IN THE

INDIANA COURT OF APPEALS

CASE NO. 93A02-1403-EX-158

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR,	)	
Appellant/Statutory Representative Below,	)	Appeal from the Indiana Utility Regulatory Commission
and	)	
NIPSCO INDUSTRIAL GROUP,	)	IURC Cause Nos. 44370 and 44371
Appellant/Intervenor Below,	)	
v.	)	The Honorable David E. Ziegner and Carolene Mays, Commissioners
NORTHERN INDIANA PUBLIC SERVICE COMPANY,	)	The Honorable David E. Veleta, Administrative Law Judge, presiding.
Appellee/Petitioner Below.	)	

BRIEF OF APPELLANT
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INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR, Appellant/Statutory Representative Below, and NIPSCO INDUSTRIAL GROUP, Appellant/Intervenor Below, v. NORTHERN INDIANA PUBLIC SERVICE COMPANY, Appellee/Petitioner Below.	)	Appeal from the Indiana Utility Regulatory Commission IURC Cause Nos. 44370 and 44371 The Honorable David E. Ziegner and Carolene Mays, Commissioners The Honorable David E. Veleta, Administrative Law Judge, presiding.

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I. STATEMENT OF THE ISSUES

Whether the Indiana Utility Regulatory Commission ("Commission") erred when it allowed Northern Indiana Public Service Company ("NIPSCO") to (a) continue rate recovery of retired equipment while also recovering costs for replacement assets under Ind. Code ch. 8-1-39, the Transmission, Distribution and Storage System Improvement Charge ("TDSIC") statute; and (b) use a rate allocation methodology other than that approved in NIPSCO's last rate case in contravention of I.C. § 8-1-39-9.

II. STATEMENT OF THE CASE

NIPSCO sought and received Commission approval in Cause No. 44370 to complete eligible projects under the TDSIC statute, I.C. ch. 8-1-39, *et seq.* (the "TDSIC statute"). The Office of Utility Consumer Counselor ("OUCC"), the statutory representative of the public before the Commission, did not oppose NIPSCO's proposed projects in Cause No. 44370. Under Cause No. 44371, NIPSCO sought approval to implement its TDSIC tracker to recover costs incurred as a result of installation of the eligible projects. The OUCC argued that sound ratemaking principles require NIPSCO to credit ratepayers for equipment retired as a result of the TDSIC projects by "netting" the retired amounts against the recovery sought in the TDSIC tracker. The OUCC argued that this was appropriate because NIPSCO already recovered a return on and a return of the retired equipment through rates, and once the equipment was retired it would no longer qualify as "used and useful" utility property pursuant to the requirements of I.C. § 8-1-2-6. The OUCC argued that without netting, NIPSCO would collect funds on both retired and replaced assets, in essence double recovering, and therefore advocated that NIPSCO only recover the incremental amount above that embedded in rates.

In allocating the costs of these projects to its various rate classes, NIPSCO also proposed to use a different rate allocation than that approved in its last rate case. Under the TDSIC statute, a TDSIC petition "*must* use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case[.]" I.C. § 8-1-39-9(a)(1) (emphasis added, punctuation omitted). In NIPSCO's most recent retail base rate case Cause No. 43969, NIPSCO, the OUCC and other parties reached a settlement that included agreed-upon customer class revenue allocation factors, which the Commission approved. *In re the Petition of N. Ind. Pub. Serv. Co. for an Increase to Its Rates and Charges,* Cause No. 43969, 2011 WL 2011 WL 6837714 (Ind. Util. Regulatory Comm'n Dec. 21, 2011). Despite the settlement and the mandatory language in I.C. § 8-1-39-9(a)(1), NIPSCO presented and the Commission approved new allocation factors to be applied to the TDSIC in this case.

The OUCC requested that the Commission reconsider its findings. The Commission denied that request. The OUCC now appeals.

III. STATEMENT OF THE FACTS

I.C. ch. 8-1-39, *et seq.* authorizes a public electric or gas utility to petition the Commission for approval of both a 7-year plan to construct transmission, distribution and storage infrastructure, and a new type of cost recovery mechanism, the Transmission Distribution System Improvement Charge (TDSIC). The statute allows a utility to recover 80% of eligible and approved capital expenditures and TDSIC costs as well as authorizing deferral, until recovery through the TDSIC tracker, of 80% of the post-in-service costs of the TDSIC projects, including carrying costs, depreciation and taxes. The other 20% of approved costs are deferred for recovery until the utility's next base rate case.

The TDSIC statute, passed in 2013, defines "eligible transmission, distribution, and storage system improvements" as

> [N]ew or replacement electric or gas transmission, distribution, or storage utility projects that:
> (1) a public utility undertakes for purposes of safety, reliability, system modernization, or economic development, including the extension of gas service to rural areas;
> (2) were not included in the public utility's rate base in its most recent general rate case; and
> (3) either were:
>> (A) designated in the public utility's seven (7) year plan and approved by the commission under section 10 of this chapter as eligible for TDSIC treatment; or
>> (B) approved as a targeted economic development project under section 11 of this chapter.

I.C. § 8-1-39-2.

On July 19, 2013, NIPSCO filed its 7-year infrastructure improvement plan for its electric operations with the Commission in Cause No. 44370 and its

TDSIC cost recovery mechanism (TDSIC tracker) in Cause No. 44371. In Cause No. 44371, as allowed by statute NIPSCO proposed a TDSIC tracker that would allow for recovery of 80% of eligible and approved capital expenditures and TDSIC costs as well as authorizing NIPSCO to defer, until recovery through the TDSIC tracker, 80% of the post-in-service costs of the TDSIC projects, including carrying costs, depreciation and taxes.[1] NIPSCO stated its intent to track the cost of eligible TDSIC projects without removing any amount for replaced items already embedded in base rates. NIPSCO argued that return on and return of the eligible TDSIC projects should be considered an incremental revenue requirement above and beyond amounts embedded in base rates. In addition to NIPSCO and the OUCC, numerous consumer groups – the Citizens Action Coalition, the Hoosier Environmental Council, the Indiana Municipal Utility Group, LaPorte County, the NIPSCO Industrial Group, NLMK Indiana, and U.S. Steel- intervened in Cause No. 44371.

Traditionally, in Indiana, utility rates and charges were established in base rate cases in which all interested parties had an opportunity to examine all facets of a utility's operation (i.e. rate base, revenues, expenses and authorized return). An increase or decrease of rate base or expenses would only be updated in a base rate case. One of the few exceptions pertained to the fuel adjustment charge ("FAC"), which reflected increases and decreases in fuel

[1] NIPSCO stated its intent to defer the other 20% of approved costs until its next base rate case.

costs. By statute, an Indiana electric utility could track fuel costs outside of a base rate case since fuel costs are a material and volatile expense.

Other expense trackers have been statutorily authorized over the years. The first capital investment tracker authorized in Indiana allowed utilities to recover the costs associated with costly environmental projects. These projects were usually mandated by federal or state law and involved the construction and retrofitting of pollution control equipment (referred to as "qualified pollution control projects" or "QPCP"). Similarly, the TDSIC tracker was passed to allow utilities to upgrade their transmission and distribution grids by tracking the replacement of routine yet vital items such as transmission and distribution lines, poles and associated infrastructure such as transformers.

The OUCC advocated that sound ratemaking principles required rate mitigation in this case. Tyler Bolinger, Director of the Electric Division of the OUCC, testified that NIPSCO's proposed TDSIC tracker did not provide any accounting or recognition of the millions of dollars already embedded in base rates for transmission and distribution related revenue requirements, including return on and return of transmission and distribution investments that are being replaced. OUCC App. 14.

Mr. Bolinger also noted that NIPSCO proposed to track eligible additions to its rate base every six months without updating for growth in the accumulated depreciation reserve until its next rate case, up to seven years from now. *Id.* Mr. Bolinger testified that the Commission should deny NIPSCO's requested TDSIC tracker in this Cause, since it should account for the on-going capital expenditure and capital recovery processes (*i.e.* depreciation). *Id.* He stated that rate base changes between rate cases are a function of both capital expenditures and capital recoveries, and the TDSIC mechanisms should accurately measure the growth in net utility plant investment for whatever eligible projects the Commission approves for tracking. *Id.*

Mr. Richard Cutbert testified on behalf of Intervenor United States Steel Corporation (U.S. Steel). He stated that by recovering costs and depreciation for assets that are retired early and replaced through its 7-year plan, NIPSCO will be getting rate recovery for assets that are no longer used and useful. OUCC App. 19. He further recommended that the TDSIC tracker should be adjusted to remove the undepreciated asset cost of the older, replaced equipment or facility that will no longer be used and useful. *Id.* This will prevent NIPSCO's ratepayers from being charged for both the older assets as part of existing rates and the new assets in TDSIC charges while only the new assets will be providing used and useful service. *Id.*

Frank Shambo, NIPSCO's Vice President for Regulatory and Legislative Affairs, opposed the OUCC's recommendation, stating that it was contrary to the TDSIC statute allowing for timely recovery of capital expenditures and TDSIC costs. OUCC App. 22. Mr. Shambo testified that it was not appropriate to compare the TDSIC adjustment mechanism to the FAC mechanism that tracks changes in fuel expenses, because the FAC mechanism is an expense-only tracker and bears no correlation to the capital investment recovery of the TDSIC. *Id.*

Mr. Shambo testified that U.S. Steel's recommendations that the TDSIC should be adjusted to represent only the additional or incremental costs of the expenditure above the undepreciated asset costs of the replaced asset should be rejected, because I.C. § 8-1-39-2 authorizes replacement projects, allows for recovery of only 80% of all TDSIC costs, and does not require any "incremental" offset. Mr. Shambo stated that NIPSCO's net book value for its transmission and distribution assets had increased since its last rate case, and that NIPSCO will have multiple transmission and distribution investments over the next seven years not included for recovery as part of NIPSCO's TDSIC eligible projects.

The Commission denied the recommendation of the OUCC and other parties in its final order.

> The statutory definition of eligible improvements at Ind. Code §8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code §8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. Further, TDSIC costs as defined at Ind. Code § 8-1-39-7 includes this unadjusted pretax return. While acknowledging that Ind. Code §8-1-39-13(a) allows the Commission to consider other information in setting the appropriate pretax return, *we read this section to be addressing the weighted cost of capital rate rather than the investment amount so as to reconcile the statutory language of Sections 13 and 3. Accordingly, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery.* In addition, the TDSIC statute requires a general rate case before the expiration of the utility's 7-year plan which provides a built in mechanism to update the net investment

> of the utility. Thus, we decline to require NIPSCO to recognize the replaced asset investment cost already embedded in base rates because Ind. Code ch. 8-1-39 does not support it outside of the required rate case.

OUCC App. 27 (emphasis added).

For purposes of allocating TDSIC cost, I.C. 8-1-39-9(a) states that cost allocation must be based upon the allocation factors based on firm load approved the public utility's most recent base rate order. There was only one set of revenue allocation factors approved in Cause No. 43969, NIPSCO's last base rate case, based solely on firm load. The TDSIC allocators NIPSCO proposed in this case were new and did not match those approved in Cause No. 43969, and thus had not been contemplated, proposed, evaluated or approved in NIPSCO's most recent retail base rate case. The OUCC advocated for compliance with the statute and the still-valid settlement agreement in Cause No. 43969. The Commission disagreed with the OUCC and approved NIPSCO's adjusted cost allocators.

The OUCC sought reconsideration of the Commission's findings, arguing that I.C. § 8-1-2-6 and Commission precedent compelled netting of retired assets against NIPSCO's TDSIC projects. OUCC App. 34. The OUCC argued that allowing a utility to earn a return on and of property that is no longer used and useful is contrary to Indiana law and is a confiscatory taking from NIPSCO ratepayers. *Id.* The OUCC further argued that NIPSCO's adjusted allocators violated the clear language of the TDSIC statute and the previously approved settlement agreement and unjustly favored one customer class to the detriment of other consumer classes. *Id.*

The Commission denied the OUCC's request for reconsideration, finding "[t]he arguments presented by the OUCC in support of its Petition for Reconsideration are similar to those presented in the underlying proceeding and rejected in our February 17, 2014 Order." OUCC App. 25.

IV. SUMMARY OF THE ARGUMENT

The Commission's decision that I.C. § 8-1-39-3 and I.C. § 8-1-39-13 do not "support" a netting of retired assets was based on the Commission's incorrect "reconciliation" of I.C. § 8-1-39-3 and I.C. § 8-1-39-13. This was caused by the Commission's failure to read I.C. ch. 8-1-39, *et seq., in pari materia* with I.C. ch. 8-1-2, *et seq.*, thereby ignoring Commission ratemaking authority and precedent allowing for the netting of retired assets in trackers. In addition, the Commission directly violated the express language of I.C. § 8-1-39-9 by adopting a rate allocation other than that approved in NIPSCO's last rate case. Finally, the Commission erred by improperly changing material terms from a previously approved settlement agreement that had been negotiated by NIPSCO and representatives of all its consumer classes.

V. ARGUMENT

A. Standard of Review

Under I.C. § 8-1-3-1, "[a]n assignment of errors that the decision, ruling, or order of the commission is contrary to law shall be sufficient to present both the sufficiency of the facts found to sustain the decision, ruling, or order, and the sufficiency of the evidence to sustain the finding of facts upon which it was rendered."

The courts use a two-tier standard of review when assessing Commission decisions. *Micronet, Inc. v. Ind. Util. Regulatory Comm'n,* 866 N.E.2d 278, 284-85 (Ind. Ct. App. 2007), *trans. denied.* The court must determine if the decision is supported by specific findings of fact and sufficient evidence and whether the decision is contrary to law. *Id.* "A decision is contrary to law when the Commission fails to stay within its jurisdiction and to abide by the statutory and legal principles that guide it." *Id., citing Gary–Hobart Water Corp. v. Ind. Util. Regulatory Comm'n,* 591 N.E.2d 649, 652 (Ind. Ct. App. 1992), *reh'g denied.* The Court must also determine "whether the agency's decision was arbitrary and capricious, and whether it was contrary to any constitutional, statutory, or legal principle." *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.,* 804 N.E.2d 289, 293 (Ind. Ct. App. 2004).

This case centers on the Commission's interpretation of I.C. ch. 8-1-39, requiring the court to review the decision *de novo.* *Ind. Ass'n of Beverage Retailers, Inc. v. Ind. Alcohol & Tobacco Comm'n,* 945 N.E.2d 187, 197 (Ind. Ct. App. 2011), *trans. denied.* "[A]ny agency determination that is not in accordance with the law may be set aside because a reviewing court owes no deference to an agency's conclusions of law." *City of Ft. Wayne v. Util. Ctr., Inc.,* 840 N.E.2d 836, 839 (Ind. Ct. App. 2006), *citing PSI Energy, Inc. v. Ind. Office of Util. Consumer Counselor,* 764 N.E.2d 769, 774 (Ind. Ct. App. 2002), *trans.*

denied (internal quotations omitted).

A statute which is clear and unambiguous should be read to mean what it plainly expresses and should be construed in a way that avoids an absurd result. *Citizens Action Coalition of Ind., Inc. v. N. Ind. Pub. Serv. Co.,* 796 N.E.2d 1264, 1269 (Ind. Ct. App. 2003), *trans. denied.* "Our supreme court has repeatedly said that when the meaning of an administrative regulation is in question, the interpretation of the administrative agency is given great weight *unless the agency's interpretation would be inconsistent with the regulation itself.*" *Citizens Action Coalition v. N. Ind. Pub. Serv. Co.,* 804 N.E.2d at 301, *citing State Bd. of Registration for Prof. Engineers v. Eberenz,* 723 N.E.2d 422, 427–28 (Ind. 2000) (emphasis added, internal marks omitted). If the court determines that the agency's interpretation is reasonable, it terminates its analysis and does not address the arguments of the party opposing the agency's interpretation.

B. The Commission's decision violated multiple rules of statutory construction.

The Commission violated basic rules of statutory construction when it:

(1) ignored the reference in I.C. § 8-1-39-13(b) to I.C. § 8-1-2-42, which provides the meaning of "return" as used in I.C. § 8-1-39-3 and I.C. § 8-1-39-13, leading the Commission to erroneously conclude that "return" meant "weighted average cost of capital" ("WACC");

(2) applied its erroneous determination of the meaning of "return" in an effort to reconcile, rather than harmonize, I.C. § 8-1-39-3 and I.C. § 8-1-39-13;

(3) did not read I.C. ch. 8-1-39, *et seq.*, *in pari materia* with the Commission's enabling statute, I.C. § 8-1-2, *et seq.*, leading it to wrongly conclude that it did not have the power to net retired assets against replacement utility assets;

(4) ignored Commission precedent that netted retired assets against replacement assets in the context of a tracker;

(5) violated the express language of I.C. § 8-1-39-9 by allowing a rate allocation other than that mandated by the statute; and

(6) unilaterally modified an approved settlement agreement in NIPSCO's last base rate case to the detriment of residential ratepayers.

