lines, and meters. I consider the testimony and case-in-chief incomplete because it lacks project specificity.

To further understand NIPSCO's rural extensions, NIPSCO provided the following reviews. On February 11, 2020 Petitioner reviewed its internal process and provided slides with its rural project development and defined 20-year margin analysis. On February 27, 2020, the OUCC and NIPSCO discussed the necessity of providing specific information such as location, number of customers, cost estimates pertaining to the rural extension location, and expected consumption.

Informal agreement was reached where Petitioner would include specific information, and the 20-year margin test, when these projects are fully developed. NIPSCO intends to provide the project location, number of customers, project level costs, and project level 20-year margin test for rural extensions as the detail matures in the Plan update process.

Q: Does NIPSCO use contingency in project estimating?

A: Yes. Petitioner varies the contingency percentage of each project, and includes a contingency risk matrix for each project. Confidential Attachment 2-B. I reviewed the various contingency risk matrices, and NIPSCO was very thorough in considering many project aspects that could affect the project’s base cost. Project contingencies vary from <Confidential [redacted] Confidential> per project, and I calculated the average percent contingency for all projects is <Confidential [redacted] Confidential> using data in Confidential Attachment 2-C.

My analysis indicates Petitioner was thorough in recognizing the potential “what if” problems specific to a project. I recommend Petitioner address major project contingency outcomes in the update process to better understand its use of contingency in the estimating process.

Q: Did NIPSCO apply an escalation factor to project contingency?

A: No. Petitioner applied an escalation factor annually to the base year estimate - before contingency was added to the base estimate. The base year estimates vary from 2017 to 2020 with an escalation factor of 3% applied. I am satisfied with the base 2017 year estimates because the vast majority of year 2017 projects are LNG or Storage projects that mimic specific LNG and Storage projects designed in Plan 1. The Plan 2 LNG and Storage projects are part of NIPSCO’s existing LNG or Storage premise and were estimated with Plan 1 projects and using 2017 costs. However, the 3% escalation is too high at this time. The U.S. Bureau of Labor Statistics shows the average annual Consumer Price Index (“CPI”) in February 2020 is 2.3%, as shown in Attachment BRK-4. Applying 3% to NIPSCO’s estimates is not in line with the CPI percentage from the Bureau of Labor Statistics. Therefore, I recommend reducing the inflation factor to 2.0%, which is more comparable to the February 2020 CPI of 2.3%.

Q: What are the OUCC's expectations of NIPSCO in the update process?

A: If the Commission approves Plan 2, then the OUCC anticipates Petitioner will provide substantive reasons, and the costs associated with project estimates or actuals that exceed the approved Plan 2 project costs by 20% or $100,000. This requirement is of particular necessity because the Plan 2 estimates have already built in contingency and escalation factors. Therefore, I recommend the Commission instruct NIPSCO to work with the OUCC to further develop and improve NIPSCO's TDSIC update reporting process.

Q: What steps do you recommend if new projects are requested as part of NIPSCO's Plan 2 update?

A: New projects should be specifically identified and include work order level detail based on bill of materials[8] similar to the detail NIPSCO provided in Plan 2. In addition, NIPSCO should provide validation on the incremental benefits, and reasons the project improves safety, reliability, or modernization while meeting all TDSIC statute requirements.

V. RECOMMENDATIONS

Q: What is your recommendation regarding NIPSCO's proposed TDSIC Plan 2?

A: I recommend the Commission deny NIPSCO's proposed TDSIC Plan 2 because NIPSCO has failed to prove the estimated costs of the eligible improvements are justified by the incremental benefits in accordance with Ind. Code §8-1-39-10(b)(3).

[8] "Bill of Materials" as described in Bull Direct, page 28, line 17 through page 29, line 1, and page 29, footnote 11.

Q: Please review your other findings and recommendations regarding the other requirements of Ind. Code § 8-1-39-10(b) of Petitioner's requests as filed in Petitioner's Verified Petition in this Cause.

