OUCC TDSIC COMMENTS FOR IURC'S DECEMBER 2, 2015 TECHNICAL CONFERENCE

General Plan Comments

Projects can be re-prioritized and asset installation years can be adjusted through TDSIC tracker documentation.

Project cost escalation should be allowed if detail submitted justifies.

When a utility removes a project proposed as part of its Plan, the total Plan budget should be reduced by the cost of that project.

Trackers (outside the confines of a base rate case) should not be viewed as a panacea or "silver bullet" solution for each and every capital need a utility may confront in between rate cases. Current base rates contain an O & M component that should be utilized to not only address unanticipated needs of the business, but also to proactively maintain the reliable operation of its utility plant on a preventative basis. The "safety net" in terms of recovery of these capital expenditures is ultimately the utility's next base rate case.

The TDSIC tracker is not a T&D tracker. No new projects should be allowed in the TDSIC tracker filings that were not in the original approved 7-Year Plan.

To qualify as TDSIC eligible, the projects must be infrastructure improvements necessary to transmit electricity from generation to the customer, or to transport or store gas to/for the customer. Therefore, vegetation management would not be TDSIC eligible unless the effort is necessary for a TDSIC eligible infrastructure project. It cannot be merely an expansion of an existing vegetation management program. Likewise, TDSIC should not be applied on facility repair works typically addressed through the O&M component of the utility's base rates.

The Court of Appeals ("COA") Order requires the same level of project detail for all projects in the 7-Year Plan. While the project detail must be equal throughout the Plan years, the accuracy level of the projects should increase as the installation year approaches.

The OUCC will provide an "audit plan" to each utility after the first TDSIC tracker filing is completed. This "audit plan" will include a listing of common workpapers needed for future TDSIC tracker/plan update filings. Utilities should submit all information included on the OUCC's "audit plan" no later than 2 business days after the petition and testimony is filed in each tracker proceeding. The OUCC reserves the right to add or delete items from the "audit plan" throughout the duration of the TDSIC trackers.

Risk Modeling

Risk modeling and prioritization of all potential projects is important to help ensure the ratepayers are paying for replacing the assets most at risk.

Company-specific data should be inputs to a risk evaluation process. In order for the OUCC, other stakeholders, and the IURC to be able to perform a meaningful evaluation of a 7-year plan, the reports should include, but not be limited to, the following critical data:

1. A single, sortable list of each asset evaluated, including the proposed installation year;
2. The process and criteria used to evaluate each asset, explaining why a project was/was not selected as part of a 7-Year Plan, including how the following contributed to the end result:
    a. Utility personnel expertise;
    b. Internal utility facility data;
    c. External industry data;
    d. Operational dependencies;
    e. Aging of assets;
    f. Reliability improvement, including how the Plan specifically will either maintain or enhance system performance; and
    g. Relevant safety information, including how the Plan will provide for enhanced safety to utility customers and workers;
3. Estimated direct costs of each project evaluated, in both today's dollars and at the anticipated time of completion;
4. Cost estimate review; and
5. Incremental benefits.

Because of the expedited procedural schedule required by Ind. Code § 8-1-39, the OUCC recommends this data should be included in each TDSIC 7-year plan case-in-chief.

<u>Plan "Programs"</u>

Anything susceptible to designation as a project cannot be incorporated into a plan under a lesser standard of particularity as an element of a "program." Hence, anything that comes in as a "program" must meet the criteria below so that the statutory protections are preserved and tracker treatment is limited to improvements that are reasonably designated in the 7-year plan.

1. A "program" subject to incorporation in a 7-year plan must involve a set of assets so numerous as to be impracticable to list individually in the plan document (a numerosity requirement);

2. The work being done in each instance must be uniform across the category, such that cost estimates by unit can be reasonably used to derive a reliable program-wide estimate (a uniformity requirement);

3. The utility must put forward ascertainable selection standards that will be applied to determine which individual units will be included in the 7-year plan, so that a designation of eligibility for TDSIC treatment will have a defined scope at the outset and the program does not turn into a discretionary process delegated to the utility (an adequate selection criteria requirement);

4. The cost per unit must fall below a threshold of materiality, such that it is impracticable to establish individualized estimates (a unit cost materiality requirement); and

5. The number of units must be identified for each year of the plan (a defined scope requirement).

6. The total number of units in a program must be capped by the number specified in the Plan. For example, if the total units in Plan were 7000, at 1000 per year, the utility could install less or more the first year, but the total 7 year total cannot exceed 7000. If during the course of the 7 year Plan the utility finds the need for additional project units, it must use the O&M and capital embedded into its base rates.