Because all of these issues concern the Commission's jurisdiction over the establishment of a utility's rates, a brief history of relevant utility ratemaking is necessary to place the arguments in context. The Commission's goal is to establish rates that will allow a utility to sufficiently cover its operating expenses as well as provide a reasonable return on investment to shareholders. *Ofc. of Util. Consumer Counselor v. Gary-Hobart Water Corp.*, 650 N.E.2d 1201 (Ind. Ct. App. 1995). The Commission's regulation of utility rates is based on the principle "that the charges for services shall be fair and reasonable...and that the rate fixed shall not be so low as to deprive the company of means of adequate service, nor so high as to unduly burden the public." *Williams v. Citizens Gas Co.*, 206 Ind. 448, 188 N.E. 212, 214 (1933), *citing Winfield v. Pub. Serv. Comm'n*, 187 Ind. 53, 60, 118 N.E. 531, 533 (1918).

The U.S. Supreme Court established the ratemaking standard in the seminal *Bluefield Waterworks* case:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties.

Bluefield Waterworks v. Pub. Serv. Comm'n, 262 U.S. 679, 692, 43 S.Ct. 675, 67 L.Ed. 1176 (1923).

These concepts were enshrined in the Commission's enabling statute, requiring the Commission to value a utility's property based on "all property...actually used and useful for the convenience of the public[.]" I.C. § 8-1-2-6(a). "The Commission's 'used and useful' standard requires: (1) that the utility plant be actually devoted to providing utility service, and (2) that the plant's utilization be reasonably necessary to the provision of utility service." *City of Evansville v. S. Ind. Gas & Elec. Co.*, 167 Ind. App. 472, 516, 339 N.E.2d 562, 589 (Ind. Ct. App. 1975). That is because "utility charges are based on service." *Citizens Action Coalition of Ind., Inc. v. N. Ind. Pub. Serv. Co.*, 485

N.E.2d 610, 613 (Ind. 1985). "Without 'used and useful' property there cannot be any service." *Id.* at 614.

Rate base consists of the utility property that is used to provide the public with the service for which rates are charged. *L.S. Ayres & Co. v. Indianapolis Power & Light Co.,* 169 Ind. App. 652, 658, 351 N.E.2d 814, 820 (Ind. Ct. App. 1976). The rate-making process, or "the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests." *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L. Ed. 333 (1944). The value of an item in rates is recaptured through the addition of depreciation to the rate formula, reflecting a reduction in the value of an asset as it ages. Bonbright, J., *Principles of Public Utility Rates,* p. 196 (Public Utility Reports, Inc. 1988). This is "designed to reflect the current value of utility properties as distinct from their cost." *Id. at* 195. Allowing for depreciation as part of rates is a form of allocating cost to ratepayers as close as is feasible to the time that the cost is incurred. *Id.* at 203. Through the process of depreciation the "utility is made whole and the integrity of its investment maintained. No more is required." *Hope Nat. Gas Co.,* 320 U.S. at 607. To determine "what constitutes a 'fair rate of return,' the Commission generally calculates a composite 'cost of capital' by adding together the weighted costs of various components of the utility's capital structure, e.g., its long term debt, preferred stock, and common stock." *Gary–Hobart Water,* 591 N.E.2d at 653 (citations omitted).

Consistent with the maxim that rates be based on property that is "used and useful", costs attributable to construction ("construction work in progress", or "CWIP") were traditionally borne by shareholders, and any benefit that accrued from the CWIP was "passed on to the investor who has borne the cost of the work and not the consumer who pays neither the cost of nor a rate of return on the construction. (Such work in progress cannot be included in a utility's rate base.)" *Ofc. of Util. Consumer Counselor v. Pub. Serv. Co. of Ind., Inc.,* 449 N.E.2d 604, 607 (Ind. Ct. App. 1983). The costs of CWIP were traditionally excluded from base rates because "the Commission is prohibited from including the value of construction work in progress in the utility's rate base, for such property has not yet achieved the status of property '*actually used and useful* for the convenience of the public.'" *Capital Improvement Bd. v. Pub. Serv. Comm'n,* 176 Ind. App. 240, 270, 375 N.E.2d 616, 637 (Ind. Ct. App. 1978) (emphasis in original).

The Indiana General Assembly created the CWIP tracker statutes[2] in recognition of the financial burden that qualified pollution control projects ("QPCP") placed on utilities. These were the first capital investment trackers allowed in Indiana. These mandated projects tended to be very expensive and pertain to large new assets of the type not previously included in rate base. The CWIP statutes and rules enable utilities to recover the cost of on-going environmental projects before the projects constituted "used and useful" utility

[2] I.C. § 8-1-2-6.6, I.C. § 8-1-2-6.8, I.C. § 8-1-8.7, *et seq.*, and I.C. § 8-1-8.8, *et seq.*

property through the use of a surcharge (or "tracker") to customers' bills, thereby "tracking" the costs as they were incurred.[3]

The only similarity between the QPCP CWIP statutes and the TDSIC statute is the fact that both allow utilities to track and recover capital costs for investments before those costs are incorporated into a utility's base rates. QPCP assets are new, were not contemplated at the time that the electric utilities built their plants and constitute expensive additions to utility property. The TDSIC tracker, on the other hand, is primarily designed to recover costs of replacement transmission, distribution and storage systems of the type that are already included in a utility's plant in service and already included in base rates. For those reasons, the OUCC argued that NIPSCO should "net", or give credit for, property being retired[4] and currently embedded in base rates against the new TDSIC investments being made. In denying that request, the Commission stated the following:

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[3] Trackers also allow recovery of costs for, *inter alia,* fuel (I.C. § 8-1-2-42(d)); regional transmission organizations; pipeline safety, and federally mandated costs.

[4] The terms "retire" and "replace" are not defined in Indiana for purposes of utility rates. However, the terms are defined under the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"), which governs electric utility ratemaking precepts. "Replacement" "means the construction or installation of electric plant in place of property retired, together with the removal of the property retired." 18 C.F.R. § 101(32)(A). "[R]etired, as applied to electric plant, means property which has been removed, sold, abandoned, destroyed, or which for any cause has been withdrawn from service." 18 C.F.R. § 101(28). "Retirement units means those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which included." 18 C.F.R. § 101(34).

> The statutory definition of eligible improvements at Ind. Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. Further, TDSIC costs as defined at Ind. Code § 8-1-39-7 includes this unadjusted pretax return. While acknowledging that Ind. Code §8-1-39-13(a) allows the Commission to consider other information in setting the appropriate pretax return, we read this section to be addressing the weighted cost of capital rate rather than the investment amount so as to reconcile the statutory language of Sections 13 and 3. Accordingly, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery.

OUCC App. 27 (emphasis added).

This case was the first opportunity for the Commission to construe I.C. ch. 8-1-39, *et seq.* and it failed to follow basic rules of statutory construction. Under I.C. § 1-1-4-1,

> the construction of all statutes of this state shall be by the following rules, unless the construction is plainly repugnant to the intent of the legislature or of the context of the statute: (1) Words and phrases shall be taken in their plain, or ordinary and usual, sense. Technical words and phrases having a peculiar and appropriate meaning in law shall be understood according to their technical import.

The rules of statutory construction were well summarized in *Ind. Alcoholic Beverage Comm'n v. Osco Drug, Inc.*

> There is a strong presumption that the legislature in enacting a particular piece of legislation is aware of existing statutes on the same subject. Statutes relating to the same general subject matter are *in pari materia* and should be construed together so as to produce a harmonious system. In this respect, when two statutes on the same subject must be construed together, the court should attempt to give effect to both; however, where the two are repugnant in any of their provisions, then the later statute will control and operate to repeal the former to the extent of the repugnancy. Similarly, where one statute deals with a subject in

> general terms and another statute deals with a part of the same subject in a more detailed or specific manner, then the two should be harmonized, if possible; but if they are in irreconcilable conflict then the more detailed will prevail as to the subject matter it covers.
>
> Another fundamental rule of statutory construction is that a statutory amendment changing a prior statute indicates a legislative intention that the meaning of the prior statute has been changed. This raises a presumption that the legislature intended to change the law unless it clearly appears that the amendment was made only to express the original intention of the legislature more clearly. Another recognized rule of statutory construction is that if the legislature fails to change a statute administered by a state agency, then this inaction indicates the legislature's acquiescence in and satisfaction with the administrative construction.

Ind. Alcoholic Beverage Comm'n v. Osco Drug, Inc., 431 N.E.2d 823, 833-34 (Ind. Ct. App. 1982) (citations omitted).

1. The Commission ignored the reference in I.C. § 8-1-39-13(b) to I.C. § 8-1-2-42, leading the Commission to erroneously conclude that "return" as used in I.C. § 8-1-39-3 and I.C. § 8-1-39-13 meant "weighted average cost of capital" ("WACC").

By assuming that the word "return" meant "weighted cost of capital," the Commission created a conflict where none actually existed. Rather than following the express language of the statute and considering all sections of the statute *in pari materia*, the Commission unnecessarily "reconciled" Sections 3 and 13.

When a statute is being interpreted for the first time, the analysis is controlled "by the express language of the statute itself and applicable rules of statutory construction, the objective of such rules being to determine and effect the intent of the Legislature." *Loza v. State,* 263 Ind. 124, 128-29, 325 N.E.2d 173, 176 (Ind. 1975) (citations omitted). As noted in *Osco, supra,* "[t]here is a strong presumption that the legislature in enacting a particular piece of legislation is aware of existing statutes on the same subject." *Osco Drug,* 431 N.E.2d at 833.

The TDSIC statute sections at issue in this appeal work together in much the same way a set of nesting boxes do. The largest box is the category of TDSIC costs for eligible projects (I.C. § 8-1-39-7), including depreciation (the "return of" the investment), operations and maintenance expense ("O&M"), property taxes, and "pretax returns." "Pretax returns" (I.C. § 8-1-39-3) in the middle box is a calculation of the revenue needed to earn a "return on" the investment of the TDSIC eligible projects and pay associated taxes by taking the WACC from the utility's last rate case and multiplying it by investments in eligible TDSIC improvements. *Id.* Contained in the smallest box within "pretax return" is the Commission's exercise of discretion (I.C. § 8-1-39-13). The Commission determines the total amount of "pretax return" by considering the utility's capital structure, tax rates, cost of equity, stock, and other information that the Commission determines is necessary. Each of the factors in I.C. § 8-1-39-13 contemplates an application of ratemaking judgment that will impact the final calculation of total pretax return. These "nested boxes" contain the parameters to determine the TDSIC costs that utilities can pass on to customers.

The Commission interpreted "return" to mean WACC, also called "rate of return", the percentage applied to a utility's rate base to determine a utility's "return on" investment. This was in error. The legislature's use of "weighted average cost of capital" in I.C. § 8-1-39-3 shows that it knows how to use the phrase when it means to, and therefore the word "return" in I.C. § 8-1-39-13 should not be equated to WACC. "Statutory language is deemed intentionally chosen by the legislature to give effect to the meaning of an act." *Caylor-Nickel Clinic, P.C. v. Ind. Dept. of Revenue*, 569 N.E.2d 765, 769 (Tax Ct. 1991) (citations and quotation marks omitted).

And even though there was no definition of "return" in I.C. ch. 8-1-39, the Commission should have looked to other provisions of the statute and the statute's underlying policies and goals to determine the word's meaning. *United Rural Elec. Membership Corp. Ind. Mich. Power Co.*, 716 N.E.2d 1007, 1013-14 (Ind. Ct. App. 1999), *trans. denied* 735 N.E.2d 229 (2000). The other provisions of the statute were apparent, although overlooked, in I.C. § 8-1-39-13(b), governing the Commission's adjustments of a utility's "authorized return for purposes of IC 8-1-2-42(d)(3) or to reflect incremental earnings from an approved TDSIC."

The provisions of I.C. § 8-1-2-42(d)(3) and I.C. § 8-1-2-42(g)(3) govern the approval of fuel tracker calculations, including Commission review of the proposed factor based on the amount of a utility's previously authorized "return." The application of I.C. § 8-1-2-42(d)(3)[5] prevents a utility from over-earning as a consequence of tracked expenses, and "return" in this context differs from "rate of return", WACC, or the definition of "pretax return" of I.C. § 8-1-39-3.

Construing "return" in the context of I.C. § 8-1-2-42(g)(3), this Court found that to determine the return, "[t]he focus is the *rate base* as determined in the last rate case." *Ind. Gas Co., Inc. v. Ofc. of Util. Consumer Counselor,* 575 N.E.2d 1044, 1051 (Ind. Ct. App. 1991) (emphasis added). This Court applied the same meaning to "return" when it construed the use of the earnings test of I.C. § 8-1-2-42(d)(3) as applied to the tracking of qualified pollution control projects. *Citizens Action Coalition,* 804 N.E.2d at 298-99. Rate base "consists of that utility property employed in providing the public with the service for which rates are charged and constitutes the investment upon which the 'return' is to be earned...[and] is usually defined as that utility property 'used and useful' in rendering the particular utility service." *L.S. Ayres,* 169 Ind. App. at 658, 351 N.E.2d at 820.

Once the language of I.C. § 8-1-2-42(d)(3) is read in conjunction with I.C. § 8-1-39-13, it is apparent that that the Commission's determination that "return" meant WACC was in error. By failing to consider the statutory cross-references in I.C. § 8-1-39-13, the Commission applied an inconsistent

[5] The language of I.C. § 8-1-2-42(g)(3) is largely identical, with the only difference being its application to the fuel expenses of gas utilities as opposed to electric utilities.

meaning of "return." The U.S. Supreme Court has held that "words and phrases...must be given a consistent usage and be read *in pari materia,* [as] to do otherwise would 'attribute a schizophrenic intent to the drafters.'" *Marek v. Chesny,* 473 U.S. 1, 21, 105 S.Ct. 3012, 3022-3023, 87 L.Ed.2d 1 (1984).

The Commission's incorrect reading of "return" as "WACC" laid the groundwork for the next error in statutory construction, as the Commission then found it necessary to "reconcile" two sections that were not in conflict. Again, the Commission's failure to apply rules of statutory construction lead to this result. "There is no irreconcilable conflict, unless after the application of every recognized rule of [statutory] construction, substantial harmony is found impossible." *People's Trust & Savings Bank v. Hennessey,* 106 Ind. App. 257, 153 N.E. 507, 511 (Ind. Ct. App. 1926). The Commission made no attempt to harmonize the provisions of I.C. ch. 8-1-39, caused in part by its failure to read I.C. ch. 8-1-39 *in pari materia* with the Commission's authorizing statute.

2. The Commission did not read I.C. ch. 8-1-39, et seq., in pari materia with the Commission's enabling statute, I.C. ch. 8-1-2, et seq., leading it to wrongly conclude that it did not have the power to net retired assets against replacement utility assets.

By erroneously extrapolating "return" to mean WACC, the Commission wrongly concluded that there was no statutory "support" to credit retired assets against newly installed replacements. This mistaken result was also caused by the Commission's failure to read I.C. ch. 8-1-39 *in pari materia* with I.C. § 8-1-2-6 and established ratemaking precedent. It is clear that the legislature intended that I.C. ch. 8-1-39 be read *in pari materia* with the Commission's general enabling statute, as both speak to the same subject matter.

Statutes relating to the same general subject matter "are in *pari materia* [on the same subject] and should be construed together so as to produce a harmonious statutory scheme." *Klotz v Hoyt*, 900 N.E.2d 1, 5 (Ind. 2009) (citations omitted, brackets in original). To determine the intent of the legislature, it is important when "construing words in a single section of a statute [to] construe them with due regard for all other sections of the act in order to ensure the spirit and purpose of the act is carried out." *U.S. Steel v. Review Bd. of Ind. Employment Sec. Div.*, 527 N.E.2d 731, 737 (Ind. Ct. App. 1988) (citations omitted). As elegantly stated by the U.S. Supreme Court, the resolution of statutory questions must

> be sought by following the elementary rules, that is, by turning primarily to the context of the section and secondarily to provisions *in pari materia* as affording an efficient means for discovering the legislative intent in enacting the statute, thereby vivifying and enforcing the remedial purposes which it was adopted to accomplish.