A: I find Petitioner has provided best estimates for proposed projects and will improve these estimates as actual construction becomes near term. However, I recommend reducing the inflation factor to 2.0% to be applied to NIPSCO's estimates, which is more comparable to the February 2020 CPI of 2.3%. Petitioner has substantiated project RE1 consists of rural extension projects and has provided the OUCC with its method for determining adequacy in meeting the 20-year margin test. I reviewed Petitioner's definitions of key terms from Cause No. 44403 and recommend continued use of these key terms. Finally, I recommend approval of Petitioner's proposal for updating the 2020-2025 Gas Plan in future semi-annual tracker adjustment proceedings.

Q: Do you have any recommendation concerning Petitioner's Update process if the Commission approves the Plan?

A: Yes, the following are my recommendations for the Update process.

1. Petitioner should provide refined project location and work order level cost estimates for Plan projects originally submitted on a per unit basis in the original Plan.

2. Petitioner should provide 20–year margin tests for defined rural extensions projects including work order level costs, customers, and estimated consumption.

3. Petitioner should continue to work with the OUCC to ensure the accounting process is well understood so no projects costs are double counted.

4. Petitioner should inform the OUCC if it anticipates a project will exceed the approved best estimate by greater than 20% or $100,000, and supply reasons with estimated costs for those overages, thus creating a new best estimate request for approval.

5. Petitioner should supply reasons substantiated with actual costs incurred if a project's actual costs exceed an approved best estimate by greater than

20% or $100,000.

Q: Does this conclude your testimony?

A: Yes.

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 Masters 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.

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 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. 44429, 44430, 44942, 45131, and 45264.

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 NIPSCO's ("Petitioner") Petition, Testimony, Attachments, data request responses, and confidential work papers for this Cause. I also reviewed Petitioner's prior TDSIC Petitions and Commission Orders. I participated in OUCC case team meetings concerning Petitioner's case and "tech to tech" meetings with Petitioner.

Q: What evidence did you review that NIPSCO provided in support of its Plan?

A: I specifically reviewed and analyzed the following documents. Witness Bull's testimony contains Plan 2 project descriptions, estimates, and risk assessments. Confidential

Appendix 1 is the project risk analysis support performed by EN Engineering Corp. Confidential Appendix 2 is the work order level detailed estimates including materials, hourly labor costs, estimated hours, and equipment. Petitioner's witness Wittorp's testimony, Petitioner's Exhibit No. 4, focuses on system operations with Plan impacts from the transmission system and the high pressure distribution system.

Q: What other information did you receive from NIPSCO regarding its Plan projects?

A: In addition to two February meetings previously mentioned in my testimony, an additional meeting was held on February 27, 2020, at which NIPSCO answered the OUCC's specific rural extension questions. I've also reviewed NIPSCO's responses to OUCC and Industrial Group data requests.

Cause No. 45330
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Set No. 2

OUCC Request 2-001:
Referencing Don Bull's direct testimony, page 11, lines 16-17: a. Please provide the portfolio of prioritized projects reviewed as potential Plan projects as identified in Mr. Bull's testimony as "[a] broader portfolio of projects was prioritized to develop the specific improvements included in the Plan." b. Please explain how NIPSCO determined which projects of the broader portfolio should be included in the Plan, and which projects should not be included in the Plan. Please provide any documentation supporting this determination. c. Please explain how NIPSCO determined the priorities of the projects included in the Plan. d. Please provide a list of the individuals responsible for determining which projects should be included in the Plan. e. Please provide a list of the individuals responsible for determining the priorities of the projects included in the Plan.
Objections:
NIPSCO objects to subparts (d) and (e) of this Request to the extent the Request seeks the identification of specific individuals on the grounds that: (a) the requests are overbroad and unreasonably burdensome given the nature and scope of the request and the many and varied people involved in the decision making process; and (b) the requests seek information that is subject to the attorney/client and/or work product privileges.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's gas system is comprised of more than 17,500 miles of distribution line, almost 700 miles of transmission line, over 1500 regulator stations, 38 points of delivery from seven interstate pipeline systems, and two natural gas storage facilities. NIPSCO personnel routinely assess the assets from different perspectives, including reliability and ability to serve its customers, safety, ability to maintain aging equipment, and areas where system growth has occurred or is anticipated.