<u>Emergent Work</u>

Plan projects and programs must be part of a planned infrastructure improvement process necessary to transmit electricity from generation to the customer or, similarly, from sources of gas supply to the customer. Placing dollars into broad emergency or “emergent” work categories do not meet these criteria.
“Public improvement” projects are driven by requests from third parties, typically government entities where existing utility assets are in conflict with proposed road or utility changes. These projects cannot be identified, defined, and estimated in advance and therefore should not be included in a 7-year plan.

Natural gas service line replacements which are the result of emergent operational issues (so-called “blanket projects”, or placeholders) should be addressed within funds allocated in a rate case for this purpose. These replacements cannot be identified in advance with any certainty, and therefore cannot be defined and estimated for inclusion as TDSIC.

As the Commission recently concluded in Cause No. 42743-DSIC 3 – Indiana Water Service, Inc. Order dated October 14, 2015 at pages 5 – 6:

> Further, as noted by OUCC witness Rees, we find that the invoices appear to represent emergency repairs, which are not appropriate for DSIC recovery because they are not "eligible distribution system improvements." Eligible improvements are "projects," which implies that the replacements were made as part of a planned process in order to improve the distribution system. See also 170 IAC 6-1.1-5

> (setting forth the supporting documentation a utility shall submit, including a statement and outline for planned replacements over the next five years). Emergency repairs such as those at issue here are made as a reaction to a plant failure, not part of a predetermined planning process. Petitioner's base rates include some level of repair expense to cover ongoing repairs such as those proposed for recovery in this Cause.

<u>Rural Natural Gas Extensions</u>

The OUCC considers the rural natural gas extensions to be separate from the “targeted economic development” and therefore within the 2% retail revenue cap. The utility’s extension plan should be targeted at the areas where customers have shown the greatest interest. Each extension will not be a separate project, but rather the build-out planning will incorporate a wider scope, making the extensions more cost effective. There should be a balance between satisfying the needs of the new rural customers and the associated expenditure’s rate impact on all customers.

<u>Rural Extension Margin Credit</u>

While the TDSIC Statute does not specifically address a rural extension margin credit, the Commission has jurisdiction and discretion to interpret language in the statute that might be considered vague. Ind. Code § 8-1-39-9(a) permits “…adjustment of the public utility’s basic rates and charges to provide for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs.” The statute does not preclude the offset of TDSIC cost recovery with recognition of cost recovery through other means, such as revenue margins recovered from new rural customers. The statute does not dictate how recovery of costs must be collected in rates. The statute provides for recovery of capital expenditures and TDSIC costs, and this is achieved through TDSIC rate adjustments combined with new margin revenue collected from established rates charged to new rural customers. Ind. Code § 8-1-39-9(b) further addresses the cost recovery as a deferral of the remaining twenty percent (20%) of approved capital expenditures and TDSIC costs. With 80% TDSIC recovery and 20% deferred recovery, the utility receives one hundred percent (100%) recovery of costs, in some combination of TDSIC rate recovery and base rate margin revenue recovery.

The margin credit balances the interests of the utility and the ratepayers. More importantly, the absence of a margin credit on rural extensions would be a significant oversight for any utility collecting TDSIC cost recovery revenue on rural extension investments. Historically, utilities have invested in plant to serve new customers between rate cases. Also between rate cases, the utility receives a revenue margin from each new customer through existing rates. These existing rates, and the margin per customer, are set in the utility’s last rate case. When those rates are set in the rate case, they include a return on utility plant (rate base) investment, depreciation, O&M expenses, and taxes. When a utility adds a new customer it receives a revenue margin from that customer, which includes a return on investment, depreciation, O&M expenses, and taxes. Customer growth helps pay for the investment in plant to serve new customers between rate cases. The utility receives an embedded return on its investment, and embedded recovery of depreciation and other expenses from each new customer. When a utility receives a revenue margin from new rural extension customers - and *also* receives, through TDSIC rates, a return on the new plant investment, depreciation, O&M expenses, and taxes - then the utility is receiving a double recovery. New customers are paying the revenue margin for new gas service, and all customers are paying the TDSIC rates for that same investment. Therefore, ratepayers are paying *two* returns on the *same* investment, *double* the depreciation expense, and at least incrementally, excess O&M expenses and taxes.