U.S. v Ewing, 237 U.S. 197, 200, 35 S.Ct. 571, 59 L. Ed. 913 (1915).

This legislative intent is evidenced by repeated references in I.C. ch. 8-1-39 to sections of I.C. ch. 8-1-2 and other statutes governing Commission regulation of rates. I.C. § 8-1-39-1 states that the definitions in I.C. § 8-1-2-1 apply "throughout this chapter." I.C. § 8-1-39-4 states that "[a]s used in this chapter, 'public utility' means: an energy utility (as defined in I.C. § 8-1-2.5-2);

(2) a municipally owned utility (as defined in I.C. § 8-1-2-1(h)); or (3) a department of public utilities created by I.C. ch. 8-1-11.1."[6]

Most significantly, I.C. § 8-1-39-16(b)(2) states that "[I.C. ch. 8-1-39] does not limit...the commission's valuation of utility property under IC 8-1-2-6"- the statute that establishes Commission valuation of utility property in order to determine rates.[7] Read *in pari materia*, I.C. § 8-1-39-16 explicitly contemplates that the Commission can exercise ratemaking discretion and authority in valuing utility property for the purpose of TDSIC costs.

Under I.C. § 8-1-2-6, the Commission's ratemaking dictate is to calculate public utility rates as will permit the utility to earn a return on the value of the property "which it employs for the convenience of the public." *Bluefield,* 262

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[6]The exception is municipal wastewater utilities, which are specifically exempted from Commission jurisdiction under I.C. § 8-1-2-1(g).

[7] The relevant sections of I.C. § 8-1-2-6 are:

(a) The commission shall value all property of every public utility actually used and useful for the convenience of the public at its fair value, giving such consideration as it deems appropriate in each case to all bases of valuation which may be presented or which the commission is authorized to consider by the following provisions of this section. As one of the elements in such valuation the commission shall give weight to the reasonable cost of bringing the property to its then state of efficiency.....

(b)...No account shall be taken of construction costs unless such costs were actually incurred and paid as part of the cost entering into the construction of the utility. All public utility valuations shall be based upon tangible property, that is, such property as has value by reason of construction costs, either in materials purchased or in assembling of materials into structures by the labor or (of) workers and...insurance and interest charges on capital accounts during the construction period. As an element in determining value the commission may also take into account reproduction costs at current prices, less depreciation, based on the items set forth in the last sentence hereof and shall not include good will, going value, or natural resources.

U.S. at 690. In other words, rates are based on 'used and useful' utility plant pursuant to I.C. § 8-1-2-6. *See also City of Evansville,* 167 Ind. App. at 516, 339 N.E.2d at 589. Since rates must be based on 'used and useful' property being used for the convenience of the public, fully depreciated utility plant that is retired no longer qualifies to be recovered through rates.[8] It is this concept that underlies the OUCC's argument.

The Commission reviewed the language of I.C. ch. 8-1-39 and found no support for the netting of retired utility property because it interpreted "return" as WACC. This was despite the terms of I.C. § 8-1-39-13(a)(5) granting the Commission the right to consider "[o]ther information that the commission determines is necessary" in deciding a utility's pre-tax return and I.C. § 8-1-39-16's direct reference to the Commission's ratemaking authority. The Commission's conclusion had the effect of "abrogat[ing] the discretion entrusted to the [Commission.]" *Appolon v. Faught,* 796 N.E.2d 297, 299 (Ind. Ct. App. 2003). Further, the Commission ignored its own precedent allowing for the same type of netting the OUCC argued for.

The Commission has previously accepted and approved the "netting" of retired assets against the amount embedded in base rates in a NIPSCO case that closely parallels the proceeding at bar. The Commission did so as an

[8] To the extent that utility plant is retired before it is fully depreciated, the utility will continue to collect depreciation through rates, thus recognizing the 'return of' that plant. This is done to avoid "stranded costs." The OUCC did not oppose NIPSCO collecting any remaining amounts for undepreciated plant, but advocated for adjustments to the TDSIC to prevent NIPSCO from earning a "return on" an investment that was no longer in service.

exercise of its ratemaking discretion despite the absence of explicit language authorizing the "netting" of retired assets in CWIP statutes.

NIPSCO sought approval for an increase to its CWIP tracker to recover the cost of a replacement part for a unit used to curb air pollutants. *Petition of N. Ind. Pub. Serv. Co., for Approval of an Adjustment to Its Electric Service Rates Through its Environmental Expense Recovery Mechanism Factor Pursuant to Ind. Code §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-8.7, 8-1-8.8 and 170 I.A.C. 4-6-1, et seq.*, Cause No. 42150 ECR 21, 2013 WL 5740184 (Ind. Util. Regulatory Comm'n Oct. 16, 2013) ("ECR 21")(OUCC Addend). The OUCC challenged NIPSCO's request to recover the value of the replacement layer and associated costs through the CWIP tracker (designated as an environmental cost recovery ("ECR") tracker), recommending instead that NIPSCO provide a credit in the ECR to reflect the retirement of the existing catalyst layer already embedded in NIPSCO's base rates. OUCC Addend. 12. There was no dispute that the catalyst layers qualified as QPCP under I.C. §§ 8-1-2-6.6, 8-1-2-6.8, 8-1-8.7, 8-1-8.8 and 170 I.A.C. 4-6-1, *et seq.*, and were thus eligible for recovery through the ECR. *Id.*

Neither the CWIP rules nor the various QPCP statutes provide the express authority for the Commission to offset the value of the replacement environmental property that is under construction and will ultimately be used and useful, with the value of the environmental property that is being retired or replaced. Nevertheless that is what the Commission did. The Commission endorsed the OUCC's proposal, finding that:

> [I]f NIPSCO recovers a *return on and return of* its investment for the replacement layer through its trackers and for the original layer through its base rates and charges, *ratepayers are paying for two catalyst layers, when only one is actually in service. Multiplied over several catalyst layers per SCR unit and several SCR units over NIPSCO's generation fleet, this issue could have a significant impact on customer rates.* There is no evidence that the original catalyst layer did not function as intended, i.e., that it needed to be replaced prematurely. In light of this, we see no reason that NIPSCO should be prohibited from recovering a *return of* its investment in the original layer. Similarly, because the replacement layer is necessary for the continued operation of the SCR, NIPSCO should be allowed to recover the full *return of* its investment in the replacement layer. However, should we grant full recovery of NIPSCO's *return on* its investment in the replacement layer when it already receives a *return on* its investment in the original layer through its base rates and charges, then until its next base rate case, *NIPSCO would receive a return on investment for two catalyst layers, while only one layer is in service.*
>
> ....In making our determination, Ind. Code § 8-1-8.7-3(b)(9)[9] allows us to consider any other factors we consider relevant, including the public's interest. In order to do so, we must seek a solution that allows the utility to recover the costs of necessary replacements to its pollution control systems, but does not require ratepayers to continue paying a return on an investment in catalyst layers that are no longer in service. In light of this and our discussion above, we conclude that NIPSCO shall be allowed to seek recovery of its full depreciation expense (return of investment) for the replacement layer. However, *NIPSCO shall only be allowed to seek recovery of the incremental amount of the return on its investment for the replacement catalyst layer that exceeds the return on investment currently included in its base rates and charges for the original catalyst layer.* This approach is similar to our treatment of replacement capital projects in *Ind. Mich. Power Co.*, Cause No. 44182, 2013 Ind. PUC LEXIS 212, at *178-79 (IURC July 17,

[9] I.C. § 8-1-8.7-3 governs Commission approval of QPCP projects, and states that in deciding whether to grant approval the Commission "shall examine... [a]ny other factors the commission considers relevant, including whether the construction, implementation, and use of [QPCP] is in the public's interest."

> 2013), where we allowed I&M to recover incremental depreciation and property tax expenses through its LCM tracker for replaced equipment that was already included in I&M's base rates and charges.

OUCC Addend. at 13 (emphases added, footnote omitted).

There is no explicit language in the CWIP statutes that allows for the Commission to take the action it did in Cause No. 42150 ECR 21. Instead, the Commission recognized that it had a duty to balance the utility's right to recover its investments with the public's right not to be charged unjust and unreasonable rates.[10] It therefore read the CWIP statutes *in pari materia* with established precedent under I.C. § 8-1-2-6 to reach a result that correctly balanced the utility's and consumers' rights. "The Commission's 'in service' test seeks to focus on whether existing utility plant will continue to be actually employed in future operations." *City of Evansville,* 167 Ind. App. At 517-18, 339 N.E.2d at 590. Because the catalyst layers were no longer 'in service' and therefore no longer 'used and useful,' the Commission was correct to credit ratepayers to prevent NIPSCO from "double-recovery."

The Commission has also approved netting of new and old assets with regard to the comparable DSIC tracker. I.C. ch. 8-1-31-*et seq.* and 170 I.A.C. 6-1.1 provide for the tracked recovery of new distribution system improvement charges ("DSIC") for water utilities. Like the TDSIC tracker, the DSIC tracker

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[10] "The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited and declared unlawful." I.C. § 8-1-2-4.

allows a water utility to adjust its base rates and charges to recover a pre-tax return and depreciation expense on eligible distribution system improvements. In the first DSIC case, Cause No. 42351 DSIC-1, the OUCC advocated for reducing the amount on which the return applies by the original cost of those assets that are no longer in service as they have been replaced by the assets eligible for the DSIC. The Commission agreed with the OUCC, finding that "if retirements are ignored and a utility is allowed to earn a return on new plant thought a DSIC, they will collect a return on both the new plant through its DSIC and on the retired asset through its return on the fair value rate base determination from the utility's last rate case." OUCC Addend. at 37.

Although the language contained in the TDSIC statute is not identical to the DSIC statute, the same principles of ratemaking apply. The determination of appropriate utility rates is "not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts." *Bluefield,* 262 U.S. at 690. Further, "there [is] no constitutional requirement that the owner who embarks in a wasting-asset business of limited life *shall receive at the end more than he has put into it.*" *Hope Nat. Gas Co.*, 320 U.S. at 606 (emphasis added, citations and internal quotes omitted). Through the process of depreciation the "utility is made whole and the integrity of its investment maintained. No more is required." *Id.*, 320 U.S. at 607. The Commission's decision in ECR 21 recognized this maxim and applied it accordingly, allowing NIPSCO to recover the value of its investment, but not double-recover. The decision complied with the requirements of I.C. § 8-1-2-6 that rates be "reasonable and just."

In failing to read I.C. ch. 8-1-39 *in pari materia* with I.C. ch. 8-1-2 in the case at bar, the Commission abdicated its ratemaking responsibility to protect consumers from utilities "receiv[ing] more" than the value of the actual investment. This was error.

C. The Commission improperly applied I.C. § 8-1-39-9(a)(1) by approving NIPSCO's proposed TDSIC customer class revenue allocation factors, which were not approved by the Commission in NIPSCO's most recent retail base rate case order as required by the TDSIC statute.

As previously established, I.C. § 8-1-39-9(a) permits a TDSIC "that will allow the periodic automatic 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." There are additional requirements with which a TDSIC must comply, including I.C. § 8-1-39-9(a)(1), which requires that the "petition must use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order[.]"

NIPSCO proposed recovering the costs of its 7-year infrastructure improvement plan through its TDSIC. The various types of customers, residential, commercial, industrial, street lighting, etc. would pay, based on which of NIPSCO's 21 rates each respective customer was served under. NIPSCO assigned each rate a customer class allocation factor, assessing their share of the TDSIC costs. NIPSCO witness Derric J. Isensee sponsored NIPSCO's proposed 21 TDSIC customer class revenue allocation factors ("TDSIC Factors") in Pet. Ex. DJI-1, Exhibit 2, Schedule 4. Tr. at 923-924. In that exhibit, page 1, column C contains the TDSIC Factors for "distribution" projects and Page 2, column C contains the TDSIC Factors for "transmission" projects.

Describing the TDSIC Factors, NIPSCO witness Frank Shambo testified both in his direct testimony (Tr. at 956, lines 2-5) and in his rebuttal (Tr. at 1017, lines 5-8) that they were "[c]onsistent with Ind. Code § 8-1-39-9(a)(1)" and "its customer class revenue allocation factor based on firm load that was approved as Joint Exhibit C to the Stipulation and Settlement Agreement approved in NIPSCO's most recent retail base rate case order in Cause No. 43969." Mr. Shambo testified that NIPSCO's TDSIC Factors "adjusted" the 43969 settlement allocation factors, and under cross-examination, Mr. Isensee also stated the TDSIC Factors were not the same factors approved by the Commission in Cause No. 43969. Tr. at 195-196. Mr. Shambo argued the proposed adjustments were necessary for NIPSCO's TDISC Factors to "satisfy the requirement of Ind. Code § 8-1-39-9(a)(1)" and to address rate making cost-causation principles that transmission and distribution costs should only be allocated to customers that use those systems. Tr. at 956-57, 1016-1019.

In Cause No. 43969, the OUCC, NIPSCO, NIPSCO Industrial Group and other parties reached a settlement resolving all issues in that proceeding. Section 10 of the Settlement Agreement discusses cost allocation and rate design. Settlement Joint Exhibit C is identified therein as "a table that contains the allocation revenue and percentages to the various customer classes" ("Settlement Factors") agreed to by the settling parties. The Settlement Agreement, along with Joint Exhibit C, was approved by the Commission on December 21, 2011 and was attached and incorporated as part of the final order ("43969 Order").[11] Final Order, Cause No. 43969, 2011 WL 6837714 (Ind. Util. Regulatory Comm'n Dec. 21, 2011).

In the instant case, OUCC witness Eric Hand opposed NIPSCO's proposed NIPSCO's TDSIC Factors because they were not "approved in the public utility's most recent retail base rate case order" as required by I.C. § 8-1-39-9(a)(1). A table in his direct testimony (Tr. at 1309, also admitted as Pub. Ex. CX-2, Tr. at 199) compared the differences between the proposed TDSIC Factors and the Settlement Factors. Mr. Hand noted that the Settlement Factors approved in NIPSCO's last base rate case do not distinguish between transmission and distribution costs. Tr. at 1313. He also testified that because the proposed TDSIC Factors were created years after the final order in Cause No. 43969, they were not proposed, evaluated or approved in that case. *Id.* Mr. Hand concluded the Settlement Factors "were based on all the other appropriate factors and components considered in a rate case, including firm load," and that I.C. § 8-1-39-9(a)(1) does not require the allocations to be "only"

[11] The City of Hammond appealed the order, but ultimately moved to dismiss its appeal, which was granted. *City of Hammond v. Ind. Util. Regulatory Comm'n*, Cause No. 93A02-1201-EX-40, June 22, 2012.

or "solely" a product of firm load. He recommended denial of NIPSCO's TDSIC Factors and approval of the Settlement Factors. *Id.* at 1314.

The Commission approved NIPSCO's proposed TDSIC Factors:

> The 43969 Order allocated revenue to customer classes based on a settlement agreement rather than a cost of service study. A cost of service study would have included separate allocation factors for distribution and transmission. However, the 43969 Order includes all costs in one factor. Further, the approved customer class revenue allocation factors included non-firm load, which was effectively adjusted out of the revenue allocation in a subsequent ratemaking step. Ind. Code § 8-1-39-9(a) requires NIPSCO to use the customer class revenue allocation factor based on firm load developed in the most recent base rate case. The evidence shows that many of the same customers currently taking interruptible service under Rider 675 were interruptible prior to the date the 43969 Order was issued. However, the evidence shows that pursuant to the 43969 Order, NIPSCO's old interruptible rates were terminated and replaced by the new firm rates plus an interruptible Rider 675 which established a different method to designate load as non-firm or interruptible. Thus, in order for the Joint Exhibit C allocation factors to properly reflect the customer class revenue allocation factors based on firm load, they must be adjusted to reasonably reflect non-firm load that was treated as firm under the construct of the settlement agreement as approved in the 43969 Order. Based on our review of the TDSIC statute and the evidence in this Cause, we find that NIPSCO's proposal that the revenue allocation factor be adjusted for the Rider 675 interruptible credit in order to remove the nonfirm portion of revenues from Rates 632 and 634 is consistent with Ind. Code § 8-1-39-9(a)(1) and should be approved.
>
> Further, NIPSCO's proposal to exclude Rates 632, 633 and 634 is a reasonable method to accomplish the alignment of the cost causation with cost allocation, under the evidence specific conditions presented in this proceeding together with the 43969 Order, for the purpose of allocating distribution costs in a manner that comports with Ind. Code § 8-1-39-9(a)(1). We find it is appropriate to adjust the 43969 Order approved Joint Exhibit C allocation factors by removing Rates 632, 633 and 634 from the calculation for purposes of allocating distribution related TDSIC costs so that rate classes that do not use the distribution system are not allocated distribution costs.