Cause No. 45330
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor's Set No. 2

a. Please see OUCC Request 2-001 Confidential Attachment A and OUCC Request 2-001 Confidential Attachment B.

b. NIPSCO considered several information sources as well as subject matter expert input. NIPSCO utilized the EN Transmission Risk Comparison, Confidential Attachment 2-A, Confidential Appendix 1 to Mr. Bull's testimony to prioritize transmission pipeline work. NIPSCO reviewed results from its Distribution Integrity Management Program (DIMP) risk assessment (see Industrial Group Request 2-014 Confidential Attachment A). NIPSCO utilized operational data including deliverability studies and system operations reviews (see NIPSCO response and supplemental response to Industrial Group Request 2-018). NIPSCO coordinated across departments to develop a list of projects that would increase safety, reliability, and system performance.

c. NIPSCO considered a variety of factors to determine a portfolio of projects that would improve the safety, reliability, or modernize the natural gas system to the benefit of its customers. These factors included prior commitments to its customers; risk reduction on its transmission system; deliverability opportunities across its service territory; and equipment that is either obsolete or past its expected life.

d. The process to identify and prioritize projects included consultation with different departments within NIPSCO including, but not limited to, Gas System Engineering, Transmission Integrity, Field Operations, Gas Systems Planning, Instrument and Controls, Gas Projects & Construction. NIPSCO evaluates projects on an ongoing basis based on dynamic system conditions and constantly evolving information involving many and varying individuals.

e. Please see the response to subpart d.

Note: Attachment BRK-2, Page 1 is Confidential.

Note: Attachment BRK-2, Page 2 is Confidential.

Note: Attachment BRK-2, Page 3 is Confidential.

Note: Attachment BRK-2, Page 4 is Confidential.

Note: Attachment BRK-2, Page 5 is Confidential.

Note: Attachment BRK-2, Page 6 is Confidential.

Note: Attachment BRK-2, Page 7 is Confidential.

Note: Attachment BRK-2, Page 8 is Confidential.

Northern Indiana Public Service Company
Cause No. 45330
Comparison of TDSIC 1 Plan Project ID and TDSIC 2020-20205 Plan Project ID

TDSIC 1 Plan Project ID	2025 Plan Project ID	Projects Completed in Old Plan	Line Segments	New/ILI Modified Miles	Retired/Pressure Reduced Miles
TP1	NA	State Line to Highland Junction	36-100,101	3.5	3.5
ILI3	NA	RC Storage to Laketon 24" ILI	24-100,101,102,103,104,105	35.3	NA
ILI4	NA	N Hayden to Tassinong Line I 30" ILI	30-108,109,110	26.8	NA
ILI4	NA	N Hayden to Tassinong Line II 30" ILI	30-127,128,129	26.8	NA
IM17	NA	Pressure Reduction (State Road 1 Regulator Station Rebuild)	16-163,20-131,132,133,134,135	NA	2.1
		Projects to be Completed in New Plan			
TP2	TP12	Aetna to US35 Laporte*	22-100,101,102,103,104,113,114,115,30-105	29.5	~30 reduced
TP7	TP7	Hessen Cassel to Hanna	10-136,12-124	4.7	4.7 retired, 4.7 reduced
NA	TP11	Aetna to 483	14-100,101,102,103,24-109,30-120,121	9.2	7 retired
TP9	TP10, TP13	Aetna to Tassinong	16-100,101,102,103,104,105,152	23	7 retired, 16 reduced
NA	TP14	Colfax and Cline Replacement	36-102,103	5.5	7 miles
TP8	TP8	Highland to Grant Recommission	30-106	5.6	0

* New pipe installation completed in TDSIC 1 Plan, pressure reduction to complete in TDSIC 2020-2025 Plan

NEWS RELEASE
BUREAU OF LABOR STATISTICS
U. S. DEPARTMENT OF LABOR

Transmission of material in this release is embargoed until 8:30 a.m. (EDT) March 11, 2020