Economic Development

Funds designated for use as economic development should not be used for any TDSIC category other than economic development. If unused for any given year, the economic development annual fund should roll forward in the event an economic development project surfaces in a future 7-Year Plan year. If, at the end of the 7-Year Plan, any part of the designated economic development dollars remains unused, then that amount will not be collected from ratepayers.

Cost Recovery

For replacement of assets already in rate base, utilities should only seek cost recovery of the incremental amount of the return on its investment for any transmission, distribution or storage plant placed in service through the TDSIC tracker which exceeds the return on investment currently included in base rates and charges for the original asset that has been replaced. Further, if new capital investments result in the retirement of an existing asset, depreciation expense included in the revenue requirement should be reduced by the depreciation expense amount attributed to those retired assets. The Court of Appeals has clarified that the Commission has the authority to deal with ratepayer concerns over "double recovery" of both new plant (through the TDSIC) and retired plant (through base rates) at the same time. Ind. Code 8-1-39-13. Allowing such inaccuracies and double recoveries for seven (7) years between rate cases will not balance interests and will not produce "just and reasonable" rates. With the exception of NIPSCO Choice, ratepayers have no choice of retail supplier, and all ratepayers are entitled to just and reasonable rates under the regulatory compact and Indiana law. TDSIC provides a new means for utilities to request relief, but the just and reasonable standard has not been relaxed or redefined.

Pre-tax return on new capital investments should be calculated by multiplying the pre-tax rate of return based on the weighted average cost of capital (WACC) by the total new capital investments, net of retirement.

The utility's WACC should be calculated using its updated capital structure (including zero-cost capital), current cost rates, and the cost of common equity authorized by the Commission in its most recent rate proceeding. This is and should be consistent with the method used in the Environmental Cost Recovery (ECR) proceedings where the return on equity stays static to the last approved general rate proceeding. The other components of the capital structure are calculated as of the date of valuation of the utility's property under construction. (See 170 IAC 4-6-14(1)(A) and (1)(B)).

There should be no carrying cost applied to deferred depreciation expense and property tax expense after a project is placed in-service.

Allocation

Cost allocations not approved in the most recent retail base rate case order have been approved by the Commission in TDSIC filings. This deviation from the allocation method approved in the last rate case can change the allocation of system improvement costs significantly. The Indiana Court of Appeals, ruling on an appeal from NIPSCO's electric TDSIC case, found the Commission improperly approved NIPSCO's proposed transmission and distribution allocators that were not approved in its last base rate case. The language of the Indiana Appellate Court Order supports the position that transmission and distribution costs should be allocated in accordance with Petitioner's last base rate case order.

Filing Dates

As a matter of due process on behalf of utilities' ratepayers, the Indiana Office of Utility Consumer Counselor (OUCC) must be afforded sufficient time to review 7-year plans and ensuing TDSIC tracker filings, including supporting utility testimony, exhibits, and work papers, as well as conduct discovery requests, invite consumer comments, and synthesize any discovery responses and consumer comments as the OUCC develops its position on behalf of the utility's customers.

The information filed in previous 7-year plan cases has been particularly voluminous and complex, while implicating far more money than a typical base rate case within the same timeframe. (As an example, I&M's 7-year plan – ultimately denied – implicated more than $713 million while the same utility requested about $170 million in its most recent base rate case.) Given these considerations, timeframes of 90 and 60 days in the 7-year plan and TDSIC tracker cases, respectively, while not optimal, are the minimum necessary for the OUCC's review in order to fully advance and complete the regulatory process.

The OUCC reserves the right and flexibility to revise and refine the stated positions as necessary. Our agency will continue to perform due diligence and look at all case aspects on a case-by-case basis.