Cause No. 44371, OUCC App. at 24-25. The OUCC filed a Motion for Reconsideration of the issue on March 10, 2014, and which the Commission denied. OUCC App. at 33-35.

As previously established, a statute that is clear and unambiguous on its face must be read to mean what it plainly expresses, and its plain and obvious meaning may not be enlarged or restricted. *Id.* (quotation and citation omitted). The words and phrases of such a statute shall be taken in their plain, ordinary, and usual sense and should be construed and interpreted only if it is ambiguous.

I.C. § 8-1-39-9(a)(1) mandates that a TDSIC petition "*must* use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order[.]" (Emphasis added, punctuation omitted). No party disputes NIPSCO's eligibility to petition the Commission for approval of a TDSIC to recover costs associated with its 7-year electric infrastructure improvement plan pursuant to I.C. ch. 8-1-39. There is also no dispute that Commission Cause No. 43969 was NIPSCO's last retail base rate case and that Joint Settlement Exhibits C & E contain the only allocation percentages in the Settlement Agreement approved by the Commission in that Cause. There is also no dispute that in this case NIPSCO created new TDSIC Factors to separately allocate transmission and distribution costs that are not identical to the Settlement Factors approved in Cause No. 43969.

I.C. § 8-1-39-9(a)(1) is clear and unambiguous. This is a new statute, and is before the court for the first time. Statutes that provide new and extraordinary remedies must be construed strictly both to the cases embraced within their terms and as to the methods to be pursued. *In the Matter of the Termination of the Parent–Child Relationship of S.L. and D.L., Children, and R.M.*, 599 N.E.2d 227, 229 (Ind. Ct. App. 1992). This section imposes two conditions, both equally necessary.

NIPSCO's characterization of the proposed TDSIC Factors as "approved as Joint Exhibit C to the Stipulation and Settlement Agreement approved in NIPSCO's most recent retail base rate case order in Cause No. 43969" (Tr. at 956, 1017) is inaccurate. NIPSCO's proposed TDSIC factors adjusted the Cause No. 43969 Settlement Factors and the TDSIC factors were created more than a year after the Cause No. 43969 Order approving separate rate allocations. By definition, the TDSIC Factors are not "approved in the public utility's most recent retail base rate case order."

Neither are NIPSCO's cost-causation arguments persuasive. While acknowledging that general rate-making and cost-of-service principles support transmission and distribution customers paying costs for the respective delivery systems they use, the Settlement Factors demonstrate that all parties to Cause No. 43969 agreed, including NIPSCO and its industrial customers, not to make such a distinction. NIPSCO agreed to collect, and the industrial customers agreed to pay, certain negotiated rate allocation percentages.

NIPSCO affirmatively chose not to initiate a rate case with a cost of service study that would produce its preferred separate transmission and distribution cost customer class revenue allocation factors or that could reflect participation in its Rider 675. Further, NIPSCO was not required to file its TDSIC in July 2013.

The Commission misread I.C. § 8-1-39-9(a) when it said the statute "requires NIPSCO to use the customer class allocation factor based on firm load *developed* in the most recent base rate case." OUCC App. at 25, (emphasis added.) Subsection 9(a)(1) requires the allocation factors be *approved* in the last base rate case; the language is clear, unambiguous and does not require interpretation. The Commission used this lesser "developed" standard, in conjunction with its finding that the Settlement Factors did not "properly reflect the customer class allocation factors based on firm load," to erroneously conclude NIPSCO's proposed TDSIC Factors were necessary and "consistent with Ind. Code 8-1-39-9(a)(1)."

Presumably, the word "approved" in the statute means what it plainly expresses in its ordinary and usual sense. There is no cause to either enlarge or restrict the plain and obvious meaning. Had the Commission agreed with the OUCC that Settlement Factors were consistent with Section 9(a)(1), those could have supported the TDSIC approval. However, once the Commission determined the Settlement Factors did not meet the section 9(a)(1) requirement, the appropriate course of action for the Commission would have been to deny NIPSCO's TDSIC request, as there were no other customer class allocation factors that were compliant.

The Commission erred in its reading of I.C. § 8-1-39-9(a)(1) and in approving the TDSIC Factors proposed by NIPSCO. As a result, there is no record evidence of any set of customer class revenue allocation factors. These factors are required for the Commission to approve a TDSIC petition.

D. The OUCC was unfairly prejudiced by the Commission's failure to enforce the terms of the Settlement Agreement approved in its December 21, 2011 Final Order in Cause No. 43969, when the Commission approved NIPSCO's requested customer class revenue allocation factors in Cause No. 44371.

Attached to the Commission's 43969 Order, Joint Exhibit No. 1 is the Settlement Agreement ("43969 Settlement") entered into on July 18, 2011 between NIPSCO, the OUCC, NIPSCO Industrial Group, NLMK Indiana f/k/a Beta Steel and the Indiana Municipal Utilities Group resolving all issues in that cause. 2011 WL 6837714 at 63-78. The Settlement also contained Joint Exhibits A through H, which were documents supporting various terms of the Settlement.

Section 10 of the Settlement addresses Cost Allocation and Rate Design:

> The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that NIPSCO should generally design its rates using the structure of its existing 800 Series tariffs.

> The Settling Parties agree that NIPSCO's settlement base rates in total will be designed to produce $1.355 billion. Attached to this Agreement as Joint Exhibit C is a table that contains the allocation revenue and percentages to the various customer classes. The Settling Parties agree to the rate design specifics summarized in Joint Exhibit D.
>
> The Settling Parties agree that the cost allocation herein results in fair and reasonable rates and charges.

Id. at 65. The Commission attached a copy of the Settlement to its 43969 Order, which it incorporated into the Order by reference. *Id.* at 4. The Commission approved the Settlement in its entirety without modification. *Id.* at 62, Ordering paragraph No. 1.

In the instant case NIPSCO's petition included certain customer class revenue allocation factors (TDSIC Factors) that set forth the percentage of approved capital expenditures and TDSIC costs each of NIPSCO's customer rate classes will be required to pay. NIPSCO's proposed TDSIC Factors were a product of adjustments NIPSCO made to the allocation percentages included in Joint Exhibit C from the 43969 Settlement (Settlement Factors). NIPSCO Industrial Group and U.S. Steel supported NIPSCO's adjusted TDSIC Factors.

The OUCC supported using the Settlement Factors. The OUCC opposed NIPSCO's TDSIC Factors on several grounds, including that they were not those negotiated by the 43969 Settlement parties, were not approved by the Commission in NIPSCO's most recent retail base rate case, would undermine the 43969 Settlement and in turn, produce bad public policy. Tr. at 1307-1314.

In cross-answering testimony, both NIPSCO Industrial Group and U.S. Steel supported the TDSIC Factors and opposed the Settlement Factors. They argued the Settlement Factors a) included "interruptible load," and therefore were not "based on firm load" as required by Section 9(a)(1), and b) were not in accord with cost causation and cost-of-service principles. NIPSCO Industrial Group Ex. NP-2, Tr. at 1238-1243; US Steel Ex. 2, Tr. at 1182-1185. As discussed previously, the Commission approved NIPSCO's adjusted TDSIC Factors over OUCC's objections. In support of its decision, the Commission stated, "in order for the Joint Exhibit C allocation factors to properly reflect the customer class revenue allocation factors based on firm load, they must be adjusted to reasonably reflect non-firm load that was treated as firm under the construct of the settlement agreement as approved in the 43969 Order." OUCC App. at 15-16.

I.C. § 8-1-39-9(a)(1) requires NIPSCO's TDSIC `petition "use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order." Having rejected the OUCC's recommendation to apply the Settlement Factors, the only remaining customer class revenue allocation factors in the record were NIPSCO's proposed TDSIC factors, created by NIPSCO well after the 43969 Settlement Agreement was signed by the parties and approved by the Commission. Rather than deny NIPSCO's petition on the grounds the TDSIC Factors were not "approved in the utility's most recent retail base rate case order," the Commission accepted

NIPSCO's proposed TDSIC Factors. In so doing, the Commission failed its duty to enforce the 43969 Settlement Agreement and Order.

The 43969 Order explicitly recognized the importance and value of settlement agreements generally, and that those approved by the Commission must serve the public interest:

> Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 664 N.E.2d 401,406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling or order - including the approval of a settlement - must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before the Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such Settlement serves the public interest...
>
> We have previously discussed our policy with respect to settlements:
>
> Indiana law strongly favors settlement as a means of resolving contested proceedings. See, e.g., *Manns v. State Department of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes v. Forest Lake Corp.*, 607 N.E.2d 978,982 (Ind. Ct. App. 1993); *Harding v. State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992)...
>
> Furthermore, we are mindful regarding a settlement which has been entered by representatives of all customer classes, including OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban Utils.*, Cause No. 41254, at 4-5 (IURC 4/14/99).

43969 Order, 2011 WL 6837714 at 54-55.

The Commission reiterated these thoughts later in the Order:

> Additionally, as noted above, public policy favors settlements. This public policy is part of the overall public interest. Hence, in the context of settlement, the public interest appropriately includes consideration of the compromise inherent in the negotiation process, particularly where, as here, the Settlement results from a rigorous process and presents a balanced and comprehensive resolution of all the issues among most of the parties. The Commission is particularly mindful of the impact of its decisions. The disparate interests of the Settling Parties provide the Commission some assurance that the interests of all customers have been considered by the Settling Parties. Based upon the evidence of record in this proceeding, the Commission finds that the Settlement is reasonable and in the public interest and should be approved. We further find that the new proposed IURC Electric Service Tariff, Original Volume No. 12, including, but not limited to, the rates and charges set forth therein, is fair, just and reasonable and should be approved subject to the terms and conditions contained in the Settlement.

Id. at 61.

Describing its support for the 43969 Settlement as a whole, the Commission said,

> As shown by substantial evidence of record, the Settlement provides a just and reasonable resolution of all matters pending before the Commission in this case. It reflects the significant collaboration and compromise inherent in serious negotiations among a diverse group of interests. While the Settlement is reasonable as a whole, the evidence in support of the Settlement explains the basis for the proposed rates and other included elements. As a result, the Commission is able to understand how each disputed issue was resolved and to determine that the Settlement is amply supported by the evidence of record, and we so find.

Id.

The 43969 Order also specifically addressed the agreed allocation methodology and compromise necessary to achieve Joint Exhibit C Settlement Factors:

> The Settling Parties chose to allocate revenue by class in a manner designed to mitigate the level of increase to anyone customer class....Given the diverse nature of the Settling Parties, and their willingness to agree to the proposed allocation of revenue, and given that no party to this proceeding provided evidence in opposition to the proposed allocation of revenue, we find that the proposed allocation of revenue is supported by substantial evidence of record and is appropriate for development of NIPSCO's retail rates and charges....
>
> ...As discussed by Mr. Bolinger, the revenue requirement, revenue allocation and Rider 675 were interrelated and reflected difficult and painstaking negotiations to reach a balanced outcome and resolution which was acceptable to the Settling Parties[.]....
>
> ...Revenue allocation was one of the most contentious issues in this case, and in Cause No. 43526. Although not all parties were signatories to the Settlement, the Settling Parties respectively represent every customer class, and negotiated the allocation of costs or revenues to the respective classes. Accordingly, we give substantial weight to the Settling Parties' agreement with respect to revenue allocation. We find that the Settlement revenue allocation constitutes just and reasonable rates under Ind. Code § 8-1-2-4.

Id. at 57-58.

The Commission's approval of NIPSCO's adjusted TDSIC allocators in this case flies in the face of these explicit pronouncements. It unnecessarily undermines the very balance of both issues and interests the Commission found crucial to its reasonableness determination and ultimate approval of the Settlement. As the administrative body approving settlements in the cases over which it presides, the Commission is primarily responsible for enforcing those settlements. Parties must feel confident that the Commission will impartially and fairly enforce the agreements approved through its orders, or they will have little reason pursue future settlements. The result would be not only increased litigation and administrative expense, but regulatory lag and an erosion of the public's confidence in the regulatory process.

Pursuant to the Settlement Factors in Joint Exhibit 1, Joint Exhibit C, Rate Class 611 would be allocated 27.882%. *Id.* at 68; Tr. at 951, 1309. NIPSCO's proposed TDSIC adjusted allocation factors for Rate Class 611 are 37.86% for distribution costs. NIPSCO's Rate Class 611 is primarily composed of residential ratepayers. Tr. at 196. In comparison, the Settlement Factors for Rate Classes 632 (10.4%), 633 (8.968%) and 634 (6.992%) were all adjusted downward by NIPSCO in Cause No. 44371 to 0.00% for distribution costs. Rate Classes 632, 633 and 634 are composed primarily of large interruptible (industrial) customers. The result of the Commission's approval of adjusted factors is that residential customers will pay a greater share of NIPSCO's more than one billion dollar, 7-year infrastructure improvement plan than the Settlement Factors OUCC negotiated for, and agreed to in Cause No. 43969's Settlement Agreement approved by the Commission. Conversely, Rate 632, 633 and 634 customers will pay a smaller portion.

I.C. § 8-1-39-9(a)(1) neither requires nor authorizes the Commission to unilaterally alter an approved Settlement Agreement so that its terms might advantage one settling party to the detriment of another, or to fit its terms more comfortably within conditions included in a post-settlement statute. In approving the TDSIC Factors proposed by NIPSCO, the Commission failed to enforce the terms of its Order in Cause No. 43969 as required by law.

VI. CONCLUSION

The Commission failed to read I.C. ch. 8-1-39 *in pari materia* with the Commission's enabling statute, and thereby committed multiple errors of statutory construction requiring reversal. In addition, the Commission violated the explicit language of the statute and allowed rate allocations other than those mandated by I.C. § 8-1-39-9. The Court should reverse the Commission's order with instructions to apply the appropriate rules of statutory construction in the application of the TDSIC statute.

Respectfully submitted,

RC/dr

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ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF A TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, (2) APPROVAL OF PETITIONER'S PROPOSED COST ALLOCATIONS, (3) APPROVAL OF THE TIMELY RECOVERY OF TDSIC COSTS THROUGH PETITIONER'S PROPOSED TDSIC RATE SCHEDULE, AND (4) AUTHORITY TO DEFER APPROVED TDSIC COSTS, PURSUANT TO IND. CODE CH. 8-1-39.	)	CAUSE NO. 44371 APPROVED: FEB 17 2014

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On July 19, 2013, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") petitioned the Indiana Utility Regulatory Commission ("Commission") for (1) approval of a Transmission, Distribution and Storage System Improvement Charge ("TDSIC") Rate Schedule, (2) approval of Petitioner's proposed cost allocation, (3) approval of the timely recovery of TDSIC costs through Petitioner's proposed TDSIC Rate Schedule, and (4) authority to defer approved TDSIC costs, pursuant to Ind. Code Ch. 8-1-39. On July 19, 2013, Petitioner filed its prepared testimony and exhibits constituting its case-in-chief. Citizens Action Coalition of Indiana, Inc. ("CAC"), Indiana Municipal Utilities Group ("IMUG"), LaPorte County Board of Commissioners ("LaPorte"), Hoosier Environmental Council, NIPSCO Industrial Group ("Industrial Group"), United States Steel Corporation ("U.S. Steel") and NLMK, Indiana, filed petitions to intervene, all of which were subsequently granted.

On October 11, 2013, the Indiana Office of Utility Consumer Counselor ("OUCC"), Industrial Group, LaPorte, IMUG and U.S. Steel prefiled direct testimony. Industrial Group and U.S. Steel prefiled cross answering testimony on October 25, 2013. NIPSCO prefiled rebuttal testimony on October 30, 2013.

Pursuant to notice given as provided by law, proof of which was incorporated into the record, an evidentiary hearing was commenced on November 12, 2013, at 9:00 a.m., in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. The OUCC, CAC, Hoosier Environmental Council, Industrial Group, LaPorte, IMUG and U.S. Steel appeared and participated in the evidentiary hearing. No members of the general public appeared or participated at the hearing.