USDL-20-0402

Technical information: (202) 691-7000 • cpi_info@bls.gov • www.bls.gov/cpi
Media Contact: (202) 691-5902 • PressOffice@bls.gov

CONSUMER PRICE INDEX – FEBRUARY 2020

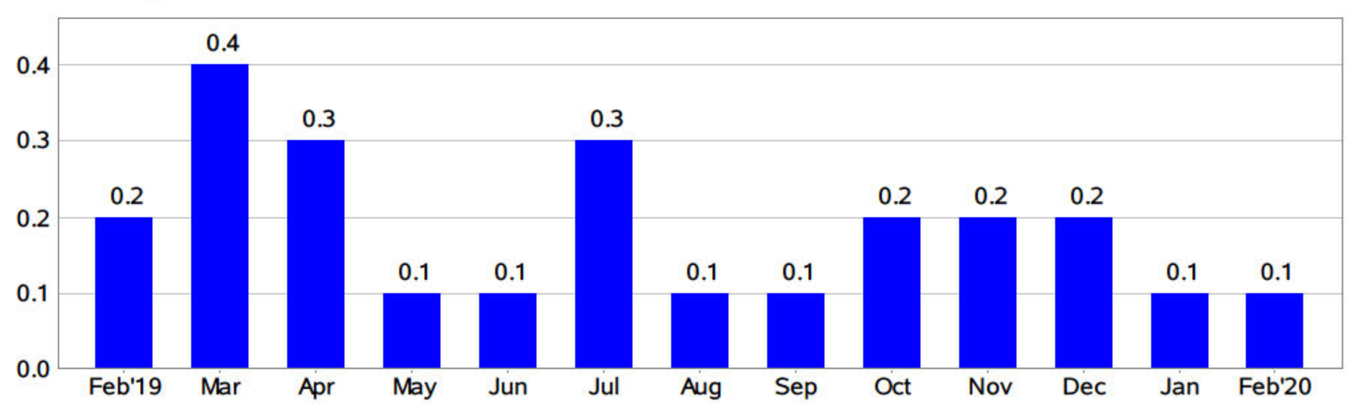
The Consumer Price Index for All Urban Consumers (CPI-U) rose 0.1 percent in February on a seasonally adjusted basis, the same increase as in January, the U.S. Bureau of Labor Statistics reported today. Over the last 12 months, the all items index increased 2.3 percent before seasonal adjustment.

Increases in the indexes for shelter and for food were the main causes of the increase in the seasonally adjusted all items index, more than offsetting a decline in the energy index. The food index increased 0.4 percent over the month, with the food at home index rising 0.5 percent, its largest monthly increase since May 2014. The index for energy fell 2.0 percent in February, with all of its major component indexes declining.

The index for all items less food and energy rose 0.2 percent in February, the same increase as in January. Along with the index for shelter, the indexes for apparel, personal care, used cars and trucks, education, and medical care were among those that increased in February. The indexes for recreation and airline fares declined over the month.

The all items index increased 2.3 percent for the 12 months ending February, a smaller increase than the 2.5-percent figure for the period ending January. The index for all items less food and energy rose 2.4 percent over the last 12 months. The food index rose 1.8 percent over the last 12 months, while the energy index increased 2.8 percent over that period.

Chart 1. One-month percent change in CPI for All Urban Consumers (CPI-U), seasonally adjusted, Feb. 2019 - Feb. 2020
Percent change



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 April 9, 2020.

Christopher C. Earle
NISOURCE CORPORATE SERVICES
Email:cearle@nisource.com

Alison Becker
NIPSCO LLC
Email: abecker@nisource.com

Todd A. Richardson
Aaron A. Schmoll
LEWIS & KAPPES, P.C.
Email:TRichardson@lewis-kappes.com
Email:ASchmoll@lewis-kappes.com

Nikki G. Shoultz
Kristina Kern Wheeler
Bose McKinney & Evans LLP
Email: nshoultz@boselaw.com
Email: kwheeler@boselaw.com

/s/ T. Jason Haas
T. Jason Haas
Attorney No. 34983-29
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
115 West Washington Street
Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Telephone
317/232-5923 – Facsimile