Having considered the evidence and being duly advised, the Commission now finds:

1. **Notice and Jurisdiction.** Notice of the hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility as that term is defined in Indiana Code § 8-1-2-1(a). Under Indiana Code ch. 8-1-39, the Commission has jurisdiction over a public utility's petition to approve rate schedules establishing a TDSIC that will allow the periodic automatic adjustment of the public utility's basic rates and charges to provide for timely recovery of eighty percent of approved capital expenditures and TDSIC costs. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of the proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric and gas public utility service in the State of Indiana and owns, operates, manages and controls, among other things, plant and equipment within the State of Indiana used for the generation, transmission, distribution and furnishing of such service to the public.

3. **Requested Relief.** In accordance with Ind. Code Ch. 8-1-39, Petitioner requests the following relief:

A. approval of Petitioner's proposed TDSIC Rate Schedule and accompanying changes to its electric service tariff, which will allow for timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs and authorizing Petitioner to defer, until recovery through the TDSIC, 80% of the post in service TDSIC costs of the TDSIC projects, including carrying costs, depreciation and taxes;

B. approval of Petitioner's proposal that transmission project costs be allocated on the basis of the revenue allocation found in Joint Exhibit C of the Stipulation and Settlement Agreement approved in the Commission's December 21, 2011 Order in Cause No. 43969 (the "43969 Order") modified to reflect an adjustment for Rider 675 credits paid related to the interruptible load served under Rates 632 and 634 over the previous twelve months.

C. approval of Petitioner's proposal that distribution costs be allocated to distribution customers on the basis of the revenue allocation found in Joint Exhibit C of the Stipulation and Settlement Agreement approved in the 43969 Order with the exclusion of Rates 632, 633 and 634, which are only available to transmission and subtransmission customers;

D. authorization to defer 20% of eligible and approved capital expenditures and TDSIC costs under Ind. Code § 8-1-39-9(b) and authorizing Petitioner to recover those capital expenditures and TDSIC costs as part of Petitioner's next general rate case;

E. approval of Petitioner's proposed method of calculating pretax return under Ind. Code § 8-1-39-13;

F. authorization to adjust its authorized net operating income to reflect any approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(d)(3) pursuant to Ind. Code § 8-1-39-13(b); and

G. approval of Petitioner's proposed method of calculating the average aggregate increase in its total retail revenue attributable to the TDSIC to determine whether the TDSIC will result in an average aggregate increase of more than 2% in a twelve month period.

4. **Evidence Presented.**

A. **NIPSCO's Case-in-Chief.** Frank A. Shambo, Vice President, Regulatory and Legislative Affairs for NIPSCO provided testimony to support NIPSCO's request to establish a TDSIC Rate Schedule. He explained that while NIPSCO is not seeking approval of a factor to recover costs at this time, there are certain issues that can be resolved in this proceeding that require additional time not afforded under the 90 day time frame established in the statute for approval of the factor.

Mr. Shambo testified that NIPSCO requests approval to use its customer class revenue allocation factor based on firm load that was approved as Joint Exhibit C to the Stipulation and Settlement Agreement approved in NIPSCO's most recent retail base rate case in Cause No. 43969 ("43969 Order"). For transmission TDSIC costs, NIPSCO proposes that the revenue allocation factor be adjusted for the Rider 675 interruptible credit in order to remove the non-firm portion of revenues from Rates 632 and 634. For distribution TDSIC costs, Mr. Shambo testified that NIPSCO proposes that the revenue allocation factor from the 43969 Order be adjusted to exclude revenues from Rates 632, 633, and 634 which are transmission and subtransmission service rates.

Mr. Shambo testified NIPSCO proposes that its allowable pretax return be calculated using the following two cost of capital items: long-term debt and common equity. NIPSCO proposes to use the actual cost of debt and the return on equity of 10.2% authorized by the Commission in NIPSCO's most recent general rate proceeding in Cause No. 43969.

Mr. Shambo testified that the capital structure for the TDSIC investments should be consistent with how NIPSCO will actually finance these new investments—with long-term debt and equity. He stated the proposed $1.073 billion capital program cannot be funded with zero cost capital items like deferred income taxes, customer deposits or pension deferrals.

Derric J. Isensee, Manager, Regulatory Support and Analysis in the Rates and Regulatory Finance Department of NIPSCO testified that in accordance with Ind. Code § 8-1-39-9(a), NIPSCO proposes to recover, through the TDSIC, 80% of TDSIC costs incurred with respect to eligible transmission, distribution and storage system improvements incurred both while the improvements are under construction and post in service. These costs will include, but are not limited to, depreciation expense, property taxes, pretax returns, allowance for funds used during construction ("AFUDC") and post in service carrying costs. NIPSCO proposes to recover 80% of TDSIC costs on a historical basis subsequent to the date in which the actual costs were incurred. As part of this request, NIPSCO requests authority to defer on an interim basis 80% of the post in service TDSIC costs of the TDSIC projects, including carrying costs, depreciation and taxes until the costs are recovered through the TDSIC.

NIPSCO proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during the construction of capital projects. NIPSCO will cease accruing AFUDC the earlier of the date in which such expenditures receive CWIP ratemaking treatment through the TDSIC or the date the project is placed in service. NIPSCO proposes to recover 80% of all post in service carrying costs incurred in connection with projects approved as part of the 7-Year Electric Plan. NIPSCO proposes that post in service carrying costs be determined based on NIPSCO's proposed capital structure and will include all financing costs incurred from the in service date until such projects receive ratemaking treatment.

In each semi-annual filing, NIPSCO proposes to calculate a revenue requirement, which will consist of two components: (1) a return of financing costs related to capital expenditures including AFUDC, post in service carrying costs and pretax returns; and (2) recovery of depreciation expense and property tax expense associated with the approved TDSIC projects. Then NIPSCO will multiply the total revenue requirement by 80% to establish the TDSIC revenue requirement. Mr. Isensee testified that the revenue requirement will also include the variance associated with the under or over collection of these costs due to the difference between the forecasted volumes used to calculate the rates and actual volumes billed. Mr. Isensee explained that NIPSCO will gross-up the revenue requirement for all incremental taxes incurred as a result of the additional revenues. Finally NIPSCO proposes to depreciate the TDSIC capital expenditures according to each asset's designated Federal Energy Regulatory Commission ("FERC") account classification. Upon being placed in service, NIPSCO will depreciate each asset according to the FERC account composite remaining life approved by the 43969 Order.

Mr. Isensee also testified that NIPSCO requests approval to (1) defer, as a regulatory asset, 20% of approved capital expenditures and TDSIC costs, including depreciation, pretax returns, AFUDC, post in service carrying costs and property taxes and requests to recover those costs as part of NIPSCO's next general rate case, and (2) record ongoing carrying charges based on NIPSCO's weighted cost of capital on these costs until the costs are included for recovery in NIPSCO's basic rates and charges in its next general rate case.

B. OUCC's Case-in-Chief. Tyler E. Bolinger, Director of the Electric Division of the OUCC, provided testimony addressing (1) cash returns on construction work in progress ("CWIP"), (2) accurate measurement of rate base investment growth between base rate cases, and (3) capital structure and tracker impacts on risk, and recommended denial of NIPSCO's proposed TDSIC Rate Schedule. After recommending denial of NIPSCO's TDSIC mechanism, Mr. Bolinger recommended that a more reasonable TDSIC mechanism would, at a minimum, account for base amounts of revenue requirements already embedded in base rates to support Transmission and Distribution ("T&D") investments.

OUCC Witness Bolinger testified the addition of TDSIC trackers represents a major change to Indiana retail electric ratemaking. He stated the OUCC believes this is a crucial juncture and important opportunity to review and improve investment tracking methodologies. Mr. Bolinger stated the TDSIC statute (when combined with previously enacted legislation) would permit investment tracking to become the standard practice for Indiana electric utilities and not just a tool used in exceptional circumstances, such as paying for expensive environmental retrofits.

Mr. Bolinger testified that NIPSCO's TDSIC is best described as a Capital Expenditure ("CapEx") tracker for eligible capital expenditures. He stated that NIPSCO's TDSIC is not a transmission and distribution rate base (i.e. net utility plant) tracker, because it does not account for capital recoveries (depreciation and the growth in accumulated depreciation) between rate cases. Mr. Bolinger stated NIPSCO's base rates determined in the 43969 Order include millions of dollars for transmission and distribution related revenue requirements, including return on and return of transmission and distribution investment. Mr. Bolinger opined that a reasonably designed transmission and distribution investment tracker should account for the base amounts already provided in base rates, just as a reasonably designed fuel tracker accounts for the base amount of fuel costs embedded in base rates.

Mr. Bolinger testified that NIPSCO's proposed TDSIC mechanism provides no accounting and no recognition of the base amounts already embedded in base rates for transmission and distribution related revenue requirements, including return on and return of transmission and distribution investment. He stated NIPSCO proposes to track eligible additions to its rate base every six months and not update for growth in the accumulated depreciation reserve until the next rate case, up to seven years from now. He testified that NIPSCO proposes to account for capital expenditures but not capital recoveries related to the rate base as determined in the 43969 Order.

Finally, Mr. Bolinger stated it is not an exaggeration to conclude that NIPSCO fails to account for hundreds of millions of dollars relevant to the calculation of transmission and distribution revenue requirements and TDSIC tracking factors. He testified that the Commission should deny NIPSCO's requested TDSIC mechanism in this Cause. Mr. Bolinger testified that a reasonable TDSIC mechanism should account for the on-going capital expenditure and capital recovery processes (i.e. depreciation). He stated that rate base changes between rate cases are a function of both capital expenditures and capital recoveries. He opined that TDSIC mechanisms should accurately measure the growth in net utility plant investment for whatever set of transmission and distribution plant accounts the Commission approves for tracking.

Wes R. Blakley, Senior Utility Analyst in the Electric Division of the OUCC, provided testimony to address NIPSCO's (1) proposed method of calculating its allowable return and proposes that NIPSCO calculate its weighted average cost of capital ("WACC") in a manner consistent with its last base rate case and its ECR proceedings, (2) request for approval of the TDSIC costs through the proposed TDSIC Rate Schedule including its request for authority to defer TDSIC costs at the WACC rate that is deferred as earnings and grossed up for taxes, plus the application of the WACC rate as a carrying charge to apply to deferred depreciation and property tax expense and (3) lack of recognition of investment already existing in its base rates with regard to assets that will be replaced under its 7-Year Electric Plan while seeking to recover its new investment in transmission, distribution or storage system improvements and other associated costs through the TDSIC Rate Schedule.

Mr. Blakley testified that NIPSCO's proposed weighted average cost of capital WACC is 8.59% which results in a 1.98% increase from the WACC approved in NIPSCO's Cause No. 42150-ECR-22 proceeding (6.61%). Mr. Blakley opined that an 8.59% WACC would have the effect of awarding NIPSCO the equivalent of a 14.48% return on equity if zero-cost capital was included in the capital structure.

Mr. Blakley stated that the TDSIC statute does not support the exclusion of zero-cost capital or any deviation from the traditional method of calculating the WACC. He stated that there is no mention of incentives or premiums of return on equity ("ROE") that would permit a radical departure from the traditional method of calculating WACC in the TDSIC tracker. He opined that excluding the zero-cost capital would lead to excessive returns and unreasonably higher rates. Mr. Blakley stated that NIPSCO's deferred income tax balance was $426 million as of June 30, 2010 which was the test year cut-off in NIPSCO's last base rate case. He stated that the June 30 2013 deferred income tax balance was $682 million which is a 60% increase of $256 million from the 2010 balance. Mr. Blakley testified that there are no restrictions against NIPSCO using these funds to finance any of its capital projects. Finally, Mr. Blakley recommended that the Commission should require that the calculation of WACC be consistent with NIPSCO's last rate case and NIPSCO's ECR proceedings, and that all zero-cost capital be included in the capital structure which is standard practice followed by the Commission in hundreds of Indiana ratemaking proceedings, including NIPSCO's last base rate case and its ECR cases.

Mr. Blakley testified that NIPSCO wants to apply the WACC, which is used to calculate earnings, to all deferred costs including deferred depreciation expense and property tax expense, which then would be grossed up for taxes again by NIPSCO. When granting post in service AFUDC/carrying charges and deferred depreciation, the ultimate purpose is to grant financial statement relief, not to create earnings that are grossed up for taxes. This will happen when the deferred costs are included in rates. He also stated that should the Commission approve a CapEx tracker, as proposed by NIPSCO in this proceeding, the OUCC recommends the disallowance of a carrying cost applied to deferred depreciation expense and property tax expense after a project is placed in service.

Eric M. Hand, Utility Analyst in the Electric Division of the OUCC, provided testimony (1) describing the historical basis for NIPSCO's current class cost of service allocators and methodology and indicate transmission and distribution costs were part of the total revenue requirement allocated to all customer classes in accordance with the 43969 Order, (2) explaining NIPSCO's current TDSIC proposal is incongruent with the Commission's prior orders, is non-compliant with the TDSIC statute and is contrary to the parties' Settlement Agreement, (3) evaluate NIPSCO's proposed cost allocation adjustments, wherein the Settlement Agreement did not include any exclusions, waivers, exceptions or other adjustments for allocations of distribution costs and (4) demonstrating that NIPSCO's TDSIC proposal is non-compliant with Ind. Code § 8-1-39-9(a)(1) and with the requirements found in the 43969 Order and should be denied. Mr. Hand testified that Joint Exhibit C and Joint Exhibit E filed in Cause No. 43969 should be reaffirmed as the only customer class revenue allocators allowable for NIPSCO TDSIC petitions until new allocators are appropriately determined on the basis of a 12 CP cost of service study in NIPSCO's next base rate case.

Mr. Hand testified that the OUCC does not consider NIPSCO's adjustments to the Joint Exhibit C allocators to be appropriate. He stated there is no evidence or cost of service study to invalidate the cost allocations approved by the Commission in its 43969 rate Order or in favor of the specific TDSIC proposed class allocation adjustments NIPSCO proposed in this Cause. Mr. Hand testified that the 43969 Order sets forth two tables of approved allocators for NIPSCO's customer classes – Joint Exhibit C "Allocation of Base Rate Revenue Requirement," and Joint Exhibit E "Demand Allocators" for purposes of the RTO Tracker and RA Tracker – and these are significantly different than NIPSCO's proposed allocators in this Cause. Mr. Hand recommended the Commission deny NIPSCO's proposed allocation factors in this Cause and affirm that Joint Exhibit C and Joint Exhibit E (approved in the 43969 Order) are the only customer class revenue allocators allowable for NIPSCO's TDSIC petitions until new allocators are appropriately determined on the basis of a 12 CP cost of service study in NIPSCO's next base rate case.

Michael D. Eckert, Senior Utility Analyst in the Electric Division of the OUCC, provided testimony to (1) demonstrate how NIPSCO's proposed TDSIC Rate Schedule may seek to recover costs not directly related to transmission and distribution investments, (2) discuss how NIPSCO's proposed tracker will impact ratepayers, and (3) recommend that NIPSCO not be allowed to recover transmission and distribution investments that are already recovered through other tracker mechanisms or base rate components.

Mr. Eckert testified that NIPSCO has identified 22 plant accounts that are eligible for TDSIC Treatment and that it was not entirely clear that NIPSCO had limited its TDSIC Mechanism to plant investment for T&D accounts only. He testified that the tracker should be limited to T&D plant only and explained that, for example, if a T&D project requires the utility to make a change at a Production Plant, it should not be allowed to track that change at the Production Plant in the TDSIC tracker.

Mr. Eckert testified that the TDSIC tracker will impact future rate proceedings in many areas, such as weighted average cost of capital/ROE; maintenance expense; and T&D capital expenditures. He stated that Petitioner's ROE in future base rate cases should be lower because the TDSIC tracker should mitigate risk as it allows for more frequent rate changes to reflect the utility's invested capital costs. Mr. Eckert testified that T&D maintenance expense should decrease in future years as the T&D system is upgraded and that T&D capital expenditures in future rate cases should be less contentious as most of Petitioner's T&D capital expenditures should have been reviewed and approved in Petitioner's 7-Year Electric Plan.

Mr. Eckert testified that NIPSCO has a variety of cost recovery mechanisms that allow it to recover both capital expenditures and operating expenses from ratepayers, such as the ECR. Mr. Eckert stated that he is concerned that monitoring the NIPSCO projects and the payment for such projects will be very detailed and complicated when factoring in the various tracking mechanisms. He also testified that there could be situations where an investment that Petitioner seeks recovery for in its TDSIC tracker could already be embedded in NIPSCO's base rates for an item such as storm restoration. Mr. Eckert also testified that the OUCC will need an in-depth understanding of Petitioner's work order process.

Mr. Eckert also testified that the OUCC believed "emergent expenses" are those costs attributable to an unexpected or unplanned event and that recovering "emergent costs" in a tracker expressly designed to recover costs associated with a detailed 7-year plan is inconsistent with the purpose of the TDSIC statute.

C. **Industrial Group's Case-in-Chief.** Michael P. Gorman, Managing Principal with Brubaker & Associates, Inc., provided testimony to respond to NIPSCO's proposed method of developing the overall rate of return applied to develop the post in service carrying cost which NIPSCO proposed to seek recovery of for the semi-annual TDSIC.

Industrial Group Witness Gorman testified that NIPSCO's proposed overall rate of return is excessive and NIPSCO's proposed capital structure is not appropriate for any aspects of rate-setting by NIPSCO. Mr. Gorman testified that the rate of return should reflect the risk reduction that results from recovering costs in a rider mechanism. Mr. Gorman testified that setting the TDSIC revenue requirement using a capital structure with a 60.9% common equity ratio does not reflect the investment stability and low-risk nature of an electric utility. He stated that the industry-approved rate of return is based on capital structures that have common equity ratios of between 48% and 51% since 2005. Mr. Gorman opined that a return on equity of approximately 9.55% is appropriate for the TDSIC tracker based on the industry average return on equity for the first six months of 2013 and an adjustment to account for the spread between "A" and "Baa" utility bond yields.

Mr. Gorman also stated the capital structure could be adjusted to reflect the risk reduction. He recommends a capital structure composed of 40% common equity and 60% debt for the TDSIC. He stated this is the same capital structure mix that NIPSCO agreed to for a major environmental project in its last base rate settlement in Cause No. 43969. He stated that if NIPSCO is directed to use a 40% common equity and 60% debt incremental capital mix for its TDSIC investments, there will be an improvement to the reasonableness of NIPSCO's common equity ratio and capital structure over time. Finally, Mr. Gorman testified that NIPSCO's proposed capital structure does not include customer-supplied sources of capital such as customer deposits, deferred income taxes, post-retirement liability, and post-1970 investment tax credits which are lower cost than investor-supplied sources capital. Mr. Gorman testified that in NIPSCO's last case, its total rate base was $2.7 billion while the total capital used to establish its overall rate of return was $3.16 billion. He stated that NIPSCO had significantly more capital than investments in rate base but that NIPSCO did not attempt to synchronize the level of capital with rate base then, and it is not appropriate to do so now.

Nicholas Phillips, Jr., Managing Principal with Brubaker & Associates, Inc., testified that he agrees with NIPSCO's approach to not charge customers on Rates 632, 633 and 634 for distribution system costs. Mr. Phillips testified that customers on these rates do not use the distribution system in the delivery of electric power from NIPSCO and should not be charged with costs associated with the distribution system. Mr. Phillips testified that the 43969 Order approved a credit for interruptible load under which customers must agree that certain load is interruptible or non-firm and receive a revenue credit under Rider 675 for the amount of designated interruptible load. He stated the revenue credit by class was unknown at the time of the 43969 Order since the customers could not sign up to be interruptible until the order was issued. Mr. Phillips also testified that if the Commission authorizes tracking of new distribution in between rate cases, those costs should not be allocated to high-voltage customers.

Industrial Group Witness Phillips testified that NIPSCO's proposal to defer TDSIC costs for recovery in NIPSCO's next rate case lacks specificity. He stated it is not reasonable to defer projects of this nature without the opportunity to review the deferred projects for ratemaking when facts are known and a procedure is established to provide for a review of the expenditures. Otherwise, he explained, the deferred amounts would be preapproved without an opportunity for a reasonable review by impacted parties.

Industrial Group Witness Phillips testified that NIPSCO's filing shows that the TDSIC will exceed the 2% cap ($30 million based on NIPSCO's 2012 retail revenues). He stated that he does not agree with NIPSCO's approach because it is based on the incremental increase in total revenues due to the TDSIC. He opined that the TDSIC should be capped at 2% or approximately $30 million. Mr. Phillips recommended that the 2% cap be applied on the basis of total TDSIC charge. In this way, the TDSIC will not exceed a 2% average aggregate increase in retail revenues in a 12 month period, where TDSIC is the total charge applied to customers' usage or bills. Mr. Phillips testified that NIPSCO's approach appears to be based on the premise that the previous year's increase to customers does not count. He stated customers' rates were in fact increased. Under the Industrial Group's interpretation of the 2% cap, NIPSCO would be expected to hit a capped amount in 2017 and not be able to recover additional amounts under the TDSIC tracker. Mr. Phillips stated that based on NIPSCO data, the 2% cap would amount to $30.2 million. He stated if the TDSIC applied to customers' bills collects $13 million for a six month period and $17.2 million for the next six month period, the average aggregate increase to customers is $30.2 million for the 12 month period which exceeds the cap of 2% on total revenues. Mr. Phillips opined that absent an increase in the total revenues, the TDSIC cannot be increased to a higher level in the next year because the TDSIC will increase rates to customers by more than the 2% cap.

D. <u>LaPorte's Case-in-Chief.</u> Reed W. Cearley, an independent contractor retained by LaPorte as a special utility consultant testified that the revenue allocation factor approved as Joint Exhibit C to the Stipulation and Settlement Agreement in the 43969 Order should not be adjusted to remove Rider 675 interruptible credits. He testified that at the time Joint Exhibit C was approved in the 43969 Order, there were no contracts in place under Rider 675. Mr. Cearley stated the revenue allocation factor approved in the 43969 Order was based solely on firm load. Mr. Cearley testified the 43969 Order, and the terms of Rider 675, cannot be modified in the TDSIC Rate Schedule. Mr. Cearley testified that no adjustment based upon Rider 675 is required or permitted.

LaPorte County Witness Cearley testified that he does not agree that the TDSIC statute allows CWIP ratemaking treatment of financing costs. He stated Indiana Code § 8-1-39-9 does not provide for ratemaking treatment of CWIP. Mr. Cearley stated Ind. Code § 8-1-39-9(b) specifically states that financing costs are recovered through AFUDC, indicating that all financing costs are capitalized with the project during construction. He testified that customers would avoid the negative effects of compounding accrued AFUDC by enduring the negative effects of paying higher rates sooner. He stated NIPSCO has not identified any significant cash flow problems or any significant earnings erosion that would occur in the absence of CWIP ratemaking treatment of financing costs.

E. **IMUG's Case-in-Chief.** Theodore Sommer, Partner with London Witte Group, LLC provided testimony to support inclusion of the (1) replacement of NIPSCO-owned street lights in the IMUG municipalities with modern lights that enhance public safety, are energy efficient, foster economic development and enhance the quality of life of the citizens of the group in the 7-Year Electric Plan, and (2) NIPSCO-owned street light modernization program in NIPSCO's TDSIC.

F. **U.S. Steel's Case-in-Chief.** Richard W. Cuthbert, President of Cuthbert Consulting, Inc., testified that excluding deferred income taxes and other elements to only include long-term debt and equity amounts from the regulatory capital structure approved by the Commission in NIPSCO's last general rate case is inconsistent with NIPSCO's calculation of weighted cost of capital in the Environmental Cost Recovery Mechanism factor and that significantly increases the ratio of equity in the capital structure to nearly 61% compared with only 39% long term debt. Mr. Cuthbert testified that the TDSIC assets will be long lived, many with useful lives as long as 40 to 50 years. He stated it would be appropriate for NIPSCO to use significantly more long-term debt to finance these capital replacement projects as this would more closely tie the appropriate financing period and risk profile to the asset lives. He also stated the return on equity that is currently being awarded by the FERC and other state commissions is significantly lower than the 10.2% that NIPSCO was awarded in its last general rate case. Mr. Cuthbert testified that because full capital recovery of the transmission and distribution assets recovered through the TDSIC factor is virtually assured and therefore the capital risk for these assets is lower than average, this lower risk should be reflected in a lower cost of capital. Mr. Cuthbert testified that it would be inappropriate for the Commission to use NIPSCO's proposed capital structure and should use an updated regulatory capital structure in the TDSIC calculation methodology.

Mr. Cuthbert testified that a significant number of renewal and replacement projects are included in NIPSCO's 7-Year Electric Plan and certain of these types of projects will be replacing assets before they are fully depreciated. He opined that NIPSCO could end up charging as part of the TDSIC mechanism the costs for assets that are no longer used and useful because they are replaced and the original costs for these assets would still be recovered through NIPSCO's existing rates and charges which would violate the basic "used and useful" requirement for asset recovery through rates. Mr. Cuthbert recommended that NIPSCO's costs for asset replacements in both the 7-Year Electric Plan and the calculation of the TDSIC should be adjusted to represent only the additional or incremental costs of the expenditure that are above the undepreciated asset costs of the older equipment or facility as part of the determination of the TDSIC mechanism. Otherwise, Mr. Cuthbert stated, NIPSCO's ratepayers will be charged for both assets as part of existing rates and TDISC charges while only the new one will be providing used and useful service. He opined that this double cost recovery will continue until electric rates are revised in NIPSCO's next general rate case.

G. **Industrial Group's Cross-Answering Testimony.** Mr. Phillips provided cross-answering testimony to respond to (1) OUCC Witness Hand's recommendation regarding the use of revenue allocation factors and (2) LaPorte Witness Cearley's concern with NIPSCO's subtraction of revenues associated with the Rider 675 interruptible credit.

In response to Mr. Hand's proposal to use Joint Exhibit E, Mr. Phillips testified that Joint Exhibit E is an allocator based on production rate base. Production rate base, or NIPSCO's generating plant investment, is completely different from transmission plant or distribution plant investment at issue in this proceeding. Second, Mr. Phillips stated the cost of service methodology, which is controversial and contested in most rate proceedings is associated with the method of allocation for production plant. The various methods put forth by various parties such as 4-CP, 12-CP, and peak and average, are methods to allocate production investment. Therefore, Mr. Hand's recommendation regarding the new 12-CP allocators in NIPSCO's next rate case is speculative.

In response to Mr. Cearley, Mr. Phillips testified that customers could not participate in the interruptible program until after the 43969 Order was issued and established the parameters of the interruptible program through Rider 675. Mr. Phillips also testified that many of the same customers taking interruptible service under Rider 675 were interruptible prior to the date the 43969 Order was issued and continued to be interruptible after the 43969 Order was issued which established a different method to designate load as non-firm or interruptible in accordance with the 43969 Order.

H. U.S. Steel's Cross-Answering Testimony. Mr. Cuthbert testified that OUCC Witness Hand's proposal to use the unadjusted Joint Exhibit C allocators or the demand allocation factor would be inappropriate because they are contrary to the TDSIC statute and because it would not be fair and equitable for customers that are served at a transmission voltage level (and thus do not use distribution facilities) to have to pay for the TDSIC improvements that are made to the distribution system. He testified that transmission and sub-transmission voltage customers will not benefit from TDSIC distribution improvements. However, under Mr. Hand's proposal, 26% of TDSIC distribution costs would be allocated to these customers.

I. NIPSCO Rebuttal. With respect to OUCC Witness Blakley's opinion that deferred income taxes can be used to finance TDSIC investments, Mr. Shambo testified that initially they cannot. Mr. Shambo explained that investments made as part of NIPSCO's 7-Year Electric Plan will eventually begin to generate deferred income tax benefits after they are in service but that any existing deferred income tax items are related to previous capital expenditures that are not related to the 7-Year Electric Plan. NIPSCO is not relying on existing deferred income tax items to fund the 7-Year Electric Plan. However, eventually and before the conclusion of the 7-Year Electric Plan, NIPSCO will begin to realize deferred income tax benefits from its TDSIC investments that can be used to partially fund later years of the 7-Year Electric Plan. To that end, NIPSCO is agreeable to including the amount of deferred income tax benefits attributable to actual investments from the 7-Year Electric Plan and NIPSCO's 7-Year Gas Plan currently pending in Cause No. 44403 as a zero-cost capital item in the calculation of NIPSCO's weighted average cost of capital in this Cause. However, Mr. Shambo testified that customer deposits, post retirement liability and post-1970 investment tax credits should not be included because these amounts may change over time but have no relationship to the investments.

With respect to the suggestion by the Industrial Group and U.S. Steel that the Commission could lower the return on equity used to calculate the weighted cost of capital for purposes of the TDSIC, Mr. Shambo testified that it would be problematic to reduce NIPSCO's return on equity just before NIPSCO has to raise the necessary capital from debt and equity investors to finance a $1.073 billion investment program that is needed to maintain safe and reliable service for its customers. He stated that numerous transmission providers have requested incentive rates for transmission projects that are FERC-jurisdictional and NIPSCO currently receives a return on equity of 12.38% on its FERC-jurisdictional transmission projects. Mr. Shambo also testified that the Commission recently found a return on equity of 10.2% to be reasonable for Indiana Michigan Power Company in its February 13, 2013 Order in Cause No. 44075, after considering current interest rates and the increased use of trackers.

In response to the suggestion by the Industrial Group and U.S. Steel that NIPSCO's equity ratio is too high, Mr. Shambo testified that NIPSCO's proposal in this Cause is rooted in the reality of how NIPSCO will finance the $1.073 billion required to complete the 7-Year Electric Plan. NIPSCO is not proposing that the overall after tax return of 8.59% is a static return that will not be recalculated in future TDSIC tracker filings. Rather, NIPSCO will update its WACC to reflect actual future levels as well as to include the deferred taxes at zero cost that are generated by NIPSCO's 7-Year Electric Plan and 7-Year Gas Plan currently pending in Cause No. 44403. Mr. Shambo testified that the Commission should reject Mr. Gorman's suggestion that the Commission should dictate that NIPSCO finance the TDSIC investments with 60% debt. He explained that NIPSCO competes for capital both internally within NiSource and externally through NiSource in debt and equity markets. Requiring a particular financing structure limits NIPSCO's flexibility in accessing these markets. Mr. Shambo stated that although NIPSCO agreed to particular financing for certain projects in a settlement, settled outcomes are based on negotiated positions. Here, the statute is silent as to any potential restriction on how NIPSCO finances these investments, and for these reasons, the Commission should reject Mr. Gorman's proposal.

Mr. Shambo testified the overall weighted cost of capital should not be reduced to reflect lower risk associated with a recovery mechanism such as the TDSIC. During the hearing, Mr. Shambo testified that he does not agree that the risk of recovery of TDSIC assets is fairly low once they have been approved in the 7-Year Electric Plan because they are long-lived assets and if NIPSCO makes investments in Years 5, 6 and 7, those are merely a year or two ahead of when NIPSCO would actually file a rate proceeding as required under the statute. He stated that from that point forward, the TDSIC assets will have the normal risk associated with any other investment that NIPSCO would make. Mr. Shambo testified that once the TDSIC assets go into rates in a rate case, the utility is subject to changes in economic conditions and other factors, which can minimize the utility's ability to recover those costs. Mr. Shambo also noted in rebuttal testimony that there is additional risk that NIPSCO's investors will bear in increasing NIPSCO's capital structure by at least 33% ($3.16 billion to over $4.1 billion) to fund the investments NIPSCO must make in the 7-Year Electric Plan. He testified this is not a risk-free proposition for NIPSCO's debt and equity investors, and NIPSCO requests that the full import of that increased scale of investment be recognized in adopting NIPSCO's proposed approach.

Mr. Shambo testified the TDSIC adjustment mechanism should not measure the amount of "T&D rate base growth" relative to the rate base determined in NIPSCO's last electric rate case as OUCC Witness Bolinger suggests throughout his testimony because it is contrary to the plain language of the TDSIC statute. He stated the statute provides for timely recovery of approved capital expenditures and TDSIC costs – it says nothing about tracking "T&D investment growth." Mr. Shambo testified it is not appropriate to compare the TDSIC adjustment mechanism to the Fuel Adjustment Clause ("FAC") mechanism that tracks changes in fuel expenses as Mr. Bolinger suggests because the FAC mechanism is an expense-only tracker and bears no correlation to the capital investment recovery of the TDSIC.

Mr. Shambo testified that NIPSCO's proposed TDSIC mechanism is in essence a "net utility plant" tracker for the investments included in the 7-Year Electric Plan because it does account for accumulated depreciation of these assets. He explained that in each semi-annual filing, NIPSCO will determine the total TDSIC investment net of TDSIC accumulated depreciation. Therefore, Mr. Shambo testified that he assumes Mr. Bolinger's recommendation for a "Net Utility Plant" tracker must include all of NIPSCO's assets – not just the eligible investments included in NIPSCO's 7-Year Electric Plan.

Mr. Shambo testified that if the Commission were interested in adopting a rate base growth approach as proposed by Mr. Bolinger, it would not be appropriate to narrowly look at only transmission and distribution rate base investment. He stated the appropriate approach would be to adopt formula rates as utilized by FERC, which considers changes in rate base and changes in operating expenses.

In response to U.S. Steel Witness Cuthbert's recommendations regarding replacement projects, Mr. Shambo testified that Mr. Cuthbert's recommendation that the TDSIC should be adjusted to represent only the additional or incremental costs of the expenditure that are above the undepreciated asset costs of the replaced asset should be rejected because the TDSIC statute specifically authorizes replacement projects (Ind. Code § 8-1-39-2), allows for recovery of only 80% of all TDSIC costs, and does not require any "incremental" offset. Mr. Shambo also testified that NIPSCO's net book value for transmission and distribution assets has increased since NIPSCO's last rate case and that NIPSCO has multiple other transmission and distribution investments that will occur over the next seven years that are not included for recovery as part of NIPSCO's 7-Year Electric Plan.

Mr. Shambo testified that the Industrial Group is the only party that proposed a different interpretation of Ind. Code § 8-1-39-14. He stated that Mr. Phillips has taken a convenient interpretation of Ind. Code § 8-1-39-14 that is not rooted in the language and lessens the impact to his client, but it is simply wrong. Furthermore, he testified, due to the requirement that any approved costs in excess of the 2% cap are to be deferred, Mr. Phillips' proposed interpretation of Ind. Code § 8-1-39-14 would cause a massive rate increase in NIPSCO's next general rate case because a substantial percentage of NIPSCO's 7-Year Electric Plan would exceed Mr. Phillips' version of the 2% cap. Mr. Shambo stated that Mr. Phillips' interpretation would likely also cause more frequent rate cases, which is contrary to the TDSIC statute passed by the Indiana General Assembly. Finally, Mr. Shambo testified that NIPSCO's proposed calculation of the average aggregate increase in total retail revenues attributable to the TDSIC in a twelve month period presented in NIPSCO's direct testimony is consistent with Ind. Code § 8-1-39-14.

In response to LaPorte County Witness Cearley's position that CWIP ratemaking should not be approved, Mr. Isensee testified that CWIP ratemaking reduces the negative effects of compounding accrued AFUDC as CWIP ratemaking allows for the recovery of these amounts as they are incurred. He explained that the customer will benefit as NIPSCO will only accrue the initial AFUDC amounts and will be able to avoid accruing the ongoing compounding AFUDC incurred if such amounts were not recovered on a timely basis.

In response to Mr. Phillips' testimony regarding the deferral of 20% of TDSIC costs, Mr. Isensee stated that consistent with Ind. Code § 8-1-39-9(b), NIPSCO proposes to defer 20% of approved capital expenditures and TDSIC costs—not "projects." Furthermore, Mr. Isensee testified that NIPSCO's proposal is very specific and is consistent with Ind. Code § 8-1-39-9(b). He explained that the entire revenue requirement will be reviewed by stakeholders and the Commission in each TDSIC tracker filing and 20% of that will be deferred as required by the TDSIC statute for subsequent recovery in NIPSCO's next general rate case.

In response to OUCC Witness Blakley's testimony regarding NIPSCO's proposal to gross up deferred costs for taxes, Mr. Isensee testified that NIPSCO is required to accrue tax expense as a result of the deferral of pre-tax returns and is seeking the same deferral treatment for these expenses as requested for depreciation expense, property tax expense and as afforded by Ind. Code § 8-1-39-9(b).

Mr. Isensee testified that when NIPSCO defers for future recovery 20% of post in service carrying charges as permitted by Ind. Code § 8-1-39-9(b), NIPSCO will need to record a journal entry that credits the income statement and debits as a regulatory asset. He stated this journal entry will create income on NIPSCO's books which will trigger the need to record a tax expense accrual related to such amounts. Mr. Isensee explained that a tax accrual on the books is calculated by simply applying statutory tax rates to the book income of an entity. Therefore, an increase in income typically necessitates an income tax accounting accrual (e.g., the recording of tax expense). When NIPSCO seeks a "gross-up" for taxes on the AFUDC and post in service AFUDC, NIPSCO is simply seeking to defer on the balance sheet the tax expense recorded as a result of deferring 20% of the post in service carrying charges. Mr. Isensee stated the deferral of this expense is simply a bookkeeping adjustment and has no impact on the amounts customers will pay. NIPSCO will seek recovery for these amounts in its next general rate case and adjust these amounts upward or downward if there is a change in the statutory tax rates related to the amounts. Therefore, NIPSCO is seeking approval to defer as a regulatory asset and recover in NIPSCO's next general rate case all tax expenses recorded as a result of the deferral of 20% of approved capital expenditures and TDSIC costs.

Finally, Mr. Isensee testified that without explanation or support, the OUCC recommends the disallowance of a carrying cost applied to deferred depreciation expense and property tax expense after a project is placed in service. Similar to many of the OUCC's recommendations in this Cause, Mr. Isensee testified that this recommendation must be rejected because it is contrary to the TDSIC statute. Ind. Code § 8-1-39-9(b) provides for deferral of post in service carrying charges. Mr. Isensee stated NIPSCO will need to acquire additional capital on an ongoing basis to carry (and continue carrying) the uncollected 20% deferred balance. He stated NIPSCO incurs post in service carrying charges on the deferred depreciation and property tax expenses.

5. **Commission Discussion and Findings.**

A. **Request for Rate Schedule establishing a TDSIC under Ind. Code § 8-1-39-9.** NIPSCO requests approval of its proposed TDSIC Rate Schedule and accompanying changes to its electric service tariff which will allow for timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs pursuant to Ind. Code § 8-1-39-9. We must first determine whether NIPSCO's petition in this Cause meets the various requirements of Section 9. Ind. Code § 8-1-39-9(a) states:

> Subject to subsection (c)[1], a public utility that provides electric or gas utility service may file with the commission rate schedules establishing a TDSIC that will allow the periodic automatic 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 petition must:
>
> (1) use the customer class revenue allocation factor based on firm load approved in the public utility's most recent retail base rate case order;
> (2) include the public utility's seven (7) year plan for eligible transmission, distribution, and storage system improvements; and
> (3) identify projected effects of the plan described in subdivision (2) on retail rates and charges....

i. **Customer Class Revenue Allocation under Ind. Code § 8-1-39-9(a)(1).** Petitioner is requesting approval to use modified versions of its customer class revenue allocation factor based on firm load that was approved as Joint Exhibit C to the settlement agreement approved in the 43969 Order. Mr. Shambo testified that for transmission costs the revenue allocation factor should be adjusted for Rider 675 interruptible credit in order to remove the non-firm portion of revenues from Rates 632 and 634. Mr. Shambo noted that for distribution costs the revenue allocation factor from Joint Exhibit C should be adjusted to exclude revenue from Rates 632, 633, and 634, which are transmission and sub-transmission rates.

OUCC witness Mr. Hand argued that NIPSCO's request to apply adjusted customer class allocation factors should be denied and they should be required to apply the customer class revenue allocators from the 43969 Order.

The 43969 Order allocated revenue to customer classes based on a settlement agreement

[1] Ind. Code § 8-1-39-9(c) is discussed below in Paragraph E.

rather than a cost of service study. A cost of service study would have included separate allocation factors for distribution and transmission. However, the 43969 Order includes all costs in one factor. Further, the approved customer class revenue allocation factors included non-firm load, which was effectively adjusted out of the revenue allocation in a subsequent ratemaking step. Ind. Code § 8-1-39-9(a) requires NIPSCO to use the customer class revenue allocation factor based on firm load developed in the most recent base rate case. The evidence shows that many of the same customers currently taking interruptible service under Rider 675 were interruptible prior to the date the 43969 Order was issued. However, the evidence shows that pursuant to the 43969 Order, NIPSCO's old interruptible rates were terminated and replaced by the new firm rates plus an interruptible Rider 675 which established a different method to designate load as non-firm or interruptible. Thus, in order for the Joint Exhibit C allocation factors to properly reflect the customer class revenue allocation factors based on firm load, they must be adjusted to reasonably reflect non-firm load that was treated as firm under the construct of the settlement agreement as approved in the 43969 Order. Based on our review of the TDSIC statute and the evidence in this Cause, we find that NIPSCO's proposal that the revenue allocation factor be adjusted for the Rider 675 interruptible credit in order to remove the non-firm portion of revenues from Rates 632 and 634 is consistent with Ind. Code § 8-1-39-9(a)(1) and should be approved.

Further, NIPSCO's proposal to exclude Rates 632, 633 and 634 is a reasonable method to accomplish the alignment of the cost causation with cost allocation, under the evidence specific conditions presented in this proceeding together with the 43969 Order, for the purpose of allocating distribution costs in a manner that comports with Ind. Code § 8-1-39-9(a)(1). We find it is appropriate to adjust the 43969 Order approved Joint Exhibit C allocation factors by removing Rates 632, 633 and 634 from the calculation for purposes of allocating distribution-related TDSIC costs so that rate classes that do not use the distribution system are not allocated distribution costs.

ii. <u>NIPSCO's Current 7-Year Electric Plan under Ind. Code § 8-1-39-9(a)(2).</u> As part of its case-in-chief, NIPSCO attached its current proposed 7-Year Electric Plan which was simultaneously pending approval in Cause No. 44730 as Petitioner's Exhibit No. FAS-1-C and therefore NIPSCO has satisfied the requirement set forth in Ind. Code § 8-1-39-9(a)(2). We note that in each semi-annual TDSIC filing, NIPSCO must update its 7-Year Electric Plan pursuant to Ind. Code § 8-1-39-9(a) and in accordance with the specific parameters set forth in our Order in Cause No. 44370.

iii. <u>Projected Effect on Retail Rates and Charges as Required by Ind. Code § 8-1-39-9(a)(3).</u> NIPSCO Witness Isensee provided the total estimated revenue requirement for each rate class by year based on the proposed 7-Year Electric Plan as well as the total estimated incremental revenue requirement for each rate class by year based on the proposed 7-Year Electric Plan. Further, Mr. Shambo provided the projected impact on retail revenue from the TDSIC Rate Schedule. Based on our review of the evidence, and given that no specific factors are proposed in this proceeding, we find that NIPSCO provided sufficient information regarding the projected effects of the 7-Year Electric Plan on retail rates and charges as required by Ind. Code § 8-1-39-9(a)(3).

B. Parameters Applicable to the Timely Recovery of 80% of Approved Capital Expenditures and TDSIC costs through the TDSIC under Ind. Code Ch. 8-1-39. In this proceeding, NIPSCO proposed ratemaking and accounting treatment for the TDSIC mechanism. Various parties have opposed some or all of NIPSCO's proposals.

i. Determination of Pretax Return under Ind. Code §§ 8-1-39-3 and 8-1-39-13. NIPSCO proposed that its allowable pretax return be calculated using only the following two cost of capital items: long-term debt and common equity, to be consistent with how NIPSCO finances new investments. NIPSCO proposed to use the actual cost of debt and the return on equity of 10.2% authorized by the Commission in NIPSCO's most recent general rate proceeding in Cause No. 43969. OUCC Witness Blakley testified that the claim that zero cost capital, such as deferred income tax, cannot help fund TDSIC projects is incorrect. Further, the exclusion of zero cost capital is inconsistent with the calculation of WACC in NIPSCO's last rate case and its ECR proceedings and would provide an incentive return on its capital investment.

The pre-approval of TDSIC projects and the timely recovery of TDSIC costs are regulatory tools that work to enhance the assurance and timeliness of cash flow to cover investments that utility investors fund. It seems reasonable that such investors would likely have a different risk-return expectation when making an investment in a standalone project versus an investment in an ongoing enterprise. NIPSCO presented no evidence that it expects to finance its TDSIC projects outside of its normal utility funding process. Accordingly, we are not persuaded that a capital structure more in line with project specific financing is appropriate. The regulatory capital structure for NIPSCO as an enterprise includes equity, debt and zero cost capital. We believe NIPSCO and other Indiana utilities are better viewed as an ongoing concern that utilizes all of their capital resources in a holistic manner to finance that ongoing concern, including resources which have no cost attached. This view and methodology is consistent with other long-standing capital investment trackers such as the ECRs. Accordingly, the Commission finds that NIPSCO shall calculate WACC in a manner consistent with its last rate case and ECR proceedings, which includes zero cost capital in the capital structure.

Some parties recommended that we reduce the return on equity approved in NIPSCO's last general rate case in order to reflect the reduced risk associated with cost recovery trackers. Industrial Group witness Mr. Gorman testified that this tracker will reduce NIPSCO's risk profile significantly, and in his opinion, 9.55% would be an appropriate rate of return on equity. Ind. Code § 8-1-39-13(a) does not preclude us from increasing or decreasing the allowed return on equity, as the Commission is authorized to consider other necessary information in determine the appropriate pretax return. However, we note that NIPSCO's authorized return on equity of 10.2% was approved relatively recently in our 43969 Order on December 21, 2011. Further, we acknowledge the offsetting effects of this tracker's cost recovery security and timeliness and the increased investment being made for the associated projects. Consistent with our finding above on the appropriate capital structure, we decline to lower NIPSCO's authorized return on equity from that approved in its most recent rate case.

ii. Treatment of Replaced Asset Investment Cost. The OUCC recommended that NIPSCO should only be permitted to recover the incremental capital, depreciation and operating and maintenance costs of replacement TDSIC projects because ratepayers are already paying for the replaced assets in basic rates. Similarly, U.S. Steel recommended NIPSCO should be required to produce adjustments in its updated 7-Year Electric Plan and in the calculation of the periodic TDSIC trackers to account for and eliminate the recovery of costs and depreciation associated with the early retirement and replacement of assets replaced and recovered in the TDSIC charges. U.S. Steel argued that by recovering carrying costs and depreciation expense for assets that are retired early and replaced through the 7-Year Electric Plan, NIPSCO will be recovering for assets that are no longer used and useful. U.S. Steel argued to allow such double recovery is not in the public interest or consistent with fundamental ratemaking principles.

The statutory definition of eligible improvements at Ind. Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Ind. Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. Further, TDSIC costs as defined at Ind. Code § 8-1-39-7 includes this unadjusted pretax return. While acknowledging that Ind. Code § 8-1-39-13(a) allows the Commission to consider other information in setting the appropriate pretax return, we read this section to be addressing the weighted cost of capital rate rather than the investment amount so as to reconcile the statutory language of Sections 13 and 3. Accordingly, we do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery. In addition, the TDSIC statute requires a general rate case before the expiration of the utility's 7-year plan which provides a built in mechanism to update the net investment of the utility. Thus, we decline to require NIPSCO to recognize the replaced asset investment cost already embedded in base rates because Ind. Code ch. 8-1-39 does not support it outside of the required rate case.

iii. Adjustment of Net Operating Income for Purposes of Ind. Code § 8-1-2-42(d)(2) and (d)(3) Pursuant to Ind. Code § 8-1-39-13(b). NIPSCO requests authority to increase the authorized net operating income approved in the 43969 Order to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test.

Mr. Isensee testified that this request is consistent with the way earnings associated with NIPSCO's qualified pollution control property and clean coal technology are treated. Further, NIPSCO requests authority to include the expenses associated with the TDSIC projects within the "TDSIC Taxes Other Than Income" and "TDSIC Depreciation and Amortization" line items included in the actual electric expenses for purposes of the Ind. Code § 8-1-2-42(d)(2) expense test. Mr. Isensee testified that this request is consistent with the way expenses associated with NIPSCO's qualified pollution control property and clean coal technology are treated.

Ind. Code § 8-1-39-13(b) provides that "[t]he commission shall adjust a public utility's authorized return for purposes of IC 8-1-2-42(d)(3)... to reflect incremental earnings from an approved TDSIC." Based on our review of the TDSIC statute and the evidence in this Cause, we find that NIPSCO's requests to increase the authorized net operating income approved in the 43969 Order to include the earnings associated with the TDSIC projects for purposes of the Ind. Code § 8-1-2-42(d)(3) earnings test and include the expenses associated with the TDSIC projects within the "TDSIC Taxes Other Than Income" and "TDSIC Depreciation and Amortization" line items included in the actual electric expenses for purposes of the Ind. Code § 8-1-2-42(d)(2) expense test are reasonable, consistent with the TDSIC statute, and should be approved.

iv. <u>**TDSIC Mechanism.**</u> Based on our review of the evidence in this Cause, we find that NIPSCO's proposed TDSIC mechanism as adjusted herein comports with the TDSIC statute and should be approved. It provides for timely recovery of eighty percent (80%) of approved capital expenditures and TDSIC costs including depreciation expense, property taxes, and pretax returns.

C. <u>**Request to Defer Remaining 20% of Approved Capital Expenditures and TDSIC Costs under Ind. Code § 8-1-39-9(b).**</u> The Industrial Group argues that costs deferred pursuant to Ind. Code § 8-1-39-9(b) should not be automatically approved for recovery in NIPSCO's next base rate case. However, the capital investment and TDSIC costs which are deferred in the context of the TDSIC statute are not distinguished from the 80% afforded recovery in the tracker by project or activity. That is, the recoverability of both the tracker and deferred amount are decided at the same time. The only differentiation is in when the applicable portion of the cost is included in rates. This is consistent with Ind. Code § 8-1-39-9(b), which provides that:

> [A] public utility that recovers capital expenditures and TDSIC costs under subsection (a) shall defer the remaining twenty percent (20%) of approved capital expenditures and TDSIC costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, and shall recover those capital expenditures and TDSIC costs as part of the next general rate case that the public utility files with the Commission.

Thus, the statute ensures recovery of deferred costs in the next rate case because the recoverability of the 80% and 20% is determined simultaneously.

The OUCC recommended that we deny NIPSCO's request to record ongoing carrying charges on deferred depreciation expenses and property taxes under Ind. Code § 8-1-39-9(b). It is not disputed that NIPSCO will be deferring cost recovery for these cost components and during the deferral period, it will not have available the cash flow that would have occurred if not for the deferral. Accordingly, the deferral gives rise to carrying costs. Further, Ind. Code § 8-1-39-9(b) recognizes that carrying charges are a cost component that will be incurred and deferred for recovery in the utility's next general rate case. Thus, NIPSCO should be authorized to defer post in service TDSIC costs, including carrying costs based on the WACC consistent with that approved herein, on an interim basis until such costs are recognized for ratemaking purposes through Petitioner's proposed TDSIC mechanism or otherwise included for recovery in NIPSCO's base rates in its next general rate case.

Finally, we find the evidence demonstrates that NIPSCO should be authorized to defer as a regulatory asset and recover in NIPSCO's next general rate case all tax expenses recorded as a result of the deferral of 20% of all approved capital expenditures and TDSIC costs. This is appropriate because, as the evidence demonstrates, deferring 20% of post in service carrying charges for future recovery will cause NIPSCO to record a journal entry that credits the income statement and debits a regulatory asset which will create income on NIPSCO's books and will trigger the need to record a tax expense accrual related to such amounts.

D. Average Aggregate Increase in Total Retail Revenues Under Ind. Code § 8-1-39-14. NIPSCO and the Industrial Group have presented two different interpretations of Ind. Code § 8-1-39-14. NIPSCO's calculation compares the increase in TDSIC revenue in a given year with the total retail revenues for the past 12 months whereas the Industrial Group compares the total TDISC revenue in a given year with the total retail revenues for the base 12 months. Since this is a case of first impression, we must interpret and apply this statutory language for the first time based on the express language of the statute and the general rules of statutory interpretation. *Appolon v. Faught*, 796 N.E.2d 297, 300 (Ind. Ct. App. 2003).

Section 14(a) states as follows:

> The commission may not approve a TDSIC that would result in an average aggregate increase in a public utility's total retail revenues of more than two percent (2%) in a twelve (12) month period. For purposes of this subsection, a public utility's total retail revenues do not include TDSIC revenues associated with a target economic development project.

Based on the unambiguous language of Section 14, we find that NIPSCO's proposed calculation that compares the increase in TDSIC revenue in a given year with the total retail revenues for the past 12 months is consistent with the TDSIC statute. Under the Industrial Group's interpretation, a utility would be capped at an amount of TDSIC revenue that would have the effect of being a cumulative 2% increase. However, the average aggregate increase language of the statute allows a utility to increase its TDSIC revenues by 2% a year, on a year over year basis. Thus, we find that NIPSCO's proposed calculation is consistent with Section 14 and should be approved.

E. TDSIC Timing. Ind. Code § 8-1-39-9(c) states that "[e]xcept as provided in section 15 of this chapter, a public utility may not file a petition under subsection (a) within nine (9) months after the date on which the commission issues an order changing the public utility's basic rates and charges with respect to the same type of utility service." Mr. Shambo testified that the Commission issued an order changing Petitioner's basic rates and charges on December 21, 2011. NIPSCO filed its Petition under Ind. Code § 8-1-39-9(c) on July 19, 2013. We find that this Cause was filed more than 9 months after NIPSCO's last general rate case in accordance with Ind. Code § 8-1-39-9(c).

Ind. Code § 8-1-39-9(d) states that "[a] public utility that implements a TDSIC under this chapter shall, before the expiration of the public utility's approved seven (7) year plan, petition the commission for review and approval of the public utility's basic rates and charges with respect to the same type of utility service." Mr. Shambo testified that NIPSCO will comply with this requirement, and we order NIPSCO to petition the Commission for review and approval of NIPSCO's basic electric rates and charges before the expiration of NIPSCO's 7-Year Electric

Plan pursuant to Ind. Code § 8-1-39-9(d).

Ind. Code § 8-1-39-9(e) states that "[a] public utility may file a petition under this section not more than one (1) time every six (6) months." Mr. Isensee testified that NIPSCO proposes to file its petition and case in chief by September 1 and March 1 each year with new rates becoming effective for the 6 month periods starting on December 1 and June 1, respectively. He stated the petition filed on September 1 will be based on capital spend and expenses through the previous six month period ended June 30, while the petition filed on March 1 will be based on capital spend and expenses through the previous six month period ended December 31. He stated the reconciliation of actual revenues will be completed on a 12 month lag as illustrated in Petitioner's Exhibit No. DJI-3. Mr. Isensee stated that in accordance with Ind. Code § 8-1-39-9(a), as part of each TDSIC proceeding, NIPSCO will also provide a report on the progress of its 7-Year Electric Plan, including any changes such as scheduling changes, proposed project additions or subtractions, and proposed changes in cost estimates. We find that NIPSCO's proposed timeline for its TDSIC filings is consistent with Ind. Code § 8-1-39-9(e) and is reasonable and should be approved. Therefore, Petitioner's initial semi-annual filing following the issuance of this Order shall be filed under Cause No. 44371 TDSIC 1.

F. Confidentiality. Petitioner filed a motion for protective order on July 19, 2013 which was supported by affidavit showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry on August 1, 2013 finding such information to be preliminarily confidential, after which such information was submitted under seal. We find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

G. Procedural Issues.

i. Appeal of Denial of Industrial Group's Motion to Strike. On November 7, 2013, the Industrial Group filed a Motion to Strike portions of Frank Shambo's Rebuttal Testimony ("Motion to Strike"). The Industrial Group argued that Mr. Shambo testified that the language of Ind. Code § 8-1-39-14 is clear and unambiguous. Therefore, the Industrial Group argued that Petitioner should not be permitted to offer evidence of legislative intent for the purpose of interpreting Ind. Code § 8-1-39-14. Further, the Industrial Group argued that Petitioner should not be permitted to offer evidence of what the Indiana Energy Association ("IEA") told the Indiana General Assembly. NIPSCO filed is Response to Industrial Group's Motion to Strike on November 12, 2013. NIPSCO argued that the testimony at issue in the Motion to Strike was not offered to provide evidence of legislative intent and does not include hearsay. On November 13, 2013 at the evidentiary hearing, the administrative law judge denied the Motion to Strike. The Industrial Group appealed that decision to the full Commission.

This is a case of first impression in which the Commission interpreted and applied the language of Ind. Code § 8-1-39-14. Petitioner and the Industrial Group offered competing interpretations of Ind. Code § 8-1-39-14. However, the testimony at issue in the Motion to Strike is not evidence of legislative intent, but instead, is evidence of actions taken by Petitioner and the

IEA. Having considered the evidentiary record, the Commission denies the Industrial Group's appeal to full Commission. The Commission is ultimately charged with evaluating the evidence in this Cause and giving the evidence of record the appropriate weight.

ii. **Motion to Strike PO-1.** On December 13, 2013, the OUCC filed its Public's Exhibit PO-1, including calculations from the 43969 Order embedded revenue requirements for return and depreciation. The OUCC submitted this exhibit as a supplement to its proposed order. On December 20, 2013, NIPSCO filed its Motion to Strike Public's Exhibit PO-1 as a late-filed exhibit. NIPSCO argued that Public's Exhibit PO-1 is an attempt by the OUCC to introduce a late-filed exhibit into the record after the record has been closed. However, a proposed order is not evidence. Thus, Public's PO-1, a supplement to its proposed order cannot be a late filed exhibit. Further, the OUCC did not seek to reopen the record under 170 IAC 1-1.1-22. Accordingly, we hereby deny Petitioner's Motion to Strike PO-1.

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

1. Petitioner is authorized to implement its TDSIC Rate Schedule as described in Petitioner's Exhibit No. DJI-1 pursuant to Ind. Code § 8-1-39-9(a) to effectuate the timely recovery of 80% of eligible and approved capital expenditures and TDSIC costs;

2. Petitioner's proposed method of calculating pretax return under Ind. Code § 8-1-39-13 is hereby approved as modified herein;

3. Petitioner is authorized to defer post in service TDSIC costs, including carrying costs based on the weighted cost of capital approved in Paragraph C, on an interim basis until such costs are recognized for ratemaking purposes through Petitioner's proposed TDSIC mechanism or otherwise included for recovery in NIPSCO's base rates in its next general rate case;

4. Petitioner's proposal that transmission project costs be allocated on the basis of the revenue allocation found in Joint Exhibit C of the Stipulation and Settlement Agreement approved in the 43969 Order modified to reflect an adjustment for Rider 675 credits paid related to the interruptible load served under Rates 632 and 634 over the previous twelve months is hereby approved;

5. Petitioner's proposal that distribution costs be allocated to distribution customers on the basis of the revenue allocation found in Joint Exhibit C of the Stipulation and Settlement Agreement approved in the 43969 Order with the exclusion of Rates 632, 633 and 634, which are only available to transmission and subtransmission customers is approved;

6. Petitioner is authorized to defer 20% of eligible and approved capital expenditures and TDSIC costs under Ind. Code § 8-1-39-9(b) and Petitioner is hereby authorized to recover the deferred capital expenditures and TDSIC costs as part of Petitioner's next general rate case;

7. Petitioner is authorized to adjust its authorized net operating income to reflect any

approved earnings associated with the TDSIC for purposes of Ind. Code § 8-1-2-42(d)(3) pursuant to Ind. Code § 8-1-39-13(b);

8. The information filed by Petitioner in this Cause pursuant to its Motion for Protective Order is deemed confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission; and

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

ATTERHOLT, MAYS, AND ZIEGNER CONCUR:

APPROVED: FEB 17 2014

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

Shala M. Coe

Shala M. Coe, Acting
Secretary to the Commission

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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR (1) APPROVAL OF A TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENT CHARGE ("TDSIC") RATE SCHEDULE, (2) APPROVAL OF PETITIONER'S PROPOSED COST ALLOCATIONS, (3) APPROVAL OF THE TIMELY RECOVERY OF TDSIC COSTS THROUGH PETITIONER'S PROPOSED TDSIC RATE SCHEDULE, AND (4) AUTHORITY TO DEFER APPROVED TDSIC COSTS, PURSUANT TO IND. CODE CH. 8-1-39.	CAUSE NO. 44371 APPROVED: MAY 07 2014

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Administrative Law Judge

On July 19, 2013, Northern Indiana Public Service Company ("NIPSCO" or "Petitioner") petitioned the Indiana Utility Regulatory Commission ("Commission") for (1) approval of a Transmission, Distribution and Storage System Improvement Charge ("TDSIC") Rate Schedule, (2) approval of Petitioner's proposed cost allocation, (3) approval of the timely recovery of TDSIC costs through Petitioner's proposed TDSIC Rate Schedule, and (4) authority to defer approved TDSIC costs, pursuant to Indiana Code ch. 8-1-39.

An evidentiary hearing was conducted on November 12, 2013 at 9:30 a.m. in Room 222, PNC Center, Indianapolis, Indiana. On February 17, 2014, the Commission issued an Order in this Cause.

On March 10, 2014, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the OUCC's Petition for Reconsideration ("Petition for Reconsideration"), requesting the Commission reconsider portions of its findings within its February 17, 2014 Order in this Cause. On March 20, 2014, NIPSCO filed its Response to the OUCC's Petition for Reconsideration. On March 20, 2014, the NIPSCO Industrial Group ("Industrial Group") filed its Response to the OUCC's Petition for Reconsideration.

1. Commission Jurisdiction. The bases for our jurisdiction over NIPSCO and the subject matter of this proceeding is set forth in our February 17, 2014 Order, and are hereby incorporated into this Order on Reconsideration. The Commission has jurisdiction over NIPSCO and the subject matter of this proceeding in the manner and to the extent provided by the law of the State of Indiana.

2. **Petition for Reconsideration.** The OUCC, in its Petition for Reconsideration, requests that the Commission reconsider portions of its February 17, 2014 Order in this Cause. The OUCC's brief filed in support of its Petition for Reconsideration sets forth the following two reasons for reconsideration. First, the OUCC argues that the recoverable TDSIC costs should be adjusted to reflect the removal of any return and depreciation expenses embedded in base rates that are associated with original transmission and distribution investments that will be retired as a result of new TDSIC investments.

Second, the OUCC argues that NIPSCO's request to apply adjusted customer class allocation factors should be denied and they should be required to apply the customer class revenue allocators from the Commission's Order in Cause No. 43969.

3. **NIPSCO's Response.** NIPSCO argues that the TDSIC statute specifically authorizes recovery of the costs of eligible replacement projects. Further, the TDSIC statute does not require any adjustment or offset to the TDSIC costs. Thus, NIPSCO argues that the Commission should reject the OUCC's request that TDSIC costs be adjusted to remove any return and depreciation expenses embedded in base rates that are associated with original transmission and distribution investments that will be retired as a result of new TDSIC investments.

Second, NIPSCO argues that the "cost allocation factors approved by the Commission in Section 5(A)(i) of the February 17, 2014 Order comport with the TDSIC statute and with the basic cost causation principles…." Therefore, NIPSCO requests that the Commission reject the OUCC's request to reconsider its findings regarding the proper allocation of TDSIC costs.

4. **Industrial Group's Response.** The Industrial Group argues that the OUCC has not presented any new evidence to justify the Commission's reconsideration of the allocation of NIPSCO's estimated transmission and distribution costs. Thus, the Industrial Group argues that the Commission should reject the OUCC's argument regarding costs allocation.

5. **Commission Discussion and Findings.** The OUCC noted in its Petition for Reconsideration that "netting or offset of retired assets is not expressly required or permitted by statute or rule." Instead, the OUCC argued "it is in the public interest and consistent with good regulatory practice." The arguments presented by the OUCC in support of its Petition for Reconsideration are similar to those presented in the underlying proceeding and rejected in our February 17, 2014 Order. As we noted in our February 17, 2014 Order, the statutory definition of eligible improvements at Indiana Code § 8-1-39-2 authorizes recovery of investment for replacement projects and the definition of pretax return at Indiana Code § 8-1-39-3 provides that revenues should provide for such investments, notably without suggesting any deduction or netting of the replaced asset. We do not find statutory support for the netting of investment in determining the appropriate investment to be afforded cost recovery. Furthermore, the TDSIC statute requires a general rate case before the expiration of the utility's 7-year plan, which provides a built in mechanism to review all costs. Thus, we decline to require NIPSCO to adjust TDSIC costs to reflect the removal of any return and depreciation expenses embedded in base rates that are associated with original transmission and distribution investments that will be

retired as a result of new TDSIC investments.

With respect to the OUCC's second issue, we note that our February 17, 2014 Order in this Cause addressed this issue, and the OUCC presents no additional basis for the Commission to reconsider its prior determination.

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

1. The OUCC's Petition for Reconsideration, filed on March 10, 2014, is hereby denied.

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

ATTERHOLT, MAYS, AND STEPHAN CONCUR; WEBER NOT PARTICIPATING; ZIEGNER ABSENT:

APPROVED: MAY 07 2014

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission

WORD COUNT CERTIFICATE

I verify that this brief contains no more than 14,000 words.

Randall C. Helmen

CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of August, 2014, the foregoing Brief of Appellant Indiana Office of Utility Consumer Counselor (Corrected) was served upon the following persons, by depositing same in the United States Mail, first-class postage prepaid, addressed to:

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